RATE BASE OVERVIEW

1. INTRODUCTION

This Schedule provides an overview of Hydro Ottawa's distribution rate base and a discussion of year-over-year variances.

In accordance with the OEB's *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications*, as updated on July 12, 2018 and amended on July 15, 2019, the rate base used to determine the revenue requirement for the Test Years should be presented. This Schedule provides yearly information on Hydro Ottawa's rate base, including information on forecast net fixed assets, calculated on a mid-year average basis, along with working capital allowance ("WCA"). Net fixed assets are gross assets in service minus accumulated amortization and contributed capital.

The capital expenditure plan for the 2021-2025 period is outlined in Exhibit 2-4-1: Capital Expenditure Summary, Exhibit 2-4-2: Capital Expenditure Details, and Exhibit 2-4-3: Distribution System Plan. Details regarding WCA can be found in Exhibit 2-3-1: Working Capital Requirement.

2. SUMMARY OF 2016-2020 APPROVED AND ACTUAL RATE BASE

Table 1 below shows Hydro Ottawa's approved rate base values for 2016-2020, as per the Approved Settlement Agreement governing the utility's 2016-2020 rate term.[1] Table 1 provides the opening, closing, and average balances for gross assets and accumulated depreciation. The table further provides the closing balance for net fixed assets and Hydro Ottawa's WCA.

Amounts in Table 1 do not include fixed assets related to items that have been removed from base rates, and recorded into Regulatory Accounts, as per the Approved Settlement Agreement. These items are the following: the utility's new administrative and operations facilities, as described in Attachment 2-1-1(A): New Administrative Office and Operations

[1] Ontario Energy Board, *Decision and Order*, EB-2015-0004 (December 22, 2015).

Facilities; and Connection Cost Recovery Agreement ("CCRA") payments, as described in Exhibit 9-1-3: Group 2 Accounts.

Table 1 – Summary of Approved 2016-2020 Rate Base With Adjustments ($'000s)

	2016	2017	2018	2019	2020
Opening Gross Assets	$810,428	$882,472	$962,598	$1,050,061	$1,111,912
Closing Gross Assets	$882,472	$962,598	$1,050,061	$1,111,912	$1,218,811
Average Gross Assets	**$846,450**	**$922,535**	**$1,006,329**	**$1,080,986**	**$1,165,362**
Opening Accumulated Depreciation	$(70,764)	$(110,130)	$(152,675)	$(198,050)	$(245,195)
Closing Accumulated Depreciation	$(110,130)	$(152,675)	$(198,050)	$(245,195)	$(293,565)
Average Accumulated Depreciation	**$(90,447)**	**$(131,402)**	**$(175,363)**	**$(221,623)**	**$(269,380)**
Opening Net Book Value	$739,664	$772,342	$809,923	$852,011	$866,717
Closing Net Book Value	$772,342	$809,923	$852,011	$866,717	$925,246
Average Net Book Value	**$756,003**	**$791,132**	**$830,967**	**$859,364**	**$895,981**
Working Capital Allowance	$77,116	$78,617	$81,882	$76,760	77,820
RATE BASE[2]	**$833,119**	**$869,749**	**$912,849**	**$936,124**	**$973,801**

To facilitate comparisons with Table 1, Table 2 below shows Hydro Ottawa's approved 2016-2020 rate base without adjustments for the inclusion of the new administrative and operations facilities and new CCRA.

[2] Totals may not sum due to rounding.

Table 2 – Summary of 2016-2020 Rate Base Without Adjustments ($'000s)

	Approved	Historical Years			Bridge Years	
	2016	2016	2017	2018	2019	2020
Opening Gross Assets	$810,428	$822,731	$902,630	$992,882	$1,089,257	$1,177,108
Closing Gross Assets	$882,472	$902,630	$992,882	$1,089,257	$1,177,108	$1,257,217
Average Gross Assets	**$846,450**	**$862,681**	**$947,756**	**$1,041,070**	**$1,133,182**	**$1,217,162**
Opening Accumulated Depreciation	$(70,764)	$(71,580)	$(111,437)	$(148,273)	$(193,925)	$(232,568)
Closing Accumulated Depreciation	$(110,130)	$(111,437)	$(148,273)	$(193,925)	$(232,568)	$(279,866)
Average Accumulated Depreciation	**$(90,447)**	**$(91,509)**	**$(129,855)**	**$(171,099)**	**$(213,247)**	**$(256,217)**
Opening Net Book Value	739,664	751,151	791,193	844,609	895,332	944,540
Closing Net Book Value	$772,342	$791,193	$844,609	$895,332	$944,539	$977,351
Average Net Book Value	**$756,003**	**$771,172**	**$817,901**	**$869,971**	**$919,936**	**$960,945**
Working Capital Allowance	$77,116	$82,676	$75,590	$74,431	$76,221	$77,789
RATE BASE (net of exclusions)[3]	**$833,119**	**$853,848**	**$893,491**	**$944,402**	**$996,157**	**$1,038,734**

Table 3 below reconciles Hydro Ottawa's approved, Historical Year, and Bridge Year rate base for 2016-2020, adjusted to include the new administrative and operations facilities and new CCRA. Appendix 2-BA includes the fixed assets related to items held outside base rates (see Attachments 2-2-1(A) through (J)). The revenue requirement related to the aforementioned assets is approved to be recorded in regulatory assets during the 2016-2020 period. Hydro Ottawa is requesting to place these assets (i.e. new facilities and new CCRA) into rate base at their net book value in the 2021 Test Year.

[3] Totals may not sum due to rounding.

Table 3 – Summary of Adjustments to Rate Base 2016-2020 ($'000s)

	Approved	Historical Years			Bridge Years	
	2016	**2016**	**2017**	**2018**	**2019**	**2020**
Gross Assets						
Opening Gross Assets - net of exclusions	**$810,428**	**$822,731**	**$902,630**	**$992,882**	**$1,089,257**	**$1,177,108**
Excluded Item: New Facilities	$19,493	$19,493	$19,493	$19,697	$19,693	$99,543
Excluded Item: New CCRA	$0	$0	$0	$706	$3,381	$13,258
Adjusted Opening Gross Assets[4]	**$829,921**	**$842,224**	**$922,123**	**$1,013,285**	**$1,112,335**	**$1,289,909**
Closing Gross Assets - net of exclusions	**$882,472**	**$902,630**	**$992,882**	**$1,089,257**	**$1,177,108**	**$1,257,217**
Excluded Item: New Facilities	$19,493	$19,493	$19,697	$19,697	$99,543	$99,543
Excluded Item: New CCRA	$0	$0	$706	$3,381	$13,258	$14,169
Adjusted Closing Gross Assets	**$901,965**	**$922,123**	**$1,013,285**	**$1,112,335**	**$1,289,909**	**$1,370,929**
Accumulated Depreciation						
Opening Accumulated Depreciation - net of exclusions	**$(70,764)**	**$(71,580)**	**$(111,437)**	**$(148,273)**	**$(193,925)**	**$(232,568)**
Excluded Item: New Facilities	$0	$0	$0	$0	$0	$1,792
Excluded Item: New CCRA	$0	$0	$0	$0	$36	$162
Adjusted Opening Accumulated Depreciation	**$(70,764)**	**$(71,580)**	**$(111,437)**	**$(148,273)**	**$(193,961)**	**$(234,522)**
Net Closing Accumulated Depreciation - net of exclusions	**$(110,130)**	**$(111,437)**	**$(148,273)**	**$(193,925)**	**$(232,568)**	**$(279,866)**
Excluded Item: New Facilities	$0	$0	$0	$0	$(1,792)	$(4,452)
Excluded Item: New CCRA	$0	$0	$0	$36	$(162)	$(459)
Adjusted Closing Accumulated Depreciation	**$(110,130)**	**$(111,437)**	**$(148,273)**	**$(193,961)**	**$(234,522)**	**$(284,777)**
Adjusted Net Book Value						
Adjusted Opening Net Book Value	$759,157	$770,644	$810,686	$865,012	$918,374	$1,055,387
Adjusted Closing Net Book Value	$791,835	$810,686	$865,012	$918,374	$1,055,387	$1,086,152
Adjusted Average Net Book Value	**$775,496**	**$790,665**	**$837,849**	**$891,693**	**$986,881**	**$1,070,769**
Working Capital Allowance	$77,116	$82,676	$75,590	$74,431	$76,221	$77,789
ADJUSTED RATE BASE[5]	**$852,612**	**$873,341**	**$913,439**	**$966,124**	**$1,063,102**	**$1,148,558**

[4] This aligns with Attachments 2-2-1(A) through (E): OEB Appendices 2-BA - Fixed Asset Continuity Schedules for the years 2016 through 2025, and includes new facilities and new CCRA.
[5] Totals may not sum due to rounding.

The difference between the closing 2020 gross assets in Table 2 above and the opening 2021 gross assets in Table 4 relate to adding back into rate base assets whose revenue requirement was recorded into a Regulatory Account in 2016-2020.

2020 Closing Gross Assets	$1,257,217
New Administrative Office & Operations Facilities	$99,543
CCRA	$14,169
2021 Opening Gross Assets	$1,370,929

Similarly, the difference between the closing 2020 accumulated depreciation in Table 2 above and the opening 2021 accumulated depreciation in Table 4 below also relates to adding back into rate base assets whose revenue requirement was recorded into a Regulatory Account in 2016-2020.

2020 Closing Accumulated Depreciation	$279,866
New Administrative Office & Operations Facilities	$4,452
CCRA	$459
2021 Opening Accumulated Depreciation	$284,777

Hydro Ottawa's previously-owned facilities (Albion land and building, and Merivale land and building) were disposed of in September 2019 and November 2019, respectively. Those previously-owned facilities' net book value was therefore removed from rate base as of the applicable months.

3. SUMMARY OF PROPOSED 2021-2025 RATE BASE

Table 4 below provides a summary of Hydro Ottawa's proposed rate base for the 2021-2025 rate period.

Table 4 – Summary of 2021-2025 Rate Base ($'000s)[6]

	Test Years				
	2021	2022	2023	2024	2025
Opening Gross Assets	$1,370,929	$1,517,861	$1,634,839	$1,710,177	$1,790,724
Closing Gross Assets	$1,517,861	$1,634,839	$1,710,177	$1,790,724	$1,911,057
Average Gross Assets	**$1,444,395**	**$1,576,350**	**$1,672,508**	**$1,750,450**	**$1,850,891**
Opening Accumulated Depreciation	$(284,777)	$(334,623)	$(389,254)	$(446,435)	$(505,659)
Closing Accumulated Depreciation	$(334,623)	$(389,254)	$(446,435)	$(505,659)	$(568,753)
Average Accumulated Depreciation	**$(309,700)**	**$(361,938)**	**$(417,845)**	**$(476,047)**	**$(537,206)**
Opening Net Book Value	$1,086,152	$1,183,238	$1,245,585	$1,263,741	$1,285,065
Closing Net Book Value	$1,183,238	$1,245,585	$1,263,741	$1,285,065	$1,342,304
Average Net Fixed Assets	**$1,134,695**	**$1,214,412**	**$1,254,663**	**$1,274,403**	**$1,313,685**
Working Capital Allowance	$83,965	$89,510	$94,956	$102,402	$106,078
RATE BASE[7]	**$1,218,659**	**$1,303,922**	**$1,349,619**	**$1,376,805**	**$1,419,763**

4. 2016-2020 RATE BASE VARIANCES - APPROVED VS. ACTUALS

Table 5 below shows the variances between the OEB-approved rate base amounts (Table 1 above) and the Historical Year and Bridge Year amounts (Table 2 above), without adjustments to rate base for inclusions of assets that are requested for inclusion in rate base as of January 1, 2021.

[6] Figures in Table 4 include Facilities and CCRA.
[7] Totals may not sum due to rounding.

Table 5 – Variances in 2016-2020 Rate Base Without Adjustments - OEB-Approved vs. Historical and Bridge Year Amounts ($'000s)

	Actual			Bridge	
	2016	**2017**	**2018**	**2019**	**2020**
Opening Gross Assets	$12,303	$20,158	$30,284	$39,196	$65,196
Closing Gross Assets	$20,158	$30,284	$39,196	$65,196	$38,406
Average Gross Assets	**$16,231**	**$25,221**	**$34,740**	**$52,196**	**$51,801**
Opening Accumulated Depreciation	$(816)	$(1,307)	$4,402	$4,125	$12,627
Closing Accumulated Depreciation	$(1,307)	$4,402	$4,125	$12,627	$13,699
Average Accumulated Depreciation	**$(1,062)**	**$1,548**	**$4,264**	**$8,376**	**$13,163**
Average Net Fixed Assets	$15,169	$26,769	$39,004	$60,572	$64,964
Working Capital Allowance	$5,560	$(3,027)	$(7,452)	$(539)	$(31)
RATE BASE[8]	**$20,729**	**$23,742**	**$31,553**	**$60,033**	**$64,933**

The following section provides high-level rate base variance explanations. For additional details regarding capital variances, please refer to Exhibit 2-4-1: Capital Expenditure Summary or Attachment 2-4-3(E): Material Investments. For more information on Capital Additions, please see Exhibit 2-2-1: Assets - Property, Plant & Equipment Continuity Schedule. In addition, for details related to WCA, please see Exhibit 2-3-1: Working Capital Requirement.

4.1. *2016 ACTUAL vs. 2016 APPROVED*

- Hydro Ottawa's average net fixed assets were $15.2M higher than the OEB-approved amounts. This was largely due to increases in emergency renewal work related to severe storms, increased spending in the Corrective Renewal Program, and CCRA true-up payments to Hydro One Networks Inc. ("HONI") related to the Hinchey substation.
- An additional $5.6M in WCA was required in 2016 as a result of higher Power Supply Expenses than estimated, mainly in relation to the commodity and Global Adjustment expense. This was partially offset by a lower Wholesale cost than estimated.

[8] Totals may not sum due to rounding.

4.2. 2017 ACTUAL vs. 2017 APPROVED

- Hydro Ottawa's average net fixed assets for 2017 were $26.8M higher than approved amounts due, in part, to the previous year's balance and an increase in 2017 in customer-driven demand work related to the following: residential and commercial infills and/or subdivisions; the City of Ottawa's Light Rail Transit project; and unforecasted embedded generation nameplate credit. In addition, a new Human Resources software module was added to the enterprise resource planning system upgrade project, which increased its overall project cost.
- In 2017, $3.0M less WCA was required mainly as a result of lower Power Supply Expenses than estimated. The larger than estimated Global Adjustment expense was offset by the lower than anticipated Commodity and Wholesale expense.

4.3. 2018 ACTUAL vs. 2018 APPROVED

- Hydro Ottawa's average net fixed assets for 2018 were $39.0M higher than approved amounts due, in large part, to the previous year's balance, emergency work from three severe storms (including the September 2018 tornadoes), and a sustained increase in System Access demands, including from museums and large industrial complexes.
- In 2018, $7.4M less WCA was required as a result of a lower Power Supply Expenses than estimated. With the exception of the Transmission Connection charge, which had a negative variance, all other charges were lower than anticipated or very close to the estimate.

4.4. 2019 BRIDGE YEAR vs. 2019 APPROVED

- Hydro Ottawa's average net fixed assets for 2019 are set to be $60.6M higher than approved amounts due, in part, to the previous year's balance and the capitalization of three large substation projects (Merivale DS, Overbrook DS, and Richmond South DS). For more details on these projects, please refer to Exhibit 2-4-3: Distribution System Plan.
- For 2019, the WCA is set to be mainly in-line with approved amounts, as Hydro Ottawa has maintained the original estimate of Power Supply Expenses from the 2016-2020 rate

application for 2019. With the goal of being consistent with the working capital rate used in the Test Years, Hydro Ottawa has used 7.5% as the working capital rate percentage for 2019.

4.5. 2020 BRIDGE YEAR vs. 2020 APPROVED

- Hydro Ottawa's average net fixed assets for the 2020 Bridge Year is budgeted to be $65.0M higher than the previously approved amount for 2020, largely as a result of overages in the previous years' balances.
- For 2020, the WCA is mainly in-line with approved amounts, as Hydro Ottawa has maintained the original estimate of Power Supply Expenses from the 2016-2020 rate application for 2020. With the goal of being consistent with the working capital rate used in the Test Years, Hydro Ottawa has used 7.5% as the working capital rate percentage for 2020.

5. 2016-2025 YEAR-OVER-YEAR RATE BASE VARIANCES

Table 6 below provides the year-over-year change in rate base from 2016-2025. Further details for the annual changes are provided in the subsections which follow.

Table 6 – Year-over-Year Change in Rate Base ($'000s)

	2017 vs. 2016	2018 vs. 2017	2019 vs. 2018	2020 vs. 2019	2021 vs. 2020	2022 vs. 2021	2023 vs. 2022	2024 vs. 2023	2025 vs. 2024
Opening Gross Assets	$79,899	$90,252	$96,375	$87,851	$193,821	$146,933	$116,978	$75,337	$80,548
Closing Gross Assets	$90,252	$96,375	$87,851	$80,109	$260,645	$116,978	$75,337	$80,548	$120,333
Average Gross Assets	**$85,076**	**$93,314**	**$92,113**	**$83,980**	**$227,233**	**$131,955**	**$96,158**	**$77,943**	**$100,440**
Opening Accumulated Depreciation	$(39,857)	$(36,836)	$(45,652)	$(38,643)	$(52,209)	$(49,846)	$(54,631)	$(57,182)	$(59,224)
Closing Accumulated Depreciation	$(36,836)	$(45,652)	$(38,643)	$(47,298)	$(54,757)	$(54,631)	$(57,182)	$(59,224)	$(63,094)
Average Accumulated Depreciation	**$(38,347)**	**$(41,244)**	**$(42,148)**	**$(42,971)**	**$(53,483)**	**$(52,238)**	**$(55,906)**	**$(58,203)**	**$(61,159)**
Average Net Fixed Assets	$46,729	$52,070	$49,965	$41,009	$173,750	$79,717	$40,251	$19,740	$39,282
Working Capital Allowance	$(7,086)	$(1,159)	$1,790	$1,568	$6,176	$5,545	$5,446	$7,446	$3,676
RATE BASE[9]	**$39,643**	**$50,911**	**$51,755**	**$42,577**	**$179,926**	**$85,262**	**$45,697**	**$27,186**	**$42,958**

5.1. 2017 ACTUAL vs. 2016 ACTUAL

- Hydro Ottawa's average net fixed assets for 2017 were $46.7M higher than 2016 due to capital additions in 2017.
- In 2017, WCA was $7.1M less than 2016 due to a decrease in Power Supply Expenses.

5.2. 2018 ACTUAL vs. 2017 ACTUAL

- Hydro Ottawa's average net fixed assets for 2018 were $52.1M higher than 2017 due to capital additions in 2018.
- In 2018, WCA was $1.2M less compared to 2017. This decrease was the result of lower Power Supply Expenses.

[9] Totals may not sum due to rounding.

5.3. 2019 BRIDGE YEAR vs. 2018 ACTUAL

- Hydro Ottawa's average net fixed assets for 2019 are set to be $50.0M higher than 2018 due to capital additions in 2019.
- In 2019, WCA is estimated to be $1.8M more than 2018 due to an increase in Power Supply Expenses.

5.4. 2020 BRIDGE YEAR vs. 2019 BRIDGE YEAR

- Hydro Ottawa's average net fixed assets for 2020 are budgeted to be $41.0M higher than 2019 due to capital additions in 2020.
- In 2020, WCA is estimated to increase $1.6M over 2019 due to anticipated increases in Power Supply Expenses.

5.5. 2021 TEST YEAR vs. 2020 BRIDGE YEAR

- Hydro Ottawa's average net fixed assets for 2021 are budgeted to be $173.8M higher than 2020 due to capital additions in 2021. These include $50.0M in additions related to Cambrian Municipal Transformer Station ("MTS").[10] In addition, the inclusion of adjustments to rate base of items that were previously held outside base rates (i.e. new facilities and new CCRA for 2016-2020 - see section 2 above) is likewise planned, with these assets being added at their net book value in the 2021 Test Year.
- In 2021, the WCA is estimated to increase $6.2M over 2020 mainly due to increases in Power Supply Expenses. For more information on WCA, please refer to Exhibit 2-3-1: Working Capital Requirement.[11]

5.6. 2022 TEST YEAR vs. 2021 TEST YEAR

- Hydro Ottawa's average net fixed assets for 2022 are budgeted to be $79.7M higher than 2021 due to capital additions in 2022. These additions include $26.9M related to Cambrian MTS.

[10] For more information on Cambrian MTS, please see Attachment 2-4-3(E): Material Investments.
[11] Please refer to Exhibit 2-3-1: Working Capital Requirement for details related to WCA for all of the Test Years.

- In 2022, the WCA is estimated to increase $5.5M over 2021 mainly due to increases in Power Supply Expenses.

5.7. 2023 TEST YEAR vs. 2022 TEST YEAR

- Hydro Ottawa's average net fixed assets for 2023 are budgeted to be $40.3M higher than 2022 due to capital additions in 2023.
- In 2023, the WCA is estimated to increase $5.4M over 2022 mainly due to increases in Power Supply Expenses.

5.8. 2024 TEST YEAR vs. 2023 TEST YEAR

- Hydro Ottawa's average net fixed assets for 2024 are budgeted to be $19.7M higher than 2023 due to capital additions in 2024.
- In 2014, the WCA is estimated to increase $7.4M over 2023 due mainly to increases in Power Supply Expenses.

5.9. 2025 TEST YEAR vs. 2024 TEST YEAR

- Hydro Ottawa's average net fixed assets for 2025 are budgeted to be $39.3M higher than 2024 due to capital additions in 2025.
- In 2025, the WCA is estimated to increase $3.7M over 2024 mainly due to increases in Power Supply Expenses.

6. FACILITIES RENEWAL PROGRAM

Appended to this Schedule is Attachment 2-1-1(A): New Administrative Office and Operations Facilities, which contains detailed information with respect to Hydro Ottawa's Facilities Renewal Program ("FRP"). This includes the assessment of prudence of the expenditures over $66.0M, as required in the Approved Settlement Agreement governing the utility's 2016-2020 rate term.

In addition, appended to this Schedule is a copy of the formal report that was prepared by the Fairness Commissioner who was engaged by Hydro Ottawa at the outset of the FRP Request for Qualifications process. The Fairness Commissioner ultimately concluded that "the procurement process for the Facilities Renewal Program Design Build up to the completion of the evaluation process was conducted in a fair, open and transparent manner." Please see Attachment 2-1-1(B): Fairness Commissioner Report for further details.

NEW ADMINISTRATIVE OFFICE AND OPERATIONS FACILITIES

1. EXECUTIVE SUMMARY

1.1. BACKGROUND

Hydro Ottawa was formed as a result of the amalgamation of five municipalities in the year 2000. At the time of amalgamation, the most advantageous option was to move all central functions to a new, purpose-built facility and to create distributed work centres for all construction and maintenance functions. However, due to the time constraints associated with the amalgamation and the magnitude of the capital decision to be made, all facilities were retained for the time being. As part of its distribution rate application filed in June 2011[1] (hereinafter referred to as its ”2012 Cost of Service application”), a Facilities Strategy was presented and it described the status of facilities and the need to further evaluate and identify the best development solution. At that time Hydro Ottawa requested funding to purchase land, but not did not seek funding for the overall project.

In its 2016-2020 Custom Incentive Rate-Setting (“Custom IR”) application[2] filed April 29, 2015 (hereinafter referred to as its “2016-2020 Custom IR application”), Hydro Ottawa proposed to construct new facilities on two parcels of land that were purchased in 2012 and 2013, namely the Eastern Operations and Administrative Office Building (“East Campus”) and a Southern Operations & Warehouse (“South Campus”), collectively referred to as “New Administration and Operations Facilities”. In that application, the estimated cost of the New Administration and Operations Facilities was $92.3M. This funding was for land and to construct new facilities that, amongst other objectives, would:

a) replace end of life buildings;

[1] Hydro Ottawa Limited, *2012 Cost of Service Distribution Rate Application*, EB-2011-0054 (June 17, 2011).
[2] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

b) move Hydro Ottawa's operational centers out of high traffic residential districts to sites with ready access to major highways within the Ottawa area;
c) consolidate operations and administrative staff; and
d) upgrade the operational centers in order to provide better response to customers.

In its Decision and Order dated December 22, 2015[3] ("2015 Decision"), the OEB assessed and approved the need for the New Administration and Operation Facilities.

The OEB also approved provisional funding of up to $66.0M to enable Hydro Ottawa to proceed with the Request for Proposal process while ensuring that the final cost of the New Administration and Operation Facilities would be subject to a prudence review at a future date. In order for Hydro Ottawa to track actual project cost versus the provisional funding amount, the OEB established a series of deferral accounts.

Concurrent with the 2016-2020 Custom IR proceeding, in August 2015 a Request for Qualifications ("RFQ") process was initiated in order to identify potential contractors capable of providing Design Build services in support of the construction of new facilities.

In September 2015 the Strategic Initiatives Oversight Committee ("SIOC") of the Hydro Ottawa Board reviewed the project cost estimate and agreed that based on early indications of increased costs, the budget for the project would be capped at $96.5M plus interest and overhead. By January 2016 a more detailed estimate of project costs was completed, identifying estimated costs of $124.7M. This higher project cost estimate was unacceptable to Hydro Ottawa senior management and the Board of Directors and direction was provided to reduce the estimated project cost and scope. Based on this direction a revised plan and estimate was developed, re-confirming a project budget of $96.5M plus interest and overhead. A Request for Proposals ("RFP") was then sent to the top four qualified respondents identified through the

[3] Ontario Energy Board, *Decision and Order*, EB-2015-0004 (December 22, 2015).

RFQ process. Competitive bids were received and evaluated and a Design-Build contractor was selected for the project.

In order to ensure that the procurement process was conducted in a fair, open and transparent manner, a Fairness Commissioner was engaged from the outset of the RFQ process to the conclusion of the RFP phase. The Commissioner was satisfied that due process was followed. The report in its entirety is included in this Application as Attachment 2-1-1(B): Fairness Commissioner Report. The project was actively managed by a project team and ongoing oversight was provided by Hydro Ottawa senior management and the Hydro Ottawa Board of Directors through the SIOC.

1.2. DESCRIPTION OF FACILITIES

The new facilities consist of two campuses, described as follows:

1. The East Campus is located at 2711 Hunt Club Rd. and is the new eastern operations centre and administration office. This facility consists of three distinct buildings comprised of:
   - a) an Administrative Office Building ("EC-1"),
   - b) an Operations Centre ("EC-2"), and
   - c) a Paper Insulated Lead Covered ("PILC") Cable Storage Facility ("EC-3").

   There is also a solar generation net metering facility on the property.

   Hydro Ottawa moved into this property in stages over the January to May 2019 period.

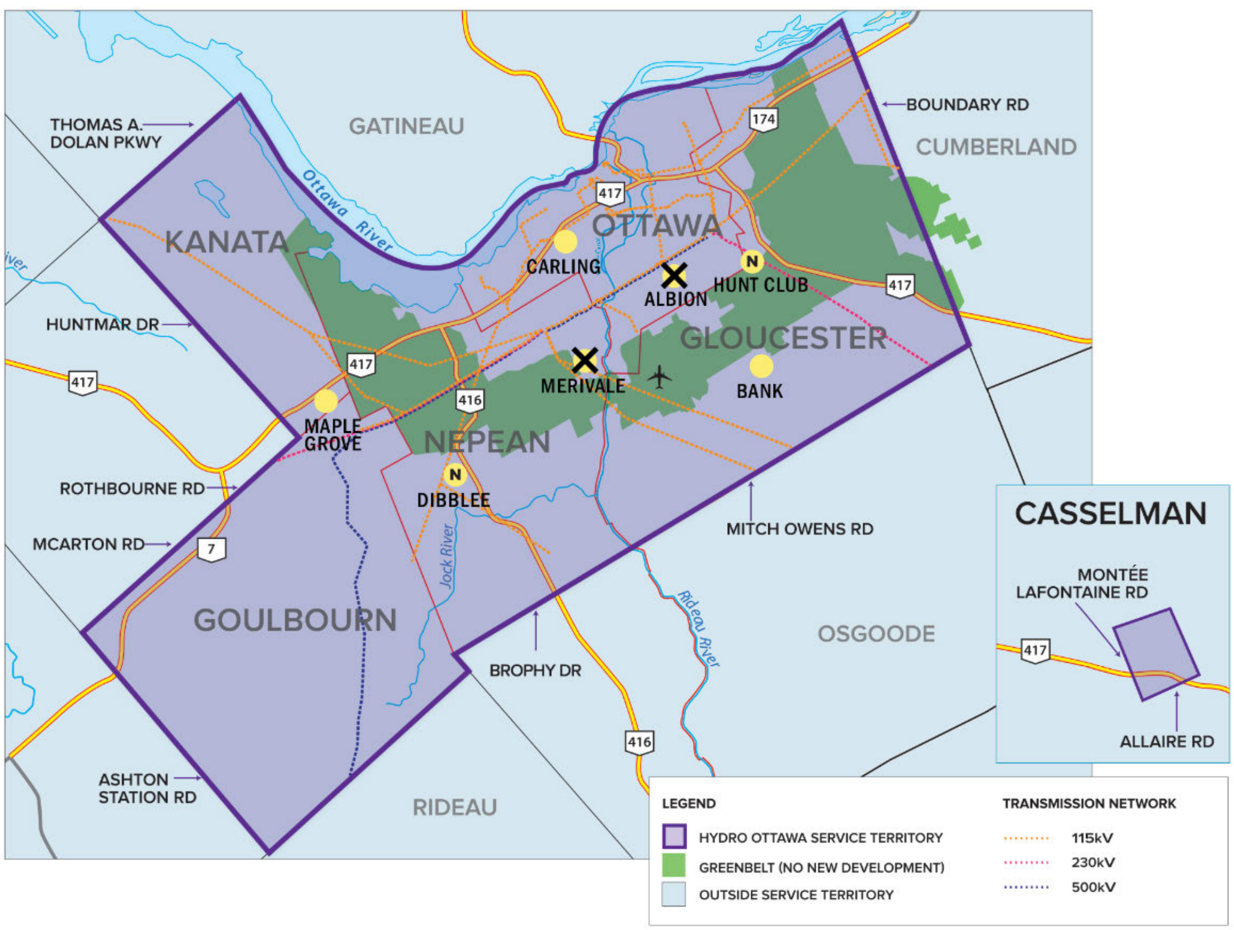
2. The South Campus is located at 201 Dibblee Rd. and is the Operations Centre for the south and western portion of Hydro Ottawa service territory. This facility is one building ("SC-1") that includes office space, an enclosed garage, warehousing and

stores, metering and transformer shops, and storage space. There is also a solar generation net metering facility on the property.

Hydro Ottawa moved into this property in May 2019.

The location of the new facilities at Hunt Club Rd. and Dibblee Rd. can be seen in Figure 1.

Figure 1 – Service Territory and Location Map



In total, 293,873 square feet of New Administration and Operations facilities space has been constructed. Table 1 provides a summary of the location, functionality and size of these new facilities.

Table 1 – Building Size (Square Feet)

	Office	Garage	Warehouse / Storage Space	Total
East Campus - Hunt Club Rd.				
EC-1 Building	127,132			127,132
EC-2 Building	10,780	46,735		57,515
EC-3 Building			10,318	10,318
Sub-Total for East Campus	**137,912**	**46,735**	**10,318**	**194,965**
South Campus - Dibblee Rd.				
SC-1 Building	22,644	42,773	33,491	98,908
TOTAL	**160,556**	**89,508**	**43,809**	**293,873**

The main buildings at the East Campus can be seen in Figures 2 and 3 below. The main building at the South Campus can be seen in Figure 4 below.

Figure 2 – East Campus 1

Figure 3 – East Campus 2 and 3

Figure 4 – South Campus 1

1.3. COST OF NEW FACILITIES

The total cost of the New Administration and Operations Facilities investment is $99.5M including land ($80.0M excluding land). This amount is included in rate base for the 2021-2025 Test Years in this Application. These costs are summarized below in Table 2 below.

Table 2 – Total Cost of New Administration and Operations Facilities

	Construction + Interest & OH	Land	Total Cost
East Campus			
EC-1 Administrative Office	$47,311,660		
EC-2 East Operations Centre	$9,682,771		
EC-3 PILC Storage	$2,524,621		
	$59,519,052	**$12,694,254**	**$72,213,306**
South Campus			
SC-1 South Operations Centre and Warehouse	$20,530,091	$6,800,443	$27,330,534
TOTAL	**$80,049,143**	**$19,494,697**	**$99,543,840**

In summary, subsequent to the $92.3M requested in its 2016-2020 Custom IR proceeding, through the detailed design, estimation, procurement phase and construction process, overall project costs came in $7.2M higher than the preliminary estimate. Table 3 provides a breakdown of the total project cost compared to the cost projections proposed in its 2016-2020 Custom IR proceeding.

Table 3 – Comparison of Final Cost to Costs filed in Previous Application

Total Project ($)	Total Cost	As Filed in 2016-2020 Custom IR Application	*Variance ($)*	*Variance (%)*
- Land	$19,494,697	$19,514,000	*$(19,303)*	*0%*
- Construction	$76,526,966	$68,902,690	*$7,624,276*	*11%*
Subtotal	**$96,021,663**	**$88,416,690**		
- Interest & O/H	$3,522,176	$3,930,289	*$(408,113)*	*-10%*
TOTAL	**$99,543,840**	**$92,346,979**	***$7,196,861***	***8%***

1.4. PROJECT BENEFITS AND PRUDENCY

The guiding principles for the project were collaboration, innovation, flexibility & adaptability, health & wellness and sustainability. Through the construction of the East Campus and South

Campus facilities the identified objectives are being met and the expected benefits are starting to be achieved. These benefits include operational efficiency in areas such as responsiveness to customer trouble calls and outages, work team collaboration, logistics and inventory management, safety and wellbeing, and reduced environmental impact.

The buildings have been “right sized” and Hydro Ottawa has reduced its workplace space standards. Office sizes are now lower than the Federal Government workplace space standards for most positions and office space per employee is lower than benchmarked LDCs. Land is fully utilized and there is room for nominal future office staff growth through the use of flexible office design and touch-down work stations. Overall, project costs compare favourably to other LDCs when escalation and land costs are taken into consideration.

The project was prudently managed throughout each phase and had an active governance, reporting and cost control structure. Potentially higher-than-anticipated costs were identified in advance and decisions made on a timely basis regarding appropriate trade-offs and changes.

Hydro Ottawa has received “value for money” from this project with the stated objectives of the project being achieved and costs comparing favourably to similar construction projects. This was a “once in a generation” capital project and the results will benefit Hydro Ottawa customers over many years to come.

The following sections provide details on the background of the project, a description of the facilities constructed, a summary of project costs and a demonstration of the various aspects of overall project prudency.

2. BACKGROUND

2.1. HISTORY OF NEW ADMINISTRATION AND OPERATIONS FACILITIES PROJECT

In its 2012 Cost of Service application, Hydro Ottawa provided evidence that discussed a strategy to address the future use of facilities acquired through the amalgamation of five municipalities. This evidence also identified the need for new facilities to meet future Administration and Operations facility needs. The facilities strategy identified and evaluated four options that would address the facility needs of Hydro Ottawa. These options were:

1. Retain Existing Facilities;
2. Consolidate all of the inside Administrative Staff at the Albion Road Facility;
3. Consolidate all of the inside Administrative Staff at the Merivale Road Facility; or
4. Construct New Facilities at Optimal Locations.

After considering the four options, it was decided that the lowest cost and best value option to pursue was Option 4 “Construct New Facilities at Optimal Locations”. At that time, approval was sought and subsequently received to include $4.0M in capital expenditures to acquire land for the new facilities. Funding for the actual construction cost was not sought in that application with the expectation being that construction would take place over the 2013-2015 period and approval for these costs would be included in a future rate application.

Subsequent to the OEB’s Decision in Hydro Ottawa’s 2012 Cost of Service application, the purchase of land and the construction of the new facilities was deferred. Over the 2012-2014 period appropriate land was identified and purchased and more detailed plans were developed for the construction of new facilities.

Over the course of Hydro Ottawa’s 2016-2020 Custom IR proceeding, the utility presented evidence in support of a request to spend $92.3M on land and buildings for New Administration and Operations Facilities at two new locations, as presented in Table 4 below.

Table 4 – 2016-2020 Custom IR Application - Facilities Project Estimate ($'000s)

	East Campus	South Campus	Total
Land	$12,716	$6,798	$19,514
Construction	$56,813	$16,020	$72,833
TOTAL	**$69,529**	**$22,818**	**$92,347**

Hydro Ottawa and intervenors participated in a settlement conference and subsequently filed a Settlement Agreement dated September 18, 2015. As part of that agreement, the parties accepted,

> *"... Hydro Ottawa's evidence that the proposed budget of $73 million (without land) for the construction of Hydro Ottawa's new operating centers and administrative facilities as set out in project description and business case contained in Exhibit B-1-2 and Exhibit B-1(A) is an appropriate spending level on the capital spending for the proposed facilities. The Parties agree that the new facilities represents a once in a generation investment."*[4]

Subsequent to filing the Settlement Agreement, the OEB convened an oral hearing on September 30, 2015 to ask questions on the proposed Settlement Agreement. At this hearing, various aspects of the agreement were discussed including the new facilities and the use of deferral accounts. In the OEB's subsequent Decision on the Settlement Proposal,[5] the OEB said:

> *"The OEB does not approve the settlement proposal as filed. The OEB does not find sufficient evidence to determine prudence of the following:*
>
> - *The $73 million cost estimate of the new administration and operations buildings (the New Buildings).*
> - *The need for approximately 9 acres of land in excess of the building requirements at a cost of $4 million "to expand in future, if necessary".* [6]

[4] Hydro Ottawa Limited, *Settlement Proposal*, EB-2015-0004 (September 15, 2015), page 15.
[5] Ontario Energy Board, *Decision on Settlement Proposal and Procedural Order No. 11,* EB-2015-0004 (November 23, 2015).
[6] *Ibid*, page 2.

Notwithstanding this determination, it is critical to note that the OEB also stated the following:

> *"The OEB finds that* ***Hydro Ottawa has demonstrated the need for the New Buildings****. The current buildings are at the end of their useful lives and at capacity from a staffing perspective".*[7] *(***Emphasis added***)*

With respect to funding, the OEB Findings stated that*:*

> *"The OEB is prepared to approve Y-factor treatment based on the recovery of up to $66 million combined for the proposed New Buildings and the land…. The $66 million was determined by the OEB as a reasonable amount to enable Hydro Ottawa to proceed with the Request for Proposal process while ensuring that any additional cost of the New Buildings and the land is subject to a prudence review at a future date… While Hydro Ottawa has applied for recovery of up to $92 million for the New Buildings and land in the Custom IR term, the OEB is only prepared at this point to accept up to $66 million."*

> *"The OEB expects that Hydro Ottawa will provide the evidence to support its spending above $66 million for the New Building and land and proposed rate base additions as part of its next rebasing application. The evidence would need to demonstrate prudence of the cost of the New Buildings, land and the associated benefit to customers.*[8]

The Settlement Agreement was updated accordingly and re-filed on December 7, 2015 to include the following section:

> ***"****The Parties agree, pursuant to Procedural Order No. 11 that Hydro Ottawa may proceed to issue a Request for Proposal and that Hydro Ottawa is approved to incur expenses up to $66 million for the land and buildings associated with the New Facilities as described in Hydro Ottawa's Custom IR Application. The Parties agree that this approval is based on the OEB's assessment of and concurrence with Hydro Ottawa of its need for the New Facilities. The $66 million includes $15 million for the cost of land and $51 million towards the construction of the New Facilities. The Parties acknowledge the OEB's statement that the $66 million is in no way determinative of the final amount the OEB will accept as being prudently incurred and that the OEB will assess prudence for additions above $66 million based on evidence to support spending above $66 million as supplied by Hydro Ottawa at its next rebasing. For clarity the Parties understand that the original agreement*

[7] *Ibid*, page 3.
[8] *Ibid*, pages 4-5.

> *reached on September 18, 2015 was for $93 million which comprised of $19 million for the land and $73 million for the buildings construction. In Procedural Order No. 11 the Board approved expenses up to $66 million comprising of $15 million for the land, $51 million for the New Facilities."*[9]

The OEB issued its Decision in the proceeding on December 22, 2015. With respect to the proposed new facilities the OEB said:

> "*However, the OEB did not find sufficient evidence to determine prudence of the $73 million cost estimate of the New Buildings and the $19 million cost of land. While* ***the OEB found that Hydro Ottawa had established the need for the New Buildings,*** *the excess building and land capacity was not supported by the evidence."*[10] *(***Emphasis added)**

Based on its review of the evidence, the OEB stated that it was prepared to approve Y- factor treatment based on the recovery of up to $66M combined for the proposed New Buildings and the land. The decision stated that:

> *"The $66 million was determined by the OEB as a reasonable amount to enable Hydro Ottawa to proceed with the Request for Proposal process while ensuring that any additional cost of the New Buildings and the land is subject to a prudence review at a future date."*[11]

Further to the OEB direction provided in the 2016-2020 Custom IR Decision, Hydro Ottawa is now providing information by way of this Application to support the prudency of expenditures related to land purchased and the construction of buildings for new facilities.

2.2. RECAP OF THE NEED FOR NEW FACILITIES

The need for new facilities was established in the 2016-2020 Custom IR proceeding where

[9] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Amended September 18th, 2015 Settlement Proposal*, EB-2015-0004 (Originally filed September 18, 20015; refiled December 7, 2015), page 18.
[10] Ontario Energy Board, *Decision and Order*, EB-2015-0004 (December 22, 2015), page 5.
[11] *Ibid,* page 5.

> *"The OEB finds that **Hydro Ottawa has demonstrated the need for the New Buildings**. The current buildings are at the end of their useful lives and at capacity from a staffing perspective."*[12] **(Emphasis Added)**

The following provides a summary of evidence previously submitted in support of the need for new facilities. The need for new facilities was identified 20 years ago when Hydro Ottawa amalgamated from five former municipalities namely Ottawa Hydro, Gloucester Hydro, Nepean Hydro, Kanata Hydro and Goulbourn Hydro. Due to the short timeframe given for amalgamation and the magnitude of capital required, Hydro Ottawa opted to temporarily keep the facilities that existed at that time. These facilities are now between 45 and 60 years old, not in optimal locations, were designed and built in a different era and are at the end of their useful life. These facilities are also at capacity, in need of major repair and no longer meet operational needs. Key reasons in support of the established need for the new facilities are:

Asset End of Life

Hydro Ottawa's investment in new facilities is a once in a generation investment. This investment was identified 20 years ago to better locate the operation centres within the service territory, to consolidate administrative functions, to modernize the work environment and to provide for future growth. Buildings such as the Albion Road facility are 60 years old and were designed and built in an era to meet a very different need from what is currently and prospectively served.

Public Safety

Due to commercial and residential growth in the areas surrounding Hydro Ottawa facilities, truck and employee traffic poses safety risks to the general public. At the Albion Road facility for example, school children board and debark from school buses just outside the Hydro Ottawa facility. Wide turning bucket trucks must navigate heavily populated residential streets posing a risk to public safety.

[12] Ontario Energy Board, *Decision on Settlement Proposal and Procedural Order No. 11,* EB-2015-0004 (November 23, 2015), page 3.

Operational Efficiency

Hydro Ottawa's move to new facilities is further motivated by the need to consolidate its administrative and operational staff promoting organizational and operational synergies. Consolidating administrative, technical and operational staff will permit greater operating efficiencies by increasing opportunities for collaboration and cross-functional teamwork. In addition to providing a greater foundation for productive collaboration, the new facilities are located close to major traffic arteries in the City of Ottawa and significantly reduce travel time to work locations by work crews resulting in improved customer service and response times. The East Campus location decreases travel time to the core service area, and the South Campus improves the access to main warehousing and expanded south/west service areas and is aligned with the growth of the City.

Employee Health and Safety

Hydro Ottawa's existing facilities are being extended beyond their useful lives and are unable to meet future requirements without major renovations or requiring new construction/leasing off-site facilities. The current facilities have many deficiencies several of which present possible health and safety concerns for Hydro Ottawa staff, crews and customers and/or require substantial investment to replace or repair. For example there have been elevator motor failures trapping staff, rodent infestations, poor air quality and there is uneven pavement and flooring causing a risk of slips and falls. The building also requires major investment to upgrade the building envelope (roof, windows, flooring, HVAC system) to facilitate a more favourable work environment.

2.3. KEY OBJECTIVES

Key objectives of the Facilities Renewal Program were to:

- replace end of life buildings;

- move Hydro Ottawa's operational centers out of high traffic residential districts to sites with ready access to major highways within the Ottawa area;
- consolidate operations and administrative staff;
- upgrade the operational centers in order to enhance customer service and satisfaction;
- increase overall operating efficiencies through proper location, integration and streamlining of services;
- facilitate organizational synergies by consolidating administrative and technical staff and adapting modern technologies and innovative workplace standards;
- provide leadership in energy conservation and sustainability;
- create a healthy, flexible and multi-functional work environment for Hydro Ottawa employees; and
- achieve Leadership in Energy and Environmental Design ("LEED") Gold certification for the East Campus Administrative Office building and LEED Silver for East and South Operation Buildings, and maximize energy efficiency.

2.4. TIMELINE OF KEY DATES

The following summarizes key milestones and dates culminating in the completion of the new facilities project:

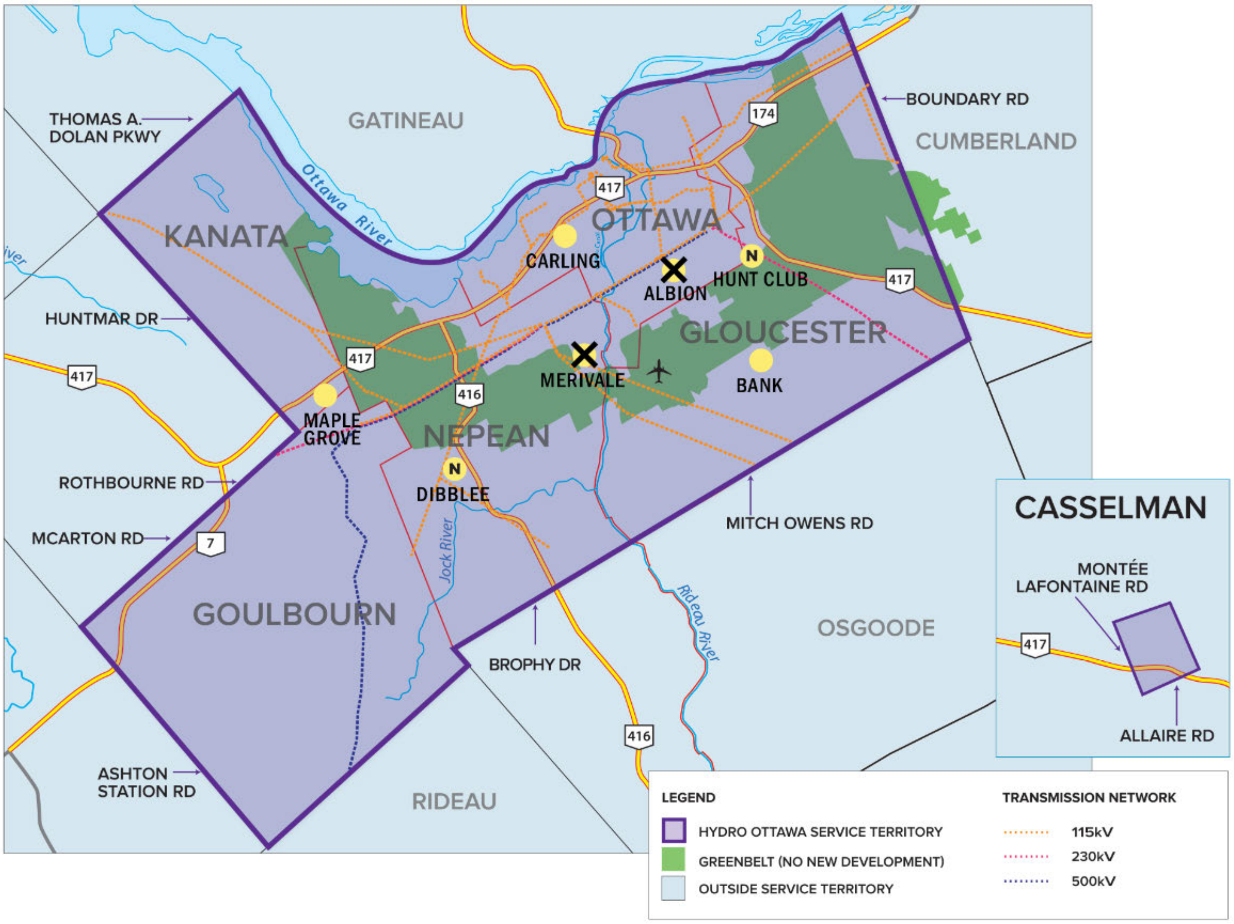
- December 28, 2011, 2012 Cost of Service proceeding: OEB Decision accepted need to proceed with development work on new facilities including land purchase.
- December 24, 2013: Initial RFQ was posted and closed on February 28, 2014
- April 2015: Retained a third party project advisor to do a peer review on the project procurement and intended Design Build contract
- April 29, 2015: Hydro Ottawa filed its 2016-2020 Custom IR application which included a request for $92.3M for the Facilities Renewal Program; The $92.3M was based on a high level (Class D) feasibility estimate

- July 30, 2015: Peer review report on design build procurement for new facilities prepared, recommending improvements in the RFQ/RFP documentation and to revise and re-initiate the process
- August 26, 2015: Updated RFQ issued
- September 22, 2015: SIOC agreed that total project cost would be capped at $96.5M plus capitalized interest and overhead
- November 23, 2015: RFQ submissions evaluated and results communicated, four qualified proponents identified
- December 22, 2015:: OEB Decision concurred with the need for new facilities and approved provisional funding of $66.0M with requirement to demonstrate prudency for any amounts in excess of that amount
- January 20, 2016: a more thorough estimate (Class C) of $124.7M plus capitalized interest and overhead was developed
- February 3, 2016: SIOC review and decision to make necessary design changes and scope reductions and re-confirm project budget at $96.5M plus capitalized interest and overhead
- May 18, 2016: Completed value engineering and revised design validation and a detailed Class B estimate prepared
- May 26, 2016: RFP issued to four qualified proponents
- October 14, 2016: Fairness Commissioner report issued, confirming fairness of RFP process
- October 18, 2016: Final results of RFP evaluation communicated; M. Sullivan & Son chosen as Design-Builder
- October 2016 – May 2019: Ongoing project construction, monitoring and cost control
- May 2019: Project completed at a cost of $80.0M ($99.5M including land, capitalized interest and overhead) and staff move to new facilities

3. DESCRIPTION OF FACILITIES

Hydro Ottawa's Facilities Renewal Program involved construction of new facilities on two parcels of land purchased in 2012 and 2013, namely the Eastern Operations and Administrative Office Campus and a Southern Operations & Warehouse. The location of the New Administration and Operations Facilities are indicated on the the map of Hydro Ottawa's service territory in Figure 5 below.

Figure 5 – Service Territory and Location Map



In total, 293,873 square feet of New Administration and Operations facilities space has been constructed. Table 5 below provides a summary of the location, functionality, and size of these new facilities.

3.1. THE EAST CAMPUS

The East Campus is located at 2711 Hunt Club Rd. This facility consists of three distinct buildings comprised of:

1. EC-1: The Administrative Office Building
2. EC-2: The Operations Centre for eastern sector of Hydro Ottawa service territory, and
3. EC-3: PILC Cable storage facility

The East Campus land parcel was purchased in April 2013 and is located at the corner of Hunt Club Rd. and Hawthorne Ave. near Highway 417 (see Figure 6 below). Table 5 provides site specific details of the East Campus.

Table 5 – East Campus Overview

Site Specific Information		TOTAL EAST CAMPUS	EC-1	EC-2 / EC-3
Site Size	acres	21.08	9.07	12.01
Office Area	sq. ft	137,912	127,132	10,780
Garage Area	sq. ft	46,735		46,735
Indoor Material Storage	sq. ft	10,318		10,318
Yard Space	acres	2.07		
Employee parking spaces (all outdoor)	#	439		
Outdoor fleet vehicle parking spaces	#	40		
Indoor fleet vehicle parking spaces	#	42		
Inside Staff	#	419		
Outside Staff	#	140		
Building cost excluding land	$	$59,519,052	$47,311,660	$12,207,392
Land	$	$12,694,254	$5,459,235	$7,235,019
Building cost including land	$	$72,213,306	$52,770,894	$19,442,411

Three separate buildings are part of the East Campus with a total building footprint of 194,965 Sq. Ft. The largest structure, the Administrative Office Building, is a reinforced concrete building consisting of three floors of administrative office space, a partial lower level and structural steel roof over the top level mechanical floor for a total of 127,132 Sq. Ft.

The Eastern Operation Centre is a 57,515 Sq. Ft. single-storey building with a pre-engineered garage and a conventional masonry and steel structure for the office space and material management functions, plus the necessary operational muster rooms, boot washing, lockers and shower areas. This building has an indoor garage for parking 42 heavy duty fleet vehicles, and also provides kitting bays, material kanbans, and overhead and underground tool storage rooms.

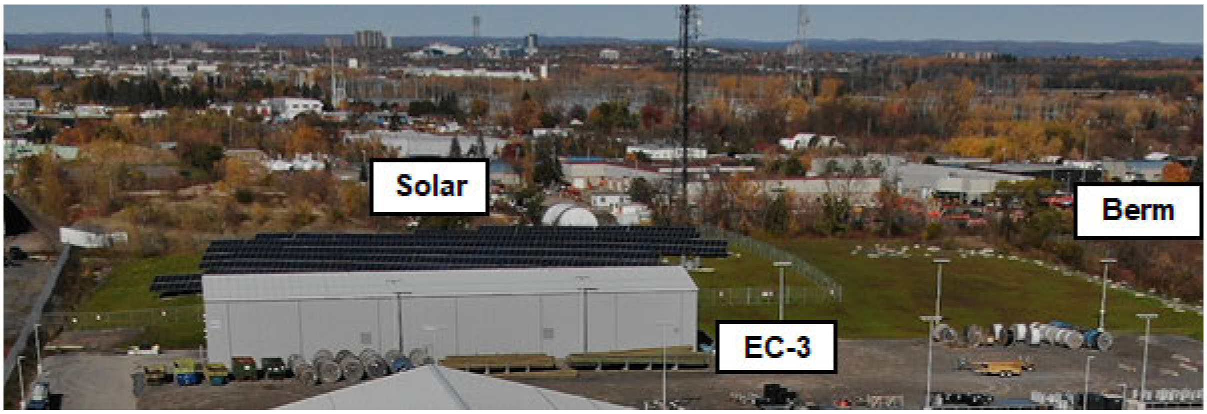
The enclosed PILC Storage Facility is a 10,318 Sq. Ft. Paper Insulated Lead Covered cable storage building with a clear span pre-engineered steel frame superstructure which is supported on a reinforced concrete foundation. This building is a warehouse to store and process overhead and underground cable and provides protection from the elements.

The East Campus also has a 2.52 acre solar yard and an exterior material storage yard.

Images of the East site and main buildings are included in Figures 6 and 7 below.

Figure 6 – EC-1 and EC-2 Buildings

Figure 7 – EC-3 Building, Solar Field and Berm



3.2. THE SOUTH CAMPUS

The South Campus is located at 201 Dibblee Rd. and is the Operations Centre for the south and western portion of Hydro Ottawa's service territory. This facility is predominantly operational and is contained in one building that includes office space, an enclosed garage and warehouse/storage space and a transformer shop. There is also a solar generation facility on the property.

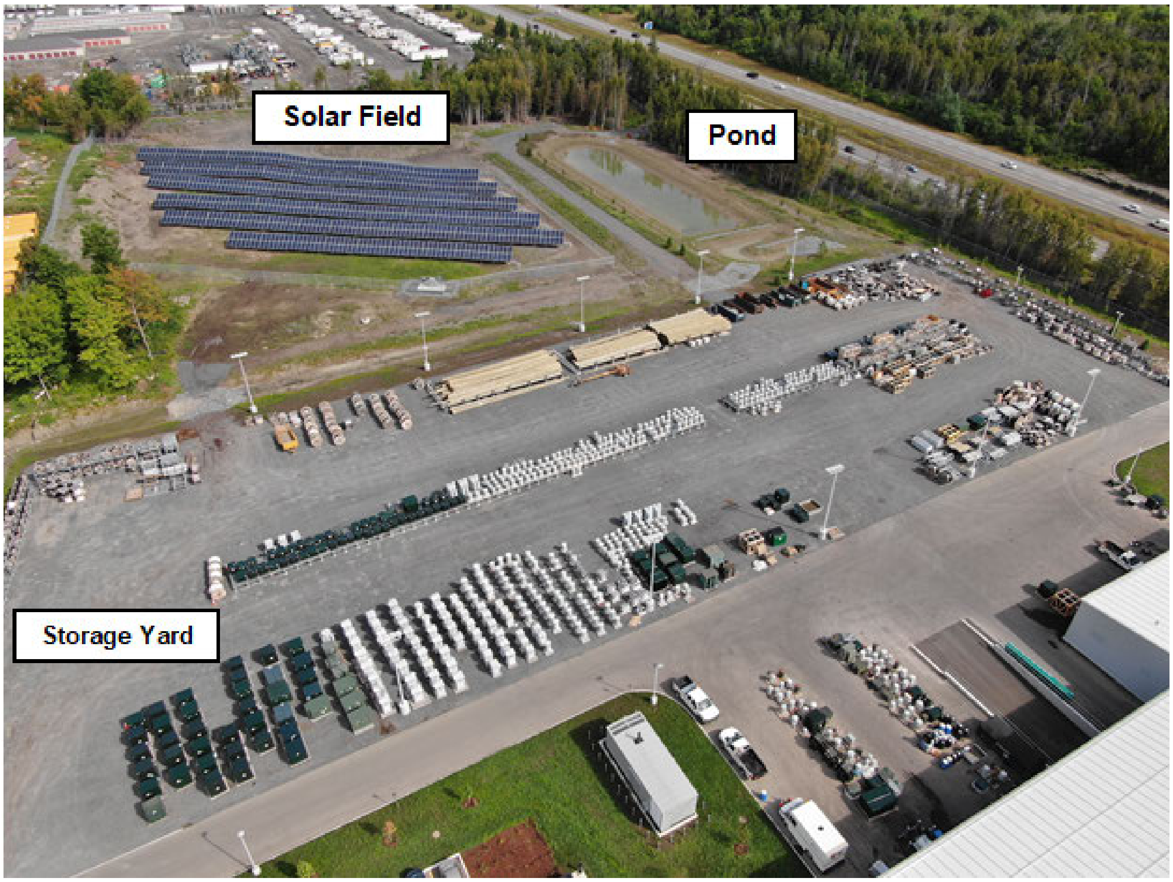
The overall site plan and photographs of the constructed facilities can be seen provided in Figures 8 and 9 below.

1 **Figure 8 – South Campus Operations Building**

2 

3

Figure 9 – SC Storage Yard, Solar Field and Storm Water Management Pond



Key statistics regarding the South Campus facility are provided in Table 6.

Table 6 – South Campus Overview

Site Specific Information		TOTAL SOUTH CAMPUS
Site Size	acres	20.26
Office Area	sq. ft	22,644
Garage Area	sq. ft	42,773
Indoor Material Storage	sq. ft	33,491
Yard Space	acres	2.77
Employee parking spaces (all outdoor)	#	101
Outdoor fleet vehicle parking spaces	#	36
Indoor fleet vehicle parking spaces	#	54
Inside Staff	#	18
Outside Staff	#	76
Building cost excluding land	$	$20,530,091
Land	$	$6,800,443
Building cost including land	$	$27,330,534

The South Campus consists of one 98,908 Sq.Ft. building made up of three separate components comprised of (a) a pre-engineered garage, and (b) warehouse and transformer structures, which book-end (c) a central one storey conventional reinforced masonry and steel structure with office space, muster and meeting areas, lockers and showers, and the metering calibration, repair and storage functions.

The South Campus site includes the following features:

- Indoor heavy duty fleet vehicle parking;
- Indoor kitting bays, material kanbans, tool and equipment storage areas;
- Office and operations support areas;

- Outdoor storage and equipment yard;
- Outdoor fleet parking area;
- Retention receiving area – 10-ton overhead crane;
- Warehouse;
- Metering calibration, workshop and storage; and
- Transformer shop

3.3. STAFF IN NEW FACILITIES

Where staffing numbers are presented in this document, Hydro Ottawa is using headcount not FTEs, as headcount more accurately reflects space usage needs. For example, when students are hired in the summer there is a need to have space for the whole person, not a calculated FTE amount.

The East Campus facility includes space for staff of both Hydro Ottawa and other affiliates of Hydro Ottawa Holding Inc. ("Holding Company"). Cost transfers associated with the shared use of the East Campus space are transacted consistent with the Affiliate Relationships Code as discussed in Exhibit 4-2-1: Shared Services and Corporate Cost Allocation. Given that the East Campus facility was built to accommodate both regulated and affiliate company staff, Table 7 provides staff level headcount information for Hydro Ottawa and affiliates.

Table 7 – Number of Staff at New Facilities - Hydro Ottawa and Affiliates

(Headcount - June 30, 2019)	East Campus	South Campus
Administration (Inside)	419	18
Operations (Outside)	140	76
TOTAL	**559**	**94**

The East Campus includes Hydro Ottawa staff associated with the following functions: Executive Team, Information Management and Information Technology, Human Resources, Finance, Customer Service, Communications and Public Affairs, Distribution Operations – Central & East, Distribution Asset Management, Distribution Operations Underground, System Operations, Business Performance, GIS and Records, Policies and Standards, Design & Asset, Distribution Operations Business Performance and Scheduling, Stations East and Engineering. In addition, as noted above, the East Campus includes space for staff from affiliate companies.

The South Campus includes Hydro Ottawa staff associated with the following functions: Metering, Distribution Operations - South, Stations South, Engineering, Business Planning and Scheduling and Materials Management.

3.4. PROJECT BENEFITS

Key Principles that guided the design of the buildings were:

- *Collaboration: A flexible and adaptable workplace that encourages collaboration and new ways of working and making decisions;*
- *Health & Wellbeing: Put physical and mental wellbeing, as well as sustainable living, at the forefront of your daily routine; and*
- *Innovation: A resilient workforce that embraces change and disruption through innovative ways of thinking and working.*

As discussed in section 2.1 above, the OEB agreed that Hydro Ottawa had demonstrated the need for the new facilities. Hydro Ottawa identified several factors that drove the established need, some of which include: (i) the replacement of aging buildings that are at the end of their useful lives; (ii) a relocation of operational centers out of high traffic residential districts; (iii) increase of overall operating efficiencies through proper location, integration and streamlining of services; and (iv) an upgrade of the operational centers in order to provide better operational response to customers.

Hydro Ottawa's old facilities were between 45 and 60 years old and were designed and built in a different era and according to outdated standards. In light of this, at the core of the new facilities' design was not only to address Hydro Ottawa's need for new facilities but also to take advantage of modern best building practices and to build healthy and sustainable facilities. There is research that demonstrates employers who care about the environmental impact of their buildings as well as the health and wellbeing of their staff are rewarded by improved productivity and loyalty, which can be worth more than their initial investment.[13]

Hydro Ottawa completed construction of the new facilities in May 2019. Staff moved into the facilities over a series of moves during the January to May 2019 period. By designing and building the new facilities, Hydro Ottawa addressed operational and safety needs. The utility also expects that the new facilities will improve employee workplace wellness and productivity and reduce the environmental footprint of building operations. The new facilities are sustainable, energy efficient and certified to LEED Gold standards. The resulting benefits of the new facilities are described in more detail below.

3.4.1. Operational Efficiency

One of the objectives of the new facilities was to enhance operational efficiency. This objective involves consolidating operations and administrative staff as well as upgrading operational centers in order to provide better response to customers and create better, more efficient working conditions. The resulting benefits in this regard include the following but not limited to:

- *Work team collaboration:* Consolidating administrative, technical and operational staff allows for greater operating efficiencies and opportunities. Having various work teams (e.g. Underground Lines, Overhead Lines, 24/7, Stations, Designers, Engineers) within the Operations Centers or adjacent, in the case of EC-1, allows for more efficient collaboration amongst these work groups that improves timely information

[13] World Green Building Council, *Building the Business Case: Health, Wellbeing and Productivity in Green Offices* (October 2016).

communication and reduces travel time. This, in turn, results in more effective work planning and execution as well as improved response time. Hydro Ottawa's underground and metering groups are able to allocate their resources between the East and South campuses to enable more efficient delivery of projects across the service territory and reduce overall travel time. Meeting rooms and common spaces in operations centres help to promote collaboration. For example, the use of "Ready Rooms" allows for improved tail boarding amongst teams at the beginning of the work day. Meeting room technology improves timely information communication and reduces travel time as meetings across the service territory can be conducted virtually. Also, the use of touchdown locations in operations centres allows designers, engineers and other work groups to temporarily work from various locations to better support field activities.

- *Accessibility:* The new facilities are located in close proximity to major traffic arteries in the City of Ottawa (Highway 417 in the East and Highway 416 in the South portions of Hydro Ottawa service territory). This reduces travel time to work locations by work crews resulting in better customer service and improved incident response times. Consolidated 24/7 operation located more centrally within the city, leading to better accessibility to ready access to highways 416 and 417, leads to improved incident response times.

- *Logistics*: At both the East Campus and the South Campus, there are better designed yards to load/unload and store large material and equipment (pole trailers, transformers, semi-truck deliveries, etc.). There are also multiple tool cribs providing for the separation and improved organization of material and operating equipment for individual teams within work groups and safety and accident prevention is enhanced with larger garage entrances and exits, including one-way traffic flow. The specific building for PILC cable EC-3 has space and a dedicated crane for loading and unloading reels and scrapping cable in an efficient manner. The EC-3 building also provides a facility which significantly decreases the risk of cross contamination of lead and asbestos by providing separate washing facilities and storage for designated substances.

- *Warehouse benefits*: Having a centralized warehouse reduces overall inventory administration. It provides for a more efficient layout for stock-picking and workflow. It also eliminates travel between sites, reduces potential communication gaps and standardizes site specific procedures for ease of training. Improved highway proximity also improves delivery access for third party supply chain providers.

- *Indoor vehicle parking*: The operational benefits of indoor parking for heavy duty fleet vehicles include:
    - reduced warm-up time resulting in higher productivity, and lower greenhouse emissions that would result from outside cold weather idling;
    - expected longer average service life of vehicles;
    - improved functionality of live line tools on aerial devices as these tools must be kept clean and dry in order to maintain dielectric strength and insulation levels. The former facility was severely constrained in this regard as the newer bucket trucks did not fit in the garages; and
    - keeping electronic test equipment, mobile computers, first aid supplies, rubber cover up and live line tools in an above freezing environment.

3.4.2. Safety

Another objective of the new facilities was to move Hydro Ottawa's operational centers out of high traffic residential areas to sites that have an easy access to major highways. Due to commercial and residential growth in the areas surrounding Hydro Ottawa facilities, truck and employee traffic posed safety risks to the general public. For example, at the Albion Road facility, school children boarded and debarked from school buses just outside the Hydro Ottawa facility. Wide turning trucks had to navigate heavily populated residential streets posing a risk to public safety. Through their location in commercial and light industrial areas close to main highways, the new facilities largely resolve this concern. Furthermore, the new facilities enhance safety and accident prevention for Hydro Ottawa's employees by having larger garage entrances and exits, with one-way traffic flow and separated staff vehicle parking and routes.

3.4.3. Employee Wellness and Productivity

Hydro Ottawa is committed to improving health, wellbeing and productivity of its employees. The new facilities were designed and built with the goal to create a healthy working environment that enhances the health, wellbeing and productivity of Hydro Ottawa's employees. In 2017, a multidisciplinary team of experts from Harvard University carried out a study to identify the elements and effects of healthy indoor environments as well as to understand the interaction between personal and public health, productivity, and building design (the "Study").[14] Some of the highlights of the Study include the following:

- *People work more efficiently in environments with good air quality.* Common indoor pollutants that pose risks to human health include nitrogen oxides, carbon monoxide, ozone, particulate matter, and volatile organic compounds ("VOCs") found in building materials, printer emissions, cleaning supplies, paint, glue, furniture, and other materials. Exposure has been linked to numerous health problems, such as cancer and respiratory diseases, as well as absenteeism, poor productivity, and low cognitive function.

- *Buildings constructed with low-VOC materials and finishes reduce exposure to toxic substances.* Studies show employees who work in buildings where fresh air is adequately circulated and distributed are more productive and healthier than those who work in poorly ventilated spaces. A low-VOC, high-ventilation office space with superior air quality improves cognitive function by as much as 101%.

[14] Harvard T.H. Chan School of Public Health, *The 9 Foundations of a Healthy Building* (February 2017).

- *Comfortable temperature and humidity levels are less likely to make workers feel sick or get sick.* A study on workplace thermal conditions found that workers experienced itchy and watery eyes, headaches, and throat irritation when exposed to poor ventilation, humidity, and heat. When indoor environments are too warm, occupants can experience symptoms of “sick building syndrome,” such as headaches, dizziness, fatigue, and flu-like symptoms, as well as negative moods, heart rate changes, and respiratory problems. Temperature and humidity may also influence disease transmission, as cold, dry environments are more likely to spread the flu virus, and warm, humid environments are conducive to the growth of mold and fungus.

- *Good lighting leads to better sleep at night and better productivity during the day.* Lack of natural light has been associated with physiological and sleep problems and depression. Exposure to daylight and access to windows at work have been linked to better sleep duration, an improved mood, less sleepiness, lower blood pressure, and increased physical activity. Office workers with access to natural light have a better circadian rhythm, which is important for sound sleep and cognitive function.

- *Reducing the noise level improves productivity and job satisfaction.* With about 70% of offices now having an open floor plan, more workers are susceptible to distractions from noise. A survey of more than 1,200 senior executives and nonexecutive employees found that 53% reported ambient noise reduced their work satisfaction and productivity. Exposure to environmental noise can increase accidents and impair employee performance and productivity, especially during difficult and complex tasks, and has been linked to higher blood pressure, changes in heart rate, and hypertension. Sound masking was included in the administration building to eliminate ambient noise.

Through designing and building the new facilities according to healthy and green building standards, Hydro Ottawa expects to achieve the following benefits: (i) maximize employee performance and productivity, (ii) attract and retain high-quality employees, (iii) reduce impacts of presenteeism and absenteeism and (iv) promote improved health for employees.

The new facilities are functional – not opulent. They have modern audio-visual and information technologies and amenities that help to promote employee collaboration, innovation and flexibility. The offices have been ergonomically designed and furnished in order to create a productive work environment (e.g. sit/stand desks). The office design will lead to reduced absenteeism, reduced sick time, increased staff morale and retention and recruitment success.

3.4.4. Environmental Footprint of the New Facilities

Hydro Ottawa is committed to reducing the environmental impacts of its building operations. Buildings can generate up to 35% of all greenhouse gases, 35% of landfill waste comes from construction and demolition activities, and up to 70% of municipal water is consumed in and around buildings. As such, making buildings greener can have a substantial impact on larger environmental goals. Furthermore, in recognition of the potential negative impacts associated with the design, construction and operation of the municipal building inventory, the City of Ottawa enacted a policy that requires all new municipal buildings to be designed and delivered in accordance with the Certified performance level of the LEED green building rating system.

LEED certification provides independent, third-party verification that a building has been designed and built using strategies aimed at achieving high performance in key areas of human and environmental health: location and transportation, sustainable site development, water savings, energy efficiency, materials selection and indoor environmental quality. There are four certification levels: Platinum, Gold, Silver and Certified. Regardless of the certification level achieved, all projects must meet mandated prerequisites and then choose from 110 available credit points to reach the desired certification level. The LEED Platinum level certification achieves the highest honor and the LEED Certified level achieves fundamental performance. Hydro Ottawa's new facilities have been built and certified to LEED Gold standards. The project budget called for the Operations buildings, namely EC-2 and SC-1, to be designed and built to a LEED Silver standard. However, through negotiations with the Design-Builder, these facilities were built to a LEED Gold standard at no incremental cost.

In addition to the above mentioned LEED certification, the new facilities also provide environmental benefits as they receive a portion of their electrical power through on-site solar generation. Overall, the new facilities help to reduce the environmental impact of Hydro Ottawa's building operations.

3.5 CUSTOMER ENGAGEMENT

As noted above the Facilities Renewal Program has been considered by Hydro Ottawa since amalgamation 20 years ago. As part of Hydro Ottawa's 2012 Cost of Service application, a Facilities Strategy was presented and it described the status of facilities and the need to further evaluate and identify the best development solution. At that time, Hydro Ottawa requested funding to purchase land, but did not seek funding for the overall project. The rate hearing process was a public, open and transparent process. The plans were reviewed by the OEB in that proceeding. In addition, at the proceeding intervenor groups, representing various public interests, participated in the process and reviewed Hydro Ottawa's plans.

On April 29, 2015 Hydro Ottawa submitted its 2016-2020 Custom IR application to the OEB. This application presented evidence in support of a request to spend $92.3M on land and buildings for New Administration and Operations Facilities at two new locations, and outlined the need for the facilities. During the customer consultation process that preceded the filing of the 2016-2020 Custom IR application, Hydro Ottawa engaged customers on the matter of these facilities. For example, the workbook survey utilized by the company to solicit feedback from customers included such questions as what customers' views were on Hydro Ottawa having proper facilities to house its staff, vehicles, and tools.[15] In addition, as part of the OEB

[15] Innovative Research Group, *Customer Consultation Report: 2016 Rate Application Review Prepared for Hydro Ottawa Limited* (April 2015). This report can be found in Hydro Ottawa's *2016-2020 Custom Incentive Rate-Setting*

proceeding to review the application, Hydro Ottawa held a public meeting on July 7, 2015, during which information about the new facilities and the plan to recover costs through a Y Factor was shared.[16]

During the hearing process information on the Facilities Renewal Program was once again scrutinized by both the OEB and the intervenor community, with the intervenor community and OEB Staff agreeing to total projected funding amount as part of the initial Settlement Agreement dated September 15, 2015.[17] In addition, as a result of this proceeding the OEB found that Hydro Ottawa had established the need for the New Buildings.

During the scoping process for the new facilities in late 2015 and early 2016, a revised estimate indicated that the cost to construct the facilities as planned would be $124.7M (see section 4.1 of this Attachment). Hydro Ottawa considered this cost to be unacceptable from a customer rates perspective and the scope of the project was re-visited to bring the budget down to $96.5M excluding interest and overhead. This consideration of customer impacts resulted in a reduction in cost of approximately $28M. The project was completed in 2019, on-time and on budget for a final total cost of $99.6M including interest and overhead. An average residential customer in Ottawa will see approximately $0.93 per month on their bill as a result of the new facilities.

Throughout this period, management of Hydro Ottawa reported to its Board of Directors and, through its shareholder the Holding Company, to the City of Ottawa on the status of the project. This project has been highlighted in Hydro Ottawa's annual report every year since 2012. The annual report is part of a package that is provided by the Chair of the Hydro Ottawa Board to the

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Distribution Rate Application, EB-2015-0004 (April 29, 2015), Attachment A-3(A): Customer Engagement Report, page 135.

[16] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-setting Application Presentation to the Ontario Energy Board*, (July 7, 2015), page 29.

[17] Hydro Ottawa Limited, *Settlement Proposal*, EB-2015-0004 (September 15, 2015), page 15.

Mayor of Ottawa and Ottawa City Council at their Annual General Meeting ("AGM") held in June each year.

The new facilities are also identified on Hydro Ottawa's public web site and were mentioned in the customer engagement effort associated with this Application.[18]

4. PROJECT COSTS

4.1. OVERALL COSTS

Since 2015, as the project progressed, cost estimates were refined. These cost refinements resulted in increases from the initial estimated cost as more detailed design information became available. In order to control costs to a level closer to the original budget, adjustments were made in a number of different areas such as project scope, office size and building finish. The progression of key project estimates is presented in the following table:

Table 8 – Summary of Project Costs

	EB-2015-0004 **Submitted**	SIOC Approved **Budget**	EB-2015-0004 **Approved**	Updated **Estimate**	SIOC **Re-Confirmed**	EB-2019-0261 **Final Cost**
Total Project						
- Land	$19,514	$19,514	$15,000	$19,514	$19,514	$19,495
- Construction	$68,903	$76,986	$51,000	$105,186	$76,986	$76,527
	$88,417	**$96,500**	**$66,000**	**$124,700**	**$96,500**	**$96,022**
- Interest & O/H	$3,930					$3,522
TOTAL	**$92,347**					**$99,544**
	April 29, 2015	Sept. 22, 2015	Dec. 20, 2015	Jan. 20, 2016	Feb. 3, 2016	Sept. 30, 2019

At the time, the initial $92.3M estimate was developed for the 2016-2020 Custom IR application, minimal detailed design information had been prepared. As the project progressed and further

[18] See Exhibit 1-2-2: Customer Engagement on the 2021-2025 Rate Application for details.

planning and design information was prepared, it became apparent to Hydro Ottawa that the cost of the project as initially envisaged would be higher than estimated. In September 2015, the SIOC of the Hydro Ottawa Board of Directors discussed potential cost cutting measures and agreed that the budget for the project would be capped at $96.5Mplus interest and overhead.

By early 2016, further detailed costing information was developed and the estimated cost of the project increased to $124.7M (plus interest and overhead). This information was presented to the SIOC at a meeting on February 3, 2016. This increase was unacceptable to Hydro Ottawa senior management and to the SIOC, and action was taken to reduce various aspects of the project costs. These reductions included reducing the size of the Administrative Office Building, reducing office workplace standards (Workplace 2.0 modified) and retaining the Bank Street facility for fleet and training. Based on the proposed cost reduction measures, the Hydro Ottawa SIOC re-confirmed the project budget to be $96.5M.

Detailed design requirements were then updated to reflect these changes and a Request for Proposals was issued on May 26, 2016 to the four proponents qualified through the RFQ process. The RFP responses were evaluated and M. Sullivan and Son was chosen to be the Design Build contractor for the project.

Upon completion of the new facilities project, the total project costs were $99.5M ($19.5M for land, $76.5M for construction and $3.5M for Allowance for Funds Used During Construction ("AFUDC") and burdens), this represents an increase of $7.2M or 7.8% over the preliminary estimate of $92.3M in the last rate application. With respect to the hard construction costs of approximately $57.5M, discussed in section 4.2, these came in below the detailed design (Class B) estimate of May 2016 by 2% or $1.2M.

The overall project cost excluding interest, AFUDC, and overhead was $96.0M ($0.5M under the Hydro Ottawa Board-approved figure of $96.5M). The contingency provided for in the Hydro

Ottawa Board budget of $96.5M was used primarily to address issues encountered during construction such as:

(i) development charges and municipal requirements from the City of Ottawa;
(ii) unexpected site conditions (e.g. soil issues at the East Campus);
(iii) "protected vegetation" at field operations site; and
iv) technological security and operational improvements.

4.2. QUANTITY SURVEY REPORT

A *"Quantity Survey Report"* dated May 18, 2016 was prepared by an independent professional construction cost estimator. The purpose of the report was to provide Hydro Ottawa a realistic estimate of expected probable direct and indirect construction costs for the East Campus and South Campus new facilities. This report was based on the experience of the professional construction cost estimator, historical costing information and familiarity with the construction industry in the Ottawa area. This estimate was prepared in accordance with generally accepted principles and practices for estimating construction projects.

The methodology followed as described in the report is as follows:

> *"From the documentation and information provided, quantities of all major elements were assessed or measured from the drawings and outline specifications where possible and priced at rates considered competitive for a project of this type under a fixed price sub-contract in Ottawa, Ontario.*
>
> *Pricing shown reflects probable construction costs obtainable in the Ottawa area on the effective date of this report. This estimate is a determination of fair market value for the construction of this project. It is not a prediction of low bid. Pricing assumes competitive bidding for every trade."*

Estimated project costs as per the Quantity Survey report are presented in Table 9 below. This estimate relates to "hard" construction costs and excludes costs such as land, furniture and furnishings, development fees, professional fees, overheads and financing charges. It is noted that actual costs came in $1.2M or 2.1% lower than the estimate that was prepared over three years prior. This demonstrates both the rigour of the estimate and also active cost management and control throughout the project life cycle. The hard construction costs as shown below represent 72% of the total construction costs excluding land. The higher than estimated costs on EC-1 is largely attributable to construction issues noted earlier, offset by savings largely in SC-1. Note that the functionality of initially envisioned separate SC-2 building (standalone storage) was incorporated into SC-1 thereby saving hard construction costs on this campus.

Table 9 – Final Building(s) Cost Compared to Quantity Survey Estimate

($)	Quantity Survey May 18, 2016	Final Actual Cost	Variance	Variance %
East Campus				
EC-1	$29,087,871	$32,629,279	*$3,541,408*	*12.2%*
EC-2	$9,355,861	$7,686,656	*$(1,669,205)*	*-17.8%*
EC-3	$1,828,092	$1,989,609	*$161,517*	*8.8%*
	$11,183,953	$9,676,265	*$(1,507,688)*	*-13.5%*
Sub-Total EC	**$40,271,824**	**$42,305,544**	*$2,033,720*	*5.0%*
South Campus				
SC-1	$18,122,397			
SC-2	$348,605			
Sub-Total SC	**$18,471,002**	**$15,210,734**	*$(3,260,268)*	*-17.7%*
TOTAL	**$58,742,826**	**$57,516,278**	*$(1,226,548)*	*-2.1%*

Planned building sizes that served as the basis for the costing in the Quantity Survey report are presented in Table 10 below. As compared to the Quantity Survey report, total actual building constructed square footage was 10,705 Sq. Ft (or 3.8%) greater than estimated.

Table 10 – Final Actual Building(s) Size Compared to Quantity Survey Report (Square Feet)

East Campus	Quantity Survey May 18, 2016	Final Actual	Variance	Variance %
East Campus				
EC-1	120,825	127,132	*6,307*	*5.2%*
EC-2	57,727	57,515	*(212)*	*-0.4%*
EC-3	10,361	10,318	*(43)*	*-0.4%*
	68,088	**67,833**	*(255)*	*-0.4%*
Subtotal EC	**188,913**	**194,965**	*6,052*	*3.2%*
South Campus				
SC-1	90,503			
SC-2	3,752			
Subtotal SC	**94,255**	**98,908**	*4,653*	*4.9%*
TOTAL	**283,168**	**293,873**	*10,705*	*3.8%*

In summary, with respect to the direct construction costs as estimated in the Quantity Survey report, actual project costs were 2.1% lower than estimated and actual building square footage delivered was 3.8% higher than estimated. The result is essentially more building space for a lower price than planned.

Table 11 – Other Development Costs

	Budget	Final Actual Cost	Variance	Variance %
Design Build Costs	$58,900,000	$57,516,278	*$(1,383,722)*	*-2.3%*
Other Development Costs[19]	$18,300,000	$19,010,689	*$710,689*	*3.9%*
Land	$19,300,000	$19,494,697	*$194,697*	*1.0%*
Sub-total	**$96,500,000**	**$96,021,665**	*$(478,335)*	*-0.5%*
Interest		$2,838,753		
Overhead		$683,423		
TOTAL		**$99,543,840**		

The main building structures of the new East Campus and South Campus facilities have been designed and constructed to have a service life of 75 years. Other components of the new facilities such as the roofing system, parking lot and internal furnishings and equipment have shorter service lives consistent with the Kinectrics study and engineering and operational experience.[20]

4.3. SALE OF FORMER ADMINISTRATIVE AND OPERATIONAL FACILITIES

Hydro Ottawa's New Facilities Plan included the sale of buildings that were to be vacated upon completion of the new construction.

The original New Facilities Plan called for the sale of the Bank Street location and the development of new training and fleet facilities. However, in order to help control project costs, it was decided by the Executive Management Team and SIOC to retain the Bank Street facility for training centre and fleet management purposes instead of building new facilities for these functions.

[19] Other Development Costs include cash allowances, professional fees, furniture, equipment, and permits.
[20] Kinetrics Inc., *Asset Depreciation Study for Use by Electricity Distributors*, EB-2010-0178 (July 8, 2010).

The settlement agreement states that any gain or loss from the sale of Albion Road (A & C properties), Merivale Road and Bank Street will be given back/charged to customers. The Albion Road "A" property is one of the former Administrative Office Buildings and the Eastern Operations centre. Albion Road "B" property is being retained as there is a transformer station on that site. The Albion Road "C" property is vacant/surplus land and was used for yard storage.

The Albion Rd. Property "A" and Merivale properties have been sold to third parties. Albion Rd. Property "A" closed on November 27, 2019 and the Merivale Property closed on September 30, 2019. Albion Rd. Property "C" (surplus land) is being sold to an affiliate as of December 31, 2019. An independent valuation was performed by Altus Group to determine the sale price of Property "C". The net proceeds are accounted for in deferral accounts as per the OEB's 2015 Decision. Further detail on the deferral accounts and the values being recorded can be found in Exhibit 9-1-1: Current Deferral and Variance Accounts.

The Merivale Rd., Albion Rd. Property "A" and Property "C" have been removed from rate base effective September 30, 2019, November 30, 2019 and December 31, 2019 respectively.
A summary of the properties and the net gain/(loss) is provided in Table 12 below.

Table 12 – Sale of Facilities

Anticipated Disposal Date	Merivale September 30, 2019	Albion (Property A) November 27, 2019	Albion (Property C) December 20, 2019
Proceeds	$9,200,000	$6,800,000	$1,827,000
Less: NBV	$(8,900,302)	$(5,895,766)	$ (4,271)
Sub-total	**$299,698**	**$904,234**	**$1,822,729**
Less:			
Legal Costs	$(16,859)	$(58,924)	$(50,000)
Environmental Costs	$0	$(650,946)	$(11,935)
Other (e.g. Prof. Fees, Survey)	$(82,876)	$(129,410)	$(0)
TOTAL OF ALL ASSOCIATED SELLING COSTS	**$(99,735)**	**$(839,280)**	**$(61,935)**
Net Gain or (Loss)	**$199,963**	**$64,953**	**$1,760,794**

4.4. Y-FACTOR TREATMENT

As the in-service date of the New Buildings was uncertain, in its April 29, 2015 Application, Hydro Ottawa proposed to record the revenue requirement impact of the new facilities as a Y-Factor. When the New Buildings became in-service, the new facilities revenue requirement impact would be calculated, and tracked in a deferral account. In its Decision in the 2016-2020 Custom IR proceeding, the OEB approved Y-factor treatment based on the recovery of up to $66.0M for the new facilities ($51.0M for the New Buildings and $15.0M for the land.) When one new facility was in-service, Hydro Ottawa would file an application with the OEB and propose a rate rider to clear the associated revenue requirement.

The new facilities came into service on May 1, 2019. Using the OEB-approved amount for Y-factor treatment of $66.0M, the annual revenue requirement associated with the new facilities is $ 3,320,514 for 2019 and $5,823,637 for 2020. On a monthly basis the revenue requirement is added to the Y-factor deferral account, no carrying charges apply to the Y-factor account. Hydro Ottawa is collecting the initial estimate of the Y-factor through a rate rider effective January 1, 2020. For further detail regarding the calculations, accounting and disposition of these Y-factor costs, please see Exhibit 9-1-3: Group 2 Accounts. The total revenue requirement for the new facilities is $ 5,019,369 for 2019 and $8,758,841 for 2020. The difference between revenue requirement of the $66.0M captured in the Y-factor Account and the full cost of the new facilities is being recorded in a separate Regulatory Account, to be collected from customers after a prudencey review.

5. PRUDENCY OF THE NEW FACILITIES PROJECT

At the early stage of the new facilities project, Hydro Ottawa established a number of processes and reviews to ensure that each decision associated with the project was prudent and reasonable in light of the given circumstances. Hydro Ottawa also established checks and balances to control the project costs and ensure the project adhered to the schedule. Taken together, these actions demonstrate that Hydro Ottawa exercised prudent management in planning and execution of the new facilities project.

To demonstrate the prudency of the new facilities, this section describes the following:

- right sizing of building design and full utilization of space;
- land usage and functionality;
- prudent project planning and procurement processes;
- execution stages of the new facilities project, including ongoing project cost review and control; and
- external benchmarking review of similar projects proposed by LDCs.

5.1. SIZE OF BUILDING AND SPACE UTILIZATION

A modern, healthy workplace supports greater productivity, a more engaged workforce and better results for customers. Hydro Ottawa as an employer has a responsibility to create workplaces that support the well-being, wellness and productivity of its employees.

Given the need for new facilities, Hydro Ottawa completed an office standards review to determine the new building space requirements. As the primary guiding workplace standard and the basis for its assessment, Hydro Ottawa used the Federal Government Workplace 2.0 Fit Up Standards ("Workplace 2.0 Standards"), industry research promoting a healthy workplace and Hydro Ottawa Guiding Principles of collaboration, innovation, flexibility & adaptability, health & wellness and sustainability. The Workplace 2.0 Standards have been used by the Federal Government, regulated entities and various municipalities, including the City of Ottawa. Hydro Ottawa also used industry research to support the function of common workspace areas and the impact that these spaces can have on employees and productivity.

Hydro Ottawa then tailored the Workplace 2.0 Standard incorporating industry trends to better align with its operational requirements. Hydro Ottawa modified (i.e. reduced) the standard office space sizes during the design development to increase space allocation consistency, minimize operational costs, and increase office arrangement flexibility for any potential future growth. The resulting Hydro Ottawa workplace standards maximize real estate utilization, reducing overall building areas footprint and long term operational carrying costs. This was done by way of smaller open office workstation environments, increased touch-down work areas for highly mobile or temporary staff, more and varied types of meeting spaces including break-out or collaboration areas for staff, including areas such as a cafeteria, which can transform into a multi-purpose area. Open office environments were designed to maximize direct daylight into work areas, improving staff health and wellness and efficiency. Hydro Ottawa's design of the new facilities promotes its Guiding Principles of Collaboration, Health & Wellness and Innovation that are also in line with office design industry standards. By doing this, the overall health and wellbeing of employees improves which, increases innovation, creativity and productivity, benefiting all parties involved.

Table 13 below summarizes the reduction in space standards by position coincident with the development of the new facilities.

Table 13 – Hydro Ottawa Workplace Standards (Square Feet)

Position	Original Standard	New Standard	Change
Enclosed Offices			
CEO	300	300	0
Executives	265	200	(65)
Directors	225	125	(100)
Managers	150	107	(43)
Workstations			
Supervisors	80	36	(44)
Executive Assistant	64	48	(16)
Employees	64	36	(28)
Assigned Touchdown Stn.	64	15	(49)
Unassigned Touchdown Stn.	16	15	(1)
Touchdown Stn. - Trades	16	One 15 per 5 Empl.	(1)

As completed, the new Administrative Office Building ("EC-1") building has 127,132 Sq. Ft. of space and houses 419 staff at June 30, 2019. This is approximately 303 gross square feet per employee. Hydro Ottawa notes that this is well below the International Facility Management Association ("IFMA") average of 396 gross Sq. Ft. per occupant as well as the IFMA average of 425 gross Sq. Ft. per occupant for utilities. In addition to being lower than IFMA standards, Hydro Ottawa's workplace standards are typically lower than or at the lower end of the Workplace 2.0 Standard range. A comparison of Hydro Ottawa workplace space standards with the Government of Canada Workplace 2.0 and the IFMA standards for Utilities is provided in Table 14 below.

Table 14 – Space Standard Comparison (Square Feet)

Position	Hydro Ottawa	Workplace 2.0	IFMA
Executives	200	200	332
Directors	125	150	228
Managers	107	108	158
Employees	36	48	86
Free Address	15	16	n/a

In assessing comparable workplace space allocation, Hydro Ottawa reviewed the overall Sq.Ft./Employee space allotment for other LDCs in their new facilities projects. Hydro Ottawa's office and workstation space allocations are lower than the space allocations of other utilities who have (or are proposing to construct) a dedicated administration facility. This comparison is summarized in Table 15.

Table 15 – Space Standard Comparison, LDC Administration Buildings

	Hydro Ottawa	PowerStream (Now Alectra)	Enersource (Now Alectra)	Energy + Southworks
Gross Sq.Ft./FTE	303	368	527	327

Although the main Administrative Office Building is fully utilized and "right-sized" for the current staff level, future staff growth can be accommodated within the current building footprint through re-arranging workstation configuration and making use of peripheral aisle space and common areas.

5.2. LAND USAGE AND FUNCTIONALITY

The land parcels upon which the two projects are built were purchased in 2012 and 2013. In total Hydro Ottawa purchased approximately 41 acres for a total price of $19.5M. The cost of land and acreage is summarized in Table 16 below.

Table 16 – Land Cost

Location	Purchase Price	# Acres	$/Acre
EC - Hunt Club Rd	$12,694,255	21.08	$602,194
SC - Dibblee Rd.	$6,800,443	20.26	$335,659
Total Land Cost	**$ 19,494,697**	**41.34**	

In its 2015 Decision, the OEB made findings based on information that was provided at that time. Subsequent to the proceeding the site design layout and use has changed and there is no developable surplus land at either location, as further explained below. OEB findings at the time were as follows:

> *'The OEB finds that Hydro Ottawa has not demonstrated the prudence of the $19 million cost for the 41 acres of land. The land was purchased in 2012 and 2013. The total cost of $19 million includes 9 acres of excess land valued at $4 million. The benefit to customers associated with the $4 million cost of the excess land has also not been explained."*
>
> *"The OEB finds the evidence to be inconclusive, suggesting that the purchased land area included a contingency over and above what is required for the New Buildings, by indicating that the "actual land acquisition provides capacity to expand in future, if necessary."*[21]

The 2015 OEB Decision to not approve a portion of the land purchased ($4M representing approximately 9 acres of land) was based on information contained in a presentation dated November 17, 2014, which was provided by Hydro Ottawa in response to School Energy Coalition interrogatory #11, Attachment B. The rationale for the Decision was that the land was excess to the current needs of Hydro Ottawa and was required to be able to expand in the future if necessary. Subsequent to the presentation produced in response to the interrogatory, both sites have been fully developed to meet current needs and there is no "surplus" land at either location. The 41.34 acres purchased is all necessary and is providing value to current

[21] Ontario Energy Board, *Decision on Settlement Proposal and Procedural Order No. 11*, EB-2015-0004 (November 23, 2015), pages 3-4.

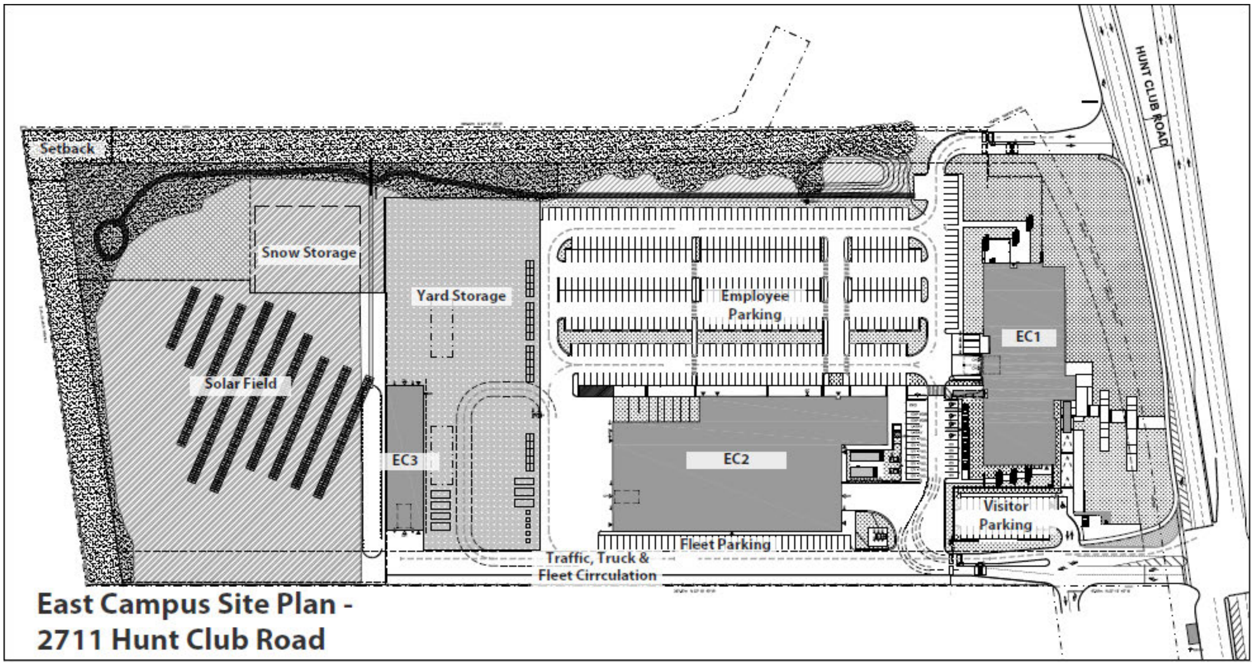
Hydro Ottawa customers.

The East Campus land area is 21.08 acres and consists of three buildings, parking, material storage, protected natural lands and property set-backs in respect of local planning requirements. The site includes 1.95 acres which could be considered as non-operational. However, the 1.95 acres is used to store "surplus fill" encountered during construction which was not considered clean soils per Ministry of the Environment, Conservation and Parks ("MECP") Guidelines for external off-site disposal. Hydro Ottawa saved in excess of $700K by keeping these soils on site, which is permitted by MECP guidelines. This area was shaped into a berm at the north east end of the property and there is no environmental risk as the soils were considered contaminated mostly due to the amount of debris (broken concrete, rubble, scrap metal, etc.) preventing it being disposed off-site as clean fill.

The East Campus also has a 2.52-acre Solar Field at the north-west section of the property. This 414 MWh net metering facility supplies electricity to the on-site buildings helping to reduce the consumption from the grid thereby lowering OM&A costs associated with the monthly electricity bill.

Figure 10 below shows East Campus land (21.08 acres) and the current buildings and uses of this site.

Figure 10 – Diagram Showing Use of EC Site

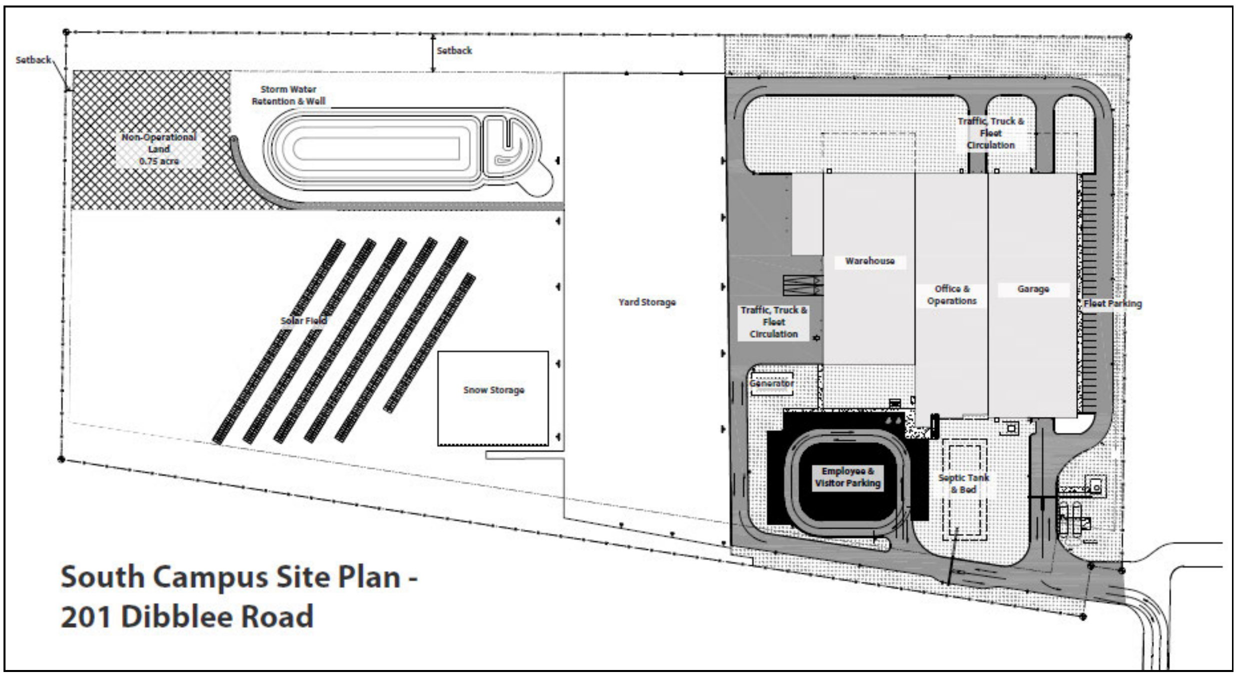


The South Campus land area is 20.26 acres and consists of one main building which houses office, garage and warehouse facilities. A condition pertaining to the South Campus site is that it is not serviced by municipal infrastructure (water and sewer) and required well water and treatment system and a septic system. The site has the main operational warehouse and equipment yard storage, and a stormwater management facility. There is a 0.76 acre non-operational portion of land at the extreme north-east end of the property. This portion has limited access and it is highly impractical to utilize this portion for future operations, or as it is “landlocked”, to sever this portion of land from the main lands.

The South Campus also has a 4.2-acre Solar Field at the north-west section of the property. This 424 MWh net metering facility supplies electricity to the on-site buildings helping to reduce the consumption from the grid, thereby lowering OM&A costs associated with the monthly electricity bill. Further information on this solar facility can be found in Exhibit 2-4-3: Distribution System Plan - Section 8.5.1- General Plant.

Figure 11 is a site plan of the South Campus land and facilities.

Figure 11 – Diagram Showing Use of SC Site

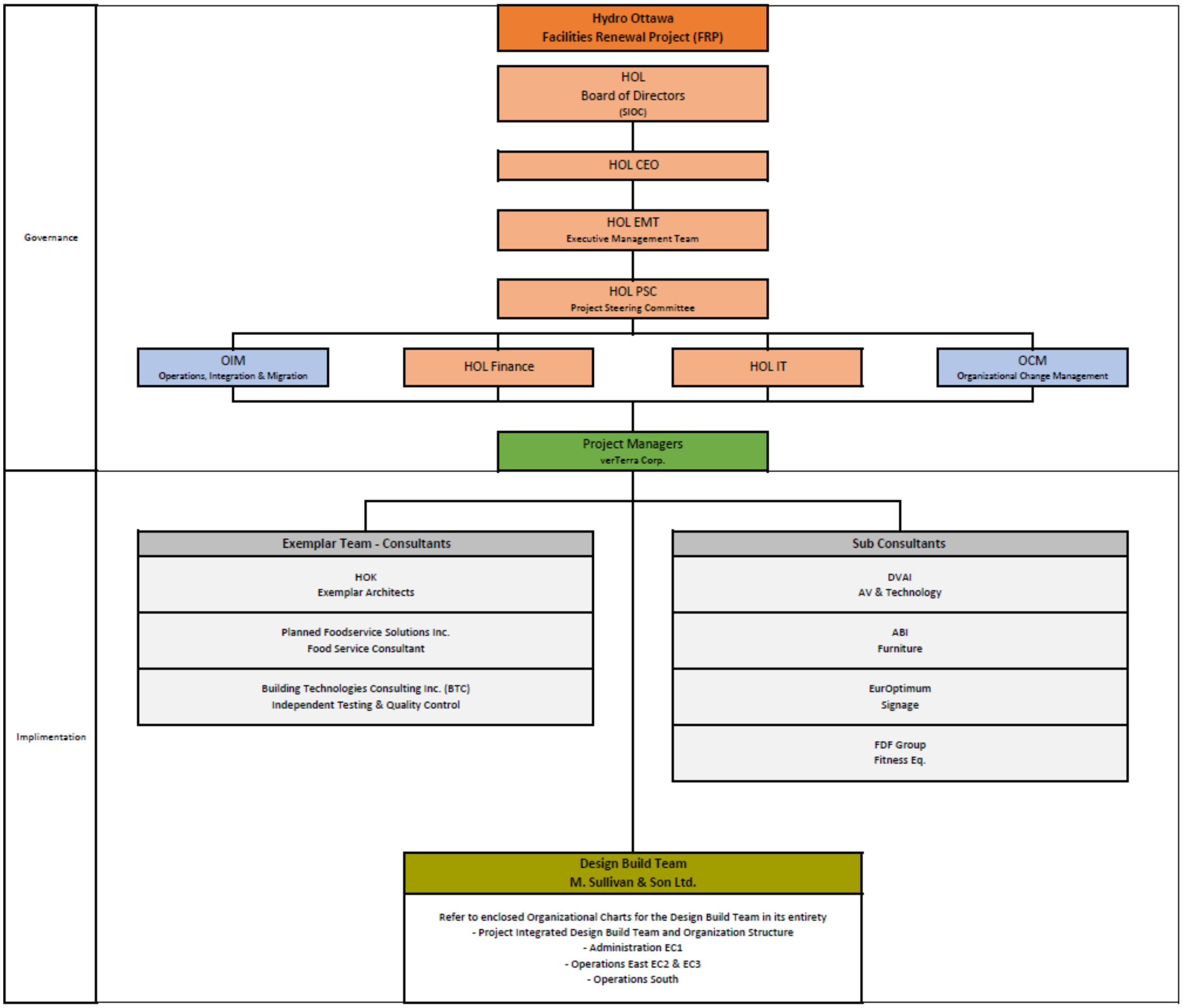


5.3. PRUDENCY DURING THE PLANNING STAGE

As part of its prudent management strategy, at the early stage of the project, Hydro Ottawa formed a Project Management Team to oversee all day-to-day aspects of the facilities renewal program. This team was comprised of Hydro Ottawa staff, an independent project management firm, verTerra Corp., and an advocate architect/interior designer, HOK Canada, to manage the life-cycle of the project.

Hydro Ottawa also created various project teams tasked with distinct responsibilities. Project teams were structured to assist Hydro Ottawa with prudent and reasonable decision-making prior and during the planning stage of the new facilities project. The planning stage involved planning and procurement process to select a successful candidate to carry out the execution stage of the project. Hydro Ottawa also retained an independent, third-party Fairness Commissioner who was tasked to oversee and monitor the fairness and transparency of Hydro Ottawa's procurement process. The organization chart in Figure 12 below outlines the various roles and positions that comprised the management structure for the new facilities project. This structure was in place for the planning and execution phases of the project.

Figure 12 – Project Organization Chart



Effective project management and governance is critical to the success of a project. From the outset, Hydro Ottawa established a structure and a team of experts to help ensure the successful completion of the project and to ensure that prudent decisions were made throughout the project life-cycle.

5.3.1. Project Teams

In the early stage of the new facilities project, prior to initiating a public tender process, Hydro Ottawa formed a project Design Team to provide preliminary design and technical scope definitions that outline and convey Hydro Ottawa's requirements. The Design Team also participated during the tendering process as a technical adviser to Hydro Ottawa. The Design Team was comprised of the following firms:

- verTerra Corp. – Project Manager and Procurement Advisor
- HOK Architects Corporation – Advocate Architect
- R.V. Anderson – Civil Engineering
- Cunliffe & Associates – Structural Engineering
- Morrison Hershfield – Mechanical and Electrical Engineering
- HOK Canada – Landscape Architecture, Interior Layouts, Signage andWayfinding

Hydro Ottawa also formed an Evaluation Team to review, evaluate and select a successful proponent to build the new facilities project. The Evaluation Team consisted of Hydro Ottawa Executive Management members and other staff, the Project Manager, the Advocate Architect and Fairness Commissioner.

Hydro Ottawa engaged an independent procurement advisor to develop the procurement strategy for the new facilities project, this advisor also had broader scope responsibilities and served as Project Manager. Hydro Ottawa's requirement was to ensure its procurement strategy adhered to the industry best practices for publicly tendered construction projects and was consistent with the Canadian Construction Association and the Canadian Design Build Institute standards for procurement. Additionally, Hydro Ottawa requested that its design build procurement structure be based on similar scale design build procurement models successfully implemented by the City of Ottawa. The procurement strategy was reviewed and approved by the Executive Team and Hydro Ottawa's Board of Directors.

The Project Manager, was verTerra Corp. ("verTerra"), an Ottawa based Project Management and Real Estate Advisory Firm, that brought Design Build, Procurement and Operational Migration expertise to the project. verTerra served as the Owner's Representative to help protect the best interests of Hydro Ottawa during the entire project cycle. Prime areas of responsibility included managing and controlling project scope, budget and schedule. Given that the day-to-day construction of the facilities project was managed by a Design Builder (Sullivan & Son), verTerra assisted with the development of Hydro Ottawa's procurement documentation for the intended Design Build contract. verTerra was part of the Hydro Ottawa Project Team. The Project Team was comprised of Hydro Ottawa staff, verTerra and HOK Canada (HOL's advocate architect and interior designer). This arrangement helped to reduce project risk and maximize project success.

5.3.2. Request for Qualifications & Request for Proposals

A two stage procurement process is standard, where the RFQ provides the technical and qualitative requirements for market respondents to structure their teams and base their responses. An RFQ also provides critical insight into the commercial structure of the opportunity and sets out the expectations for the second RFP stage. The RFQ process also thoroughly assesses the capabilities and strengths of the proposed Design Build teams with the qualifications and requirements of Hydro Ottawa's specific project needs.

Hydro Ottawa retained verTerra to help develop a procurement strategy that would adhere to the industry best practices and standards. verTerra confirmed Hydro Ottawa's desire to select a design build contractor for the new facilities project using a two-stage procurement. The first stage was an RFQ, the purpose of which was to invite interested parties to submit RFQ submissions indicating their interest and qualifications to perform and complete the new facilities project. Hydro Ottawa initiated the RFQ stage on August 26, 2015 by posting a nation-wide online public solicitation. The RFQ required interested proponents to submit their design build qualifications and expertise with respect to Hydro Ottawa's specific design criteria and to demonstrate and substantiate their design build expertise and capability to execute similar scale and like projects in order to be qualified.

Hydro Ottawa received a total of ten RFQ submissions from firms both local and external to the Ottawa market. The RFQ submissions were then evaluated by an Evaluation Team with the assistance of the Design Team. The RFQ evaluation criteria had both Mandatory requirements (e.g. capacity to bond, insurance, financial letter of good standing, etc.) and Qualitative requirements (e.g. design-builder overview and expertise, project references, design-build methodology, etc.). Proponents had to first satisfy the Mandatory requirements to be deemed compliant, and if compliant, were then evaluated against the Qualitative criteria. At the conclusion of the evaluation process, which was witnessed and assessed by the Fairness Commissioner, Hydro Ottawa short-listed the four highest ranking proponents, which were then invited to proceed to the second stage of the procurement process, the Request for Proposals.

On May 26, 2016, Hydro Ottawa issued the RFP to the four pre-qualified proponents. The purpose of the RFP was to obtain a fixed tender price for the design build components and evaluate the various design-build proposals for the new facilities project. The RFP stage was a stringent procurement process, and was overseen by the Hydro Ottawa Project Team, Hydro Ottawa Executive Management Team, Supply Chain Management and the Fairness Commissioner. Similar to the RFQ, the RFP consisted of Mandatory requirements that Proponents had to meet in order to be evaluated and also Qualitative requirements. All four pre-qualified proponents submitted responses, met the Mandatory requirements and advanced to the Qualitative evaluations.

Each member of the Evaluation Team was required to independently review and score each proponent submission based on the RFP's stipulated criteria and point distribution. Then the Evaluation Team met and developed consensus scoring for each proponent. The consensus sessions were facilitated by Hydro Ottawa's Supply Chain unit and overseen by the Fairness

Commissioner to ensure fairness and complete objectivity. At the conclusion, Hydro Ottawa selected M. Sullivan and Son ("Sullivan") based in Arnprior Ontario, as the successful proponent ("Design Builder") for the new facilities project. M. Sullivan and Son is a full service general contractor and has been in business for over 100 years. Sullivan submitted the combined best value proposal, having both the best design and the lowest cost.

Once the successful proponent was selected, Hydro Ottawa required the Design Builder, on Hydro Ottawa's behalf, to tender most of the work that was required as part of the project. This included civil, mechanical, electrical, landscaping, road/access improvement work, kitchen equipment, signage, etc. To ensure the Design Builder exercised prudent management, verTerra was tasked to oversee that the Design Builder had a minimum of three bidders for each discrete work package and that all sub-trade bidders were pre-qualified by the Design Builder to meet Hydro Ottawa's established safety and quality requirements.

Aspects of the project not managed by the Design Builder (e.g. furniture) were tendered on an industry best practice basis, i.e. a minimum of three qualified bidders had to submit their proposals, evaluation and selection by the Project Manager. The Hydro Ottawa Supply Chain unit competitively tendered the necessary technology equipment, which was then integrated into the construction work and managed by verTerra and Sullivan as the design and construction advanced.

Hydro Ottawa's procurement process was structured to provide competitiveness and a variety of options from the proponents to ensure the utility was able to make prudent and reasonable decisions. The submitted proposals were subject to a rigorous evaluation process with participation of diverse range of stakeholders tasked with various responsibilities.

5.3.3. Fairness Commissioner and Report

The Fairness Commissioner was PPI Consulting Limited. An independent third party commissioned by Hydro Ottawa to oversee and monitor each stage of the RFQ/RFP process, to ensure that the process was fair, transparent, and in compliance with stated requirements.

The Fairness Commissioner's responsibilities included the following, but were not limited to:

- providing advice on fairness issues concerning the development of the request for proposal;
- monitoring and providing advice on potential or real barriers to proponent participation;
- identifying key issues and potential risks in the procurement process;
- identifying any situation which may compromise the integrity of the evaluation process (i.e. overseeing the evaluation team and procurement processes and assessing potential bias or undue influence);
- monitoring the evaluation of all submissions to oversee the fair treatment of all proponents;
- monitoring the adherence of established government procurement practice in the planning, issue, evaluation, and
- providing a Fairness Report at the conclusion of the evaluation process.

The Fairness Commissioner's report was provided to Hydro Ottawa on October 14, 2016, and concluded that *"the procurement process for the Facilities Renewal Program Design Build up to the completion of the evaluation process was conducted in a fair, open and transparent manner."*

5.4. PRUDENCY DURING THE EXECUTION STAGE

With the selection of Sullivan as the Design Builder , Hydro Ottawa proceeded to the execution stage, to build the new facilities. Hydro Ottawa created a robust project management and governance structure, which included various levels of project oversight, detailed reporting and cost control. Hydro Ottawa also continued to retain verTerra as a third-party project management expert to provide project support and cost-control management of the new facilities project . Hydro Ottawa's Board of Directors, Strategic Initiatives Oversight Committee of the Board and the Executive Team received regular reports from the Project Team relating to, among other things, project costs and schedule and issues. The project management and governance structure helped to allow Hydro Ottawa senior management to be informed at every step of the project and make prudent decisions as the new facilities project was being constructed.

5.4.1. Effective Project Management and Governance

Hydro Ottawa structured a robust governance and reporting regime on the new facilities project which was overseen by Hydro Ottawa's Board of Directors and Executive Management Team. The project was managed by the Project Steering Committee.

The Executive Management Team provided direct executive management oversight and control on all aspects of the project, including the design build contract, all procurements and all Hydro Ottawa managed scope of work. The Board of Directors provided strategic oversight and governance. The new facilities project was a standing reporting item to Hydro Ottawa's Board of Directors, SIOC, with updates on the project status including budget, schedule, safety, key risks and mitigations.

Hydro Ottawa created a Project Steering Committee which was co-chaired by the Chief Financial Officer ("CFO") and Chief Human Resource Officer ("CHRO"). In addition to the Co-Chairs, the Steering Committee included a cross section of Hydro Ottawa staff including managers from all operation divisions, technology, finance, communications and human resources. As the project evolved the Steering Committee created two distinct sub-committees: (i) the Operational Migration Committee ("OCM") chaired by the CFOwhich dealt with all the operational requirements, and (ii) the Change Management committee chaired by the CHRO which led staff engagement, communications and interior workplace matters. These two sub-committees were active across the entire duration of the new facilities project ensuring compliance with the original specified requirements, and where necessary providing direction to the Project Management Team.

verTerra Corp. assigned a full team of Project Management Professionals on the project under a Project Director who had direct responsibility over the project and the Project Management and Design Build teams. The Project Director directly reported to Hydro Ottawa's CEO, CFO and CHRO and Board of Directors.

Hydro Ottawa held quarterly Executive Partnership Meetings with the Design Build Executive Management Team, Hydro Ottawa's Project Manager, and Hydro Ottawa's CEO and CFO. The purpose of these meetings was to ensure that Hydro Ottawa's Executive Team had oversight and understanding of the project status, costs, emerging issues and risks. It also created an open line of communication between Hydro Ottawa and the Design Builder.

5.4.2. Project Reporting

The Design Builder was required to provide highly structured, effective, and regular reporting to Hydro Ottawa, at both the senior management and project team levels, for the duration of the project. Senior project leadership was required on the part of the Design Builder to lead and control the reporting interfaces with Hydro Ottawa and to structure appropriate reporting formats and presentations that provide at a minimum, project status and progress on:

- project approvals
- design development
- construction progress (including photographic documentation)
- project finances
- value engineering opportunities/innovations
- schedule

- risks and mitigation strategies
- quality control
- site safety

The new facilities project was reported as follows:

- Quarterly reports and presentations made to Hydro Ottawa's Board of Directors, including status, budget, schedule, key risks and opportunities, and a next quarter look ahead.
- Monthly Executive Status reports were provided by the Project Manager, inclusive of project status, work completed last period, budget and changes, schedule, quality, key risks and opportunities, site photographs and next period look ahead.
- Monthly Design Build Reports were submitted by the Design Builder to the Project Manager, inclusive of overall status, sub-trade procurements, budget, schedule, quality, manpower and safety.
- Weekly site reports were provided by the Design Builder to the Project Manager and Hydro Ottawa Executives, including work performed, site photographs, quality and volumetric data, manpower and safety. It is noted that the project was completed without any lost time injuries.

5.4.3. Project Cost Review and Change Order Control

Once the project management and governance structure was established, it was important to constantly monitor project costs and have a stringent process for approval of any deviations from the originally quoted prices. The project total budget was managed by the Project Manager and monthly forecasts were submitted to Hydro Ottawa's CFO, and circulated to the CEO and Board of Directors. The Design Build cost reports were submitted monthly to the Project Manager by the Design Builder, complete with change order and change request forecasts/estimates. Changes to the contract were formalized by the Design Builder with detailed fixed price quotations upon direction by the Project Manager. Hydro Ottawa established a robust, stringent process to ensure that any changes to price were prudent and warranted.

Prior to a change being submitted for approval changes were first reviewed for accuracy and cost fairness by the Design Builders Design and Engineering teams. The Project Manager would then review the quotation and if deemed fair, certify the recommendation and submit it directly to Hydro Ottawa's CFO for final approval. The CFO and the Project Manager conducted regular change review meetings to review / discuss all submitted changes, review the budget forecast, and if deemed acceptable, the CFO would sign off and a change order would be issued to the Design Builder. The approval process employed by Hydro Ottawa was designed in accordance with and adhered to Project Management Institutes and Canadian Construction Association standard practices.

5.4.4. Payment Control

With respect to payment control, the Design Builder submitted monthly progress payment requests with a complete breakdown of expenditures for the period, including all relevant sub-trade, supply and change order invoices to Hydro Ottawa's Project Manager. All monthly progress payment submissions included a Statutory Declaration from the Design Builder certifying supply payments for the previous period had been made and also included a budget and schedule update. Hydro Ottawa's Project Manager reviewed for compliance with the contract and accuracy to work performed on site, and if acceptable, issued a written recommendation to Hydro Ottawa for payment. This process was compliant with the terms of the contract and adhered to PMI and industry best practices.

Billing and payment recommendation on all other contracts, outside of the Design Builder contract responsibility, were managed by the Project Manager who acted as payment certifier, verifying payment accuracy and fairness on all other related contracts.

5.4.5. Project Schedule Control

Another important aspect of the prudent management included project schedule control. The project schedule was managed by the Project Manager with a master critical path schedule set as the baseline, inclusive of all project scope of work. The Design Builder also developed a critical path schedule for the design and construction works, which was linked to the Master Project Schedule. The project schedule was reviewed every two weeks in a Project Team meeting and updated monthly. Short term look ahead schedules were provided every two weeks and verified by the Project Manager on site.

5.5. EXTERNAL BENCHMARKING

5.5.1. Benchmarking Other LDCs

Hydro Ottawa is aware that benchmarking can be a useful measure of project cost performance. The associated comparative information on building size, cost and staff levels can be informative, however it is not precise. There can be differences in the nature of the projects (e.g. new build or refurbishment), location (e.g. urban or rural), land costs (e.g. serviced, un-serviced, nominal value) and year built (e.g. inflation) that all have an influence on project cost and unitized comparisons.

Attempts have been made in previous OEB rate-regulated utility Cost of Service proceedings to present and compare both administrative office and operations building costs. For example, Table 17 summarizes administrative office and operations comparison information in pages 8 and 9 of the OEB Staff Submission dated March 29, 2019 from the EB-2018-0028 Energy+ proceeding (with the exception of the last column which has been added to reflect final project information for Hydro Ottawa new facilities).

Table 17 – Head Office Cost Comparison

	Power Stream EB-2008-0244	Waterloo North EB-2010-0144	Enersource EB-2012-0033	InnPower EB-2014-0086	Milton Hydro EB-2015-0004	PUC Distribution EB-2012-0162	Energy+ EB-2019-0180	Hydro Ottawa EB-2019-0261
Year In Service	2008	2011	2012	2015	2015	2012	2022	2019
Function	Admin.	Admin /Ops	Admin.	Admin/ Ops.	Admin/ Ops.	Admin./Ops.	Admin.	Admin./ Ops.
Type of Project	New Build	Custom Build	Purch./ Refurb	Custom Build.	Purch./ Refurb.	New Build	Purch./ Refurb.	New Build
Capital Cost	$27,700,000	$26,682,000	$18,000,000	$10,896,704	$12,524,798	$23,000,000	$8,100,000	$99,543,840
Sq ft	92,000	105,000	79,000	36,172	91,872	110,382	21,892	293,873
FTEs	250	125	150	41	62	87	67	653
Sq.Ft./FTE	368	840	527	882	1,494	1,269	327	450
Cost/FTE	$110,800	$213,456	$120,000	$265,773	$203,655	$264,368	$120,896	$152,441
Cost/Sq.Ft.	$301	$254	$228	$301	$136	$208	$370	$339

These comparisons are not necessarily made on an "apples to apples" basis or with full information (e.g. being able to isolate land costs and similar building functions). For example, Operations, Warehouse and Storage construction typically costs less than Administrative Office space costs, yet the total square footage in the above table is aggregated. Land costs vary across comparator LDCs and some are at a nominal value (e.g. Energy +). If land costs are removed from Hydro Ottawa, the Cost/Sq.Ft is $272 which compares favourably to other LDCs as shown in Table 18 below.

Table 18 – Head Office Cost Comparison, Excluding Hydro Ottawa Land

	Power Stream EB-2008-0244	Waterloo North EB-2010-0144	Enersource EB-2012-0033	InnPower EB-2014-0086	Milton Hydro EB-2015-0004	PUC Distribution EB-2012-0162	Energy+ EB-2019-0180	Hydro Ottawa EB-2019-0261
Year In Service	2008	2011	2012	2015	2015	2012	2022	2019- Excl. Land
Function	Admin.	Admin /Ops	Admin.	Admin/ Ops.	Admin/ Ops.	Admin./Ops.	Admin.	Admin./ Ops.
Type of Project	New Build	Custom Build	Purch./ Refurb	Custom Build.	Purch./ Refurb.	New Build	Purch./ Refurb.	New Build.
Capital Cost	$27,700,000	$26,682,000	$18,000,000	$10,896,704	$12,524,798	$23,000,000	$8,100,000	$80,049,143
Sq ft	92,000	105,000	79,000	36,172	91,872	110,382	21,892	293,873
FTEs	250	125	150	41	62	87	67	653
Sq.Ft./FTE	368	840	527	882	1,494	1,269	327	450
Cost/FTE	$110,800	$213,456	$120,000	$265,773	$203,655	$264,368	$120,896	$122,587
Cost/Sq.Ft.	$301	$254	$228	$301	$136	$208	$370	$272

In order to help benchmark facilities on a comparable basis, information from Table 19 below identifies facilities that are strictly Administration and then capital costs are escalated to 2019 dollars. These results are then compared with Hydro Ottawa's Administrative Office Building. This comparison, which reflects escalation for PowerStream and Enersource capital cost is presented in Table 19 below.

Table 19 – Head Office Admin. Building Costs, PowerStream & Enersource Escalated

	Energy+ (Southworks)	PowerStream	Enersource	Hydro Ottawa
OEB Docket	EB-2018-0028	EB-2008-0244	EB-2012-0033	EB-2019-0261
Functions	Admin.	Admin	Admin.	Admin. (EC-1)
In-Service Year	2022	2008	2012	2019
Total Cost	$8,100,000	$37,588,900	$21,114,000	$52,770,894
Total Sq. Ft.	21,892	92,000	79,000	127,132
FTEs	67	250	150	419
Sq.Ft./FTE	327	368	527	303
Cost/FTE	$120,896	$150,356	$140,760	$125,945
Cost/Sq.Ft.	$370	$409	$267	$415

Costs for PowerStream and Enersource were escalated/normalized using the Statistics Canada Building Construction Price Index. Cost escalation results from this Statistics Canada information are summarized in Table 20.

Table 20 – Statistics Canada Building Construction Price Index

	Q1 2008	Q1 2012	Q2 2019	Q2'2019/Q1'2008	Q2'2019/Q1'2012
Toronto	83.0	90.4	108.3	30.5%	19.8%
Ottawa/Gatineau	81.0	93.7	109.9	35.7%	17.3%

The 2008 cost of the PowerStream Admin. Building ($27,700,000) was escalated by 35.7% and the 2012 cost of the Enersource Admin. Building ($18,000,000) was escalated by 17.3%. The Building Construction Price Index for Ottawa-Gatineau was used to enable a closer comparison to the vintage of a building had it been constructed in the Ottawa area. It is noted that non-residential construction cost escalation in the Ottawa-Gatineau area has been higher than in Toronto over the 2008 to 2019 period (35.7% compared to 30.5%) but lower in the 2012 to 2019 period. The most direct comparison to Hydro Ottawa’s building is the PowerStream building as it is similar in nature in that it is a new build, primarily administration and does not include operations, garage and warehousing facilities. The PowerStream escalated cost of $409 sq./ft. is close to the Hydro Ottawa cost of $415 sq./ft.. Further differences between the PowerStream and Hydro Ottawa cost per sq./ft. would be the price of land but Hydro Ottawa does not have the information needed to remove the land costs from the comparator LDCs. Hydro Ottawa recognizes that while attempting to normalize data through escalation could be helpful in some cases, it does not necessarily result in a meaningful comparisons as there are other factors that create unit cost differences the nature of the project (new build vs. refurbishment, the cost of land and the mix of space (e.g. office / warehouse / garage / operations / storage).

With respect to other unitized measures that are not impacted by escalation, it is noted that the Hydro Ottawa Administrative Office Building, when compared to the other administrative office buildings in Table 19 above, has the lowest number of Sq. Ft,/FTE (303 Sq.Ft/FTE), reflecting efficient use of space. Hydro Ottawa also has the lowest Cost/FTE when compared to PowerStream and Enersource ($125,945/FTE). The Energy+ Southworks Cost/FTE, while lower than Hydro Ottawa's, is not directly comparable with Hydro Ottawa Administrative Office Building as the nature of the Energy+ project is a refurbishment/renovation and the building was purchased for $1.[22]

Removing the cost of Hydro Ottawa land from Table 19, results in a Cost of $372 per Sq. Ft. as shown in Table 21 below.

[22] Update to Evidence, EB-2018-0028 (December 13, 2018), page 10.

Table 21 – Head Office Admin Building Costs, PowerStream & Enersource Escalated – Excluding Hydro Ottawa EC Land

	Energy+ (Southworks)	PowerStream	Enersource	Hydro Ottawa
OEB Docket	EB-2018-0028	EB-2008-0244	EB-2012-0033	EB-2019-0261
Functions	Admin.	Admin	Admin.	Admin. (EC-1)
In-Service Year	2022	2008	2012	2019
Total Cost	$8,100,000	$37,588,900	$21,114,000	$47,311,660
Total Sq. Ft.	21,892	92,000	79,000	127,132
FTEs	67	250	150	419
Sq.Ft./FTE	327	368	527	303
Cost/FTE	$120,896	$150,356	$140,760	$112,916
Cost/Sq.Ft.	$370	$409	$267	$372

Table 22 below compares the East Campus Administration & Operations buildings (EC-2 & EC-3) to other Administration & Operations buildings identified in Table 18 above. In order to compare on a current cost basis, costs have been escalated using the Statistics Canada Building Construction Price Index for the relevant In-Service year as per Table 23.[23]

[23] Update to Evidence, EB-2018-0028 (December 13, 2018), page 10.

Table 22 – Comparison of Administration & Operations Buildings (Escalated $) to East Campus (EC-2 & EC-3)

East Campus (EC-2/EC-3) - Operations, Office, Garage, Warehouse						
	Waterloo North Hydro Inc.	InnPower	Milton Hydro Distribution Inc.	PUC Distribution Inc.	Hydro Ottawa EC-2 & EC-3 Scenario 1: Incl. Land	Hydro Ottawa EC-2 & EC-3 Scenario 2: Excl. Land
Functions	Admin & Ops	Admin & Ops	Admin & Ops	Admin & Ops	Admin & Ops	Admin & Ops
In-service Year	2011	2015	2015	2012	2019	2019
Total Cost	$32,578,722	$12,487,623	$14,353,419	$26,979,000	$19,442,411	$12,207,392
Total Sq. Ft.	105,000	36,172	91,872	110,382	67,833	67,833
FTEs	125	41	61.5	87	140	140
Sq. Ft./FTE	840	882	1,494	1,269	485	485
Cost/FTE	$260,630	$304,576	$233,389	$310,103	$138,874	$87,196
Cost/Sq. Ft.	$310	$345	$156	$244	$287	$180

It is noted that when costs are escalated, Hydro Ottawa's EC-2/EC-3 facilities have the lowest Cost/FTE ($138,874) and is in the midrange of Cost/Sq.Ft. ($287). The EC-2/EC-3 facility has the lowest Sq.Ft./FTE result (485) which is significantly lower than all other comparative results – this result is not impacted by escalation. As land prices vary across the Province, Scenario 2 removes the cost of land from the Hydro Ottawa Total Cost to provide a clear picture of construction costs, resulting in a Cost/Sq. Ft of $180. Hydro Ottawa does not have the information needed to remove land costs from the comparator LDCs.

In order to compare on a current cost basis, costs have been escalated using the Statistics Canada Building Construction Price Index for the relevant In-Service year as per Table 23 below.[24]

[24] Update to Evidence, EB-2018-0028 (December 13, 2018), page 10.

Table 23 – Statistics Canada Building Construction Price Index

	Q1 2011	Q1 2012	Q1 2015	Q2 2019	Q2'2019 / Q1'2011	Q2'2019 / Q1'2012	Q2'2019 / Q1'2015
Toronto	87.5	90.4	93.7	108.3	23.8%	19.8%	15.6%
Ottawa/Gatineau	90	93.7	95.9	109.9	22.1%	17.3%	14.6%

Table 24 below compares the South Campus Administration & Operations building to other Administration & Operations buildings identified in Table 18 above.

It is noted on Table 24 below, that when costs are escalated, Hydro Ottawa's SC-1 facility costs as measured by Cost/FTE and Cost/Sq. Ft. are in the middle of the comparator LDCs. The number of Sq. Ft/FTE is also in the middle of the range. Hydro Ottawa acknowledges that there are a variety of configurations to the mix of Administration and Operations space and also differences in cost between a refurbished facility (e.g. Milton Hydro) and a new build. Also, differences in land values and size will have an impact on comparator costs. As such, a Scenario 2 has been provided which removes the land cost from the SC-1 building in order to provide an indication of direct construction costs.

Table 24 – Comparison of Administration & Operations Buildings (Escalated $) to South Campus (SC-1)

South Campus (SC) - Operations, Office, Garage, Warehouse						
	Waterloo North Hydro Inc.	InnPower	Milton Hydro Distribution Inc.	PUC Distribution Inc.	Hydro Ottawa SC-1 Scenario 1: Incl. Land	Hydro Ottawa SC-1 Scenario 2: Excl. Land
Functions	Admin & Ops	Admin & Ops	Admin & Ops	Admin & Ops	Admin & Ops	Admin & Ops
In-service Year	2011	2015	2015	2012	2019	2019
Total Cost	$32,578,722	$12,487,623	$14,353,419	$26,979,000	$27,330,534	$20,530,091
Total Sq. Ft.	105,000	36,172	91,872	110,382	98,908	98,908
FTEs	125	41	61.5	87	94	94
Sq. Ft./FTE	840	882	1,494	1,269	1,052	1,052
Cost/FTE	$260,630	$304,576	$233,389	$310,103	$290,750	$218,405
Cost/Sq. Ft.	$310	$345	$156	$244	$276	$208

PPI CONSULTING LIMITED

FAIRNESS COMMISSIONER REPORT

C O N F I D E N T I A L

Project:	**Hydro Ottawa Request for Proposal - Facilities Renewal Program Design Build**
Report Stage:	**Final Report**
Date of submission:	**October 14, 2016**
Fairness Commissioner:	**Rick Wilson**
David Ayer	**David Ayer, Manager, Supply Chain**
Submitted by:	**PPI Consulting Limited**

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1 INTRODUCTION

PPI Consulting Limited (PPI) was engaged by Hydro Ottawa as Fairness Commissioners to observe the procurement process for the Hydro Ottawa Request for Proposal - Facilities Renewal Program Design Build. The competitive process was open to pre-qualified proponents.

PPI's engagement commenced in January 2016. The primary PPI Fairness Commissioner assigned to the project was Rick Wilson. PPI confirms that Rick Wilson and other fairness participants are independent third parties with respect to this initiative and has no conflict of interest.

This fairness report covers the period from engagement to the completion of the evaluation process.

2 SCOPE OF WORK

PPI was engaged during the drafting stage of the Request for Proposal - Facilities Renewal Program Design Build. The Fairness Commissioner was responsible for advising the Hydro Ottawa project team on the procurement process, to mitigate risk and protect the integrity of the procurement process. Responsibilities included, but were not limited to, providing advice on:

- Fairness issues concerning the development of the RFP;
- Monitoring and providing advice on potential or real barriers to proponent participation;
- Identifying key issues and potential risks in the procurement process;
- Identifying any situation which may compromise the integrity of the evaluation process (i.e. overseeing the evaluation team and procurement processes and assessing potential bias or undue influence);
- Monitoring the evaluation of all submissions to oversee the fair treatment of all proponents;
- Monitoring the adherence of established government procurement practice in the planning, issue, evaluation, and
- Providing a Fairness Report at the conclusion of the evaluation process.

3 PPI METHODOLOGY

3.1 Our Approach and Methodology

In Canada, a ***duty of fairness*** generally exists independent of statutory law and has become a construct of both common law, and forceful public policy directed squarely at invoking public trust.

In terms of public policy, the principles of fairness, openness, transparency and accountability have been articulated and embodied in legislation, policy statements, and administrative directives (for all levels of government as well as publicly funded authorities and institutions) and set out the over-riding integrity framework for public procurement.

In this context, the *duty of fairness* in procurement can be expressed as:

- ***Procedural fairness,*** e.g. how decisions are made (the standards, criteria and steps to be followed before, during and after decisions are made); the transparency of the process (a prerequisite in system integrity); and the related enforcement of reserve rights (i.e. privilege clauses);
- ***Design and Performance Fairness***, e.g. providing clarity of requirements to competing proponents that avoids (a) incomplete descriptions, or vagueness that may favour incumbents, (b) product bias in specifications and selection criteria, and (c) conflicting requirements or ambiguous statements that may confuse design and performance conditions;
- ***Substantive fairness,*** e.g. the fairness of the decision itself relative to criteria or obligations set by law (including case law), or how the actual provisions are set out in a formal contract setting; and
- ***Relational fairness***, e.g. achieving a balance between the rights and interests of all parties, how people are treated during the decision making process (often the centre of a complaint).

The independent review of integrity issues and adherence to best practices in public sector procurement is a contemporary development that is designed to ensure fairness in the management of procurement initiatives, where fairness is defined as openness, competitiveness, and transparency.

In providing fairness consultancy services, PPI's approach and methodology includes a number of common elements, i.e.:

- reviewing the procurement methodology to be employed in the context of:
  - objectivity and diligence respecting evaluation criteria;
  - the proper use of assessment tools;
- monitoring decisions made, i.e. that decisions are made objectively, free from personal favouritism and political influence;
- assuring compliance with the assessment and selection process (ensuring that the evaluation teams follow the requirements for fair and equitable treatment of all proponents and follow the process that was detailed in the RFx);
- monitoring communications to proponents, including notification of changes in requirements;
- monitoring the confidentiality of proposals and evaluations (i.e. recognizing that the documentation arising from these initiatives, or received by the public sector in the development

and conduct of its engagement of private sector interests in procurement initiatives, may have claims of privilege attached to them);

- monitoring the security of information (i.e. providing advice on the disclosure of any information while preserving the commitment to transparency and openness of the process);
- assessing and making recommendations on any situation that may present a real or perceived conflict of interest, within the project management or evaluation team, or relevant to any supplier's proposal or representation;
- monitoring the process for any potential conflict of interest that may arise throughout the RFP assessment, selection or contracting process;
- process monitoring, including:
    - the planning and conduct of proceedings;
    - facilitation, mediation or arbitration of contentious matters arising throughout the process;
    - assuring adequate debriefing of unsuccessful proponents.

In our approach, the Fairness Commissioner activities may vary depending on the complexity of the project and could include:

- review of and attention to the planned conduct of proceedings;
- facilitation, mediation or arbitration of contentious matters that may arise throughout the process;
- recommendations on matters that require review of a specific policy or procedure;
- assessment of and recommendations on any situation that may present a real or perceived conflict of interest, within the project management or evaluation team, or relevant to any proponent proposal or representation;
- maintaining focus on objectives and outcomes;
- reporting on compliance and the overall integrity of the process;
- a review of the procurement methodology to be employed, including compliance with administrative policies and practices; transparency, inclusion, openness and fairness in the definition of requirements; the development and application of evaluation criteria applied to written proposals, oral presentations and demonstrations; scoring; and open communications with proponents.
- providing guidance on maintaining the confidentiality of all proposal and evaluation records and documents;
- assess and make recommendations on any situation that may present a real or perceived conflict of interest, within the project management or evaluation team, or relevant to any respondent's proposal or representation;
- monitor the process for any potential conflict of interest that may arise throughout the RFP assessment, selection or contracting process;
- make recommendations on any action or decision of the evaluation team;
- make recommendations on any policy or procedure that should be reviewed by the Project Authority; and

- provide reports at prescribed milestones attesting to the fairness of the process or identifying any fairness deficiencies.

3.2 In Summary

When applying our methodology, PPI assesses the process, documentation and activities that are monitored based on a number of fairness principles specific to each stage in the procurement process.

These principles are documented against each phase of the fairness engagement in our fairness reports.

4 FAIRNESS COMMISSIONER DELIVERABLES

4.1 Review of Process and Activities Prior to RFP Posting

4.1.1 Activity Monitored

The following documents were provided to PPI for review prior to posting:

- Draft and Final Request for Proposal documentation
- Evaluation Plan (scoring criteria, scoring grids and process)

Our review of documents and monitoring of activities in this phase considered the fairness principles below:

- Documents should be clearly written
- Language should be consistent, with consistent and appropriate use of defined terms
- Mandatory submission requirements should be clear and consistent with the scope of the procurement
- The bid open period should be reasonable and provide sufficient time for proponents to respond
- Sufficient information should be provided to allow a proponent to price the deliverables. If an incumbent is in place, access to relevant historic data should be provided
- Evaluation process should be clearly stated, i.e. steps in the evaluation, minimum thresholds etc.
- Evaluation criteria should contain clear direction as to the information that is required and the scoring method contains no hidden criteria
- The submission requirements should contain no bias for or against any one proponent
- All potential proponents should be provided with the same opportunity and the same information
    - All information and relevant project material necessary for a full understanding of the opportunity should be made available to all potential proponents at the same time
- All meetings with potential proponents should be attended by the Fairness Commissioner

4.1.2 Pre-Posting RFP Phase Attestation of Fairness

PPI reviewed all of the information provided and observed all relevant activities in this stage of the procurement process. Our assessment of these activities is as follows:

COMMENT/DEFICIENCY	PRE-POSTING RFP PROCESS ASSESSMENT
No deficiencies were observed during this phase of the process	It is our professional opinion that the Pre Posting process and the activities that we observed during this phase of the process were carried out in a fair, open and transparent manner

4.2 Review of Process and Activities during Bid Open Period

4.2.1 Activity Monitored

The following documents were monitored by PPI:

- Addenda which included proponent questions and answers

PPI participated in the following activities:

- Commercially Confidential Meetings (CCMs) with the exception of June 28, 2016

PPI reviewed the documents to assess their fairness. Our review considered the fairness principles listed in the table below:

- The opportunity and all proponent communications should be posted on an open bidding system accessible to all potential proponents at the same time, or if a limited procurement process, should be provided to all invited proponents at the same time
- Sufficient time should be given to proponents to prepare and submit a proposal. As a courtesy to the proponent community, consideration should be given to external influences such as March break and Christmas vacation periods when calculating the response time
- All potential proponents should have the opportunity to submit questions according to a prescribed communications protocol
- Clarification questions should be addressed in a timely manner and should be published to all potential proponents as an amendment or addendum
- All amendments or addenda to the RFP should be distributed to all potential proponents at the same time
- Information should be provided in a timely manner such that potential proponents have sufficient time to prepare their proposals. If not, an extension time applicable to the new information should be provided
- The identity of potential proponents should be removed from any Addenda/Amendments
- No new mandatory requirements result from the Addenda/Amendment phase.

4.2.2 Bid Open Period Phase Attestation of Fairness

PPI reviewed all of the information provided and observed all relevant activities in this stage of the procurement process. Our assessment of these activities is as follows:

COMMENT/DEFICIENCY	BID OPEN PERIOD PROCESS ASSESSMENT
No deficiencies were observed during this phase of the process.	It is our professional opinion that the process and the activities that were observed during this phase of the process were carried out in a fair, open and transparent procurement process.

4.3 Review of Process and Activities during Bid Evaluation Process

4.3.1 Activity Monitored

The following documents were provided to PPI for review:

- Evaluation Plan
- Scoring workbooks
- Evaluator Instructions/Process Guidelines for evaluation

PPI participated in the following activities:

- Evaluation Kick-off / Evaluator training session
- Consensus scoring of proposals
- Financial evaluation
- Proponent presentations

Our review of documents and monitoring of activities in this phase considered the fairness principles below:

- Evaluation plan should be consistent with the published procurement documents
- Evaluation team members should be chosen and confirmed prior to the receipt of proposals
- Evaluation training should be provided to all evaluators and observers. This should include informing evaluators of the following as a minimum:
    - identity of the proposals received and requesting evaluators to declare any conflict of interest
    - confidentiality protocols
    - document control
    - conduct for interaction with proponents (e.g. with an incumbent bidder)

- clarification process
- overview of scoring workbooks and method for individual assessment
- explanation of hidden criteria
- overview of consensus scoring process
- explanation of fairness and the need for objectivity, consistency and equitable treatment of all proposals
- guidance with respect to only assessing the information that is in the proposal – not info from previous experience etc.

- The scoring criteria and assessment tools should be established prior to the receipt of proposals and should be consistent with the RFP, i.e. contain no hidden scoring criteria
- The submissions should be logged and recorded upon receipt, clearly identifying those that were submitted on time
- The mandatory submission requirements were complied with
- The process for establishing one score from a team of evaluators should be established prior to the receipt of proposals (consensus, averaging, etc.)
- The same team of evaluators should evaluate all proposals (or parts thereof)
- The scoring assessment should be applied consistently and equitably by the evaluation team with no evidence of bias
- A secure location for the evaluation exercise should be established for the period of the evaluation
- Proposal documents should be physically secured within a secure location.

4.3.2 Bid Evaluation Phase Attestation of Fairness

PPI reviewed all of the information provided and observed all relevant activities in this stage of the procurement process. Our assessment of these activities is as follows:

COMMENT/DEFICIENCY	BID OPEN PERIOD PROCESS ASSESSMENT
No deficiencies were observed during this phase of the process	It is our professional opinion that the activities that we observed during this phase of the process were carried out in a fair, open and transparent manner

5 Observations

Following the initial architectural Compliance Advisory Team review, Hydro Ottawa deemed that one bid was materially non-compliant with the requirements of the exemplary design to such a degree that it was unacceptable to Hydro Ottawa. Following further review and confirmation from legal counsel that the bid was materially deficient with respect to the requirements of Hydro Ottawa as set out in the exemplary design, the bid was removed from further evaluation. PPI's observation is that the bid was removed from the evaluation process for reasons of material non-compliance to the exemplary design and was not subjected to the evaluation process as set out in the RFP.

6 ATTESTATION OF FAIRNESS

It is our professional opinion that the procurement process for the Facilities Renewal Program Design Build up to and including the completion of the evaluation process was conducted in a fair, open and transparent manner.

October 4, 2016

Rick Wilson

Dated

ASSETS – PROPERTY PLANT & EQUIPMENT CONTINUITY SCHEDULE

1. INTRODUCTION

This Schedule provides information as required under section 2.2.1.2 of the *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications*, as updated on July 12, 2018 and addended on July 15, 2019 ("Filing Requirements"). In addition, the amounts for construction work-in-progress ("CWIP") have also been provided. In accordance with the Filing Requirements, appended to this Schedule are the following:

- Attachment 2-2-1(A): OEB Appendix 2-BA - 2016 Fixed Asset Continuity Schedule
- Attachment 2-2-1(B): OEB Appendix 2-BA - 2017 Fixed Asset Continuity Schedule
- Attachment 2-2-1(C): OEB Appendix 2-BA - 2018 Fixed Asset Continuity Schedule
- Attachment 2-2-1(D): OEB Appendix 2-BA - 2019 Fixed Asset Continuity Schedule
- Attachment 2-2-1(E): OEB Appendix 2-BA - 2020 Fixed Asset Continuity Schedule
- Attachment 2-2-1(F): OEB Appendix 2-BA - 2021 Fixed Asset Continuity Schedule
- Attachment 2-2-1(G): OEB Appendix 2-BA - 2022 Fixed Asset Continuity Schedule
- Attachment 2-2-1(H): OEB Appendix 2-BA - 2023 Fixed Asset Continuity Schedule
- Attachment 2-2-1(I): OEB Appendix 2-BA - 2024 Fixed Asset Continuity Schedule
- Attachment 2-2-1(J): OEB Appendix 2-BA - 2025 Fixed Asset Continuity Schedule

2. GROSS ASSETS BY FUNCTION

Tables 1 and 2 below provide Hydro Ottawa's Gross Assets balance by function for the Historical Years 2016-2018, Bridge Years 2019 and 2020, and Test Years 2021-2025.

Table 1 – 2016-2020 Gross Assets Breakdown by Function ($'000s)

Gross Assets	Historical Years			Bridge Years	
	2016	2017	2018	2019	2020
Transmission Plant	$86,743	$86,787	$87,116	$111,468	$114,617
Distribution Plant	$677,307	$748,804	$835,567	$902,780	$962,291
General Plant	$158,074	$177,694	$189,652	$275,660	$294,021
Gross Fixed Assets Before CWIP and Accumulated Depreciation[1]	**$922,124**	**$1,013,285**	**$1,112,335**	**$1,289,908**	**$1,370,929**
Accumulated Depreciation	**$(111,437)**	**$(148,273)**	**$(193,957)**	**$(234,522)**	**$(284,777)**
CWIP	$41,389	$63,853	$129,242	$37,227	$80,744
TOTAL INCLUDING CWIP[2]	**$852,076**	**$928,862**	**$1,047,620**	**$1,092,613**	**$1,166,896**

Table 2 – 2021-2025 Gross Assets Breakdown by Function ($'000s)

Gross Assets	Test Years				
	2021	2022	2023	2024	2025
Transmission Plant	$122,864	$148,476	$152,078	$157,508	$166,731
Distribution Plant	$1,025,910	$1,102,457	$1,166,737	$1,233,617	$1,315,811
General Plant	$369,087	$383,907	$391,361	$399,599	$428,514
Gross Fixed Assets Before CWIP and Accumulated Depreciation[3]	**$1,517,861**	**$1,634,840**	**$1,710,176**	**$1,790,724**	**$1,911,056**
Accumulated Depreciation	**$(334,623)**	**$(389,254)**	**$(446,435)**	**$(505,659)**	**$(568,753)**
CWIP	$51,388	$29,536	$40,457	$54,289	$27,763
TOTAL INCLUDING CWIP[4]	**$1,234,626**	**$1,275,123**	**$1,304,198**	**$1,339,356**	**$1,370,066**

For detailed Fixed Asset Continuity Schedules for the years 2016-2025, please see Attachments 2-2-1:(A) through (J).

[1] Variances may exist due to rounding.
[2] Variances may exist due to rounding.
[3] Variances may exist due to rounding.
[4] Variances may exist due to rounding.

3. GROSS ASSETS BY MAJOR PLANT ACCOUNT

In accordance with section 2.2.1.2 of the Filing Requirements, Table 3 provides Gross Assets balance by major plant account for each functionalized plant item, for Historical Years 2016-2018 and for Bridge Years 2019 and 2020.

Table 3 – 2016-2020 Gross Assets Breakdown by Major Plant Account Organized by Uniform System of Account ($'000s)

USofA	Description	Historical Years			Bridge Years	
		2016	2017	2018	2019	2020
1815	Transformer Station Equipment >50 kV	$86,743	$86,786	$87,116	$111,468	$114,617
Subtotal Transmission Plant		**$86,743**	**$86,786**	**$87,116**	**$111,468**	**$114,617**
1612	Land Rights	$2,283	$2,294	$2,288	$2,288	$2,297
1805	Land	$4,645	$4,649	$4,652	$4,653	$4,654
1808	Buildings	$27,727	$28,802	$29,663	$30,189	$30,897
1820	Distribution Station Equipment <50 kV	$90,031	$105,595	$116,484	$136,392	$142,155
1830	Poles, Towers & Fixtures	$107,430	$117,400	$128,239	$135,443	$144,524
1835	Overhead Conductors & Devices	$99,986	$108,617	$121,174	$130,158	$146,838
1840	Underground Conduit	$123,465	$144,674	$183,207	$209,553	$232,720
1845	Underground Conductors & Devices	$121,891	$143,156	$158,562	$174,458	$198,932
1850	Line Transformers	$70,722	$79,264	$87,689	$92,878	$100,712
1855	Services (Overhead & Underground)	$53,864	$61,034	$67,353	$69,941	$74,510
1860	Meters	$38,426	$40,578	$42,379	$47,112	$51,769
1970	Load Management Controls Customer Premises	$134	$134	$134	$0	$147
1975	Load Management Controls Utility Premises	$18	$18	$0	$0	$90
1980	System Supervisor Equipment	$6,817	$7,718	$11,472	$13,759	$14,773
2440	Deferred Revenue	$(70,132)	$(95,130)	$(117,729)	$(144,044)	$(182,727)
Subtotal Distribution Plant		**$677,307**	**$748,803**	**$835,567**	**$902,780**	**$962,291**
1609	Capital Contributions Paid	$20,089	$20,776	$22,976	$35,051	$35,961
1611	Computer Software	$51,958	$64,972	$66,629	$67,874	$80,905
1905	Land	$20,356	$20,560	$20,560	$19,942	$19,942

USofA (Cont'd)	Description (Cont'd)	Historical Years (Cont'd)			Bridge Years (Cont'd)	
		2016	2017	2018	2019	2020
1908	Buildings & Fixtures	$32,327	$32,433	$35,197	$94,603	$95,284
1915	Office Furniture and Equipment	$1,330	$1,407	$1,616	$4,778	$4,879
1920	Computer Equipment - Hardware	$7,346	$6,804	$8,600	$13,652	$15,255
1930	Transportation Equipment	$13,566	$17,351	$17,504	$18,464	$18,617
1935	Stores Equipment	$6	$0	$0	$562	$562
1940	Tools, Shop & Garage Equipment	$4,064	$3,543	$4,196	$4,681	$5,131
1945	Measurement & Testing Equipment	$229	$215	$215	$252	$252
1950	Power Operated Equipment	$3,252	$1,064	$914	$1,098	$1,369
1955	Communications Equipment	$3,302	$8,318	$10,990	$14,447	$15,462
1960	Miscellaneous Equipment	$249	$250	$255	$256	$402
Subtotal General Plant		**$158,074**	**$177,693**	**$189,652**	**$275,660**	**$294,021**
Accumulated Depreciation		**$(111,437)**	**$(148,273)**	**$(193,957)**	**$(234,522)**	**$(284,777)**
	GROSS FIXED ASSETS BEFORE CWIP	**$810,687**	**$865,009**	**$918,378**	**$1,055,386**	**$1,086,152**
2055	Construction Work-in-Progress	$41,389	$63,853	$129,242	$37,227	$80,744
	TOTAL INCLUDING CWIP	**$852,076**	**$928,862**	**$1,047,620**	**$1,092,613**	**$1,166,896**

In accordance with section 2.2.1.2 of the Filing Requirements, Table 4 below provides Gross Assets balance by major plant account for each functionalized plant item for Test Years 2021-2025.

Table 4 – 2021-2025 Gross Assets Breakdown by Major Plant Account Organized by Uniform System of Account ($'000s)

USofA	Description	Test Years				
		2021	2022	2023	2024	2025
1815	Transformer Station Equipment >50 kV	$122,864	$148,476	$152,078	$157,508	$166,731
Subtotal Transmission Plant		**$122,864**	**$148,476**	**$152,078**	**$157,508**	**$166,731**
1612	Land Rights	$2,310	$2,323	$2,335	$2,348	$2,360
1805	Land	$4,655	$4,818	$4,818	$4,818	$5,597
1808	Buildings	$31,622	$39,988	$40,522	$41,453	$42,869
1820	Distribution Station Equipment <50 kV	$155,798	$165,707	$169,737	$181,635	$208,287
1830	Poles, Towers & Fixtures	$152,926	$161,774	$171,336	$179,209	$186,899
1835	Overhead Conductors & Devices	$158,007	$171,112	$184,464	$196,200	$207,644
1840	Underground Conduit	$258,416	$280,641	$301,045	$319,592	$338,120
1845	Underground Conductors & Devices	$224,573	$245,221	$263,683	$280,969	$298,142
1850	Line Transformers	$108,857	$116,780	$124,383	$131,512	$138,655
1855	Services (Overhead & Underground)	$78,914	$83,478	$88,074	$92,510	$96,939
1860	Meters	$58,145	$63,944	$69,662	$75,920	$81,661
1970	Load Management Controls Customer Premises	$855	$919	$919	$919	$919
1975	Load Management Controls Utility Premises	$484	$533	$533	$533	$533
1980	System Supervisor Equipment	$16,350	$18,052	$19,044	$20,139	$21,672
2440	Deferred Revenue	$(226,002)	$(252,833)	$(273,818)	$(294,138)	$(314,486)
Subtotal Distribution Plant		**$1,025,910**	**$1,102,457**	**$1,166,737**	**$1,233,619**	**$1,315,811**
1609	Capital Contributions Paid	$87,185	$87,395	$87,495	$89,625	$96,925
1611	Computer Software	$91,850	$98,172	$101,762	$104,435	$121,290
1905	Land	$19,942	$19,942	$19,942	$19,942	$19,942
1908	Buildings & Fixtures	$97,627	$98,054	$98,407	$98,760	$99,112
1915	Office Furniture and Equipment	$4,954	$5,030	$5,080	$5,131	$5,181
1920	Computer Equipment - Hardware	$16,837	$19,455	$20,616	$21,504	$23,077
1930	Transportation Equipment	$22,920	$26,097	$26,829	$27,726	$27,825

USofA (Cont'd)	Description (Cont'd)	Test Years (Cont'd)				
		2021	2022	2023	2024	2025
1935	Stores Equipment	$562	$562	$562	$562	$562
1940	Tools, Shop & Garage Equipment	$5,604	$6,079	$6,540	$7,005	$7,474
1945	Measurement & Testing Equipment	$252	$252	$252	$252	$252
1950	Power Operated Equipment	$1,482	$1,482	$1,597	$1,597	$2,055
1955	Communications Equipment	$18,972	$20,443	$21,318	$22,099	$23,833
1960	Miscellaneous Equipment	$900	$944	$961	$961	$986
Subtotal General Plant		**$369,087**	**$383,907**	**$391,361**	**$399,599**	**$428,514**
Accumulated Depreciation		**$(334,623)**	**$(389,254)**	**$(446,435)**	**$(505,659)**	**$(568,753)**
GROSS FIXED ASSETS BEFORE CWIP		**$1,183,238**	**$1,245,586**	**$1,263,741**	**$1,285,067**	**$1,342,303**
2055	Construction Work-in-Progress	$51,388	$29,536	$40,457	$54,289	$27,763
TOTAL INCLUDING CWIP		**$1,234,626**	**$1,275,123**	**$1,304,198**	**$1,339,356**	**$1,370,066**

4. SIGNIFICANT IN-SERVICE ADDITIONS

4.1. HISTORICAL YEARS 2016-2018 AND BRIDGE YEARS 2019-2020

The major capital projects that were executed, or are set to be executed, during this period are outlined below in Table 5. Background information on these projects can be found in Attachment 2-4-3(E): Material Investments.

Table 5 – 2016-2020 Overview of Significant In-Service Additions ($'000,000s)

Description/Type	Project	Cost
Station growth driven by capacity constraints	Merivale MTS Station Renewal	$15.9
	Richmond South Station Upgrade	$13.4
Other distribution system expansions/upgrades to provide basic levels of service and supply growing communities	Residential, Commercial, System Expansion, and Infill & Upgrade Capital Programs	$68.7
	Plant Relocation	$13.6
Ongoing replacement of existing aging distribution system to minimize failure risk	Pole Renewal	$44.8
	Cable Replacement and Renewal	$29.9
	Emergency Renewal	$34.2
	Critical Renewal	$11.7
Station protection and control renewal projects	Fibre Optic Network	$18.9
	Overbrook SO Station Switchgear Replacement	$13.3
	System Voltage Conversion	$13.0
	Woodroffe Station Switchgear Replacement	$11.1
Other	New Administrative Office and Operations Facilities[5]	$79.9
	Enterprise Resource Planning System Upgrade	$11.3
	Customer Care and Billing System Upgrades	$8.1
	Fleet Replacement[6]	$6.3

For 2016-2020, Hydro Ottawa is projecting Capital Additions to exceed the overall envelope by $54.1M. Additional details, including a variance analysis, are available in Exhibit 2-4-1: Capital Expenditure Summary.

[5] Land is excluded. For additional information on this project, please see Attachment 2-1-1(A): New Administrative Office and Operations Facilities.
[6] For additional information, please see Attachment 2-4-3(F): Fleet Replacement Program.

4.2. TEST YEARS 2021-2025

The major capital projects planned for the 2021-2025 period are outlined below in Table 6. Background information on these projects can be found in Attachment 2-4-3(E): Material Investments.

Table 6 – 2021-2025 Overview of Significant In-Service Additions ($'000,000s)

Description/Type	Project	Cost
Station growth driven by capacity constraints	Cambrian MTS	$82.4[7]
	New East Station	$30.7[8]
Other distribution system expansion/upgrade to provide basic levels of service and supply growing communities	Residential, Commercial, System Expansion, and Infill & Upgrade Capital Programs	$67.6
	Plant Relocation	$11.0
Ongoing replacement of existing aging distribution system to minimize failure risk	Pole Renewal	$33.7
	Cable Replacement and Renewal	$40.7
	Emergency Renewal	$22.4
	Critical Renewal	$21.5
Station protection and control renewal projects	Riverdale TS Station Switchgear Upgrade	$14.2[9]
	Fisher Station Rebuild	$9.6
	Bells Corners Rebuild	$10.3
	Overbrook TO Station Switchgear Replacement	$7.1[10]
	Dagmar Station Rebuild	$6.0
Other	Fleet Replacement[11]	$16.6
	Enterprise Resource Planning System Upgrade	$12.0

[7] Cost includes Connection Cost Recovery Agreement ("CCRA") payments to Hydro One Networks Inc. ("HONI").
[8] *Ibid.*
[9] Cost includes CCRA payments to HONI.
[10] *Ibid.*
[11] For additional information, please see Attachment 2-4-3(F): Fleet Replacement Program.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	**2016**

			Cost				**Accumulated Depreciation**				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 17,044,761	$ 3,044,490		$ 20,089,251	-$ 172,650	-$ 451,192		-$ 623,842	$ 19,465,409
12	1611	Computer Software (Formally known as Account 1925)	$ 49,841,304	$ 2,116,356		$ 51,957,660	-$ 12,718,283	-$ 7,775,205		-$ 20,493,488	$ 31,464,172
CEC	1612	Land Rights (Formally known as Account 1906)	$ 1,809,831	$ 472,925		$ 2,282,756	-$ 98,349	-$ 58,928		-$ 157,277	$ 2,125,479
N/A	1805	Land	$ 4,626,006	$ 18,883		$ 4,644,889	$ -	$ -	$ -	$ -	$ 4,644,889
47	1808	Buildings	$ 27,181,307	$ 548,125	-$ 1,958	$ 27,727,474	-$ 1,562,374	-$ 807,905	$ 681	-$ 2,369,598	$ 25,357,876
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 86,332,769	$ 410,684		$ 86,743,453	-$ 5,916,078	-$ 3,100,415		-$ 9,016,493	$ 77,726,960
47	1820	Distribution Station Equipment <50 kV	$ 82,697,721	$ 7,359,391	-$ 26,429	$ 90,030,683	-$ 7,645,290	-$ 3,447,469	$ 2,322	-$ 11,090,437	$ 78,940,246
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 94,688,479	$ 13,113,345	-$ 371,394	$ 107,430,430	-$ 4,351,747	-$ 2,600,754	$ 26,826	-$ 6,925,675	$ 100,504,755
47	1835	Overhead Conductors & Devices	$ 86,852,500	$ 13,529,221	-$ 396,075	$ 99,985,646	-$ 4,035,436	-$ 2,508,355	$ 34,051	-$ 6,509,740	$ 93,475,906
47	1840	Underground Conduit	$ 104,216,636	$ 19,247,873	$ -	$ 123,464,509	-$ 5,243,551	-$ 3,522,363	$ -	-$ 8,765,914	$ 114,698,595
47	1845	Underground Conductors & Devices	$ 101,480,101	$ 20,556,281	-$ 145,434	$ 121,890,948	-$ 6,377,079	-$ 3,953,829	$ 13,696	-$ 10,317,212	$ 111,573,736
47	1850	Line Transformers	$ 63,029,800	$ 8,007,899	-$ 315,329	$ 70,722,370	-$ 3,850,551	-$ 2,268,951	$ 33,434	-$ 6,086,068	$ 64,636,302
47	1855	Services (Overhead & Underground)	$ 48,210,872	$ 5,653,381	$ -	$ 53,864,253	-$ 2,556,118	-$ 1,446,998	$ -	-$ 4,003,116	$ 49,861,137
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 36,737,909	$ 1,977,455	-$ 289,399	$ 38,425,965	-$ 5,505,563	-$ 3,126,447	$ 67,569	-$ 8,564,441	$ 29,861,524
N/A	1905	Land	$ 20,355,841			$ 20,355,841				$ -	$ 20,355,841
47	1908	Buildings & Fixtures	$ 32,045,065	$ 281,924	$ -	$ 32,326,989	-$ 3,620,702	-$ 1,834,915	$ -	-$ 5,455,617	$ 26,871,372
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,257,807	$ 72,286	$ -	$ 1,330,093	-$ 460,732	-$ 224,732	$ -	-$ 685,464	$ 644,629
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 6,691,379	$ 654,364		$ 7,345,743	-$ 2,839,562	-$ 1,431,505		-$ 4,271,067	$ 3,074,676
10	1930	Transportation Equipment	$ 12,022,868	$ 1,696,026	-$ 153,184	$ 13,565,710	-$ 2,273,672	-$ 1,215,782	$ 46,141	-$ 3,443,313	$ 10,122,397
8	1935	Stores Equipment	$ 5,728	$ -	$ -	$ 5,728	-$ 5,728	$ -	$ -	-$ 5,728	$ -
8	1940	Tools, Shop & Garage Equipment	$ 3,690,030	$ 373,472	$ -	$ 4,063,502	-$ 1,318,278	-$ 574,962	$ -	-$ 1,893,240	$ 2,170,262
8	1945	Measurement & Testing Equipment	$ 228,830	$ -	$ -	$ 228,830	-$ 61,210	-$ 27,262	$ -	-$ 88,472	$ 140,358
8	1950	Power Operated Equipment	$ 1,044,717	$ 2,207,170	$ -	$ 3,251,887	-$ 145,469	-$ 166,365	$ -	-$ 311,834	$ 2,940,053

8	1955	Communications Equipment	$ 1,933,886	$ 1,367,875	$ -	$ 3,301,761	-$ 469,451	-$ 364,703	$ -	-$ 834,154	$ 2,467,607
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 240,794	$ 7,903	$ -	$ 248,697	-$ 71,332	-$ 36,676	$ -	-$ 108,008	$ 140,689
47	1970	Load Management Controls Customer Premises	$ 134,245	$ -	$ -	$ 134,245	-$ 104,852	-$ 27,781	$ -	-$ 132,633	$ 1,612
47	1975	Load Management Controls Utility Premises	$ 17,974	$ -	$ -	$ 17,974	-$ 14,388	-$ 3,587	$ -	-$ 17,975	-$ 1
47	1980	System Supervisor Equipment	$ 6,357,821	$ 459,021	$ -	$ 6,816,842	-$ 1,459,363	-$ 725,758	$ -	-$ 2,185,121	$ 4,631,721
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 48,553,292	-$ 21,578,316	$ -	-$ 70,131,608	$ 1,297,122	$ 1,621,618	$ -	$ 2,918,740	-$ 67,212,868
						$ -				$ -	$ -
		Sub-Total	**$ 842,223,689**	**$ 81,598,034**	**-$ 1,699,202**	**$ 922,122,521**	**-$ 71,580,686**	**-$ 40,081,221**	**$ 224,720**	**-$ 111,437,187**	**$ 810,685,334**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 842,223,689**	**$ 81,598,034**	**-$ 1,699,202**	**$ 922,122,521**	**-$ 71,580,686**	**-$ 40,081,221**	**$ 224,720**	**-$ 111,437,187**	**$ 810,685,334**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 40,081,221**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 40,081,221

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2017

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 20,089,251	$ 686,500	$ -	$ 20,775,751	-$ 623,842	-$ 451,404	$ -	-$ 1,075,246	$ 19,700,505
12	1611	Computer Software (Formally known as Account 1925)	$ 51,957,660	$ 14,077,258	-$ 1,063,022	$ 64,971,896	-$ 20,493,488	-$ 6,656,426	$ 1,063,022	-$ 26,086,892	$ 38,885,004
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,282,756	$ 10,866	$ -	$ 2,293,622	-$ 157,277	-$ 59,224	$ -	-$ 216,501	$ 2,077,121
N/A	1805	Land	$ 4,644,889	$ 4,136	$ -	$ 4,649,025	$ -	$ -	$ -	$ -	$ 4,649,025
47	1808	Buildings	$ 27,727,474	$ 1,074,355	$ -	$ 28,801,829	-$ 2,369,598	-$ 798,585	$ -	-$ 3,168,183	$ 25,633,646
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 86,743,453	$ 42,575	$ -	$ 86,786,028	-$ 9,016,493	-$ 3,093,977	$ -	-$ 12,110,470	$ 74,675,558
47	1820	Distribution Station Equipment <50 kV	$ 90,030,683	$ 15,638,328	-$ 73,576	$ 105,595,435	-$ 11,090,437	-$ 3,455,058	$ 73,576	-$ 14,471,919	$ 91,123,516
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 107,430,430	$ 10,488,904	-$ 519,293	$ 117,400,041	-$ 6,925,675	-$ 2,857,270	$ 42,406	-$ 9,740,539	$ 107,659,502
47	1835	Overhead Conductors & Devices	$ 99,985,646	$ 8,952,322	-$ 321,061	$ 108,616,907	-$ 6,509,740	-$ 2,754,959	$ 29,219	-$ 9,235,480	$ 99,381,427
47	1840	Underground Conduit	$ 123,464,509	$ 21,209,894	$ -	$ 144,674,403	-$ 8,765,914	-$ 4,018,835	$ -	-$ 12,784,749	$ 131,889,654
47	1845	Underground Conductors & Devices	$ 121,890,948	$ 21,522,450	-$ 257,265	$ 143,156,133	-$ 10,317,212	-$ 4,518,705	$ 57,771	-$ 14,778,146	$ 128,377,987
47	1850	Line Transformers	$ 70,722,370	$ 8,756,851	-$ 214,846	$ 79,264,375	-$ 6,086,068	-$ 2,512,829	$ 29,506	-$ 8,569,391	$ 70,694,984
47	1855	Services (Overhead & Underground)	$ 53,864,253	$ 7,169,843	$ -	$ 61,034,096	-$ 4,003,116	-$ 1,585,895	$ -	-$ 5,589,011	$ 55,445,085
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 38,425,965	$ 2,319,101	-$ 167,285	$ 40,577,781	-$ 8,564,441	-$ 4,217,004	-$ 75,539	-$ 12,856,984	$ 27,720,797
N/A	1905	Land	$ 20,355,841	$ 203,701	$ -	$ 20,559,542	$ -	$ -	$ -	$ -	$ 20,559,542
47	1908	Buildings & Fixtures	$ 32,326,989	$ 106,364	$ -	$ 32,433,353	-$ 5,455,617	-$ 1,788,731	$ -	-$ 7,244,348	$ 25,189,005
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,330,093	$ 77,259	$ -	$ 1,407,352	-$ 685,464	-$ 194,462	$ -	-$ 879,926	$ 527,426
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 7,345,743	$ 1,645,665	-$ 2,187,303	$ 6,804,105	-$ 4,271,067	-$ 1,380,126	$ 2,187,303	-$ 3,463,890	$ 3,340,215
10	1930	Transportation Equipment	$ 13,565,710	$ 3,799,293	-$ 13,042	$ 17,351,961	-$ 3,443,313	-$ 1,654,303	$ 8,370	-$ 5,089,246	$ 12,262,715
8	1935	Stores Equipment	$ 5,728	$ -	-$ 5,728	$ -	-$ 5,728	$ -	$ 5,728	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 4,063,502	$ 319,444	-$ 839,475	$ 3,543,471	-$ 1,893,240	-$ 478,984	$ 839,475	-$ 1,532,749	$ 2,010,722
8	1945	Measurement & Testing Equipment	$ 228,830	$ 1,024	-$ 14,413	$ 215,441	-$ 88,472	-$ 24,724	$ 14,413	-$ 98,783	$ 116,658
8	1950	Power Operated Equipment	$ 3,251,887	-$ 2,187,918	$ -	$ 1,063,969	-$ 311,834	$ 70,641	$ -	-$ 241,193	$ 822,776

8	1955	Communications Equipment	$ 3,301,761	$ 5,668,530	-$ 651,828	$ 8,318,463	-$ 834,154	-$ 734,781	$ 357,402	-$ 1,211,533	$ 7,106,930
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 248,697	$ 12,813	-$ 11,390	$ 250,120	-$ 108,008	-$ 36,041	$ 11,390	-$ 132,659	$ 117,461
47	1970	Load Management Controls Customer Premises	$ 134,245	$ -	$ -	$ 134,245	-$ 132,633	-$ 1,613	$ -	-$ 134,246	-$ 1
47	1975	Load Management Controls Utility Premises	$ 17,974	$ -	$ -	$ 17,974	-$ 17,975	$ -	$ -	-$ 17,975	-$ 1
47	1980	System Supervisor Equipment	$ 6,816,842	$ 1,084,733	-$ 183,550	$ 7,718,025	-$ 2,185,121	-$ 722,352	$ 183,550	-$ 2,723,923	$ 4,994,102
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 70,131,608	-$ 24,998,607		-$ 95,130,215	$ 2,918,740	$ 2,262,065		$ 5,180,805	-$ 89,949,410
						$ -				$ -	$ -
		Sub-Total	**$ 922,122,521**	**$ 97,685,684**	**-$ 6,523,077**	**$ 1,013,285,128**	**-$ 111,437,187**	**-$ 41,663,582**	**$ 4,827,592**	**-$ 148,273,177**	**$ 865,011,951**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 922,122,521**	**$ 97,685,684**	**-$ 6,523,077**	**$ 1,013,285,128**	**-$ 111,437,187**	**-$ 41,663,582**	**$ 4,827,592**	**-$ 148,273,177**	**$ 865,011,951**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 41,663,582**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 41,663,582

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2018**

			Cost				Accumulated Depreciation				
CCA Class 2	**OEB Account 3**	**Description 3**	**Opening Balance**	**Additions 4**	**Disposals 6**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals 6**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 20,775,751	$ 2,199,818		$ 22,975,569	-$ 1,075,246	-$ 480,702		-$ 1,555,948	$ 21,419,621
12	1611	Computer Software (Formally known as Account 1925)	$ 64,971,896	$ 1,656,811	$ -	$ 66,628,707	-$ 26,086,892	-$ 8,972,088	$ -	-$ 35,058,980	$ 31,569,727
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,293,622	-$ 5,223	$ -	$ 2,288,399	-$ 216,501	-$ 59,148	$ -	-$ 275,649	$ 2,012,750
N/A	1805	Land	$ 4,649,025	$ 3,509	$ -	$ 4,652,534	$ -	$ -	$ -	$ -	$ 4,652,534
47	1808	Buildings	$ 28,801,829	$ 860,484	$ -	$ 29,662,313	-$ 3,168,183	-$ 774,847	$ -	-$ 3,943,030	$ 25,719,283
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 86,786,028	$ 327,621	$ -	$ 87,113,649	-$ 12,110,470	-$ 3,057,779	$ -	-$ 15,168,249	$ 71,945,400
47	1820	Distribution Station Equipment <50 kV	$ 105,595,435	$ 11,020,767	-$ 129,498	$ 116,486,704	-$ 14,471,919	-$ 3,890,510	$ 80,461	-$ 18,281,968	$ 98,204,736
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 117,400,041	$ 11,013,471	-$ 174,862	$ 128,238,650	-$ 9,740,539	-$ 3,079,814	$ 17,545	-$ 12,802,808	$ 115,435,842
47	1835	Overhead Conductors & Devices	$ 108,616,907	$ 12,558,766	-$ 2,109	$ 121,173,564	-$ 9,235,480	-$ 2,992,071	$ 1,601	-$ 12,225,950	$ 108,947,614
47	1840	Underground Conduit	$ 144,674,403	$ 38,532,726	$ -	$ 183,207,129	-$ 12,784,749	-$ 4,751,068	$ -	-$ 17,535,817	$ 165,671,312
47	1845	Underground Conductors & Devices	$ 143,156,133	$ 15,797,489	-$ 391,873	$ 158,561,749	-$ 14,778,146	-$ 5,024,001	$ 84,153	-$ 19,717,994	$ 138,843,755
47	1850	Line Transformers	$ 79,264,375	$ 8,450,827	-$ 26,085	$ 87,689,117	-$ 8,569,391	-$ 2,766,069	$ 4,883	-$ 11,330,577	$ 76,358,540
47	1855	Services (Overhead & Underground)	$ 61,034,096	$ 6,319,026	$ -	$ 67,353,122	-$ 5,589,011	-$ 1,735,758	$ -	-$ 7,324,769	$ 60,028,353
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 40,577,781	$ 2,940,398	-$ 1,138,717	$ 42,379,462	-$ 12,856,984	-$ 4,591,778	$ 499,239	-$ 16,949,523	$ 25,429,939
N/A	1905	Land	$ 20,559,542			$ 20,559,542	$ -			$ -	$ 20,559,542
47	1908	Buildings & Fixtures	$ 32,433,353	$ 2,763,337	$ -	$ 35,196,690	-$ 7,244,348	-$ 1,752,402	$ -	-$ 8,996,750	$ 26,199,940
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,407,352	$ 208,480	$ -	$ 1,615,832	-$ 879,926	-$ 147,809	$ -	-$ 1,027,735	$ 588,097
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 6,804,105	$ 2,030,340	-$ 234,461	$ 8,599,984	-$ 3,463,890	-$ 1,397,366	$ 132,957	-$ 4,728,299	$ 3,871,685
10	1930	Transportation Equipment	$ 17,351,961	$ 165,604	-$ 84,947	$ 17,432,618	-$ 5,089,246	-$ 1,482,542	$ 48,720	-$ 6,523,068	$ 10,909,550
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 3,543,471	$ 652,919	$ -	$ 4,196,390	-$ 1,532,749	-$ 461,520	$ -	-$ 1,994,269	$ 2,202,121
8	1945	Measurement & Testing Equipment	$ 215,441	$ -	$ -	$ 215,441	-$ 98,783	-$ 24,106	$ -	-$ 122,889	$ 92,552
8	1950	Power Operated Equipment	$ 1,063,969	-$ 79,133	$ -	$ 984,836	-$ 241,193	-$ 84,639	$ -	-$ 325,832	$ 659,004
8	1955	Communications Equipment	$ 8,318,463	$ 2,671,824	$ -	$ 10,990,287	-$ 1,211,533	-$ 1,140,481	$ -	-$ 2,352,014	$ 8,638,273
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 250,120	$ 5,071	$ -	$ 255,191	-$ 132,659	-$ 32,994	$ -	-$ 165,653	$ 89,538

47	1970	Load Management Controls Customer Premises	$ 134,245	$ -	$ -	$ 134,245	-$ 134,246	$ -	$ -	-$ 134,246	-$ 1
47	1975	Load Management Controls Utility Premises	$ 17,974	$ -	-$ 17,974	$ -	-$ 17,975	$ -	$ 17,974	-$ 1	-$ 1
47	1980	System Supervisor Equipment	$ 7,718,025	$ 3,754,253	$ -	$ 11,472,278	-$ 2,723,923	-$ 825,702	$ -	-$ 3,549,625	$ 7,922,653
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	-$ 95,130,215	-$ 22,598,352		-$ 117,728,567	$ 5,180,805	$ 2,949,679		$ 8,130,484	-$ 109,598,083
						$ -				$ -	$ -
		Sub-Total	**$ 1,013,285,128**	**$ 101,250,833**	**-$ 2,200,526**	**$ 1,112,335,435**	**-$ 148,273,177**	**-$ 46,575,515**	**$ 887,533**	**-$ 193,961,159**	**$ 918,374,276**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 1,013,285,128**	**$ 101,250,833**	**-$ 2,200,526**	**$ 1,112,335,435**	**-$ 148,273,177**	**-$ 46,575,515**	**$ 887,533**	**-$ 193,961,159**	**$ 918,374,276**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 46,575,515**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 46,575,515

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2019

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 22,975,569	$ 12,075,528	$ -	$ 35,051,097	-$ 1,555,948	-$ 627,157		-$ 2,183,105	$ 32,867,992
12	1611	Computer Software (Formally known as Account 1925)	$ 66,628,707	$ 1,245,295	$ -	$ 67,874,002	-$ 35,058,980	-$ 6,286,604		-$ 41,345,584	$ 26,528,418
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,288,399		$ -	$ 2,288,399	-$ 275,649	-$ 59,341		-$ 334,990	$ 1,953,409
N/A	1805	Land	$ 4,652,534		$ -	$ 4,652,534	$ -			$ -	$ 4,652,534
47	1808	Buildings	$ 29,662,313	$ 526,950	$ -	$ 30,189,263	-$ 3,943,030	-$ 785,367		-$ 4,728,397	$ 25,460,866
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 87,113,649	$ 24,354,489	$ -	$ 111,468,138	-$ 15,168,249	-$ 3,289,916		-$ 18,458,165	$ 93,009,973
47	1820	Distribution Station Equipment <50 kV	$ 116,486,704	$ 20,145,419	-$ 240,603	$ 136,391,520	-$ 18,281,968	-$ 4,175,623	$ 106,451	-$ 22,351,140	$ 114,040,380
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 128,238,650	$ 7,501,125	-$ 296,418	$ 135,443,357	-$ 12,802,808	-$ 3,314,565	$ 85,265	-$ 16,032,108	$ 119,411,249
47	1835	Overhead Conductors & Devices	$ 121,173,564	$ 9,173,993	-$ 189,892	$ 130,157,665	-$ 12,225,950	-$ 3,281,774	$ 69,406	-$ 15,438,318	$ 114,719,347
47	1840	Underground Conduit	$ 183,207,129	$ 26,346,152	$ -	$ 209,553,281	-$ 17,535,817	-$ 5,627,617		-$ 23,163,434	$ 186,389,847
47	1845	Underground Conductors & Devices	$ 158,561,749	$ 16,249,030	-$ 352,493	$ 174,458,286	-$ 19,717,994	-$ 5,458,679	$ 115,903	-$ 25,060,770	$ 149,397,516
47	1850	Line Transformers	$ 87,689,117	$ 5,353,062	-$ 164,573	$ 92,877,606	-$ 11,330,577	-$ 3,007,650	$ 60,153	-$ 14,278,074	$ 78,599,532
47	1855	Services (Overhead & Underground)	$ 67,353,122	$ 2,588,037		$ 69,941,159	-$ 7,324,769	-$ 1,792,259		-$ 9,117,028	$ 60,824,131
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 42,379,462	$ 5,227,941	-$ 495,624	$ 47,111,779	-$ 16,949,523	-$ 4,794,834	$ 209,346	-$ 21,535,011	$ 25,576,768
N/A	1905	Land	$ 20,559,542		-$ 617,537	$ 19,942,005	$ -	-$ 1,348		-$ 1,348	$ 19,940,657
47	1908	Buildings & Fixtures	$ 35,196,690	$ 80,442,974	-$ 21,036,840	$ 94,602,824	-$ 8,996,750	-$ 3,023,314	$ 6,996,154	-$ 5,023,910	$ 89,578,914
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,615,832	$ 3,162,199	$ -	$ 4,778,031	-$ 1,027,735	-$ 337,320		-$ 1,365,055	$ 3,412,976
8	1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 8,599,984	$ 5,052,231	$ -	$ 13,652,215	-$ 4,728,299	-$ 1,634,805		-$ 6,363,104	$ 7,289,111
10	1930	Transportation Equipment	$ 17,432,618	$ 1,341,766	-$ 310,723	$ 18,463,661	-$ 6,523,068	-$ 1,674,195	$ 137,850	-$ 8,059,413	$ 10,404,248
8	1935	Stores Equipment	$ -	$ 562,235		$ 562,235	$ -	-$ 28,201		-$ 28,201	$ 534,034
8	1940	Tools, Shop & Garage Equipment	$ 4,196,390	$ 484,629		$ 4,681,019	-$ 1,994,269	-$ 456,462		-$ 2,450,731	$ 2,230,288
8	1945	Measurement & Testing Equipment	$ 215,441	$ 36,858		$ 252,299	-$ 122,889	-$ 25,285		-$ 148,174	$ 104,125
8	1950	Power Operated Equipment	$ 984,836	$ 113,601		$ 1,098,437	-$ 325,832	-$ 85,006		-$ 410,838	$ 687,599
8	1955	Communications Equipment	$ 10,990,287	$ 3,457,104		$ 14,447,391	-$ 2,352,014	-$ 1,434,564		-$ 3,786,578	$ 10,660,813
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 255,191	$ 934		$ 256,125	-$ 165,653	-$ 27,490		-$ 193,143	$ 62,982

47	1970	Load Management Controls Customer Premises	$ 134,245		-$ 134,245	$ -	-$ 134,246		$ 134,245	-$ 1	-$ 1
47	1975	Load Management Controls Utility Premises	$ -			$ -	-$ 1			-$ 1	-$ 1
47	1980	System Supervisor Equipment	$ 11,472,278	$ 2,286,989		$ 13,759,267	-$ 3,549,625	-$ 1,230,228		-$ 4,779,853	$ 8,979,414
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 117,728,567	-$ 26,315,568		-$ 144,044,135	$ 8,130,484	$ 3,983,554		$ 12,114,038	-$ 131,930,097
						$ -				$ -	$ -
		Sub-Total	**$ 1,112,335,435**	**$ 201,412,973**	**-$ 23,838,948**	**$ 1,289,909,460**	**$-$ 193,961,159**	**-$ 48,476,050**	**$ 7,914,773**	**-$ 234,522,436**	**$ 1,055,387,024**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$ 1,112,335,435**	**$ 201,412,973**	**-$ 23,838,948**	**$ 1,289,909,460**	**-$ 193,961,159**	**-$ 48,476,050**	**$ 7,914,773**	**-$ 234,522,436**	**$ 1,055,387,024**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 48,476,050**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 48,476,050

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2020**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 35,051,097	$ 910,000	$ -	$ 35,961,097	-$ 2,183,105	-$ 790,975	$ -	-$ 2,974,080	$ 32,987,017
12	1611	Computer Software (Formally known as Account 1925)	$ 67,874,002	$ 13,030,880	$ -	$ 80,904,882	-$ 41,345,584	-$ 6,468,113	$ -	-$ 47,813,697	$ 33,091,185
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,288,399	$ 8,306	$ -	$ 2,296,705	-$ 334,990	-$ 59,409	$ -	-$ 394,399	$ 1,902,306
N/A	1805	Land	$ 4,652,534	$ 1,047	$ -	$ 4,653,581	$ -		$ -	$ -	$ 4,653,581
47	1808	Buildings	$ 30,189,263	$ 707,754	$ -	$ 30,897,017	-$ 4,728,397	-$ 802,687	$ -	-$ 5,531,084	$ 25,365,933
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 111,468,138	$ 3,148,680	$ -	$ 114,616,818	-$ 18,458,165	-$ 3,669,308	$ -	-$ 22,127,473	$ 92,489,345
47	1820	Distribution Station Equipment <50 kV	$ 136,391,520	$ 5,860,007	-$ 96,181	$ 142,155,346	-$ 22,351,140	-$ 4,450,661	$ 55,028	-$ 26,746,773	$ 115,408,573
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 135,443,357	$ 9,394,503	-$ 313,703	$ 144,524,157	-$ 16,032,108	-$ 3,480,842	$ 30,864	-$ 19,482,086	$ 125,042,071
47	1835	Overhead Conductors & Devices	$ 130,157,665	$ 16,910,513	-$ 230,544	$ 146,837,634	-$ 15,438,318	-$ 3,592,858	$ 26,635	-$ 19,004,541	$ 127,833,093
47	1840	Underground Conduit	$ 209,553,281	$ 23,166,955	$ -	$ 232,720,236	-$ 23,163,434	-$ 6,137,186	$ -	-$ 29,300,620	$ 203,419,616
47	1845	Underground Conductors & Devices	$ 174,458,286	$ 24,832,592	-$ 359,069	$ 198,931,809	-$ 25,060,770	-$ 5,978,466	$ 64,812	-$ 30,974,424	$ 167,957,385
47	1850	Line Transformers	$ 92,877,606	$ 8,055,161	-$ 220,567	$ 100,712,200	-$ 14,278,074	-$ 3,187,549	$ 40,727	-$ 17,424,896	$ 83,287,304
47	1855	Services (Overhead & Underground)	$ 69,941,159	$ 4,568,833	$ -	$ 74,509,992	-$ 9,117,028	-$ 1,911,293	$ -	-$ 11,028,321	$ 63,481,671
47	1860	Meters	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 47,111,779	$ 5,077,444	-$ 420,692	$ 51,768,531	-$ 21,535,011	-$ 5,049,583	$ 156,744	-$ 26,427,850	$ 25,340,681
N/A	1905	Land	$ 19,942,005		$ -	$ 19,942,005	-$ 1,348	-$ 4,047	$ -	-$ 5,395	$ 19,936,610
47	1908	Buildings & Fixtures	$ 94,602,824	$ 681,128	$ -	$ 95,283,952	-$ 5,023,910	-$ 3,025,591	$ -	-$ 8,049,501	$ 87,234,451
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 4,778,031	$ 100,766	$ -	$ 4,878,797	-$ 1,365,055	-$ 425,555	$ -	-$ 1,790,610	$ 3,088,187
8	1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -		$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -		$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -		$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 13,652,215	$ 1,602,325	$ -	$ 15,254,540	-$ 6,363,104	-$ 1,762,186	$ -	-$ 8,125,290	$ 7,129,250
10	1930	Transportation Equipment	$ 18,463,661	$ 180,773	-$ 27,765	$ 18,616,669	-$ 8,059,413	-$ 1,560,773	$ 22,058	-$ 9,598,128	$ 9,018,541
8	1935	Stores Equipment	$ 562,235		$ -	$ 562,235	-$ 28,201	-$ 56,225	$ -	-$ 84,426	$ 477,809
8	1940	Tools, Shop & Garage Equipment	$ 4,681,019	$ 449,596	$ -	$ 5,130,615	-$ 2,450,731	-$ 446,365	$ -	-$ 2,897,096	$ 2,233,519
8	1945	Measurement & Testing Equipment	$ 252,299		$ -	$ 252,299	-$ 148,174	-$ 27,197	$ -	-$ 175,371	$ 76,928
8	1950	Power Operated Equipment	$ 1,098,437	$ 354,695	-$ 83,875	$ 1,369,257	-$ 410,838	-$ 89,524	$ 71,355	-$ 429,007	$ 940,250
8	1955	Communications Equipment	$ 14,447,391	$ 1,014,293	$ -	$ 15,461,684	-$ 3,786,578	-$ 1,560,031	$ -	-$ 5,346,609	$ 10,115,075
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -		$ -	$ -	$ -

8	1960	Miscellaneous Equipment	$ 256,125	$ 146,074	$ -	$ 402,199	-$ 193,143	-$ 28,333	$ -	-$ 221,476	$ 180,723
47	1970	Load Management Controls Customer Premises	$ -	$ 147,418	$ -	$ 147,418	-$ 1	-$ 7,371	$ -	-$ 7,372	$ 140,046
47	1975	Load Management Controls Utility Premises	$ -	$ 90,380	$ -	$ 90,380	-$ 1	-$ 4,519	$ -	-$ 4,520	$ 85,860
47	1980	System Supervisor Equipment	$ 13,759,267	$ 1,013,957	$ -	$ 14,773,224	-$ 4,779,853	-$ 1,235,550	$ -	-$ 6,015,403	$ 8,757,821
47	1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1990	Other Tangible Property	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 144,044,135	-$ 38,682,612	$ -	-$ 182,726,747	$ 12,114,038	$ 5,089,115	$ -	$ 17,203,153	-$ 165,523,594
						$ -				$ -	$ -
		Sub-Total	**$ 1,289,909,460**	**$ 82,771,468**	**-$ 1,752,397**	**$ 1,370,928,532**	**-$ 234,522,436**	**-$ 50,723,082**	**$ 468,224**	**-$ 284,777,294**	**$ 1,086,151,237**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 1,289,909,460**	**$ 82,771,468**	**-$ 1,752,397**	**$ 1,370,928,532**	**-$ 234,522,436**	**-$ 50,723,082**	**$ 468,224**	**-$ 284,777,294**	**$ 1,086,151,237**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 50,723,082**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 50,723,082

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

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6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2021**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 35,961,097	$ 51,223,891	$ -	$ 87,184,988	-$ 2,974,080	-$ 1,088,293	$ -	-$ 4,062,373	$ 83,122,615
12	1611	Computer Software (Formally known as Account 1925)	$ 80,904,882	$ 10,944,631	$ -	$ 91,849,513	-$ 47,813,697	-$ 7,305,676	$ -	-$ 55,119,373	$ 36,730,140
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,296,705	$ 13,268	$ -	$ 2,309,973	-$ 394,399	-$ 59,497	$ -	-$ 453,896	$ 1,856,077
N/A	1805	Land	$ 4,653,581	$ 1,569	$ -	$ 4,655,150	$ -		$ -	$ -	$ 4,655,150
47	1808	Buildings	$ 30,897,017	$ 724,819	$ -	$ 31,621,836	-$ 5,531,084	-$ 818,992	$ -	-$ 6,350,076	$ 25,271,760
13	1810	Leasehold Improvements	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 114,616,818	$ 8,247,498	$ -	$ 122,864,316	-$ 22,127,473	-$ 3,757,680	$ -	-$ 25,885,153	$ 96,979,163
47	1820	Distribution Station Equipment <50 kV	$ 142,155,346	$ 13,738,471	-$ 96,181	$ 155,797,636	-$ 26,746,773	-$ 4,462,581	$ 55,028	-$ 31,154,326	$ 124,643,310
47	1825	Storage Battery Equipment	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 144,524,157	$ 8,715,471	-$ 313,703	$ 152,925,925	-$ 19,482,086	-$ 3,673,027	$ 30,864	-$ 23,124,249	$ 129,801,676
47	1835	Overhead Conductors & Devices	$ 146,837,634	$ 11,400,338	-$ 230,544	$ 158,007,428	-$ 19,004,541	-$ 3,938,401	$ 26,635	-$ 22,916,307	$ 135,091,121
47	1840	Underground Conduit	$ 232,720,236	$ 25,696,125	$ -	$ 258,416,361	-$ 29,300,620	-$ 6,713,783	$ -	-$ 36,014,403	$ 222,401,958
47	1845	Underground Conductors & Devices	$ 198,931,809	$ 26,000,462	-$ 359,069	$ 224,573,202	-$ 30,974,424	-$ 6,661,033	$ 64,812	-$ 37,570,645	$ 187,002,557
47	1850	Line Transformers	$ 100,712,200	$ 8,365,754	-$ 220,567	$ 108,857,387	-$ 17,424,896	-$ 3,405,578	$ 40,727	-$ 20,789,747	$ 88,067,640
47	1855	Services (Overhead & Underground)	$ 74,509,992	$ 4,404,116	$ -	$ 78,914,108	-$ 11,028,321	-$ 2,006,006	$ -	-$ 13,034,327	$ 65,879,781
47	1860	Meters	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 51,768,531	$ 7,490,281	-$ 1,113,668	$ 58,145,144	-$ 26,427,850	-$ 4,812,311	$ 762,440	-$ 30,477,721	$ 27,667,423
N/A	1905	Land	$ 19,942,005		$ -	$ 19,942,005	-$ 5,395	-$ 4,047	$ -	-$ 9,442	$ 19,932,563
47	1908	Buildings & Fixtures	$ 95,283,952	$ 2,342,569	$ -	$ 97,626,521	-$ 8,049,501	-$ 3,116,870	$ -	-$ 11,166,371	$ 86,460,150
13	1910	Leasehold Improvements	$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 4,878,797	$ 75,574	$ -	$ 4,954,371	-$ 1,790,610	-$ 416,853	$ -	-$ 2,207,463	$ 2,746,908
8	1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -		$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -		$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -		$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 15,254,540	$ 1,582,441	$ -	$ 16,836,981	-$ 8,125,290	-$ 1,884,900	$ -	-$ 10,010,190	$ 6,826,791
10	1930	Transportation Equipment	$ 18,616,669	$ 6,124,426	-$ 1,821,564	$ 22,919,530	-$ 9,598,128	-$ 1,220,734	$ 1,578,341	-$ 9,240,521	$ 13,679,009
8	1935	Stores Equipment	$ 562,235		$ -	$ 562,235	-$ 84,426	-$ 56,224	$ -	-$ 140,650	$ 421,585
8	1940	Tools, Shop & Garage Equipment	$ 5,130,615	$ 473,651	$ -	$ 5,604,266	-$ 2,897,096	-$ 440,309	$ -	-$ 3,337,405	$ 2,266,861
8	1945	Measurement & Testing Equipment	$ 252,299		$ -	$ 252,299	-$ 175,371	-$ 27,132	$ -	-$ 202,503	$ 49,796
8	1950	Power Operated Equipment	$ 1,369,257	$ 163,845	-$ 51,487	$ 1,481,615	-$ 429,007	-$ 99,140	$ 45,489	-$ 482,658	$ 998,957
8	1955	Communications Equipment	$ 15,461,684	$ 3,510,634	$ -	$ 18,972,318	-$ 5,346,609	-$ 1,786,969	$ -	-$ 7,133,578	$ 11,838,740
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 402,199	$ 497,344	$ -	$ 899,543	-$ 221,476	-$ 53,845	$ -	-$ 275,321	$ 624,222

47	1970	Load Management Controls Customer Premises	$ 147,418	$ 707,619	$ -	$ 855,037	-$ 7,372	-$ 50,123	$ -	-$ 57,495	$ 797,542
47	1975	Load Management Controls Utility Premises	$ 90,380	$ 393,529	$ -	$ 483,909	-$ 4,520	-$ 28,714	$ -	-$ 33,234	$ 450,675
47	1980	System Supervisor Equipment	$ 14,773,224	$ 1,576,567	$ -	$ 16,349,791	-$ 6,015,403	-$ 1,261,664	$ -	-$ 7,277,067	$ 9,072,724
47	1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1990	Other Tangible Property	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 182,726,747	-$ 43,275,244	$ -	-$ 226,001,991	$ 17,203,153	$ 6,700,322	$ -	$ 23,903,475	-$ 202,098,516
						$ -				$ -	$ -
		Sub-Total	**$ 1,370,928,532**	**$ 151,139,649**	**-$ 4,206,783**	**$ 1,517,861,398**	**-$ 284,777,294**	**-$ 52,450,060**	**$ 2,604,336**	**-$ 334,623,019**	**$ 1,183,238,379**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 1,370,928,532**	**$ 151,139,649**	**-$ 4,206,783**	**$ 1,517,861,398**	**-$ 284,777,294**	**-$ 52,450,060**	**$ 2,604,336**	**-$ 334,623,019**	**$ 1,183,238,379**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 52,450,060**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 52,450,060

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2022

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 87,184,987	$ 210,000		$ 87,394,987	-$ 4,062,372	-$ 1,946,433		-$ 6,008,805	$ 81,386,182
12	1611	Computer Software (Formally known as Account 1925)	$ 91,849,511	$ 6,322,378		$ 98,171,889	-$ 55,119,373	-$ 8,607,321		-$ 63,726,694	$ 34,445,195
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,309,973	$ 13,040		$ 2,323,013	-$ 453,897	-$ 59,760		-$ 513,657	$ 1,809,356
N/A	1805	Land	$ 4,655,150	$ 162,462		$ 4,817,612				$ -	$ 4,817,612
47	1808	Buildings	$ 31,621,836	$ 8,365,966		$ 39,987,802	-$ 6,350,075	-$ 934,231		-$ 7,284,306	$ 32,703,496
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 122,864,316	$ 25,611,949		$ 148,476,265	-$ 25,885,153	-$ 4,359,904		-$ 30,245,057	$ 118,231,208
47	1820	Distribution Station Equipment <50 kV	$ 155,797,635	$ 10,005,389	-$ 96,181	$ 165,706,843	-$ 31,154,325	-$ 4,699,714	$ 55,028	-$ 35,799,011	$ 129,907,832
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 152,925,924	$ 9,161,771	-$ 313,703	$ 161,773,992	-$ 23,124,248	-$ 3,870,235	$ 30,864	-$ 26,963,619	$ 134,810,373
47	1835	Overhead Conductors & Devices	$ 158,007,430	$ 13,334,739	-$ 230,544	$ 171,111,625	-$ 22,916,308	-$ 4,247,939	$ 26,635	-$ 27,137,612	$ 143,974,013
47	1840	Underground Conduit	$ 258,416,361	$ 22,225,040		$ 280,641,401	-$ 36,014,403	-$ 7,282,382		-$ 43,296,785	$ 237,344,616
47	1845	Underground Conductors & Devices	$ 224,573,202	$ 21,007,287	-$ 359,069	$ 245,221,420	-$ 37,570,642	-$ 7,322,791	$ 64,812	-$ 44,828,621	$ 200,392,799
47	1850	Line Transformers	$ 108,857,389	$ 8,143,668	-$ 220,567	$ 116,780,490	-$ 20,789,747	-$ 3,638,351	$ 40,727	-$ 24,387,371	$ 92,393,119
47	1855	Services (Overhead & Underground)	$ 78,914,108	$ 4,563,872		$ 83,477,980	-$ 13,034,328	-$ 2,105,656		-$ 15,139,984	$ 68,337,996
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 58,145,143	$ 6,927,890	-$ 1,129,168	$ 63,943,865	-$ 30,477,720	-$ 4,261,148	$ 776,310	-$ 33,962,558	$ 29,981,307
N/A	1905	Land	$ 19,942,005			$ 19,942,005	-$ 9,442	-$ 4,047		-$ 13,489	$ 19,928,516
47	1908	Buildings & Fixtures	$ 97,626,519	$ 427,760		$ 98,054,279	-$ 11,166,370	-$ 3,185,739		-$ 14,352,109	$ 83,702,170
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 4,954,370	$ 75,574		$ 5,029,944	-$ 2,207,460	-$ 407,568		-$ 2,615,028	$ 2,414,916
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 16,836,981	$ 2,618,294		$ 19,455,275	-$ 10,010,189	-$ 2,172,161		-$ 12,182,350	$ 7,272,925
10	1930	Transportation Equipment	$ 22,919,531	$ 5,223,986	-$ 2,047,008	$ 26,096,509	-$ 9,240,521	-$ 1,577,489	$ 1,834,846	-$ 8,983,164	$ 17,113,345
8	1935	Stores Equipment	$ 562,235			$ 562,235	-$ 140,650	-$ 56,224		-$ 196,874	$ 365,361
8	1940	Tools, Shop & Garage Equipment	$ 5,604,265	$ 474,390		$ 6,078,655	-$ 3,337,404	-$ 441,144		-$ 3,778,548	$ 2,300,107
8	1945	Measurement & Testing Equipment	$ 252,299			$ 252,299	-$ 202,502	-$ 20,382		-$ 222,884	$ 29,415
8	1950	Power Operated Equipment	$ 1,481,615			$ 1,481,615	-$ 482,658	-$ 102,206		-$ 584,864	$ 896,751
8	1955	Communications Equipment	$ 18,972,319	$ 1,470,337		$ 20,442,656	-$ 7,133,579	-$ 2,060,745		-$ 9,194,324	$ 11,248,332
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 899,543	$ 44,197		$ 943,740	-$ 275,321	-$ 76,682		-$ 352,003	$ 591,737

47	1970	Load Management Controls Customer Premises	$ 855,037	$ 63,752		$ 918,789	-$ 57,494	-$ 88,692		-$ 146,186	$ 772,603
47	1975	Load Management Controls Utility Premises	$ 483,909	$ 49,475		$ 533,384	-$ 33,233	-$ 50,865		-$ 84,098	$ 449,286
47	1980	System Supervisor Equipment	$ 16,349,790	$ 1,701,727		$ 18,051,517	-$ 7,277,067	-$ 1,292,876		-$ 8,569,943	$ 9,481,574
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 226,001,990	-$ 27,430,613	$ 599,738	-$ 252,832,865	$ 23,903,477	$ 8,012,479	-$ 599,738	$ 31,316,218	-$ 221,516,647
						$ -				$ -	$ -
		Sub-Total	**$ 1,517,861,393**	**$ 120,774,330**	**-$ 3,796,502**	**$ 1,634,839,221**	**-$ 334,623,004**	**-$ 56,860,206**	**$ 2,229,484**	**-$ 389,253,726**	**$ 1,245,585,495**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		***Less Other Non Rate-Regulated Utility Assets* (input as negative)**				$ -				$ -	$ -
		Total PP&E	**$ 1,517,861,393**	**$ 120,774,330**	**-$ 3,796,502**	**$ 1,634,839,221**	**-$ 334,623,004**	**-$ 56,860,206**	**$ 2,229,484**	**-$ 389,253,726**	**$ 1,245,585,495**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 56,860,206**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 56,860,206

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year **2023**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 87,394,987	$ 100,000		$ 87,494,987	-$ 6,008,805	-$ 1,950,895		-$ 7,959,700	$ 79,535,287
12	1611	Computer Software (Formally known as Account 1925)	$ 98,171,889	$ 3,590,513		$ 101,762,402	-$ 63,726,694	-$ 9,194,054		-$ 72,920,748	$ 28,841,654
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,323,013	$ 12,296		$ 2,335,309	-$ 513,657	-$ 60,014		-$ 573,671	$ 1,761,638
N/A	1805	Land	$ 4,817,612			$ 4,817,612				$ -	$ 4,817,612
47	1808	Buildings	$ 39,987,802	$ 534,656		$ 40,522,458	-$ 7,284,307	-$ 994,934		-$ 8,279,241	$ 32,243,217
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 148,476,265	$ 3,602,046		$ 152,078,311	-$ 30,245,057	-$ 4,672,709		-$ 34,917,766	$ 117,160,545
47	1820	Distribution Station Equipment <50 kV	$ 165,706,843	$ 4,126,157	-$ 96,181	$ 169,736,819	-$ 35,799,011	-$ 4,863,301	$ 55,028	-$ 40,607,284	$ 129,129,535
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 161,773,992	$ 9,876,018	-$ 313,703	$ 171,336,307	-$ 26,963,619	-$ 4,081,762	$ 30,864	-$ 31,014,517	$ 140,321,790
47	1835	Overhead Conductors & Devices	$ 171,111,624	$ 13,582,445	-$ 230,544	$ 184,463,525	-$ 27,137,613	-$ 4,586,713	$ 26,635	-$ 31,697,691	$ 152,765,834
47	1840	Underground Conduit	$ 280,641,400	$ 20,403,122		$ 301,044,522	-$ 43,296,785	-$ 7,783,016		-$ 51,079,801	$ 249,964,721
47	1845	Underground Conductors & Devices	$ 245,221,421	$ 18,820,790	-$ 359,069	$ 263,683,142	-$ 44,828,621	-$ 7,871,614	$ 64,812	-$ 52,635,423	$ 211,047,719
47	1850	Line Transformers	$ 116,780,490	$ 7,823,557	-$ 220,567	$ 124,383,480	-$ 24,387,370	-$ 3,854,763	$ 40,727	-$ 28,201,406	$ 96,182,074
47	1855	Services (Overhead & Underground)	$ 83,477,980	$ 4,595,931		$ 88,073,911	-$ 15,139,984	-$ 2,207,425		-$ 17,347,409	$ 70,726,502
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 63,943,865	$ 6,673,267	-$ 955,308	$ 69,661,824	-$ 33,962,558	-$ 3,930,943	$ 688,888	-$ 37,204,613	$ 32,457,211
N/A	1905	Land	$ 19,942,005			$ 19,942,005	-$ 13,489	-$ 4,047		-$ 17,536	$ 19,924,469
47	1908	Buildings & Fixtures	$ 98,054,279	$ 352,679		$ 98,406,958	-$ 14,352,109	-$ 3,197,517		-$ 17,549,626	$ 80,857,332
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 5,029,944	$ 50,383		$ 5,080,327	-$ 2,615,029	-$ 400,102		-$ 3,015,131	$ 2,065,196
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 19,455,275	$ 1,160,674		$ 20,615,949	-$ 12,182,350	-$ 2,042,539		-$ 14,224,889	$ 6,391,060
10	1930	Transportation Equipment	$ 26,096,509	$ 2,233,064	-$ 1,501,028	$ 26,828,545	-$ 8,983,165	-$ 1,991,963	$ 1,413,150	-$ 9,561,978	$ 17,266,567
8	1935	Stores Equipment	$ 562,235			$ 562,235	-$ 196,874	-$ 56,224		-$ 253,098	$ 309,137
8	1940	Tools, Shop & Garage Equipment	$ 6,078,655	$ 461,809		$ 6,540,464	-$ 3,778,548	-$ 442,658		-$ 4,221,206	$ 2,319,258
8	1945	Measurement & Testing Equipment	$ 252,299			$ 252,299	-$ 222,884	-$ 8,751		-$ 231,635	$ 20,664
8	1950	Power Operated Equipment	$ 1,481,615	$ 115,377		$ 1,596,992	-$ 584,864	-$ 82,798		-$ 667,662	$ 929,330
8	1955	Communications Equipment	$ 20,442,656	$ 874,903		$ 21,317,559	-$ 9,194,324	-$ 2,173,813		-$ 11,368,137	$ 9,949,422
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -

8	1960	Miscellaneous Equipment	$ 943,740	$ 16,787		$ 960,527	-$ 352,003	-$ 76,196		-$ 428,199	$ 532,328
47	1970	Load Management Controls Customer Premises	$ 918,789			$ 918,789	-$ 146,186	-$ 91,879		-$ 238,065	$ 680,724
47	1975	Load Management Controls Utility Premises	$ 533,383			$ 533,383	-$ 84,098	-$ 53,338		-$ 137,436	$ 395,947
47	1980	System Supervisor Equipment	$ 18,051,517	$ 992,743		$ 19,044,260	-$ 8,569,942	-$ 1,274,267		-$ 9,844,209	$ 9,200,051
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 252,832,865	-$ 21,345,516	$ 360,000	-$ 273,818,381	$ 31,316,218	$ 8,806,490	-$ 360,000	$ 39,762,708	-$ 234,055,673
						$ -				$ -	$ -
		Sub-Total	**$ 1,634,839,219**	**$ 78,653,701**	**-$ 3,316,400**	**$ 1,710,176,520**	**-$ 389,253,728**	**-$ 59,141,745**	**$ 1,960,104**	**-$ 446,435,369**	**$ 1,263,741,151**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 1,634,839,219**	**$ 78,653,701**	**-$ 3,316,400**	**$ 1,710,176,520**	**-$ 389,253,728**	**-$ 59,141,745**	**$ 1,960,104**	**-$ 446,435,369**	**$ 1,263,741,151**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 59,141,745**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 59,141,745

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2024

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 87,494,987	$ 2,130,000		$ 89,624,987	-$ 7,959,699	-$ 1,958,654		-$ 9,918,353	$ 79,706,634
12	1611	Computer Software (Formally known as Account 1925)	$ 101,762,402	$ 2,672,828		$ 104,435,230	-$ 72,920,748	-$ 9,617,635		-$ 82,538,383	$ 21,896,847
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,335,309	$ 12,370		$ 2,347,679	-$ 573,671	-$ 60,424		-$ 634,095	$ 1,713,584
N/A	1805	Land	$ 4,817,612			$ 4,817,612				$ -	$ 4,817,612
47	1808	Buildings	$ 40,522,457	$ 930,941		$ 41,453,398	-$ 8,279,241	-$ 1,019,266		-$ 9,298,507	$ 32,154,891
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 152,078,311	$ 5,429,195		$ 157,507,506	-$ 34,917,766	-$ 4,810,909		-$ 39,728,675	$ 117,778,831
47	1820	Distribution Station Equipment <50 kV	$ 169,736,819	$ 11,994,416	-$ 96,181	$ 181,635,054	-$ 40,607,284	-$ 5,000,717	$ 55,028	-$ 45,552,973	$ 136,082,081
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 171,336,307	$ 8,186,322	-$ 313,703	$ 179,208,926	-$ 31,014,517	-$ 4,291,482	$ 30,864	-$ 35,275,135	$ 143,933,791
47	1835	Overhead Conductors & Devices	$ 184,463,525	$ 11,967,313	-$ 230,544	$ 196,200,294	-$ 31,697,691	-$ 4,917,860	$ 26,635	-$ 36,588,916	$ 159,611,378
47	1840	Underground Conduit	$ 301,044,522	$ 18,547,382		$ 319,591,904	-$ 51,079,800	-$ 8,246,543		-$ 59,326,343	$ 260,265,561
47	1845	Underground Conductors & Devices	$ 263,683,142	$ 17,644,613	-$ 359,069	$ 280,968,686	-$ 52,635,422	-$ 8,377,879	$ 64,812	-$ 60,948,489	$ 220,020,197
47	1850	Line Transformers	$ 124,383,480	$ 7,349,154	-$ 220,567	$ 131,512,067	-$ 28,201,406	-$ 4,055,629	$ 40,727	-$ 32,216,308	$ 99,295,759
47	1855	Services (Overhead & Underground)	$ 88,073,911	$ 4,435,769		$ 92,509,680	-$ 17,347,409	-$ 2,312,462		-$ 19,659,871	$ 72,849,809
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 69,661,825	$ 7,261,510	-$ 1,003,515	$ 75,919,820	-$ 37,204,613	-$ 3,798,330	$ 737,520	-$ 40,265,423	$ 35,654,397
N/A	1905	Land	$ 19,942,005			$ 19,942,005	-$ 17,536	-$ 4,047		-$ 21,583	$ 19,920,422
47	1908	Buildings & Fixtures	$ 98,406,958	$ 352,679		$ 98,759,637	-$ 17,549,626	-$ 3,216,137		-$ 20,765,763	$ 77,993,874
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 5,080,326	$ 50,383		$ 5,130,709	-$ 3,015,131	-$ 394,788		-$ 3,409,919	$ 1,720,790
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 20,615,950	$ 887,744		$ 21,503,694	-$ 14,224,890	-$ 1,973,655		-$ 16,198,545	$ 5,305,149
10	1930	Transportation Equipment	$ 26,828,545	$ 1,844,412	-$ 946,992	$ 27,725,965	-$ 9,561,978	-$ 2,033,557	$ 901,989	-$ 10,693,546	$ 17,032,419
8	1935	Stores Equipment	$ 562,235			$ 562,235	-$ 253,099	-$ 56,225		-$ 309,324	$ 252,911
8	1940	Tools, Shop & Garage Equipment	$ 6,540,464	$ 464,863		$ 7,005,327	-$ 4,221,206	-$ 452,760		-$ 4,673,966	$ 2,331,361
8	1945	Measurement & Testing Equipment	$ 252,299			$ 252,299	-$ 231,635	-$ 3,815		-$ 235,450	$ 16,849
8	1950	Power Operated Equipment	$ 1,596,991			$ 1,596,991	-$ 667,662	-$ 87,380		-$ 755,042	$ 841,949
8	1955	Communications Equipment	$ 21,317,559	$ 781,255		$ 22,098,814	-$ 11,368,137	-$ 2,136,078		-$ 13,504,215	$ 8,594,599

8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 960,528			$ 960,528	-$ 428,199	-$ 74,206		-$ 502,405	$ 458,123
47	1970	Load Management Controls Customer Premises	$ 918,789			$ 918,789	-$ 238,065	-$ 91,879		-$ 329,944	$ 588,845
47	1975	Load Management Controls Utility Premises	$ 533,383			$ 533,383	-$ 137,436	-$ 53,338		-$ 190,774	$ 342,609
47	1980	System Supervisor Equipment	$ 19,044,260	$ 1,094,855		$ 20,139,115	-$ 9,844,209	-$ 1,082,628		-$ 10,926,837	$ 9,212,278
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 273,818,381	-$ 20,689,619	$ 370,000	-$ 294,138,000	$ 39,762,709	$ 9,416,952	-$ 370,000	$ 48,809,661	-$ 245,328,339
						$ -				$ -	$ -
		Sub-Total	**$ 1,710,176,520**	**$ 83,348,385**	**-$ 2,800,571**	**$ 1,790,724,334**	**-$ 446,435,367**	**-$ 60,711,331**	**$ 1,487,575**	**-$ 505,659,123**	**$ 1,285,065,211**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		***Less Other Non Rate-Regulated Utility Assets* (input as negative)**				$ -				$ -	$ -
		Total PP&E	**$ 1,710,176,520**	**$ 83,348,385**	**-$ 2,800,571**	**$ 1,790,724,334**	**-$ 446,435,367**	**-$ 60,711,331**	**$ 1,487,575**	**-$ 505,659,123**	**$ 1,285,065,211**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 60,711,331**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 60,711,331

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2025

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 89,624,987	$ 7,300,000		$ 96,924,987	-$ 9,918,353	-$ 2,013,783		-$ 11,932,136	$ 84,992,851
12	1611	Computer Software (Formally known as Account 1925)	$ 104,435,229	$ 16,854,811		$ 121,290,040	-$ 82,538,383	-$ 11,048,698		-$ 93,587,081	$ 27,702,959
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,347,679	$ 12,376		$ 2,360,055	-$ 634,095	-$ 60,507		-$ 694,602	$ 1,665,453
N/A	1805	Land	$ 4,817,612	$ 779,683		$ 5,597,295				$ -	$ 5,597,295
47	1808	Buildings	$ 41,453,398	$ 1,416,046		$ 42,869,444	-$ 9,298,506	-$ 1,046,267		-$ 10,344,773	$ 32,524,671
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 157,507,506	$ 9,223,210		$ 166,730,716	-$ 39,728,675	-$ 5,003,121		-$ 44,731,796	$ 121,998,920
47	1820	Distribution Station Equipment <50 kV	$ 181,635,054	$ 26,747,897	-$ 96,181	$ 208,286,770	-$ 45,552,972	-$ 5,417,445	$ 55,028	-$ 50,915,389	$ 157,371,381
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 179,208,926	$ 8,003,940	-$ 313,703	$ 186,899,163	-$ 35,275,135	-$ 4,462,353	$ 30,864	-$ 39,706,624	$ 147,192,539
47	1835	Overhead Conductors & Devices	$ 196,200,294	$ 11,674,276	-$ 230,544	$ 207,644,026	-$ 36,588,915	-$ 5,217,477	$ 26,635	-$ 41,779,757	$ 165,864,269
47	1840	Underground Conduit	$ 319,591,904	$ 18,528,470		$ 338,120,374	-$ 59,326,343	-$ 8,650,400		-$ 67,976,743	$ 270,143,631
47	1845	Underground Conductors & Devices	$ 280,968,686	$ 17,532,469	-$ 359,069	$ 298,142,086	-$ 60,948,489	-$ 8,839,416	$ 64,812	-$ 69,723,093	$ 228,418,993
47	1850	Line Transformers	$ 131,512,066	$ 7,363,590	-$ 220,567	$ 138,655,089	-$ 32,216,309	-$ 4,226,186	$ 40,727	-$ 36,401,768	$ 102,253,321
47	1855	Services (Overhead & Underground)	$ 92,509,680	$ 4,429,274		$ 96,938,954	-$ 19,659,871	-$ 2,357,841		-$ 22,017,712	$ 74,921,242
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 75,919,820	$ 6,783,965	-$ 1,042,534	$ 81,661,251	-$ 40,265,423	-$ 3,974,133	$ 774,834	-$ 43,464,722	$ 38,196,529
N/A	1905	Land	$ 19,942,005			$ 19,942,005	-$ 21,583	-$ 4,047		-$ 25,630	$ 19,916,375
47	1908	Buildings & Fixtures	$ 98,759,638	$ 352,679		$ 99,112,317	-$ 20,765,763	-$ 3,204,028		-$ 23,969,791	$ 75,142,526
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 5,130,709	$ 50,383		$ 5,181,092	-$ 3,409,918	-$ 392,323		-$ 3,802,241	$ 1,378,851
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 21,503,694	$ 1,573,599		$ 23,077,293	-$ 16,198,545	-$ 1,958,576		-$ 18,157,121	$ 4,920,172
10	1930	Transportation Equipment	$ 27,725,965	$ 467,753	-$ 368,933	$ 27,824,785	-$ 10,693,546	-$ 2,158,407	$ 346,202	-$ 12,505,751	$ 15,319,034
8	1935	Stores Equipment	$ 562,235			$ 562,235	-$ 309,324	-$ 56,224		-$ 365,548	$ 196,687
8	1940	Tools, Shop & Garage Equipment	$ 7,005,326	$ 468,679		$ 7,474,005	-$ 4,673,967	-$ 461,217		-$ 5,135,184	$ 2,338,821
8	1945	Measurement & Testing Equipment	$ 252,299			$ 252,299	-$ 235,450	-$ 3,788		-$ 239,238	$ 13,061
8	1950	Power Operated Equipment	$ 1,596,991	$ 461,909	-$ 4,356	$ 2,054,544	-$ 755,042	-$ 89,388	$ 3,904	-$ 840,526	$ 1,214,018
8	1955	Communications Equipment	$ 22,098,814	$ 1,733,822		$ 23,832,636	-$ 13,504,216	-$ 1,885,121		-$ 15,389,337	$ 8,443,299
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -

8	1960	Miscellaneous Equipment	$ 960,528	$ 24,987		$ 985,515	-$ 502,405	-$ 74,768		-$ 577,173	$ 408,342
47	1970	Load Management Controls Customer Premises	$ 918,789			$ 918,789	-$ 329,944	-$ 91,879		-$ 421,823	$ 496,966
47	1975	Load Management Controls Utility Premises	$ 533,383			$ 533,383	-$ 190,774	-$ 53,338		-$ 244,112	$ 289,271
47	1980	System Supervisor Equipment	$ 20,139,115	$ 1,533,324		$ 21,672,439	-$ 10,926,836	-$ 1,081,462		-$ 12,008,298	$ 9,664,141
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 294,138,001	-$ 20,758,380	$ 410,000	-$ 314,486,381	$ 48,809,661	$ 9,805,553	-$ 410,000	$ 58,205,214	-$ 256,281,167
						$ -				$ -	$ -
		Sub-Total	**$ 1,790,724,331**	**$ 122,558,762**	**-$ 2,225,887**	**$ 1,911,057,206**	**-$ 505,659,121**	**-$ 64,026,640**	**$ 933,006**	**-$ 568,752,755**	**$ 1,342,304,451**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$ 1,790,724,331**	**$ 122,558,762**	**-$ 2,225,887**	**$ 1,911,057,206**	**-$ 505,659,121**	**-$ 64,026,640**	**$ 933,006**	**-$ 568,752,755**	**$ 1,342,304,451**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 64,026,640**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
			Net Depreciation	-$ 64,026,640

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

WORKING CAPITAL REQUIREMENT

1. INTRODUCTION

This Schedule provides a summary of the Working Capital Requirement for the Bridge Year 2020 and the Test Years 2021-2025.

Table 1 summarizes the 2016-2020 approved working capital allowance ("WCA"), as per the Approved Settlement Agreement governing Hydro Ottawa's 2016-2020 rate term.[1]

Table 1 – OEB-Approved Working Capital Allowance 2016-2020 ($'000s)

	2016	2017	2018	2019	2020
Power Supply Expenses	$894,825	$911,714	$947,559	$928,734	$945,199
OM&A Expenses	$83,106	$84,693	$86,311	$87,959[2]	$89,639[3]
Total Expenses for Working Capital[4]	$977,391	$966,407	$1,033,869	$1,016,693	$1,034,838
Working Capital %	7.89%	7.89%	7.92%	7.55%	7.52%
TOTAL WCA	**$77,166**	**$78,617**	**$81,882**	**$76,760**	**$77,820**

Table 2 provides the Historical and Bridge Year WCA amounts for 2016-2020.

Table 2 – Working Capital Allowance 2016-2020 ($'000s)

	Historical			Bridge	
	2016	2017	2018	2019	2020
Power Supply Expenses	$965,239	$875,802	$852,917	$928,734	$945,199
OM&A Expenses	$82,621	$82,245	$86,863	$87,545	$91,990
Total Expenses for Working Capital	$1,047,860	$958,047	$939,780	$1,016,279	$1,037,189
Working Capital %	7.89%	7.89%	7.92%	7.50%	7.50%
TOTAL WCA	**$82,676**	**$75,590**	**$74,431**	**$76,221**	**$77,789**

[1] Ontario Energy Board, *Decision and Order*, EB-2015-0004 (December 22, 2015), Schedule A, page 15.
[2] Figure does not reflect mid-term operations, maintenance and administration ("OM&A") adjustment.
[3] Figure does not reflect mid-term OM&A adjustment.
[4] Totals may not sum due to rounding.

Table 3 provides a summary of Hydro Ottawa's proposed WCA for 2021-2025.

Table 3 – Proposed Working Capital Allowance 2021-2025 ($'000s)

	2021	2022	2023	2024	2025
Power Supply Expenses	$1,025,613	$1,097,187	$1,167,387	$1,264,188	$1,310,655
OM&A Expenses	$93,923	$96,280	$98,697	$101,174	$103,714
Total Expenses for Working Capital[5]	$1,119,535	$1,193,467	$1,266,084	$1,365,362	$1,414,39
Working Capital %	7.50%	7.50%	7.50%	7.50%	7.50%
TOTAL WCA	**$83,865**	**$89,510**	**$94,956**	**$102,402**	**$106,078**

2. WORKING CAPITAL PERCENTAGE

As part of Hydro Ottawa's 2016-2020 rate application, the OEB approved a yearly WCA percentage. The utility's approved 2016-2020 WCA percentages are shown in Table 1 above.

Exhibit 2-1-1: Rate Base Overview incorporates the OEB's default WCA percentage of 7.5%, as outlined in Table 3 above, for 2021-2025 working capital requirement included in Hydro Ottawa's 2021-2025 rate base.

3. OPERATIONS, MAINTENANCE AND ADMINISTRATION

For more details on the OM&A expenses used in Table 1 above, please see Exhibit 4-1-1: Operations, Maintenance and Administration Summary.

4. CALCULATION OF POWER SUPPLY EXPENSE

The billing determinants underpinning the estimated Power Supply Expense use the forecasted monthly purchased kWh and peak kW produced by the load forecast described in Exhibit 3-1-1: Load Forecast. The forecast calculation for commodity expense is detailed in Appendix 2-Z, in the following attachments:

[5] Totals may not sum due to rounding.

- Attachment 2-3-1(A): OEB Appendix 2-Z - 2021 Commodity Expense
- Attachment 2-3-1(B): OEB Appendix 2-Z - 2022 Commodity Expense
- Attachment 2-3-1(C): OEB Appendix 2-Z - 2023 Commodity Expense
- Attachment 2-3-1(D): OEB Appendix 2-Z - 2024 Commodity Expense
- Attachment 2-3-1(E): OEB Appendix 2-Z - 2025 Commodity Expense

Attachment 2-3-1(F): 2021-2025 Cost of Power provides the complete Power Supply Expenses for the 2021-2025 period, as described within this Schedule. There are slight variances in the annual commodity expense in Attachments (A) through (E) and Attachment (F) due to rounding differences. Table 4 outlines the estimate of annual cost of power expenditures for 2021-2025.

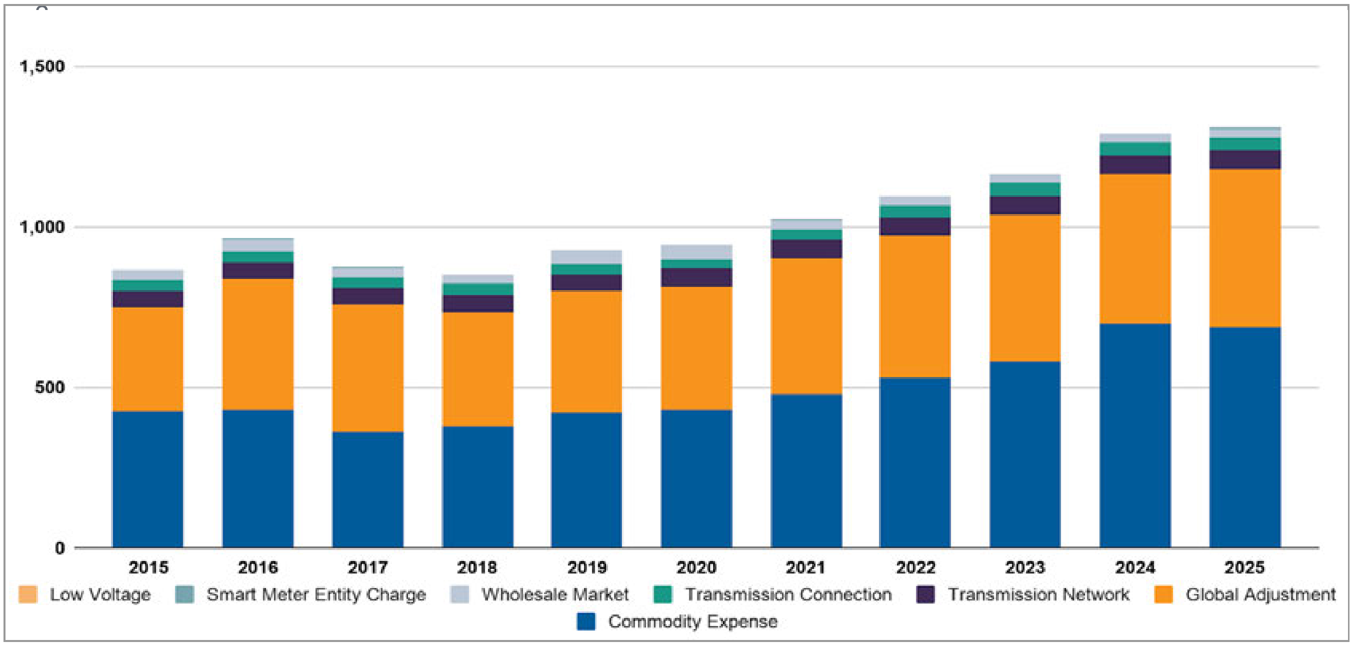
Table 4 – Summary of Estimated Annual Cost of Power Expenses ($'000s)

	2021	2022	2023	2024	2025
Commodity	$903,076	$972,245	$1,040,983	$1,135,265	$1,179,158
Wholesale Market	$28,423	$28,514	$28,628	$28,823	$28,881
Transmission Network	$55,056	$56,367	$57,032	$58,347	$59,772
Transmission Connection	$36,335	$37,308	$37,962	$38,943	$40,007
Smart Meter Entity Charge	$2,304	$2,328	$2,351	$2,372	$2,393
Low Voltage	$419	$426	$432	$439	$446
TOTAL[6]	**$1,025,613**	**$1,097,187**	**$1,167,387**	**$1,264,188**	**$1,310,655**

Figure 1 below illustrates Hydro Ottawa's annual cost of power expense from 2015-2025. Annual amounts from 2015-2018 are Historical, 2019-2020 are Bridge Years, and 2021-2025 have been forecasted as described in the subsections of this Schedule. The decrease in annual power supply expenditures from 2016-2019 can be attributed to the impacts from the *Ontario Fair Hydro Plan Act, 2017* ("Fair Hydro Plan").

[6] Totals may not sum due to rounding.

Figure 1 – Cost of Power Expense 2015-2025 ($’000,000s)



4.1. COMMODITY EXPENSE AND GLOBAL ADJUSTMENT

As per the OEB’s *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications*, as updated on July 12, 2018 and addended on July 15, 2019, Hydro Ottawa has completed Appendix 2-Z: Commodity Expense for 2021-2025.

Effective November 1, 2019, the provisions of the Fair Hydro Plan under which the OEB had been setting Regulated Price Plan (“RPP”) prices was repealed.[7] The OEB has since set RPP prices which more closely reflect the actual cost of supply. Hydro Ottawa has followed the direction OEB staff provided to Kingston Hydro Corporation in the follow-up questions for its 2020 Custom Incentive Rate-Setting (“Custom IR”) Annual Update (EB-2019-0048). On November 1, 2019, OEB staff updated Appendix 2-Z to accommodate the changes to the supply cost calculation.[8] These changes consist of the following: the amount for the Global Adjustment Modifier has been removed from the calculation; the non-RPP Actual kWh have not been split

[7] Ontario Energy Board, *Regulated Price Plan: Price Report November 1, 2019 to October 31, 2020* (October 22, 2019), page 1.
[8] Kingston Hydro Corporation, *Responses to OEB Staff follow-up Questions*, EB-2019-0048 (November 1, 2019), page 4.

between customers eligible for the Global Adjustment modifier and non-eligible customers; and the adjustment to address bias towards unfavourable variance has only been applied to RPP price forecast.

Hydro Ottawa has used 2018 Actual kWh and split each class by RPP and non-RPP and Class A and Class B customers to determine the percentage shares for the calculation of weighted average forecasted commodity expense. The RPP Supply Cost Summary from the OEB's most recent Regulated Price Plan Report has been used to determine the 2020 forecast commodity price.[9] For 2021-2025, Hydro Ottawa has used residential and commercial factors derived from Ontario's *2017 Long Term-Energy Plan*[10] ("LTEP") to estimate the RPP, Global Adjustment, and Hourly Ontario Energy Price ("HOEP"), as described below.

4.1.1. Estimated RPP Price

The commodity price for RPP customers was calculated by using the OEB's Regulated Price Plan Report. The RPP rate of $128.03/MWh was multiplied by a yearly residential factor derived from the LTEP to arrive at a yearly RPP commodity rate for 2021-2025. Table 5 provides the estimated RPP price for 2020-2025.

Table 5 – Estimated RPP Price (kWh)

2020	2021	2022	2023	2024	2025
$0.12803	$0.13203	$0.14203	$0.15204	$0.16404	$0.17104

4.1.2. Estimated Global Adjustment

The most recent Global Adjustment rate of $106.94/MWh from the Regulated Price Plan Report was multiplied by a commercial factor derived from the LTEP to arrive at a yearly Global Adjustment rate for 2021-2025. Please see Table 6 below for the yearly rates.

[9] Ontario Energy Board, *Regulated Price Plan: Price Report November 1, 2019 to October 31, 2020* (October 22, 2019), page 2.
[10] Ministry of Energy, *Ontario's Long-Term Energy Plan 2017: Delivering Fairness and Choice* (2017), pages 28-30.

Table 6 – Estimated Global Adjustment (kWh)

2020	2021	2022	2023	2024	2025
$0.10694	$0.10949	$0.11458	$0.12094	$0.12222	$0.12986

4.1.3. Estimated HOEP

For 2021-2025, the estimated HOEP rate has been calculated by taking the estimated annual Average Supply Cost for RPP customers and subtracting the annual estimated Global Adjustment and adjustment to address bias towards unfavourable variance. Table 7 identifies the estimated HOEP prices for 2021-2025.

Table 7 – Estimated HOEP (kWh)

2020	2021	2022	2023	2024	2025
$0.02009	$0.02154	$0.02645	$0.03009	$0.04082	$0.04018

4.1.4. Estimated Weighted Average Commodity Price

Hydro Ottawa calculated the weighted average commodity price from the percentage shares of RPP and non-RPP derived from the allocation of the non-loss-adjusted 2018 Actual kWh for 2021-2025. The annual forecasted loss-adjusted kWh purchases by class were multiplied by the annual weighted average forecasted commodity price. Table 8 shows the estimated weighted average commodity price for 2021-2025.

Table 8 – Estimated Weighted Average Commodity Price (kWh)

2020	2021	2022	2023	2024	2025
$0.1235	$0.13160	$0.1416	$0.1516	$0.1636	$0.1706

4.2. WHOLESALE EXPENSE

The Wholesale Market Charge is calculated by multiplying the total kWh purchased by the 2019 approved rate of $0.0039/kWh for all years.

4.3. TRANSMISSION EXPENSE

The forecasted kW monthly coincident peak is multiplied by historic percentages for each transmission charge to establish the kWs for those charges. Table 9 outlines the yearly rates calculated for Hydro One Networks Inc. ("HONI") Retail Transmission Service Rates ("RTSRs") and Uniform Transmission Rates ("UTRs").

Table 9 – Retail Transmission Service & Uniform Transmission Rates ($/kW)

	2020	2021	2022	2023	2024	2025
RTSR - Network Service	$3.3980	$3.3980	$3.4507	$3.5042	$3.5585	$3.6137
RTSR - Line Connection Rate	$0.8045	$0.8045	$0.8170	$0.8297	$0.8426	$0.8557
RTSR - Transformation Connection Service Rate	$2.0194	$2.0194	$2.0507	$2.0825	$2.1148	$2.1476
UTRs - Network	$3.92	$3.92	$4.00	$4.08	$4.16	$4.24
UTRs - Line Connection	$0.97	$0.97	$0.99	$1.01	$1.03	$1.05
UTRs - Transformation Connection	$2.33	$2.33	$2.38	$2.43	$2.48	$2.53

4.3.1. HONI Transmission Rates

For 2021, the kWs have been multiplied by the 2020 OEB-approved HONI RTSRs.[11] Hydro Ottawa has increased the transmission rates for 2022-2025 based on the inflationary method as described in the proceeding before the OEB involving HONI's most recent Custom IR Distribution Rate Application.[12]

[11] Ontario Energy Board, *Decision and Order*, EB-2019-0043 (December 17, 2019), Schedule A, page 8.
[12] Hydro One Networks Inc., *2018-2022 Custom Incentive Rate-setting Distribution Rate Application,* EB-2017-0049 (March 31, 2017), Exhibit A-3-2, page 3.

4.3.2. Uniform Transmission Rates

For 2021, the kWs have been multiplied by the 2020 Interim UTRs.[13] Hydro Ottawa has increased the transmission rates for 2022-2025 based on the 2020 OEB-approved inflationary factor.

4.4. LOW VOLTAGE CHARGES

To estimate the expense for 2021, historical kW values for Low Voltage and Common Sub Transmission Line ("Common ST Lines") have been multiplied by the 2020 OEB-approved HONI rates.[14] Hydro Ottawa has used the historical kW amounts for 2022-2025 and has adjusted the annual rates by the inflationary method as described in HONI's most recent Custom IR Distribution Rate Application. The yearly rates calculated are outlined in Table 10.

Table 10 – Low Voltage Charges ($/kWh)

	2020	2021	2022	2023	2024	2025
Connection to Common ST Lines	$1.4854	$1.4854	$1.5084	$1.5318	$1.5555	$1.5797
Connection to low-voltage delivery*	$3.8047	$3.8047	$3.8637	$3.9236	$3.9844	$4.0461

*High Voltage Distribution Station

4.5. SMART METERING ENTITY CHARGE

On March 1, 2018, the OEB approved a Smart Metering Entity charge of $0.57 per Residential and General Service <50 kW customer for the period January 1, 2018 to December 31, 2022.[15] This rate has been used for 2021-2025, without adjustment for inflation. As per the OEB decision, Hydro Ottawa has used the most recent OEB Yearbook count for Residential and General Service <50 kW customers to calculate the annual expense. The revenue has been derived based on the monthly load forecast.

[13] Ontario Energy Board, *Decision and Order*, EB-2019-0296 (December 19, 2019), Schedule A.
[14] Ontario Energy Board, *Decision and Order*, EB-2019-0043 (December 17, 2019), Schedule A, page 8.
[15] Ontario Energy Board, *Decision and Order*, EB-2017-0290 (March 1, 2018), page 5.

4.6. LOW VOLTAGE SWITCHGEAR CREDIT

Power Supply Expenses were adjusted to reflect the Low Voltage Switchgear credit which Hydro Ottawa receives as a result of owning the low voltage switchgear at certain stations.

In the green shaded cell (row 18-26) enter the most recent 12-month actual data. If there is a material difference between actual and forecasted consumption data, use forecasted data and provide an explanation

2021 Commodity Expense

Step 1: **Allocation of Commodity**

Customer Class Name		Last Actual kWh's	Class A kWh	Class B kWh	2018 Historical Actuals: non-RPP	non-RPP	non-RPP Total	RPP	Proportions (by Class) non-RPP %	Proportions (by Class) RPP %	
Residential		2,318,157,312		2,318,157,312	53,523,252		53,523,252	2,264,634,060	*2.31%*	*97.69%*	
General Service < 50 kW		727,990,863		727,990,863	104,398,586		104,398,586	623,592,277	*14.34%*	*85.66%*	
General Service 50 to 1,499 kW		2,971,283,949	284,153,894	2,687,130,055	2,228,215,001		2,228,215,001	458,915,054	*74.99%*	*15.45%*	
General Service 1,500-4999 kW		723,849,222	546,637,407	177,211,815	177,211,815		177,211,815	0	*100.00%*	*0.00%*	
Large Use		608,577,999	606,440,853	2,137,146	2,137,146		2,137,146	0	*100.00%*	*0.00%*	
Unmetered Scattered Load		14,860,742		14,860,742			-	14,860,742	*0.00%*	*100.00%*	
Sentinel Lighting		48,433		48,433			-	48,433	*0.00%*	*100.00%*	
Street Lighting		31,723,369		31,723,369	31,684,027			39,342			
				-				0			
TOTAL		**7,396,491,889**	**1,437,232,154**	**5,959,259,735**	**2,597,169,827**	**0**	**2,565,485,800**	**3,362,089,908**			
%		*100.00%*		*100.00%*	*43.58%*	*0.00%*		*56.42%*	*43.58%*	*56.42%*	*100.00%*

Step 2: **2021 Forecasted Commodity Prices**

Step 2a: **GA Modifier** ($/MWh) — non-RPP: — Source: Table 1: RPP Prices and GA Modifier: May 1, 2019 to October 31, 2019*

Step 2b: **Forecasted Commodity Prices** Table 1: Average RPP Supply Cost Summary**

			non-RPP			RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$21.54	$21.54		
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$109.49	$109.49		
Adjustments ($/MWh)						$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$131.03**	**$131.03**		**$132.03**
$/kWh			***$0.13103***	***$0.13103***		***$0.13203***
Percentage shares (%)	non-RPP (GA mod/non-GA mod), RPP		43.58%	0.00%		56.42%
WEIGHTED AVERAGE PRICE ($/kWh)	**(Sum of I43, J43 and L43)**	$ 0.1316	**$0.0571**	**$0.0000**		**$0.0745**

Step 3: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Class A

				2020					2021				
Customer		**Revenue**	**Expense**	**kWh Volume**	**kW Volume**	**HOEP Rate/kWh**	**Avg GA/kW**	**Amount**	**kWh Volume**	**kW Volume**	**HOEP Rate/kWh**	**Avg GA/kW**	**Amount**
General Service 50 to 1,499 kW		4035	4705	283,799,188	568,804	0.02154	35.84	$26,502,596	281,651,788	564,518	0.02154	35.84	$26,302,704
General Service 1,500-4999 kW		4010	4705	547,736,883	1,116,561	0.02154	35.84	$51,822,865	532,843,504	1,091,802	0.02154	35.84	$50,614,529
Large Use				590,398,123	1,067,681	0.02154	35.84	$50,989,936	575,308,315	1,045,719	0.02154	35.84	$49,877,624
				1,421,934,194	2,753,046			$129,315,397	1,389,803,607	2,702,039			$126,794,857

Class B

				2020					2021				
Customer		**Revenue**	**Expense**										
Class Name	UoM	USA #	USA #	Volume	rate ($/kWh):			Amount	Volume	rate ($/kWh):			Amount
Residential	kWh	4006	4705	2,330,090,861	0.1235			$287,682,757	2,327,657,981	$0.1316			$306,308,423
General Service < 50 kW	kWh	4010	4705	731,510,267	0.1235			$90,315,315	723,338,395	$0.1316			$95,187,800
General Service 50 to 1,499 kW	kWh	4035	4705	2,651,209,558	0.1235			$327,329,414	2,631,148,868	$0.1316			$346,246,342
General Service 1,500-4999 kW	kWh	4010	4705	177,568,250	0.1235			$21,923,318	172,740,035	$0.1316			$22,731,745
Large Use	kWh	4025	4705	2,080,611	0.1235			$256,881	2,027,433	$0.1316			$266,800
Unmetered Scattered Load	kWh	4025	4705	14,578,551	0.1235			$1,799,929	14,052,226	$0.1316			$1,849,204
Sentinel Lighting	kWh	4025	4705	48,575	0.1235			$5,997	48,556	$0.1316			$6,390
Street Lighting	kWh	4025	4705	24,870,144	0.1235			$3,070,572	22,838,742	$0.1316			$3,005,467
Drycore	kW	4025	4705	5,159,232	0.1235			$636,980	5,157,235	$0.1316			$678,667
TOTAL				**5,937,116,049**				**$733,021,163**	**5,899,009,471**				**$776,280,838**

Total

				2020					2021				
Customer		**Revenue**	**Expense**										
Class Name	UoM	USA #	USA #	Volume	avg rate ($/kWh):			Amount	Volume	avg rate ($/kWh):			Amount
Residential	kWh	4006	4705	2,330,090,861	0.1234641798			$287,682,757	2,327,657,981	0.1316			$306,308,423
General Service < 50 kW	kWh	4010	4705	731,510,267	0.1234641796			$90,315,315	723,338,395	0.1316			$95,187,800
General Service 50 to 1,499 kW	kWh	4035	4705	2,935,008,746	0.1206			$353,832,010	2,912,800,656	0.1279			$372,549,046
General Service 1,500-4999 kW	kWh	4010	4705	725,305,133	0.1017			$73,746,183	705,583,539	0.1040			$73,346,274
Large Use	kWh	4025	4705	592,478,734	0.08649562258			$51,246,817	577,335,748	0.0869			$50,144,424
Unmetered Scattered Load	kWh	4025	4705	14,578,551	0.1234641906			$1,799,929	14,052,226	0.1316			$1,849,204
Sentinel Lighting	kWh	4025	4705	48,575	0.1234585692			$5,997	48,556	0.1316			$6,390
Street Lighting	kWh	4025	4705	24,870,144	0.1234641826			$3,070,572	22,838,742	0.1316			$3,005,467
Drycore	kWh	4025	4705	5,159,232	0.1234641125			$636,980	5,157,235	0.1316			$678,667
TOTAL				**7,359,050,243**				**$862,336,560**	**7,288,813,078**				**$903,075,695**

**Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 – April 30, 2020*
*** Regulated Price Plan Cost Suppy Report May 1, 2019 - April 30, 2020*

In the green shaded cell (row 18-26) enter the most recent 12-month actual data. If there is a material difference between actual and forecasted consumption data, use forecasted data and provide an explanation

2022 Commodity Expense

Step 1: **Allocation of Commodity**

Customer Class Name		Last Actual kWh's	Class A kWh	Class B kWh
Residential		2,318,157,312		2,318,157,312
General Service < 50 kW		727,990,863		727,990,863
General Service 50 to 1,499 kW		2,971,283,949	284,153,894	2,687,130,055
General Service 1,500-4999 kW		723,849,222	546,637,407	177,211,815
Large Use		608,577,999	606,440,853	2,137,146
Unmetered Scattered Load		14,860,742		14,860,742
Sentinel Lighting		48,433		48,433
Street Lighting		31,723,369		31,723,369
				-
TOTAL		**7,396,491,889**	**1,437,232,154**	**5,959,259,735**
%		*100.00%*		*100.00%*

2018 Historical Actuals

Customer Class Name	non-RPP		Total	RPP	Proportions (by Class) non-RPP %	Proportions (by Class) RPP %	
Residential	53,523,252		53,523,252	2,264,634,060	*2.31%*	*97.69%*	
General Service < 50 kW	104,398,586		104,398,586	623,592,277	*14.34%*	*85.66%*	
General Service 50 to 1,499 kW	2,228,215,001		2,228,215,001	458,915,054	*74.99%*	*15.45%*	
General Service 1,500-4999 kW	177,211,815		177,211,815	0	*100.00%*	*0.00%*	
Large Use	2,137,146		2,137,146	0	*100.00%*	*0.00%*	
Unmetered Scattered Load			-	14,860,742	*0.00%*	*100.00%*	
Sentinel Lighting			-	48,433	*0.00%*	*100.00%*	
Street Lighting	31,684,027			39,342			
				0			
TOTAL	**2,597,169,827**	**0**	**2,565,485,800**	**3,362,089,908**			
%	*43.58%*	*0.00%*		*56.42%*	*43.58%*	*56.42%*	*100.00%*

Step 2: **2021 Forecasted Commodity Prices**

Step 2a: **GA Modifier** ($/MWh) — non-RPP — Source: Table 1: RPP Prices and GA Modifier: May 1, 2019 to October 31, 2019*

Step 2b: **Forecasted Commodity Prices** Table 1: Average RPP Supply Cost Summary**

			non-RPP		RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$26.45	$26.45	
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$114.58	$114.58	
Adjustments ($/MWh)					$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$141.03**	**$141.03**	**$142.03**
$/kWh			***$0.14103***	***$0.14103***	***$0.14203***
Percentage shares (%)	non-RPP (GA mod/non-GA mod), RPP		43.58%	0.00%	56.42%
WEIGHTED AVERAGE PRICE ($/kWh)	**(Sum of I43, J43 and L43)**	$ 0.1416	**$0.0615**	**$0.0000**	**$0.0801**

Step 3: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Class A

Customer		Revenue	Expense	2021 kWh Volume	2021 kW Volume	2021 HOEP Rate/kWh	2021 Avg GA/kW	2021 Amount	2022 kWh Volume	2022 kW Volume	2022 HOEP Rate/kWh	2022 Avg GA/kW	2022 Amount
General Service 50 to 1,499 kW		4035	4705	281,651,788	564,518	0.02154	35.84	$26,302,704	282,214,697	564,689	0.02645	35.84	$27,706,625
General Service 1,500-4999 kW		4010	4705	532,843,504	1,091,802	0.02154	35.84	$50,614,529	532,363,695	1,090,992	0.02645	35.84	$53,189,044
Large Use				575,308,315	1,045,719	0.02154	35.84	$49,877,624	573,902,832	1,043,602	0.02645	35.84	$52,589,303
				1,389,803,607	2,702,039			$126,794,857	1,388,481,224	2,699,283			$133,484,972

Class B

Customer Class Name	UoM	Revenue USA #	Expense USA #	2021 Volume	2021 rate ($/kWh):	2021 Amount	2022 Volume	2022 rate ($/kWh):	2022 Amount
Residential	kWh	4006	4705	2,327,657,981	0.1316	$306,308,423	2,349,232,208	$0.1416	$332,645,314
General Service < 50 kW	kWh	4010	4705	723,338,395	0.1316	$95,187,800	722,607,994	$0.1416	$102,319,457
General Service 50 to 1,499 kW	kWh	4035	4705	2,631,148,868	0.1316	$346,246,342	2,636,407,477	$0.1416	$373,308,603
General Service 1,500-4999 kW	kWh	4010	4705	172,740,035	0.1316	$22,731,745	172,584,487	$0.1416	$24,437,525
Large Use	kWh	4025	4705	2,027,433	0.1316	$266,800	2,022,480	$0.1416	$286,378
Unmetered Scattered Load	kWh	4025	4705	14,052,226	0.1316	$1,849,204	13,564,603	$0.1416	$1,920,713
Sentinel Lighting	kWh	4025	4705	48,556	0.1316	$6,390	48,556	$0.1416	$6,875
Street Lighting	kWh	4025	4705	22,838,742	0.1316	$3,005,467	21,927,548	$0.1416	$3,104,885
Drycore	kW	4025	4705	5,157,235	0.1316	$678,667	5,157,235	$0.1416	$730,251
TOTAL				**5,899,009,471**		**$776,280,838**	**5,923,552,588**		**$838,760,001**

Total

Customer Class Name	UoM	Revenue USA #	Expense USA #	2021 Volume	2021 avg rate ($/kWh):	2021 Amount	2022 Volume	2022 avg rate ($/kWh):	2022 Amount
Residential	kWh	4006	4705	2,327,657,981	0.1315951164	$306,308,423	2,349,232,208	0.1416	$332,645,314
General Service < 50 kW	kWh	4010	4705	723,338,395	0.131595116	$95,187,800	722,607,994	0.1416	$102,319,457
General Service 50 to 1,499 kW	kWh	4035	4705	2,912,800,656	0.1279	$372,549,046	2,918,622,174	0.1374	$401,015,228
General Service 1,500-4999 kW	kWh	4010	4705	705,583,539	0.1040	$73,346,274	704,948,182	0.1101	$77,626,569
Large Use	kWh	4025	4705	577,335,748	0.08685487451	$50,144,424	575,925,312	0.0918	$52,875,681
Unmetered Scattered Load	kWh	4025	4705	14,052,226	0.1315950939	$1,849,204	13,564,603	0.1416	$1,920,713
Sentinel Lighting	kWh	4025	4705	48,556	0.1316006261	$6,390	48,556	0.1416	$6,875
Street Lighting	kWh	4025	4705	22,838,742	0.1315951203	$3,005,467	21,927,548	0.1416	$3,104,885
Drycore	kWh	4025	4705	5,157,235	0.131595128	$678,667	5,157,235	0.1416	$730,251
TOTAL				**7,288,813,078**		**$903,075,695**	**7,312,033,812**		**$972,244,973**

**Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 – April 30, 2020*
*** Regulated Price Plan Cost Suppy Report May 1, 2019 - April 30, 2020*

In the green shaded cell (row 18-26) enter the most recent 12-month actual data. If there is a material difference between actual and forecasted consumption data, use forecasted data and provide an explanation

2023 Commodity Expense

Step 1: **Allocation of Commodity**

Customer Class Name		Last Actual kWh's	Class A kWh	Class B kWh	2018 Historical Actuals: non-RPP	non-RPP	non-RPP Total	RPP	Proportions (by Class) non-RPP %	Proportions (by Class) RPP %	
Residential		2,318,157,312		2,318,157,312	53,523,252		53,523,252	2,264,634,060	*2.31%*	*97.69%*	
General Service < 50 kW		727,990,863		727,990,863	104,398,586		104,398,586	623,592,277	*14.34%*	*85.66%*	
General Service 50 to 1,499 kW		2,971,283,949	284,153,894	2,687,130,055	2,228,215,001		2,228,215,001	458,915,054	*74.99%*	*15.45%*	
General Service 1,500-4999 kW		723,849,222	546,637,407	177,211,815	177,211,815		177,211,815	0	*100.00%*	*0.00%*	
Large Use		608,577,999	606,440,853	2,137,146	2,137,146		2,137,146	0	*100.00%*	*0.00%*	
Unmetered Scattered Load		14,860,742		14,860,742			-	14,860,742	*0.00%*	*100.00%*	
Sentinel Lighting		48,433		48,433			-	48,433	*0.00%*	*100.00%*	
Street Lighting		31,723,369		31,723,369	31,684,027			39,342			
				-				0			
TOTAL		**7,396,491,889**	**1,437,232,154**	**5,959,259,735**	**2,597,169,827**	**0**	**2,565,485,800**	**3,362,089,908**			
%		*100.00%*		*100.00%*	*43.58%*	*0.00%*		*56.42%*	*43.58%*	*56.42%*	*100.00%*

Step 2: **2021 Forecasted Commodity Prices**

Step 2a: **GA Modifier** ($/MWh) — non-RPP: — Source: Table 1: RPP Prices and GA Modifier: May 1, 2019 to October 31, 2019*

Step 2b: **Forecasted Commodity Prices** Table 1: Average RPP Supply Cost Summary**

			non-RPP		RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$30.09	$30.09	
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$120.94	$120.94	
Adjustments ($/MWh)					$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$151.04**	**$151.04**	**$152.04**
$/kWh			***$0.15104***	***$0.15104***	***$0.15204***
Percentage shares (%)	non-RPP (GA mod/non-GA mod), RPP		43.58%	0.00%	56.42%
WEIGHTED AVERAGE PRICE ($/kWh)	**(Sum of I43, J43 and L43)**	$ 0.1516	**$0.0658**	**$0.0000**	**$0.0858**

Step 3: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Class A

				2022					2023				
Customer		**Revenue**	**Expense**	**kWh Volume**	**kW Volume**	**HOEP Rate/kWh**	**Avg GA/kW**	**Amount**	**kWh Volume**	**kW Volume**	**HOEP Rate/kWh**	**Avg GA/kW**	**Amount**
General Service 50 to 1,499 kW		4035	4705	282,214,697	564,689	0.02645	35.84	$27,706,625	282,841,938	564,967	0.03009	35.84	$28,761,841
General Service 1,500-4999 kW		4010	4705	532,363,695	1,090,992	0.02645	35.84	$53,189,044	532,526,752	1,091,268	0.03009	35.84	$55,139,980
Large Use				573,902,832	1,043,602	0.02645	35.84	$52,589,303	573,045,317	1,042,311	0.03009	35.84	$54,604,433
				1,388,481,224	2,699,283			$133,484,972	1,388,414,007	2,698,546			$138,506,254

Class B

				2022					2023				
Customer		**Revenue**	**Expense**										
Class Name	UoM	USA #	USA #	Volume	rate ($/kWh):			Amount	Volume	rate ($/kWh):			Amount
Residential	kWh	4006	4705	2,349,232,208	0.1416			$332,645,314	2,375,626,880	$0.1516			$360,144,570
General Service < 50 kW	kWh	4010	4705	722,607,994	0.1416			$102,319,457	721,092,436	$0.1516			$109,317,472
General Service 50 to 1,499 kW	kWh	4035	4705	2,636,407,477	0.1416			$373,308,603	2,642,267,071	$0.1516			$400,567,170
General Service 1,500-4999 kW	kWh	4010	4705	172,584,487	0.1416			$24,437,525	172,637,348	$0.1516			$26,171,788
Large Use	kWh	4025	4705	2,022,480	0.1416			$286,378	2,019,458	$0.1516			$306,149
Unmetered Scattered Load	kWh	4025	4705	13,564,603	0.1416			$1,920,713	13,082,145	$0.1516			$1,983,251
Sentinel Lighting	kWh	4025	4705	48,556	0.1416			$6,875	48,556	$0.1516			$7,361
Street Lighting	kWh	4025	4705	21,927,548	0.1416			$3,104,885	21,088,670	$0.1516			$3,197,038
Drycore	kW	4025	4705	5,157,235	0.1416			$730,251	5,157,235	$0.1516			$781,836
TOTAL				**5,923,552,588**				**$838,760,001**	**5,953,019,799**				**$902,476,635**

Total

				2022					2023				
Customer		**Revenue**	**Expense**										
Class Name	UoM	USA #	USA #	Volume	avg rate ($/kWh):			Amount	Volume	avg rate ($/kWh):			Amount
Residential	kWh	4006	4705	2,349,232,208	0.1415974602			$332,645,314	2,375,626,880	0.1516			$360,144,570
General Service < 50 kW	kWh	4010	4705	722,607,994	0.1415974607			$102,319,457	721,092,436	0.1516			$109,317,472
General Service 50 to 1,499 kW	kWh	4035	4705	2,918,622,174	0.1374			$401,015,228	2,925,109,009	0.1468			$429,329,011
General Service 1,500-4999 kW	kWh	4010	4705	704,948,182	0.1101			$77,626,569	705,164,100	0.1153			$81,311,768
Large Use	kWh	4025	4705	575,925,312	0.09180996194			$52,875,681	575,064,775	0.0955			$54,910,582
Unmetered Scattered Load	kWh	4025	4705	13,564,603	0.1415974356			$1,920,713	13,082,145	0.1516			$1,983,251
Sentinel Lighting	kWh	4025	4705	48,556	0.141589093			$6,875	48,556	0.1516			$7,361
Street Lighting	kWh	4025	4705	21,927,548	0.1415974554			$3,104,885	21,088,670	0.1516			$3,197,038
Drycore	kWh	4025	4705	5,157,235	0.141597387			$730,251	5,157,235	0.1516			$781,836
TOTAL				**7,312,033,812**				**$972,244,973**	**7,341,433,806**				**$1,040,982,889**

**Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 – April 30, 2020*
*** Regulated Price Plan Cost Suppy Report May 1, 2019 - April 30, 2020*

In the green shaded cell (row 18-26) enter the most recent 12-month actual data. If there is a material difference between actual and forecasted consumption data, use forecasted data and provide an explanation

2024 Commodity Expense

Step 1: **Allocation of Commodity**

2018 Historical Actuals

Customer Class Name		Last Actual kWh's	Class A kWh	Class B kWh	non-RPP		Total (non-RPP)	RPP	Proportions (by Class) non-RPP %	Proportions (by Class) RPP %	
Residential		2,318,157,312		2,318,157,312	53,523,252		53,523,252	2,264,634,060	*2.31%*	*97.69%*	
General Service < 50 kW		727,990,863		727,990,863	104,398,586		104,398,586	623,592,277	*14.34%*	*85.66%*	
General Service 50 to 1,499 kW		2,971,283,949	284,153,894	2,687,130,055	2,228,215,001		2,228,215,001	458,915,054	*74.99%*	*15.45%*	
General Service 1,500-4999 kW		723,849,222	546,637,407	177,211,815	177,211,815		177,211,815	0	*100.00%*	*0.00%*	
Large Use		608,577,999	606,440,853	2,137,146	2,137,146		2,137,146	0	*100.00%*	*0.00%*	
Unmetered Scattered Load		14,860,742		14,860,742			-	14,860,742	*0.00%*	*100.00%*	
Sentinel Lighting		48,433		48,433			-	48,433	*0.00%*	*100.00%*	
Street Lighting		31,723,369		31,723,369	31,684,027			39,342			
				-				0			
TOTAL		**7,396,491,889**	**1,437,232,154**	**5,959,259,735**	**2,597,169,827**	**0**	**2,565,485,800**	**3,362,089,908**			
%		*100.00%*		*100.00%*	*43.58%*	*0.00%*		*56.42%*	*43.58%*	*56.42%*	*100.00%*

Step 2: **2021 Forecasted Commodity Prices**

Step 2a: **GA Modifier** ($/MWh) — non-RPP — Source: Table 1: RPP Prices and GA Modifier: May 1, 2019 to October 31, 2019*

Step 2b: **Forecasted Commodity Prices** Table 1: Average RPP Supply Cost Summary**

			non-RPP		RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$40.82	$40.82	
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$122.22	$122.22	
Adjustments ($/MWh)					$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$163.04**	**$163.04**	**$164.04**
$/kWh			***$0.16304***	***$0.16304***	***$0.16404***
Percentage shares (%)	non-RPP (GA mod/non-GA mod), RPP		43.58%	0.00%	56.42%
WEIGHTED AVERAGE PRICE ($/kWh)	**(Sum of I43, J43 and L43)**	$ 0.1636	**$0.0711**	**$0.0000**	**$0.0925**

Step 3: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Class A

Customer		Revenue	Expense	2023 kWh Volume	2023 kW Volume	2023 HOEP Rate/kWh	2023 Avg GA/kW	2023 Amount	2024 kWh Volume	2024 kW Volume	2024 HOEP Rate/kWh	2024 Avg GA/kW	2024 Amount
General Service 50 to 1,499 kW		4035	4705	282,841,938	564,967	0.03009	35.84	$28,761,841	284,143,471	566,394	0.04082	35.84	$31,900,935
General Service 1,500-4999 kW		4010	4705	532,526,752	1,091,268	0.03009	35.84	$55,139,980	534,022,353	1,093,784	0.04082	35.84	$61,005,078
Large Use				573,045,317	1,042,311	0.03009	35.84	$54,604,433	573,847,735	1,043,519	0.04082	35.84	$60,829,103
				1,388,414,007	2,698,546			$138,506,254	1,392,013,559	2,703,697			$153,735,115

Class B

Customer		Revenue	Expense	2023			2024		
Class Name	UoM	USA #	USA #	Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	4006	4705	2,375,626,880	0.1516	$360,144,570	2,410,578,720	$0.1636	$394,376,986
General Service < 50 kW	kWh	4010	4705	721,092,436	0.1516	$109,317,472	721,270,129	$0.1636	$118,001,680
General Service 50 to 1,499 kW	kWh	4035	4705	2,642,267,071	0.1516	$400,567,170	2,654,425,798	$0.1636	$434,271,006
General Service 1,500-4999 kW	kWh	4010	4705	172,637,348	0.1516	$26,171,788	173,122,200	$0.1636	$28,323,245
Large Use	kWh	4025	4705	2,019,458	0.1516	$306,149	2,022,285	$0.1636	$330,851
Unmetered Scattered Load	kWh	4025	4705	13,082,145	0.1516	$1,983,251	12,598,655	$0.1636	$2,061,173
Sentinel Lighting	kWh	4025	4705	48,556	0.1516	$7,361	48,556	$0.1636	$7,944
Street Lighting	kWh	4025	4705	21,088,670	0.1516	$3,197,038	20,251,859	$0.1636	$3,313,257
Drycore	kW	4025	4705	5,157,235	0.1516	$781,836	5,157,235	$0.1636	$843,737
TOTAL				**5,953,019,799**		**$902,476,635**	**5,999,475,437**		**$981,529,879**

Total

Customer		Revenue	Expense	2023			2024		
Class Name	UoM	USA #	USA #	Volume	avg rate ($/kWh):	Amount	Volume	avg rate ($/kWh):	Amount
Residential	kWh	4006	4705	2,375,626,880	0.1515998043	$360,144,570	2,410,578,720	0.1636	$394,376,986
General Service < 50 kW	kWh	4010	4705	721,092,436	0.1515998041	$109,317,472	721,270,129	0.1636	$118,001,680
General Service 50 to 1,499 kW	kWh	4035	4705	2,925,109,009	0.1468	$429,329,011	2,938,569,269	0.1586	$466,171,941
General Service 1,500-4999 kW	kWh	4010	4705	705,164,100	0.1153	$81,311,768	707,144,553	0.1263	$89,328,323
Large Use	kWh	4025	4705	575,064,775	0.09548590762	$54,910,582	575,870,020	0.1062	$61,159,954
Unmetered Scattered Load	kWh	4025	4705	13,082,145	0.1515998332	$1,983,251	12,598,655	0.1636	$2,061,173
Sentinel Lighting	kWh	4025	4705	48,556	0.1515981547	$7,361	48,556	0.1636	$7,944
Street Lighting	kWh	4025	4705	21,088,670	0.1515997927	$3,197,038	20,251,859	0.1636	$3,313,257
Drycore	kWh	4025	4705	5,157,235	0.1515998398	$781,836	5,157,235	0.1636	$843,737
TOTAL				**7,341,433,806**		**$1,040,982,889**	**7,391,488,996**		**$1,135,264,994**

**Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 – April 30, 2020*
*** Regulated Price Plan Cost Suppy Report May 1, 2019 - April 30, 2020*

In the green shaded cell (row 18-26) enter the most recent 12-month actual data. If there is a material difference between actual and forecasted consumption data, use forecasted data and provide an explanation

2025 Commodity Expense

Step 1: **Allocation of Commodity**

Customer Class Name		Last Actual kWh's	Class A kWh	Class B kWh
Residential		2,318,157,312		2,318,157,312
General Service < 50 kW		727,990,863		727,990,863
General Service 50 to 1,499 kW		2,971,283,949	284,153,894	2,687,130,055
General Service 1,500-4999 kW		723,849,222	546,637,407	177,211,815
Large Use		608,577,999	606,440,853	2,137,146
Unmetered Scattered Load		14,860,742		14,860,742
Sentinel Lighting		48,433		48,433
Street Lighting		31,723,369		31,723,369
				-
TOTAL		**7,396,491,889**	**1,437,232,154**	**5,959,259,735**
%		*100.00%*		*100.00%*

2018 Historical Actuals

Customer Class Name	non-RPP			RPP	Proportions (by Class)		
			Total		non-RPP	RPP	
					%	%	
Residential	53,523,252		53,523,252	2,264,634,060	*2.31%*	*97.69%*	
General Service < 50 kW	104,398,586		104,398,586	623,592,277	*14.34%*	*85.66%*	
General Service 50 to 1,499 kW	2,228,215,001		2,228,215,001	458,915,054	*74.99%*	*15.45%*	
General Service 1,500-4999 kW	177,211,815		177,211,815	0	*100.00%*	*0.00%*	
Large Use	2,137,146		2,137,146	0	*100.00%*	*0.00%*	
Unmetered Scattered Load			-	14,860,742	*0.00%*	*100.00%*	
Sentinel Lighting			-	48,433	*0.00%*	*100.00%*	
Street Lighting	31,684,027			39,342			
				0			
TOTAL	**2,597,169,827**	**0**	**2,565,485,800**	**3,362,089,908**			
%	*43.58%*	*0.00%*		*56.42%*	*43.58%*	*56.42%*	*100.00%*

Step 2: **2021 Forecasted Commodity Prices**

Step 2a: **GA Modifier** ($/MWh) — non-RPP — Source: Table 1: RPP Prices and GA Modifier: May 1, 2019 to October 31, 2019*

Step 2b: **Forecasted Commodity Prices** Table 1: Average RPP Supply Cost Summary**

			non-RPP			RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$40.18	$40.18		
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$129.86	$129.86		
Adjustments ($/MWh)						$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$170.04**	**$170.04**		**$171.04**
$/kWh			***$0.17004***	***$0.17004***		***$0.17104***
Percentage shares (%)	non-RPP (GA mod/non-GA mod), RPP		43.58%	0.00%		56.42%
WEIGHTED AVERAGE PRICE ($/kWh)	**(Sum of I43, J43 and L43)**	$ 0.1706	**$0.0741**	**$0.0000**		**$0.0965**

Step 3: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Class A

				2024					2025				
Customer		**Revenue**	**Expense**	**kWh Volume**	**kW Volume**	**HOEP Rate/kWh**	**Avg GA/kW**	**Amount**	**kWh Volume**	**kW Volume**	**HOEP Rate/kWh**	**Avg GA/kW**	**Amount**
General Service 50 to 1,499 kW		4035	4705	284,143,471	566,394	0.04082	35.84	$31,900,935	284,246,863	565,770	0.04018	35.84	$31,701,743
General Service 1,500-4999 kW		4010	4705	534,022,353	1,093,784	0.04082	35.84	$61,005,078	533,340,478	1,092,640	0.04018	35.84	$60,596,536
Large Use				573,847,735	1,043,519	0.04082	35.84	$60,829,103	571,399,410	1,039,825	0.04018	35.84	$60,232,809
				1,392,013,559	2,703,697			$153,735,115	1,388,986,751	2,698,235			$152,531,088

Class B

				2024			2025		
Customer		**Revenue**	**Expense**						
Class Name	UoM	USA #	USA #	Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	4006	4705	2,410,578,720	0.1636	$394,376,986	2,431,193,197	$0.1706	$414,771,910
General Service < 50 kW	kWh	4010	4705	721,270,129	0.1636	$118,001,680	719,290,710	$0.1706	$122,714,057
General Service 50 to 1,499 kW	kWh	4035	4705	2,654,425,798	0.1636	$434,271,006	2,655,391,664	$0.1706	$453,021,123
General Service 1,500-4999 kW	kWh	4010	4705	173,122,200	0.1636	$28,323,245	172,901,145	$0.1706	$29,497,671
Large Use	kWh	4025	4705	2,022,285	0.1636	$330,851	2,013,657	$0.1706	$343,538
Unmetered Scattered Load	kWh	4025	4705	12,598,655	0.1636	$2,061,173	12,116,197	$0.1706	$2,067,075
Sentinel Lighting	kWh	4025	4705	48,556	0.1636	$7,944	48,556	$0.1706	$8,284
Street Lighting	kWh	4025	4705	20,251,859	0.1636	$3,313,257	19,478,067	$0.1706	$3,323,041
Drycore	kW	4025	4705	5,157,235	0.1636	$843,737	5,157,235	$0.1706	$879,846
TOTAL				**5,999,475,437**		**$981,529,879**	**6,017,590,428**		**$1,026,626,545**

Total

				2024			2025		
Customer		**Revenue**	**Expense**						
Class Name	UoM	USA #	USA #	Volume	avg rate ($/kWh):	Amount	Volume	avg rate ($/kWh):	Amount
Residential	kWh	4006	4705	2,410,578,720	0.1636026166	$394,376,986	2,431,193,197	0.1706	$414,771,910
General Service < 50 kW	kWh	4010	4705	721,270,129	0.1636026161	$118,001,680	719,290,710	0.1706	$122,714,057
General Service 50 to 1,499 kW	kWh	4035	4705	2,938,569,269	0.1586	$466,171,941	2,939,638,527	0.1649	$484,722,866
General Service 1,500-4999 kW	kWh	4010	4705	707,144,553	0.1263	$89,328,323	706,241,623	0.1276	$90,094,207
Large Use	kWh	4025	4705	575,870,020	0.1062044409	$61,159,954	573,413,067	0.1056	$60,576,347
Unmetered Scattered Load	kWh	4025	4705	12,598,655	0.1636026227	$2,061,173	12,116,197	0.1706	$2,067,075
Sentinel Lighting	kWh	4025	4705	48,556	0.1636049098	$7,944	48,556	0.1706	$8,284
Street Lighting	kWh	4025	4705	20,251,859	0.1636026105	$3,313,257	19,478,067	0.1706	$3,323,041
Drycore	kWh	4025	4705	5,157,235	0.1636025894	$843,737	5,157,235	0.1706	$879,846
TOTAL				**7,391,488,996**		**$1,135,264,994**	**7,406,577,179**		**$1,179,157,633**

**Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2019 – April 30, 2020*

*** Regulated Price Plan Cost Suppy Report May 1, 2019 - April 30, 2020*

2021 Cost of Power

Loss Factors	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
LOSS FACTOR-every class but LU	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331
LOSS FACTOR-LARGE USERS	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053

SALES

UNADJUSTED SALES (KWH)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
RESIDENTIAL	222,057,000	194,356,000	188,428,000	158,773,000	154,330,000	186,714,000	226,531,000	207,670,000	164,645,000	165,832,000	172,475,000	211,270,000	**2,253,081,000**
GENERAL SERVICE <50KW	67,456,000	61,243,000	61,629,000	54,132,000	52,479,000	54,992,000	61,543,000	58,777,000	52,126,000	53,865,000	57,227,000	64,694,000	**700,163,000**
DRYCORE	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	**4,992,000**
GENERAL SERVICE 50-1000KW NONI	109,857,000	98,997,000	98,624,000	84,837,000	78,843,000	81,555,000	91,889,000	88,224,000	77,685,000	80,337,000	88,292,000	101,201,000	**1,080,341,000**
GENERAL SERVICE 50-1000KW INT	121,186,000	110,403,000	114,279,000	103,898,000	105,755,000	110,925,000	122,761,000	117,427,000	105,550,000	108,725,000	110,584,000	121,888,000	**1,353,381,000**
GENERAL SERVICE 1000-1500KW	33,284,000	30,679,000	32,369,000	30,649,000	31,265,000	32,109,000	34,867,000	33,868,000	31,036,000	31,280,000	31,283,000	33,065,000	**385,754,000**
GENERAL SERVICE 1500-5000 KW	58,421,000	53,124,000	56,812,000	53,717,000	55,461,000	57,672,000	63,887,000	61,540,000	55,055,000	54,985,000	54,573,000	57,730,000	**682,977,000**
LARGE USER	47,874,000	42,822,000	47,722,000	46,055,000	48,373,000	48,727,000	52,777,000	51,545,000	47,265,000	47,632,000	45,925,000	47,575,000	**574,292,000**
STREETLIGHTING	2,840,000	2,280,000	2,008,000	1,586,000	1,101,000	975,000	1,096,000	1,347,000	1,684,000	2,178,000	2,387,000	2,625,000	**22,107,000**
SENTINEL	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	**47,000**
UNMETERED	1,174,000	1,172,000	1,059,000	1,162,000	1,125,000	1,157,000	1,143,000	1,131,000	1,116,000	1,125,000	1,106,000	1,132,000	**13,602,000**
TOTAL KWH-SALES	**664,568,917**	**595,495,917**	**603,349,917**	**535,228,917**	**529,151,917**	**575,245,917**	**656,913,917**	**621,948,917**	**536,581,917**	**546,378,917**	**564,271,917**	**641,599,917**	**7,070,737,000**

PURCHASES

Power Purchases (kWh)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Total Load Forecast kWh	685,988,000	612,865,000	623,253,000	550,376,000	547,710,000	592,725,000	677,783,000	638,603,000	552,637,000	562,536,000	582,867,000	660,707,000	**7,288,050,000**

Power Purchased (kW)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Power Purchases - coincident peak (kW)	1,183,000	1,167,000	1,087,000	942,000	1,109,000	1,237,000	1,452,000	1,325,000	1,128,000	928,000	1,070,000	1,140,000	**13,768,000**

DEMAND CHARGES

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Coincident System Peak	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Transmission Network Charge IESO	95.2%	95.5%	93.7%	97.7%	92.1%	88.9%	91.5%	94.5%	94.9%	93.5%	93.4%	90.1%
Transmission Transformation Charge IESO	80.9%	82.4%	80.0%	82.4%	77.2%	75.6%	76.4%	77.0%	78.6%	78.8%	76.4%	76.8%
Transmission Line Charge IESO	92.6%	93.5%	92.1%	94.7%	88.6%	88.9%	88.4%	91.5%	92.0%	93.4%	89.4%	89.2%
Transmission Network Charge HONI	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%
Transmission Transformation Charge HONI	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
Transmission Line Charge HONI	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Transmission Network Charge IESO	1,126,020.80	1,114,982	1,018,675	920,039	1,021,184	1,100,146	1,328,478	1,252,113	1,070,745	867,746	999,338	1,027,357	**12,846,824**
Transmission Transformation Charge IESO	957,609	961,522	869,316	776,537	855,878	935,120	1,109,354	1,020,035	886,537	731,290	817,539	875,171	**10,795,906**
Transmission Line Charge IESO	1,095,277	1,091,571	1,001,320	892,124	983,046	1,099,077	1,284,061	1,211,830	1,037,455	866,502	956,904	1,016,811	**12,535,978**
Transmission Network Charge HONI	102,938	101,546	94,585	81,968	96,499	107,637	126,345	115,294	98,153	80,750	93,106	99,197	**1,198,018**
Transmission Transformation Charge HONI	70,740	69,784	65,000	56,329	66,315	73,969	86,826	79,232	67,452	55,492	63,983	68,169	**823,292**
Transmission Line Charge HONI	32,198	31,762	29,585	25,639	30,184	33,668	39,519	36,063	30,701	25,258	29,122	31,028	**374,726**

RATES

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Commodity Charge - Appendix 2Z	$0.1316	$0.1316	$0.1316	$0.1316	$0.1316	$0.1316	$0.1316	$0.1316	$0.1316	$0.1316	$0.1316	$0.1316
Transmission Network Charge IESO	$3.92	$3.92	$3.92	$3.92	$3.92	$3.92	$3.92	$3.92	$3.92	$3.92	$3.92	$3.92
Transmission Transformation Charge IESO	$2.33	$2.33	$2.33	$2.33	$2.33	$2.33	$2.33	$2.33	$2.33	$2.33	$2.33	$2.33
Transmission Line Charge IESO	$0.97	$0.97	$0.97	$0.97	$0.97	$0.97	$0.97	$0.97	$0.97	$0.97	$0.97	$0.97
Transmission Network Charge HONI	$3.40	$3.40	$3.40	$3.40	$3.40	$3.40	$3.40	$3.40	$3.40	$3.40	$3.40	$3.40
Transmission Transformation Charge HONI	$2.02	$2.02	$2.02	$2.02	$2.02	$2.02	$2.02	$2.02	$2.02	$2.02	$2.02	$2.02
Transmission Line Charge HONI	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80	$0.80
Wholesale Market Charge	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390
Smart Metering Entity Charge	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570

COST OF POWER

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	**$903,075,711**
Transmission Network Charge IESO	$4,414,001.56	$4,370,727.74	$3,993,207.78	$3,606,554.46	$4,003,039.83	$4,312,572.68	$5,207,635.09	$4,908,282.91	$4,197,319.69	$3,401,563.58	$3,917,404.87	$4,027,240.52	**$50,359,551**
Transmission Transformation Charge IESO	$2,231,228.82	$2,240,345.32	$2,025,506.15	$1,809,331.63	$1,994,194.77	$2,178,829.55	$2,584,794.22	$2,376,680.69	$2,065,631.21	$1,703,905.71	$1,904,865.87	$2,039,147.68	**$25,154,462**
Transmission Line Charge IESO	$1,062,418.38	$1,058,823.84	$971,280.35	$865,360.61	$953,554.72	$1,066,104.88	$1,245,539.28	$1,175,475.38	$1,006,331.06	$840,507.02	$928,197.07	$986,306.22	**$12,159,899**
Transmission Network Charge HONI	$403,518.44	$398,060.88	$370,773.07	$321,313.92	$378,277.22	$421,937.71	$495,273.69	$451,954.30	$384,758.07	$316,538.56	$364,974.41	$388,851.24	**$4,696,232**
Transmission Transformation Charge HONI	$164,825.19	$162,595.94	$151,449.69	$131,247.11	$154,514.91	$172,348.91	$202,304.46	$184,609.79	$157,162.14	$129,296.51	$149,081.11	$158,834.08	**$1,918,270**
Transmission Line Charge HONI	$31,232.01	$30,809.60	$28,697.55	$24,869.45	$29,278.36	$32,657.65	$38,333.80	$34,980.91	$29,779.98	$24,499.84	$28,248.74	$30,096.78	**$363,485**
Wholesale Market Charge	$2,675,353.20	$2,390,173.50	$2,430,686.70	$2,146,466.40	$2,136,069.00	$2,311,627.50	$2,643,353.70	$2,490,551.70	$2,155,284.30	$2,193,890.40	$2,273,181.30	$2,576,757.30	**$28,423,395**
Smart Meter Entity Charge	$191,830.08	$191,830.08	$191,830.08	$191,830.08	$191,830.08	$191,830.08	$191,830.08	$191,830.08	$191,830.08	$191,830.08	$191,830.08	$193,856.43	**$2,303,987**
LV Charges	$34,923.69	$34,923.69	$34,923.69	$34,923.69	$34,923.69	$34,923.69	$34,923.69	$34,923.69	$34,923.69	$34,923.69	$34,923.69	$34,923.69	**$419,084**
Total	**$86,465,641**	**$86,134,600**	**$85,454,664**	**$84,388,207**	**$85,131,992**	**$85,979,142**	**$87,900,297**	**$87,105,599**	**$85,479,329**	**$84,093,265**	**$85,049,016**	**$85,692,323**	**$1,028,874,074**
Switchgear Credit	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	**-$3,261,312**

2021 Cost of Power

Cost of Power Summary	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	$75,256,309	**$903,075,711**
Transmission Network	$4,817,520	$4,768,789	$4,363,981	$3,927,868	$4,381,317	$4,734,510	$5,702,909	$5,360,237	$4,582,078	$3,718,102	$4,282,379	$4,416,092	**$55,055,782**
Transmission Connection	$3,217,928	$3,220,799	$2,905,158	$2,559,033	$2,859,767	$3,178,165	$3,799,196	$3,499,971	$2,987,128	$2,426,433	$2,738,617	$2,942,609	**$36,334,803**
Wholesale Market	$2,675,353	$2,390,174	$2,430,687	$2,146,466	$2,136,069	$2,311,628	$2,643,354	$2,490,552	$2,155,284	$2,193,890	$2,273,181	$2,576,757	**$28,423,395**
Smart Metering Entity Charge	$191,830	$191,830	$191,830	$191,830	$191,830	$191,830	$191,830	$191,830	$191,830	$191,830	$191,830	$193,856	**$2,303,987**
LV Charges	$34,924	$34,924	$34,924	$34,924	$34,924	$34,924	$34,924	$34,924	$34,924	$34,924	$34,924	$34,924	**$419,084**
TOTAL COST of POWER EXPENSE	**$86,193,865**	**$85,862,824**	**$85,182,888**	**$84,116,431**	**$84,860,216**	**$85,707,366**	**$87,628,521**	**$86,833,823**	**$85,207,553**	**$83,821,489**	**$84,777,240**	**$85,420,547**	**$1,025,612,762**

2022 Cost of Power

Loss Factors	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
LOSS FACTOR-every class but LU	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331
LOSS FACTOR-LARGE USERS	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053

SALES

UNADJUSTED SALES (KWH)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
RESIDENTIAL	223,501,000	195,675,000	189,763,000	160,005,000	155,774,000	188,936,000	229,649,000	210,380,000	166,409,000	167,242,000	173,815,000	212,815,000	2,273,964,000
GENERAL SERVICE <50KW	67,317,000	61,115,000	61,548,000	54,060,000	52,439,000	54,985,000	61,586,000	58,797,000	52,087,000	53,800,000	57,136,000	64,586,000	699,456,000
DRYCORE	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	4,992,000
GENERAL SERVICE 50-1000KW NONI	106,033,000	95,542,000	95,192,000	81,801,000	75,913,000	78,540,000	88,590,000	85,042,000	74,787,000	77,333,000	85,127,000	97,665,000	1,041,565,000
GENERAL SERVICE 50-1000KW INT	125,079,000	113,945,000	117,983,000	107,197,000	109,052,000	114,425,000	126,749,000	121,217,000	108,842,000	112,100,000	114,111,000	125,853,000	1,396,553,000
GENERAL SERVICE 1000-1500KW	33,367,000	30,756,000	32,471,000	30,748,000	31,377,000	32,229,000	35,008,000	33,997,000	31,136,000	31,375,000	31,371,000	33,158,000	386,993,000
GENERAL SERVICE 1500-5000 KW	58,082,000	52,864,000	56,681,000	53,637,000	55,450,000	57,707,000	63,979,000	61,611,000	55,066,000	54,988,000	54,564,000	57,733,000	682,362,000
LARGE USER	47,569,000	42,595,000	47,557,000	45,937,000	48,287,000	48,656,000	52,705,000	51,474,000	47,193,000	47,560,000	45,853,000	47,503,000	572,889,000
STREETLIGHTING	2,741,000	2,191,000	1,928,000	1,513,000	1,031,000	907,000	1,029,000	1,279,000	1,617,000	2,111,000	2,320,000	2,558,000	21,225,000
SENTINEL	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	47,000
UNMETERED	1,133,000	1,132,000	1,023,000	1,122,000	1,086,000	1,117,000	1,103,000	1,092,000	1,077,000	1,086,000	1,067,000	1,092,000	13,130,000
TOTAL KWH-SALES	**665,241,917**	**596,234,917**	**604,565,917**	**536,439,917**	**530,828,917**	**577,921,917**	**660,817,917**	**625,308,917**	**538,633,917**	**548,014,917**	**565,783,917**	**643,382,917**	**7,093,176,000**

PURCHASES

Power Purchases (kWh)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Total Load Forecast kWh	686,682,000	613,627,000	624,508,000	551,621,000	549,444,000	595,481,000	681,811,000	642,054,000	554,750,000	564,220,000	584,430,000	662,543,000	**7,311,171,000**

Power Purchased (kW)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Power Purchases - coincident peak (kW)	1,186,000	1,170,000	1,090,000	944,000	1,111,000	1,242,000	1,461,000	1,332,000	1,132,000	930,000	1,073,000	1,143,000	**13,814,000**

DEMAND CHARGES

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Coincident System Peak	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Transmission Network Charge IESO	95.2%	95.5%	93.7%	97.7%	92.1%	88.9%	91.5%	94.5%	94.9%	93.5%	93.4%	90.1%
Transmission Transformation Charge IESO	80.9%	82.4%	80.0%	82.4%	77.2%	75.6%	76.4%	77.0%	78.6%	78.8%	76.4%	76.8%
Transmission Line Charge IESO	92.6%	93.5%	92.1%	94.7%	88.6%	88.9%	88.4%	91.5%	92.0%	93.4%	89.4%	89.2%
Transmission Network Charge HONI	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%
Transmission Transformation Charge HONI	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
Transmission Line Charge HONI	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Transmission Network Charge IESO	1,128,876.31	1,117,848	1,021,487	921,993	1,023,025	1,104,593	1,336,713	1,258,728	1,074,542	869,616	1,002,140	1,030,061	**12,889,621**
Transmission Transformation Charge IESO	960,037	963,993	871,715	778,186	857,421	938,900	1,116,230	1,025,423	889,681	732,866	819,831	877,474	**10,831,758**
Transmission Line Charge IESO	1,098,054	1,094,377	1,004,083	894,018	984,819	1,103,520	1,292,020	1,218,232	1,041,134	868,370	959,587	1,019,486	**12,577,701**
Transmission Network Charge HONI	103,199	101,807	94,846	82,142	96,673	108,072	127,128	115,904	98,501	80,924	93,367	99,458	**1,202,021**
Transmission Transformation Charge HONI	70,920	69,963	65,179	56,449	66,435	74,268	87,364	79,650	67,691	55,612	64,163	68,349	**826,042**
Transmission Line Charge HONI	32,280	31,844	29,667	25,693	30,238	33,804	39,764	36,253	30,810	25,312	29,204	31,109	**375,978**

RATES

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Commodity Charge	$0.1416	$0.1416	$0.1416	$0.1416	$0.1416	$0.1416	$0.1416	$0.1416	$0.1416	$0.1416	$0.1416	$0.1416
Transmission Network Charge IESO	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00
Transmission Transformation Charge IESO	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38	$2.38
Transmission Line Charge IESO	$0.99	$0.99	$0.99	$0.99	$0.99	$0.99	$0.99	$0.99	$0.99	$0.99	$0.99	$0.99
Transmission Network Charge HONI	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45	$3.45
Transmission Transformation Charge HONI	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05	$2.05
Transmission Line Charge HONI	$0.82	$0.82	$0.82	$0.82	$0.82	$0.82	$0.82	$0.82	$0.82	$0.82	$0.82	$0.82
Wholesale Market Charge	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390
Smart Metering Entity Charge	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570

Cost of Power

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	**$972,244,989**
Transmission Network Charge IESO	$4,515,505	$4,471,391	$4,085,948	$3,687,971	$4,092,101	$4,418,372	$5,346,851	$5,034,912	$4,298,167	$3,478,464	$4,008,559	$4,120,243	**$51,558,484**
Transmission Transformation Charge IESO	$2,284,889	$2,294,304	$2,074,682	$1,852,082	$2,040,662	$2,234,581	$2,656,627	$2,440,508	$2,117,440	$1,744,221	$1,951,198	$2,088,388	**$25,779,583**
Transmission Line Charge IESO	$1,087,074	$1,083,433	$994,043	$885,078	$974,971	$1,092,485	$1,279,100	$1,206,050	$1,030,722	$859,686	$949,991	$1,009,291	**$12,451,924**
Transmission Network Charge HONI	$412,798	$407,229	$379,384	$328,567	$386,693	$432,289	$508,514	$463,614	$394,003	$323,695	$373,467	$397,831	**$4,808,084**
Transmission Transformation Charge HONI	$168,789	$166,512	$155,127	$134,348	$158,115	$176,759	$207,927	$189,568	$161,104	$132,356	$152,707	$162,669	**$1,965,981**
Transmission Line Charge HONI	$31,957	$31,526	$29,370	$25,436	$29,936	$33,466	$39,367	$35,891	$30,502	$25,059	$28,912	$30,798	**$372,219**
Wholesale Market Charge	$2,678,060	$2,393,145	$2,435,581	$2,151,322	$2,142,832	$2,322,376	$2,659,063	$2,504,011	$2,163,525	$2,200,458	$2,279,277	$2,583,918	**$28,513,567**
Smart Meter Entity	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$195,736	**$2,328,157**
LV Charges	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	**$425,580**
Total	**$92,428,809**	**$92,097,278**	**$91,403,871**	**$90,314,543**	**$91,075,047**	**$91,960,064**	**$93,947,185**	**$93,124,290**	**$91,445,200**	**$90,013,675**	**$90,993,849**	**$91,644,756**	**$1,100,448,569**

Switchgear Credit	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	**-$3,261,312**

2022 Cost of Power

Cost of Power Summary	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	$81,020,416	**$972,244,989**
Transmission Network	$4,928,303	$4,878,620	$4,465,332	$4,016,539	$4,478,794	$4,850,661	$5,855,365	$5,498,526	$4,692,170	$3,802,158	$4,382,026	$4,518,075	**$56,366,568**
Transmission Connection	$3,300,933	$3,303,999	$2,981,445	$2,625,169	$2,931,908	$3,265,515	$3,911,244	$3,600,240	$3,067,992	$2,489,546	$2,811,033	$3,019,371	**$37,308,395**
Wholesale Market	$2,678,060	$2,393,145	$2,435,581	$2,151,322	$2,142,832	$2,322,376	$2,659,063	$2,504,011	$2,163,525	$2,200,458	$2,279,277	$2,583,918	**$28,513,567**
Smart Metering Entity Charge	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$193,856	$195,736	**$2,328,157**
LV Charges	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	$35,465	**$425,580**
TOTAL COST of POWER EXPENSE	**$92,157,033**	**$91,825,502**	**$91,132,095**	**$90,042,767**	**$90,803,271**	**$91,688,288**	**$93,675,409**	**$92,852,514**	**$91,173,424**	**$89,741,899**	**$90,722,073**	**$91,372,980**	**$1,097,187,257**

2023 Cost of Power

Loss Factors	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
LOSS FACTOR-every class but LU	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331
LOSS FACTOR-LARGE USERS	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053

SALES

UNADJUSTED SALES (KWH)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
RESIDENTIAL	225,668,000	197,604,000	191,729,000	161,813,000	157,676,000	191,275,000	232,560,000	213,042,000	168,469,000	169,152,000	175,665,000	214,860,000	**2,299,513,000**
GENERAL SERVICE <50KW	67,195,000	60,964,000	61,420,000	53,922,000	52,316,000	54,880,000	61,520,000	58,714,000	51,960,000	53,663,000	56,988,000	64,447,000	**697,989,000**
DRYCORE	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	**4,992,000**
GENERAL SERVICE 50-1000KW NONI	102,389,000	92,190,000	91,815,000	78,787,000	72,977,000	75,496,000	85,242,000	81,817,000	71,863,000	74,304,000	81,932,000	94,099,000	**1,002,911,000**
GENERAL SERVICE 50-1000KW INT	129,206,000	117,626,000	121,781,000	110,549,000	112,372,000	117,922,000	130,722,000	124,992,000	112,127,000	115,468,000	117,624,000	129,811,000	**1,440,200,000**
GENERAL SERVICE 1000-1500KW	33,485,000	30,849,000	32,581,000	30,847,000	31,484,000	32,341,000	35,141,000	34,121,000	31,236,000	31,473,000	31,463,000	33,258,000	**388,279,000**
GENERAL SERVICE 1500-5000 KW	58,108,000	52,842,000	56,696,000	53,634,000	55,468,000	57,739,000	64,059,000	61,671,000	55,073,000	54,990,000	54,552,000	57,739,000	**682,571,000**
LARGE USER	47,497,000	42,524,000	47,485,000	45,866,000	48,215,000	48,584,000	52,634,000	51,403,000	47,122,000	47,489,000	45,782,000	47,432,000	**572,033,000**
STREETLIGHTING	2,673,000	2,124,000	1,860,000	1,445,000	964,000	840,000	961,000	1,212,000	1,549,000	2,043,000	2,252,000	2,490,000	**20,413,000**
SENTINEL	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	**47,000**
UNMETERED	1,093,000	1,092,000	987,000	1,082,000	1,047,000	1,078,000	1,064,000	1,053,000	1,038,000	1,047,000	1,029,000	1,053,000	**12,663,000**
TOTAL KWH-SALES	**667,733,917**	**598,234,917**	**606,773,917**	**538,364,917**	**532,938,917**	**580,574,917**	**664,322,917**	**628,444,917**	**540,856,917**	**550,048,917**	**567,706,917**	**645,608,917**	**7,121,611,000**

PURCHASES

Power Purchases (kWh)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Total Load Forecast kWh	689,255,000	615,684,000	626,788,000	553,600,000	551,630,000	598,216,000	685,429,000	645,274,000	557,038,000	566,313,000	586,416,000	664,834,000	**7,340,477,000**

Power Purchased (kW)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Power Purchases - coincident peak (kW)	1,190,000	1,174,000	1,094,000	948,000	1,115,000	1,248,000	1,468,000	1,339,000	1,136,000	934,000	1,077,000	1,147,000	**13,870,000**

DEMAND CHARGES

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Coincident System Peak	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Transmission Network Charge IESO	95.2%	95.5%	93.7%	97.7%	92.1%	88.9%	91.5%	94.5%	94.9%	93.5%	93.4%	90.1%
Transmission Transformation Charge IESO	80.9%	82.4%	80.0%	82.4%	77.2%	75.6%	76.4%	77.0%	78.6%	78.8%	76.4%	76.8%
Transmission Line Charge IESO	92.6%	93.5%	92.1%	94.7%	88.6%	88.9%	88.4%	91.5%	92.0%	93.4%	89.4%	89.2%
Transmission Network Charge HONI	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%
Transmission Transformation Charge HONI	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
Transmission Line Charge HONI	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Transmission Network Charge IESO	1,132,683.65	1,121,670	1,025,235	925,900	1,026,709	1,109,929	1,343,117	1,265,343	1,078,339	873,356	1,005,876	1,033,666	**12,941,822**
Transmission Transformation Charge IESO	963,275	967,289	874,914	781,483	860,508	943,436	1,121,578	1,030,812	892,824	736,018	822,887	880,545	**10,875,570**
Transmission Line Charge IESO	1,101,758	1,098,119	1,007,768	897,807	988,365	1,108,851	1,298,211	1,224,635	1,044,813	872,104	963,164	1,023,054	**12,628,647**
Transmission Network Charge HONI	103,547	102,155	95,194	82,490	97,021	108,594	127,738	116,513	98,849	81,272	93,715	99,806	**1,206,894**
Transmission Transformation Charge HONI	71,159	70,202	65,418	56,688	66,674	74,627	87,783	80,069	67,930	55,851	64,402	68,588	**829,391**
Transmission Line Charge HONI	32,388	31,953	29,776	25,802	30,347	33,967	39,955	36,444	30,919	25,421	29,313	31,218	**377,503**

RATES

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Commodity Charge	$0.1516	$0.1516	$0.1516	$0.1516	$0.1516	$0.1516	$0.1516	$0.1516	$0.1516	$0.1516	$0.1516	$0.1516
Transmission Network Charge IESO	$4.08	$4.08	$4.08	$4.08	$4.08	$4.08	$4.08	$4.08	$4.08	$4.08	$4.08	$4.08
Transmission Transformation Charge IESO	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43
Transmission Line Charge IESO	$1.01	$1.01	$1.01	$1.01	$1.01	$1.01	$1.01	$1.01	$1.01	$1.01	$1.01	$1.01
Transmission Network Charge HONI	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50
Transmission Transformation Charge HONI	$2.08	$2.08	$2.08	$2.08	$2.08	$2.08	$2.08	$2.08	$2.08	$2.08	$2.08	$2.08
Transmission Line Charge HONI	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83
Wholesale Market Charge	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390
Smart Metering Entity Charge	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570

Cost of Power

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	**$1,040,982,905**
Transmission Network Charge IESO	$4,621,349	$4,576,412	$4,182,961	$3,777,670	$4,188,971	$4,528,511	$5,479,918	$5,162,599	$4,399,622	$3,563,293	$4,103,973	$4,217,356	**$52,802,635**
Transmission Transformation Charge IESO	$2,340,759	$2,350,512	$2,126,041	$1,899,004	$2,091,035	$2,292,548	$2,725,435	$2,504,874	$2,169,564	$1,788,524	$1,999,616	$2,139,723	**$26,427,636**
Transmission Line Charge IESO	$1,112,775	$1,109,100	$1,017,846	$906,785	$998,248	$1,119,939	$1,311,193	$1,236,881	$1,055,261	$880,826	$972,796	$1,033,285	**$12,754,933**
Transmission Network Charge HONI	$362,851	$357,972	$333,579	$289,061	$339,982	$380,536	$447,618	$408,284	$346,386	$284,792	$328,395	$349,740	**$4,229,197**
Transmission Transformation Charge HONI	$148,189	$146,196	$136,234	$118,053	$138,849	$155,411	$182,807	$166,743	$141,464	$116,309	$134,117	$142,834	**$1,727,207**
Transmission Line Charge HONI	$26,873	$26,511	$24,705	$21,408	$25,179	$28,182	$33,151	$30,237	$25,653	$21,092	$24,321	$25,902	**$313,214**
Wholesale Market Charge	$2,688,095	$2,401,168	$2,444,473	$2,159,040	$2,151,357	$2,333,042	$2,673,173	$2,516,569	$2,172,448	$2,208,621	$2,287,022	$2,592,853	**$28,627,860**
Smart Meter Entity	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$197,522	**$2,350,621**
LV Charges	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	**$432,177**
Total	**$98,281,217**	**$97,948,198**	**$97,246,165**	**$96,151,347**	**$96,913,948**	**$97,818,497**	**$99,833,621**	**$99,006,513**	**$97,290,724**	**$95,843,784**	**$96,830,567**	**$97,483,803**	**$1,170,648,384**

Switchgear Credit	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	**-$3,261,312**

2023 Cost of Power

Cost of Power Summary	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	$86,748,575	**$1,040,982,905**
Transmission Network	$4,984,200	$4,934,384	$4,516,540	$4,066,731	$4,528,953	$4,909,047	$5,927,536	$5,570,883	$4,746,008	$3,848,086	$4,432,368	$4,567,095	**$57,031,832**
Transmission Connection	$3,356,819	$3,360,544	$3,033,050	$2,673,474	$2,981,535	$3,324,305	$3,980,809	$3,666,960	$3,120,166	$2,534,975	$2,859,074	$3,069,967	**$37,961,678**
Wholesale Market	$2,688,095	$2,401,168	$2,444,473	$2,159,040	$2,151,357	$2,333,042	$2,673,173	$2,516,569	$2,172,448	$2,208,621	$2,287,022	$2,592,853	**$28,627,860**
Smart Metering Entity Charge	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$195,736	$197,522	**$2,350,621**
LV Charges	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	$36,015	**$432,177**
TOTAL COST of POWER EXPENSE	**$98,009,441**	**$97,676,422**	**$96,974,389**	**$95,879,571**	**$96,642,172**	**$97,546,721**	**$99,561,845**	**$98,734,737**	**$97,018,948**	**$95,572,008**	**$96,558,791**	**$97,212,027**	**$1,167,387,072**

2024 Cost of Power

Loss Factors	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
LOSS FACTOR-every class but LU	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331
LOSS FACTOR-LARGE USERS	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053

SALES

UNADJUSTED SALES (KWH)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
RESIDENTIAL	227,795,000	206,854,000	193,648,000	163,590,000	159,612,000	193,813,000	235,871,000	216,013,000	170,626,000	171,060,000	177,521,000	216,942,000	**2,333,345,000**
GENERAL SERVICE <50KW	67,053,000	62,426,000	61,281,000	53,777,000	52,190,000	54,778,000	61,463,000	58,641,000	51,841,000	53,535,000	56,854,000	64,322,000	**698,161,000**
DRYCORE	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	**4,992,000**
GENERAL SERVICE 50-1000KW NONI	98,685,000	91,284,000	88,398,000	75,745,000	70,018,000	72,435,000	81,880,000	78,583,000	68,934,000	71,275,000	78,744,000	90,541,000	**966,522,000**
GENERAL SERVICE 50-1000KW INT	133,290,000	124,674,000	125,557,000	113,887,000	115,689,000	121,431,000	134,725,000	128,800,000	115,437,000	118,866,000	121,175,000	133,813,000	**1,487,344,000**
GENERAL SERVICE 1000-1500KW	33,600,000	31,762,000	32,696,000	30,955,000	31,603,000	32,468,000	35,292,000	34,265,000	31,357,000	31,593,000	31,579,000	33,383,000	**390,553,000**
GENERAL SERVICE 1500-5000 KW	58,111,000	54,468,000	56,701,000	53,625,000	55,483,000	57,776,000	64,151,000	61,746,000	55,094,000	55,008,000	54,560,000	57,765,000	**684,488,000**
LARGE USER	47,426,000	44,108,000	47,414,000	45,794,000	48,144,000	48,513,000	52,563,000	51,331,000	47,051,000	47,418,000	45,711,000	47,361,000	**572,834,000**
STREETLIGHTING	2,606,000	2,056,000	1,793,000	1,377,000	896,000	772,000	894,000	1,144,000	1,482,000	1,976,000	2,184,000	2,423,000	**19,603,000**
SENTINEL	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	**47,000**
UNMETERED	1,054,000	1,052,000	950,000	1,043,000	1,009,000	1,038,000	1,025,000	1,014,000	999,000	1,008,000	990,000	1,013,000	**12,195,000**
TOTAL KWH-SALES	**670,039,917**	**619,103,917**	**608,857,917**	**540,212,917**	**535,063,917**	**583,443,917**	**668,283,917**	**631,956,917**	**543,240,917**	**552,158,917**	**569,737,917**	**647,982,917**	**7,170,084,000**

PURCHASES

Power Purchases (kWh)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Total Load Forecast kWh	691,635,000	637,162,000	628,941,000	555,500,000	553,830,000	601,171,000	689,515,000	648,878,000	559,493,000	568,485,000	588,515,000	667,278,000	**7,390,403,000**

Power Purchased (kW)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Power Purchases - coincident peak (kW)	1,196,000	1,145,000	1,100,000	954,000	1,122,000	1,256,000	1,480,000	1,349,000	1,144,000	940,000	1,083,000	1,153,000	**13,922,000**

DEMAND CHARGES

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Coincident System Peak	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Transmission Network Charge IESO	95.2%	95.5%	93.7%	97.7%	92.1%	88.9%	91.5%	94.5%	94.9%	93.5%	93.4%	90.1%
Transmission Transformation Charge IESO	80.9%	82.4%	80.0%	82.4%	77.2%	75.6%	76.4%	77.0%	78.6%	78.8%	76.4%	76.8%
Transmission Line Charge IESO	92.6%	93.5%	92.1%	94.7%	88.6%	88.9%	88.4%	91.5%	92.0%	93.4%	89.4%	89.2%
Transmission Network Charge HONI	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%
Transmission Transformation Charge HONI	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
Transmission Line Charge HONI	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Transmission Network Charge IESO	1,138,394.66	1,093,962	1,030,858	931,760	1,033,154	1,117,044	1,354,096	1,274,793	1,085,933	878,967	1,011,479	1,039,073	**12,989,514**
Transmission Transformation Charge IESO	968,132	943,395	879,713	786,429	865,910	949,483	1,130,746	1,038,511	899,112	740,746	827,472	885,151	**10,914,801**
Transmission Line Charge IESO	1,107,313	1,070,993	1,013,295	903,489	994,570	1,115,959	1,308,823	1,233,780	1,052,170	877,707	968,530	1,028,406	**12,675,034**
Transmission Network Charge HONI	104,070	99,632	95,716	83,012	97,630	109,290	128,782	117,383	99,545	81,794	94,237	100,328	**1,211,419**
Transmission Transformation Charge HONI	71,518	68,468	65,777	57,047	67,093	75,106	88,500	80,667	68,408	56,210	64,761	68,947	**832,501**
Transmission Line Charge HONI	32,552	31,164	29,939	25,965	30,538	34,185	40,281	36,716	31,136	25,584	29,476	31,381	**378,918**

RATES

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Commodity Charge	$0.1636	$0.1636	$0.1636	$0.1636	$0.1636	$0.1636	$0.1636	$0.1636	$0.1636	$0.1636	$0.1636	$0.1636
Transmission Network Charge IESO	$4.16	$4.16	$4.16	$4.16	$4.16	$4.16	$4.16	$4.16	$4.16	$4.16	$4.16	$4.16
Transmission Transformation Charge IESO	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48
Transmission Line Charge IESO	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03
Transmission Network Charge HONI	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56
Transmission Transformation Charge HONI	$2.11	$2.11	$2.11	$2.11	$2.11	$2.11	$2.11	$2.11	$2.11	$2.11	$2.11	$2.11
Transmission Line Charge HONI	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84
Wholesale Market Charge	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390
Smart Metering Entity Charge	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570

Cost of Power

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	**$1,135,265,010**
Transmission Network Charge IESO	$4,735,722	$4,550,883	$4,288,371	$3,876,120	$4,297,922	$4,646,903	$5,633,041	$5,303,138	$4,517,480	$3,656,501	$4,207,755	$4,322,543	**$54,036,378**
Transmission Transformation Charge IESO	$2,400,968	$2,339,620	$2,181,687	$1,950,345	$2,147,458	$2,354,718	$2,804,251	$2,575,507	$2,229,798	$1,837,051	$2,052,130	$2,195,174	**$27,068,705**
Transmission Line Charge IESO	$1,140,532	$1,103,123	$1,043,694	$930,594	$1,024,407	$1,149,437	$1,348,087	$1,270,794	$1,083,735	$904,038	$997,586	$1,059,258	**$13,055,285**
Transmission Network Charge HONI	$370,332	$354,540	$340,606	$295,398	$347,418	$388,910	$458,270	$417,707	$354,230	$291,063	$335,342	$357,017	**$4,310,833**
Transmission Transformation Charge HONI	$151,246	$144,796	$139,106	$120,643	$141,888	$158,833	$187,160	$170,594	$144,670	$118,872	$136,956	$145,808	**$1,760,572**
Transmission Line Charge HONI	$27,428	$26,259	$25,227	$21,878	$25,731	$28,804	$33,941	$30,937	$26,236	$21,557	$24,837	$26,442	**$319,276**
Wholesale Market Charge	$2,697,377	$2,484,932	$2,452,870	$2,166,450	$2,159,937	$2,344,567	$2,689,109	$2,530,624	$2,182,023	$2,217,092	$2,295,209	$2,602,384	**$28,822,572**
Smart Meter Entity	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$199,244	**$2,371,980**
LV Charges	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	**$438,875**
Total	**$106,363,115**	**$105,843,664**	**$105,311,072**	**$104,200,940**	**$104,984,272**	**$105,911,685**	**$107,993,371**	**$107,138,812**	**$105,377,684**	**$103,885,686**	**$104,889,325**	**$105,549,859**	**$1,267,449,486**
Switchgear Credit	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	**-$3,261,312**

2024 Cost of Power

Cost of Power Summary	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	$94,605,417	**$1,135,265,010**
Transmission Network	$5,106,053	$4,905,423	$4,628,977	$4,171,518	$4,645,340	$5,035,813	$6,091,311	$5,720,845	$4,871,710	$3,947,565	$4,543,097	$4,679,560	**$58,347,210**
Transmission Connection	$3,448,398	$3,342,022	$3,117,937	$2,751,683	$3,067,707	$3,420,017	$4,101,664	$3,776,056	$3,212,663	$2,609,742	$2,939,732	$3,154,906	**$38,942,527**
Wholesale Market	$2,697,377	$2,484,932	$2,452,870	$2,166,450	$2,159,937	$2,344,567	$2,689,109	$2,530,624	$2,182,023	$2,217,092	$2,295,209	$2,602,384	**$28,822,572**
Smart Metering Entity Charge	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$197,522	$199,244	**$2,371,980**
LV Charges	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	$36,573	**$438,875**
TOTAL COST of POWER EXPENSE	**$106,091,339**	**$105,571,888**	**$105,039,296**	**$103,929,164**	**$104,712,496**	**$105,639,909**	**$107,721,595**	**$106,867,036**	**$105,105,908**	**$103,613,910**	**$104,617,549**	**$105,278,083**	**$1,264,188,174**

2025 Cost of Power

Loss Factors	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
LOSS FACTOR-every class but LU	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331	1.0331
LOSS FACTOR-LARGE USERS	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053	1.0053

SALES

UNADJUSTED SALES (KWH)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
RESIDENTIAL	229,993,000	201,429,000	195,645,000	165,427,000	161,608,000	196,440,000	239,311,000	219,089,000	172,842,000	173,012,000	179,423,000	219,080,000	**2,353,299,000**
GENERAL SERVICE <50KW	66,926,000	60,665,000	61,186,000	53,690,000	52,139,000	54,768,000	61,516,000	58,690,000	51,856,000	53,554,000	56,881,000	64,374,000	**696,245,000**
DRYCORE	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	416,000	**4,992,000**
GENERAL SERVICE 50-1000KW NONI	94,989,000	85,410,000	84,985,000	72,703,000	67,056,000	69,368,000	78,523,000	75,365,000	66,035,000	68,284,000	75,609,000	87,049,000	**925,376,000**
GENERAL SERVICE 50-1000KW INT	137,416,000	124,958,000	129,368,000	117,250,000	119,033,000	124,972,000	138,797,000	132,689,000	118,833,000	122,367,000	124,845,000	137,958,000	**1,528,486,000**
GENERAL SERVICE 1000-1500KW	33,741,000	31,066,000	32,836,000	31,087,000	31,746,000	32,620,000	35,475,000	34,444,000	31,516,000	31,757,000	31,743,000	33,561,000	**391,592,000**
GENERAL SERVICE 1500-5000 KW	58,134,000	52,786,000	56,722,000	53,630,000	55,513,000	57,828,000	64,278,000	61,871,000	55,178,000	55,105,000	54,664,000	57,905,000	**683,614,000**
LARGE USER	47,355,000	42,381,000	47,343,000	45,723,000	48,073,000	48,442,000	52,495,000	51,266,000	46,989,000	47,359,000	45,655,000	47,309,000	**570,390,000**
STREETLIGHTING	2,538,000	1,989,000	1,725,000	1,310,000	828,000	704,000	829,000	1,083,000	1,423,000	1,920,000	2,132,000	2,373,000	**18,854,000**
SENTINEL	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	**47,000**
UNMETERED	1,014,000	1,013,000	914,000	1,003,000	970,000	998,000	985,000	975,000	961,000	969,000	952,000	974,000	**11,728,000**
TOTAL KWH-SALES	**672,525,917**	**602,116,917**	**611,143,917**	**542,242,917**	**537,385,917**	**586,559,917**	**672,628,917**	**635,891,917**	**546,052,917**	**554,746,917**	**572,323,917**	**651,002,917**	**7,184,623,000**

PURCHASES

Power Purchases (kWh)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Total Load Forecast kWh	694,201,000	619,680,000	631,303,000	557,589,000	556,234,000	604,381,000	693,998,000	652,919,000	562,390,000	571,151,000	591,186,000	670,391,000	**7,405,423,000**

Power Purchased (kW)	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	Total
Power Purchases - coincident peak (kW)	1,199,000	1,182,000	1,102,000	956,000	1,124,000	1,261,000	1,488,000	1,354,000	1,147,000	942,000	1,085,000	1,156,000	**13,996,000**

DEMAND CHARGES

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Coincident System Peak	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Transmission Network Charge IESO	95.2%	95.5%	93.7%	97.7%	92.1%	88.9%	91.5%	94.5%	94.9%	93.5%	93.4%	90.1%
Transmission Transformation Charge IESO	80.9%	82.4%	80.0%	82.4%	77.2%	75.6%	76.4%	77.0%	78.6%	78.8%	76.4%	76.8%
Transmission Line Charge IESO	92.6%	93.5%	92.1%	94.7%	88.6%	88.9%	88.4%	91.5%	92.0%	93.4%	89.4%	89.2%
Transmission Network Charge HONI	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%
Transmission Transformation Charge HONI	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
Transmission Line Charge HONI	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%

kW Breakdown by Type	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Transmission Network Charge IESO	1,141,250.16	1,129,313	1,032,733	933,713	1,034,996	1,121,491	1,361,416	1,279,518	1,088,780	880,837	1,013,347	1,041,776	**13,059,170**
Transmission Transformation Charge IESO	970,561	973,880	881,312	788,078	867,454	953,263	1,136,858	1,042,360	901,470	742,322	829,000	887,454	**10,974,012**
Transmission Line Charge IESO	1,110,090	1,105,601	1,015,138	905,383	996,342	1,120,401	1,315,897	1,238,353	1,054,930	879,574	970,319	1,031,082	**12,743,111**
Transmission Network Charge HONI	104,331	102,851	95,890	83,186	97,805	109,726	129,478	117,818	99,806	81,968	94,411	100,589	**1,217,858**
Transmission Transformation Charge HONI	71,697	70,681	65,897	57,166	67,212	75,405	88,979	80,966	68,588	56,329	64,880	69,126	**836,926**
Transmission Line Charge HONI	32,633	32,171	29,993	26,020	30,592	34,321	40,499	36,852	31,218	25,639	29,531	31,463	**380,932**

RATES

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC
Commodity Charge	$0.1706	$0.1706	$0.1706	$0.1706	$0.1706	$0.1706	$0.1706	$0.1706	$0.1706	$0.1706	$0.1706	$0.1706
Transmission Network Charge IESO	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24	$4.24
Transmission Transformation Charge IESO	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53
Transmission Line Charge IESO	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05
Transmission Network Charge HONI	$3.61	$3.61	$3.61	$3.61	$3.61	$3.61	$3.61	$3.61	$3.61	$3.61	$3.61	$3.61
Transmission Transformation Charge HONI	$2.15	$2.15	$2.15	$2.15	$2.15	$2.15	$2.15	$2.15	$2.15	$2.15	$2.15	$2.15
Transmission Line Charge HONI	$0.86	$0.86	$0.86	$0.86	$0.86	$0.86	$0.86	$0.86	$0.86	$0.86	$0.86	$0.86
Wholesale Market Charge	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390	$0.00390
Smart Metering Entity Charge	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570

Cost of Power

	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	**$1,179,157,649**
Transmission Network Charge IESO	$4,838,901	$4,788,287	$4,378,786	$3,958,943	$4,388,382	$4,755,121	$5,772,403	$5,425,155	$4,616,429	$3,734,748	$4,296,593	$4,417,132	**$55,370,881**
Transmission Transformation Charge IESO	$2,455,518	$2,463,918	$2,229,719	$1,993,838	$2,194,658	$2,411,755	$2,876,252	$2,637,171	$2,280,719	$1,878,076	$2,097,370	$2,245,258	**$27,764,251**
Transmission Line Charge IESO	$1,165,595	$1,160,882	$1,065,894	$950,652	$1,046,160	$1,176,421	$1,381,692	$1,300,271	$1,107,676	$923,553	$1,018,835	$1,082,636	**$13,380,267**
Transmission Network Charge HONI	$377,020	$371,674	$346,518	$300,609	$353,436	$396,515	$467,894	$425,759	$360,668	$296,207	$341,173	$363,498	**$4,400,972**
Transmission Transformation Charge HONI	$153,977	$151,794	$141,520	$122,771	$144,345	$161,939	$191,091	$173,882	$147,299	$120,973	$139,337	$148,455	**$1,797,381**
Transmission Line Charge HONI	$27,924	$27,528	$25,665	$22,265	$26,178	$29,368	$34,655	$31,534	$26,713	$21,939	$25,269	$26,923	**$325,964**
Wholesale Market Charge	$2,707,384	$2,416,752	$2,462,082	$2,174,597	$2,169,313	$2,357,086	$2,706,592	$2,546,384	$2,193,321	$2,227,489	$2,305,625	$2,614,525	**$28,881,150**
Smart Meter Entity	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$200,937	**$2,392,615**
LV Charges	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	**$445,678**
Total	**$110,225,839**	**$109,880,355**	**$109,149,706**	**$108,023,196**	**$108,821,993**	**$109,787,727**	**$111,930,100**	**$111,039,677**	**$109,232,346**	**$107,702,505**	**$108,723,722**	**$109,399,641**	**$1,313,916,807**

Switchgear Credit	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	-$271,776.00	**-$3,261,312**

2025 Cost of Power

Cost of Power Summary	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Commodity Charge Including Global Adjustment	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	$98,263,137	**$1,179,157,649**
Transmission Network	$5,215,920	$5,159,961	$4,725,305	$4,259,553	$4,741,819	$5,151,636	$6,240,297	$5,850,914	$4,977,097	$4,030,955	$4,637,766	$4,780,630	**$59,771,853**
Transmission Connection	$3,531,238	$3,532,345	$3,191,023	$2,817,749	$3,139,565	$3,507,708	$4,211,914	$3,871,082	$3,290,631	$2,672,764	$3,009,035	$3,231,495	**$40,006,550**
Wholesale Market	$2,707,384	$2,416,752	$2,462,082	$2,174,597	$2,169,313	$2,357,086	$2,706,592	$2,546,384	$2,193,321	$2,227,489	$2,305,625	$2,614,525	**$28,881,150**
Smart Metering Entity Charge	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$199,244	$200,937	**$2,392,615**
LV Charges	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	$37,140	**$445,678**
TOTAL COST of POWER EXPENSE	**$109,954,063**	**$109,608,579**	**$108,877,930**	**$107,751,420**	**$108,550,217**	**$109,515,951**	**$111,658,324**	**$110,767,901**	**$108,960,570**	**$107,430,729**	**$108,451,946**	**$109,127,865**	**$1,310,655,495**

CAPITAL EXPENDITURE SUMMARY

1. INTRODUCTION

The capital expenditure plan for the 2021-2025 period details the system investments planned by Hydro Ottawa utilizing the asset management and capital expenditure planning process outlined in Exhibit 2-4-3: Distribution System Plan. Expenditures are planned in the following OEB-defined categories: System Access, System Renewal, System Service, and General Plant. Table 1 provides a summary of these expenditures for 2021-2025.

Table 1 – Summary of 2021-2025 Capital Expenditures ($'000,000s)

Investment Category	2021	2022	2023	2024	2025	Average 2021-2025
System Access	$56.7	$41.0	$37.4	$34.5	$34.0	$40.7
System Renewal	$43.3	$44.0	$40.2	$39.4	$40.5	$41.5
System Service	$31.0	$27.4	$24.3	$25.2	$23.9	$26.4
General Plant	$32.0	$11.7	$7.6	$17.4	$16.9	$17.1
Capital Contributions	$(41.3)	$(25.2)	$(19.9)	$(19.2)	$(19.3)	$(25.0)
TOTAL	**$121.8**	**$98.9**	**$89.6**	**$97.2**	**$96.0**	**$100.7**

Attachment 2-4-3(A): OEB Appendix 2-AA - Capital Programs Table and Attachment 2-4-3(B): OEB Appendix 2-AB - Capital Expenditure Summary provide an overview of Hydro Ottawa's capital programs and expenditures, respectively. For comprehensive explanatory notes and variance analyses of Hydro Ottawa's capital expenditures, please refer to section 8 of Exhibit 2-4-3: Distribution System Plan.

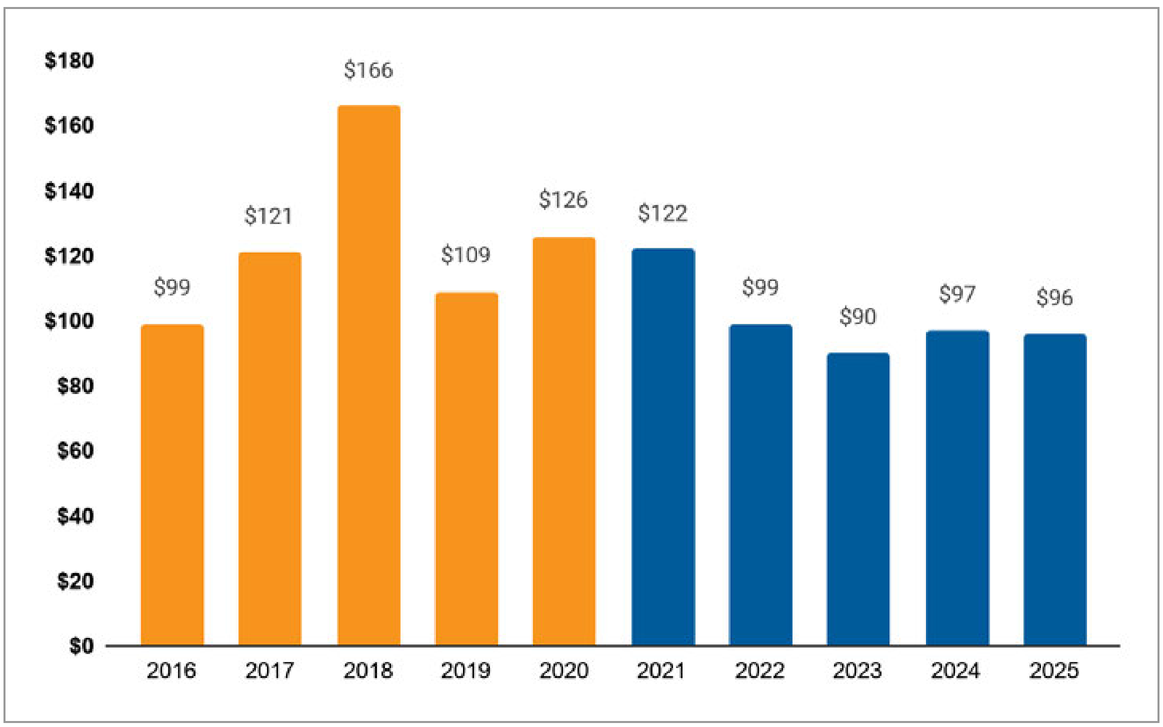
The utility's 2016-2020 capital plan represented the highest level of average annual capital expenditures in any multi-year rate term in Hydro Ottawa's history. Capital spending during this period has focused on the enhancement of system capacity to keep pace with growth and shifts in loads within the service territory, as well as renewal of the aged and aging infrastructure at risk of failure. Key accomplishments have included the following: extensive replacements and enhancements of core infrastructure, such as overhead power lines and underground cables; upgrades to fibre optic networks; acquisition of a new Supervisory Control and Data Acquisition System ("SCADA"); and asset relocations and expansions to support major local infrastructure projects, such as the City of Ottawa's Light Rail Transit and renewal of north-south arteries in the downtown core. These and other initiatives have translated into improved system reliability and performance, with the utility having consistently met or exceeded its reliability targets over the 2016-2018 timeframe. Hydro Ottawa is on track to successfully complete its plan for 2016-2020, with adjustments for typical changes and evolving circumstances.

Notwithstanding this progress, however, renewing Hydro Ottawa's aged and aging infrastructure in deteriorating condition (i.e. stations, and underground and overhead systems) at an appropriate pace remains a priority for both near-term performance and long-term sustainability of the distribution system. Hydro Ottawa's service territory continues to be characterized by both a growing and a shifting customer base. In terms of growth, expanding suburban areas and load intensification in established communities are driving a need for investments to maintain reliability, increase supply capacity, and reduce the frequency and duration of outages. At the same time, as customer priorities and needs evolve with the advancement of technology and innovation, they are triggering discernible shifts: in patterns of supply and demand, in preferences with regards to the availability of information on the services received by customers, and in expectations for how quickly and effectively Hydro Ottawa can restore service when an outage occurs.

These pressures and priorities are reflected in the top four drivers of the utility's planned expenditures for 2021-2025: Customer Service Requests, Failure Risk, System Capital Investment Support, and Capacity Constraints. Many programs under the System Access investment category are driven by Customer Service Requests, including expansion of the distribution system, residential connections, commercial connections, and generation connections. Assets that are being replaced due to Failure Risk in the System Renewal investment category include the following: station transformers, station switchgear, protection and control ("P&C") equipment, batteries, poles, overhead ("OH") switches, cables, civil structures, and underground ("UG") switchgear. Projects driven by System Capital Investment Support include capital contributions to intangible assets purchased from Hydro One Networks Inc. ("HONI") in conjunction with Hydro Ottawa's major station projects, especially the new Cambrian Municipal Transformer Station ("MTS") and the New East Station.[1] (Additional information on Cambrian MTS is presented in section 3 below). Projects driven by Capacity Constraints likewise include construction of the aforementioned stations as well as associated distribution work to bring additional capacity to growth pockets.

Figure 1 shows annual capital expenditures for both the 2016-2020 and 2021-2025 periods.

Figure 1 – Summary of 2016-2025 Annual Capital Expenditures ($'000,000s)



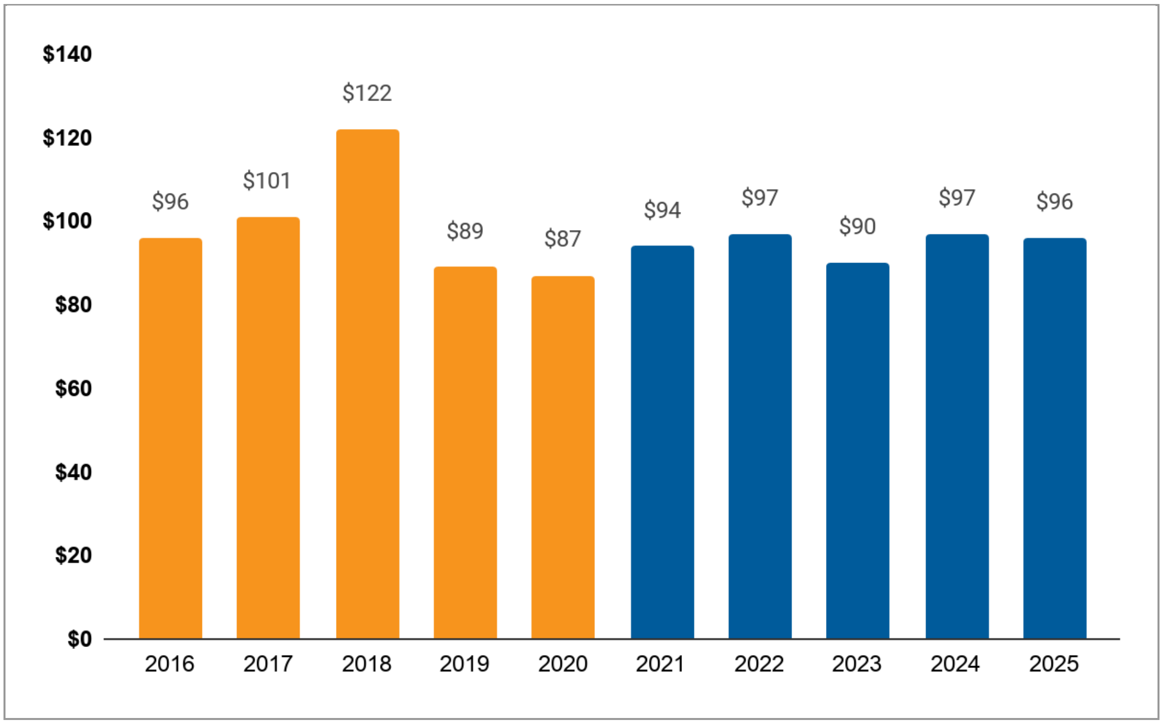
[1] The previous project name for Cambrian MTS was South Nepean MTS.

Figure 1 corroborates the expectation signalled in Hydro Ottawa's previous rebasing application that a historically high level of annual capital expenditures "will be sustained, if not increased, through the decade from 2020-2030."[2]

Both the 2016-2020 and the 2021-2025 periods contain large generational projects – most notably, the Facilities Renewal Program in the 2016-2025 period and the Cambrian MTS project in the 2021-2025 period.[3] Figure 2 below shows a summary of capital expenditures excluding these two projects. Of note, the spike in expenditures in 2018 was due, in part, to three major severe weather events, not the least of which were the six tornadoes that touched down in the Ottawa area in September of that year. Additional contributing factors for the 2018 increase included the acceleration of dark fibre installation and increased System Access demands, including those associated with projects at the Canada Science and Technology Museum and a new fulfillment centre constructed by Amazon in the eastern outskirts of Ottawa.

[2] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015), Exhibit A-2-1, page 10.
[3] For additional information on the Facilities Renewal Program, please see Attachment 2-1-1(A): New Administrative Office and Operations Facilities; for Cambrian MTS, please see Attachment 2-4-3(E).

Figure 2 – Summary of 2016-2025 Capital Expenditures Excluding Facilities Renewal Program and Cambrian MTS ($'000,000s)



2. RATIONALIZATION PROCESS

Hydro Ottawa undertook an extensive rationalization process as a prerequisite to formulating the 2021-2025 capital expenditure levels that are summarized in this Schedule.

The first step in this process was the development of an asset needs forecast. This forecast identified investment levels that were deemed to be necessary from an engineering point of view, taking into account asset age, safety, and reliability considerations.

Thereafter, a more comprehensive review was performed that assessed the following factors: asset needs; safety; reliability; customer growth; resource constraints; expected rate impacts; customer input; financial considerations; and resourcing considerations.

This review resulted in a reduction in the capital expenditure forecast of approximately $50M per year. The expenditure levels presented in this Application represent the end product of this assessment and rationalization process, and are consistent with OEB-approved levels from the 2016-2020 period. The resulting “average run rate” of approximately $100.7M per year represents the expenditure levels required to ensure the safety and reliability of the system, and to address challenges associated with aging infrastructure and customer growth.

3. 2021-2025 CAPITAL EXPENDITURES SUMMARY

Detailed justification for the projects and programs that comprise Hydro Ottawa’s overall capital investment plan for 2021-2025 are outlined in Exhibit 2-4-2: Capital Expenditure Details and Exhibit 2-4-3: Distribution System Plan.

As mentioned above, capital expenditures in this period include the construction of Cambrian MTS. This project consists of two distinct components: (1) the new MTS set to be constructed by Hydro Ottawa; and (2) upgrades to existing transmission facilities, as well as construction of a segment of new transmission line, by HONI. These facilities are required to accommodate customer load growth and increase supply capacity in the South Nepean area of Ottawa, which has already reached the limits of local transformation capacity. Seeing as this project is driven by the needs of Hydro Ottawa and its customers, the bulk of the costs are being apportioned to Hydro Ottawa. In October 2019, the OEB granted formal approval to HONI and Hydro Ottawa to proceed with construction of their respective segments of this project. The utilities had applied for leave to construct (“LTC”) authorization, pursuant to Section 92 of the *Ontario Energy Board Act, 1998* in May 2019.[4] The project is set to be energized in Q2 2022.

The sizeable Connection Cost Recovery Agreement (“CCRA”) payments associated with this project will exert significant influence on the overall capital spending envelope for 2021-2025. Projects of this magnitude are not undertaken on a regular basis, and as such, the larger capital expenditures in the 2021-2022 period are something of an anomaly.

[4] The case number of the proceeding in which the OEB adjudicated HONI and Hydro Ottawa’s joint application is EB-2019-0077.

Similar to Figure 2 above, Table 2 shows the planned capital expenditures for 2021-2025 with and without the Cambrian MTS project. In the absence of this project, annual average expenditures for the five-year rate term are $94.7M. This figure is more representative of typical capital expenditure requirements for a period of this length.

Table 2 – 2021-2025 Capital Expenditures without Cambrian MTS ($'000,000s)

Capital Expenditures (Net)	Forecast					Average 2021-2025
	2021	2022	2023	2024	2025	
Total (Table 1)	$121.8	$98.9	$89.6	$97.2	$96.0	$100.7
Cambrian MTS	$27.9	$2.2	$0.0	$0.0	$0.0	$6.0
TOTAL WITHOUT CAMBRIAN	**$93.8**	**$96.7**	**$89.6**	**$97.2**	**$96.0**	**$94.7**

With regards to productivity and continuous improvement, it should be noted that these remain firmly embedded in Hydro Ottawa's capital expenditure program. As an example, the utility has committed to adopt the ISO 55000 Asset Management Standard as part of continual improvement in asset management practices. This asset management framework strengthens the strategic asset decision-making processes by striving to do the following: balance the weighting of cost, risk, and asset performance that meet or exceed service level expectations of customers; comply with the terms of applicable acts, licences, and codes; improve asset value and resource efficiency; and minimize health, safety, and environmental impacts. Other planned productivity initiatives for the 2021-2025 period include performing detailed analysis of field crew wrench time and identifying opportunities for further optimization, implementing seasonal construction shifts, and rationalizing fleet assets. Additional information on these and other activities is available in Exhibit 1-1-13: Productivity and Continuous Improvement Initiatives.

4. 2021-2025 CAPITAL ADDITIONS SUMMARY

Hydro Ottawa's Capital Additions over the 2021-2025 period are summarized in Table 3 below. Consistent with the arrangement set forth in the Approved Settlement Agreement governing the utility's 2016-2020 rate plan, Hydro Ottawa proposes to track capital additions in the following three categories: System Access; System Renewal and System Service, and General Plant.[5]

In addition, Hydro Ottawa is requesting to continue the separate deferral account for the revenue requirement related to CCRA payments. This account would include both new facilities as well as true-up payments required by HONI for existing facilities. Hydro Ottawa is also requesting to maintain the variance account (with some modifications) to record the revenue requirement impact associated with any underspending between actual and forecasted cumulative capital additions. For more information on these accounts, please see Exhibit 9-2-1: New Deferral and Variance Accounts.

Table 3 – 2021-2025 Summary of Capital Additions ($'000s)

Category	2021	2022	2023	2024	2025
System Access (net of contribution)	$17,820	$17,879	$17,720	$15,626	$15,255
System Renewal and Service	$71,138	$92,858	$50,671	$59,601	$82,071
General Plant excluding CCRAs	$14,198	$12,343	$6,513	$5,822	$18,043
TOTAL CAPITAL ADDITIONS	**$103,156**	**$123,080**	**$74,905**	**$81,049**	**$115,369**

5. 2016-2020 CAPITAL ADDITIONS SUMMARY

For the 2016-2020 period, Hydro Ottawa is set to maintain in-service addition levels somewhat above the levels approved by the OEB. As shown in Table 4 below, the in-service additions in all three investment categories are set to exceed approved amounts. For 2016-2020, Hydro Ottawa is projecting Capital Additions to exceed the overall envelope by $54.1M.

[5] The System Renewal and System Service categories have been merged into one category to reflect Hydro Ottawa's standard operating practice to shift funds between the two categories, as warranted by customer and operational requirements.

Table 4 – 2016-2020 Capital Additions vs. OEB-Approved Amounts ($'000s)

CATEGORY	2016	2017	2018	2019	2020	Total	% Variance
OEB-Approved (Net of Contribution)							
System Access	$12,628	$11,798	$12,034	$12,274	$12,520	$61,254	
System Renewal and System Service	$52,744	$53,389	$70,133	$43,710	$81,123	$301,099	
General Plant[6]	$8,434	$16,703	$7,059	$7,630	$15,019	$54,845	
TOTAL OEB-APPROVED CAPITAL ADDITIONS	**$73,806**	**$81,889**	**$89,226**	**$63,614**	**$108,662**	**$417,198**	
Historical / Bridge (Net of Contribution)							
System Access	$14,065	$18,051	$23,084	$14,295	$20,970	$90,464	
System Renewal and System Service	$55,336	$60,632	$67,867	$84,738	$45,956	$314,529	
General Plant[7]	$12,229	$18,295	$6,510	$13,420	$15,845	$66,300	
TOTAL HISTORICAL / BRIDGE CAPITAL ADDITIONS	**$81,630**	**$96,977**	**$97,462**	**$112,453**	**$82,771**	**$471,293**	
Variance							
System Access (Net)	$1,437	$6,253	$11,050	$2,020	$8,450	$29,210	48%
System Renewal and System Service	$2,592	$7,243	$(2,266)	$41,028	$(35,167)	$13,430	4%
General Plant[8]	$3,795	$1,592	$(549)	$5,790	$826	$11,455	21%
TOTAL CAPITAL ADDITIONS VARIANCE	**$7,824**	**$15,088**	**$8,236**	**$48,838**	**$(25,890)**	**$54,095**	

System Access has the largest variance, with the level of third-party demand exceeding projections, including from such projects as the City of Ottawa's Light Rail Transit, the Canada Science and Technology Museum, Elgin Street Renewal, and construction of an Amazon distribution warehouse. The mix of the programs also changed from the original forecast.

[6] The Facilities Renewal Program and new CCRAs are excluded, as per the Approved Settlement Agreement, EB-2015-0004 (December 7, 2015).
[7] *Ibid*.
[8] *Ibid*.

System Expansion and Infill, which in general have lower contributions, exceeded the budget expectation. This explains the capital contributions which were lower than budgeted. All of these projects were third-party driven and were therefore ones which Hydro Ottawa had an obligation to complete.

System Renewal and System Service are set to exceed approved levels by 4%, mainly on account of Emergency Renewal spending (both emergency and storm restoration capital and critical renewals). The Ottawa area experienced multiple extreme weather events of significance during the 2016-2020 timeframe, especially in 2018 which featured an ice storm in April, a wind storm in May, and six tornadoes in September. All of these events resulted in the utility incurring a large amount of unbudgeted capital replacement costs.

With respect to critical renewals, over the past few years Hydro Ottawa has increased asset inspections as part of its reliability improvement program. Increased inspections have led to more assets being identified as being in a "critical state." "Critical state" means that the assets have been identified as having "functionally" failed, but have not yet caused an outage (e.g. poles that have been deemed to have deteriorated to a point where they no longer meet their designed strength requirements). Critical renewal is more cost-effective than emergency renewal when there is a power outage, as critical renewals can be performed in a planned manner with no accompanying need to incur overtime costs.

The amount for General Plant Capital Additions, as shown in Table 4 above, is in accordance with the Approved Settlement Agreement governing Hydro Ottawa's 2016-2020 rate plan. Both the Facilities Renewal Program and new CCRAs are removed for purposes of the Capital Variance Account, as they are recorded in separate Deferral and Variance Accounts. General Plant is set to exceed approved levels largely on account of the following: (i) true-up CCRA payments to HONI[9]; and (ii) scope change in several projects, including the Enterprise

[9] As per the Approved Settlement Agreement, the separate deferral account for CCRA payments is intended to facilitate recovery of costs from customers for the annual revenue requirement impact of CCRA payments paid to HONI, commencing in the year in which the facilities to which each CCRA payment relates provide services to Hydro Ottawa customers.

Resource Planning ("ERP") upgrade. A new Human Resources software module (Workday) was added to the ERP JDE 9.2 upgrade project. This module has helped lead to reduced processes, increased employee self-service capabilities, and enhanced productivity.

6. 2016-2020 CAPITAL EXPENDITURES SUMMARY

Similar to section 5 above, for the 2016-2020 period Hydro Ottawa's capital expenditures in all three investment categories are set to exceed the budget plan. As shown in Table 5, the utility is projecting an overall variance of $83.4M.

Table 5 – 2016-2020 Capital Expenditures vs. Approved ($'000s)

CATEGORY	2016	2017	2018	2019	2020	Total	% Variance
Approved[10] (Net of Contribution)							
System Access	$15,300	$11,966	$12,205	$12,450	$12,699	$64,620	
System Renewal and System Service	$60,594	$65,780	$66,010	$66,452	$69,032	$327,868	
General Plant	$45,899	$48,138	$18,276	$18,695	$13,954	$144,962	
TOTAL CAPITAL EXPENDITURES	**$121,794**	**$125,883**	**$96,491**	**$97,597**	**$95,685**	**$537,450**	
Historical / Bridge (Net of Contribution)							
System Access	$18,316	$13,597	$24,147	$18,847	$20,387	$95,294	
System Renewal and System Service	$60,320	$68,655	$84,702	$56,955	$63,731	$334,363	
General Plant	$20,423	$38,300	$56,738	$33,586	$42,170	$191,217	
TOTAL HISTORICAL / BRIDGE CAPITAL EXPENDITURES	**$99,058**	**$120,552**	**$165,587**	**$109,388**	**$126,288**	**$620,874**	
Variance							
System Access (Net)	$3,015	$1,631	$11,942	$6,397	$7,688	$30,674	47%
System Renewal and System Service	$(274)	$2,876	$18,692	$(9,498)	$(5,301)	$6,796	2%
General Plant	$(25,476)	$(9,838)	$38,462	$14,892	$28,216	$46,255	32%
TOTAL CAPITAL EXPENDITURES VARIANCE	**$(22,735)**	**$(5,331)**	**$69,096**	**$11,792**	**$30,603**	**$83,425**	

[10] Approved capital expenditures for 2016-2020 equate to those submitted, the $10M settlement reduction was applied to capital assets only

The projected System Access capital expenditure variance of $30.7M over the five years is in line with the capital additions variance of $29.2M under section 5 above. The variance is explained by increased third-party demand and lower capital contributions due to the mix of projects.

System Renewal and System Service capital expenditures are projected to only exceed budget by 2%, largely on account of higher Emergency Renewal than planned and historical levels associated with the 2018 extreme weather events.

The projected variance for General Plant capital expenditures is $46.3M. This is larger than the capital addition variance of $11.5M in Table 4 above primarily because the Facilities Renewal Program and HONI CCRA payments are not displayed in Table 4, in accordance with the Capital Variance Account that was approved for use as per the Decision rendered by the OEB on Hydro Ottawa's 2016-2020 rate application.[11] Total CCRAs for new service and true-up payments are projecting $50.4M over 2016-2020. The projection includes a $34.2M payment associated with Cambrian MTS. The CCRAs are significantly higher than historical spending and are set to exceed the budget of $24.6M by $25.8M.

The projects that led to these overages were carefully monitored by Hydro Ottawa. It was determined that proceeding with these projects was a sound business decision and was in the best interests of customers. Other projects in the utility's portfolio were delayed in an attempt to ameliorate these overages and lessen their impact. For example, some work at Riverdale TS, Overbrook TS, Bayswater DS, and Bells Corners DS was delayed.

Hydro Ottawa's new operations and administrative facilities were completed in 2019. As part of its Decision and Order on Hydro Ottawa's 2016-2020 rate application, the OEB concluded that the need for the facilities had been established.[12] During the settlement process for that application, all intervenors and OEB staff accepted the proposed project cost of $92.5M

[11] Ontario Energy Board, *Decision and Order*, EB-2015-0004 (December 22, 2015).
[12] *Ibid,* page 5.

identified by Hydro Ottawa. Ultimately, the OEB approved $66.0M in "provisional funding" for the facilities, with any additional amounts being subject to a prudency review at the utility's next rebasing.[13] Hydro Ottawa has filed evidence in this Application to support its expenditures on these new facilities (Attachment 2-1-1(A): New Administrative Office and Operations Facilities).

7. APPENDICES AND SPECIAL STUDIES

Attached to Exhibit 2-4-3: Distribution System Plan are the capital expenditure-related appendices that electricity distributors must submit, pursuant to the *Chapter 2* and *Chapter 5 Filing Requirements for Electricity Distribution Rate Applications*, as updated on July 12, 2018 and addended on July 15, 2019. In addition, a number of special studies to support Hydro Ottawa's proposed capital expenditure plan and rate base levels for the 2021-2025 period are likewise attached.

These appendices and special studies are as follows:

- Attachment 2-4-3(A): OEB Appendix 2-AA - Capital Programs Table
- Attachment 2-4-3(B): OEB Appendix 2-AB - Capital Expenditure Summary
- Attachment 2-4-3(C): OEB Appendix 5-A: Chapter 5 Appendix
- Attachment 2-4-3(D): Independent Assessment of Hydro Ottawa's Distribution System Plan
- Attachment 2-4-3(E): Material Investments
- Attachment 2-4-3(F): Fleet Replacement Program
- Attachment 2-4-3(G): Strategic Asset Management Plan
- Attachment 2-4-3(H): Distribution System Climate Risk and Vulnerability Assessment
- Attachment 2-4-3(I): Hydro Ottawa Climate Change Adaptation Plan
- Attachment 2-4-3(J): ISO 55000 Gap Analysis
- Attachment 2-4-3(K): Local Achievable Potential Study
- Attachment 2-4-3(L): Metering Roadmap
- Attachment 2-4-3(M): Asset Condition Assessment - Third Party Review

[13] *Ibid,* page 6.

CAPITAL EXPENDITURES DETAILS

In accordance with the *Chapter 2* and *Chapter 5 Filing Requirements for Electricity Distribution Rate Applications*, as updated on July 12, 2018 and addended on July 15, 2019, Hydro Ottawa has filed a consolidated Distribution System Plan ("DSP") as Exhibit 2-4-3. The Capital Expenditure plan in section 8.0 of the DSP and Attachment 2-4-3(E): Material Investments both detail the system investment decisions which are made through the asset management and capital expenditure planning processes. The DSP further details investments by investment categories. Capital Programs and Budget Programs are included for the Historical Years of 2016-2018, the Bridge Years of 2019 and 2020, and the Test Years of 2021-2025.

Please see Attachment 2-4-3(A): OEB Appendix 2-AA - Capital Programs Table and Attachment 2-4-3(B): OEB Appendix 2-AB - Capital Expenditure Summary for an overview of Hydro Ottawa's capital projects and expenditures. For comprehensive explanatory notes and variance analyses of Hydro Ottawa's capital expenditures, please refer to Section 8.0 of the DSP (Exhibit 2-4-3).

Distribution System Plan 2021-2025

Hydro Ottawa

1. DISTRIBUTION SYSTEM PLAN BACKGROUND

1.1. INTRODUCTION

Hydro Ottawa's Distribution System Plan ("DSP") provides a detailed and comprehensive view of the utility's investment plans and supporting information for the 2021-2025 period. The DSP identifies the capital investments in Hydro Ottawa's distribution system and general plant assets which are required to maintain safe and reliable service to its customers in the City of Ottawa and Village of Casselman, with operations that remain responsive to their needs and requests, 24 hours a day, 365 days a year.

In step with Ontario Energy Board ("OEB") requirements, the DSP describes how capital investments will be prioritized, paced, and optimized, while minimizing rate impacts for customers and facilitating continuous improvement and productivity. The DSP is a core deliverable emerging from multiple internal and external planning processes related to capital investment, asset management, regional planning, customer engagement, and business strategy.

This plan is a continuation of Hydro Ottawa's 2016-2020 plan, which focused on the enhancement of system capacity to keep pace with growth and shifts in loads within the service territory and renewal of the aged and aging infrastructure at risk of failure. Key accomplishments have included extensive replacements and enhancements of core infrastructure, such as overhead power lines and underground cables; upgrades to fibre optic networks; acquisition of a new Supervisory Control and Data Acquisition System; and asset relocations and expansions to support major local infrastructure projects such as the City of Ottawa's Light Rail Transit and renewal of north-south arteries in the downtown core. These and other initiatives have translated into improved system reliability and performance, with the utility having consistently met or exceeded its reliability targets over the 2016-2018 timeframe. All told, Hydro Ottawa is on track to successfully complete its plan for 2016-2020, with adjustments for typical changes and evolving circumstances.

Notwithstanding this progress, however, renewing Hydro Ottawa's aged and aging infrastructure in deteriorating condition (i.e. stations, and underground and overhead systems) at an appropriate pace remains a priority for both near-term performance and long-term sustainability of the distribution system. Hydro Ottawa's service territory continues to be characterized by both a growing and a shifting customer base. In terms of growth, expanding suburban areas and load intensification in established communities are driving a need for investments to maintain reliability, increase supply capacity, and reduce the frequency and duration of outages.

At the same time, as customer priorities and needs evolve with the advancement of technology and innovation, they are triggering discernible shifts: in patterns of supply and demand, in preferences with regards to the availability of information on the services they receive, and in expectations for how quickly and effectively utilities can restore service when an outage occurs.

What's more, alongside shifts in customer behaviour and values, Hydro Ottawa is also contending with a different form of shifting – namely, variations in weather patterns associated with climate change. From historic flooding to tornadoes, Hydro Ottawa and its customers have experienced firsthand in recent years the growing frequency of severe weather events and their adverse impacts on the distribution grid. In turn, the utility is having to enhance adaptation and risk mitigation measures within the design, operation, and maintenance of its system, in order to help protect infrastructure, service delivery, health, and safety.

Taken together, all of these factors are injecting greater complexity into the system, underscoring the urgent imperative for renewal of aged systems, and emphasizing the need for continued investment in information technology, operational technology, and cyber security solutions.

Through its robust and multi-layered planning processes, Hydro Ottawa has sought to strike a balance between these pressures on the distribution system and the top priorities of customers: (i) keeping distribution rates low; (ii) maintaining reliability; and (iii) investing in new technology.

The DSP serves as a critical point of culmination for these processes and represents the minimum level of investment needed to ensure this balance is achieved – all while avoiding the accumulation of risk and declines in performance over the long-term.

Hydro Ottawa's DSP has been developed to align with the OEB's *Chapter 5 Filing Requirements for Electricity Distribution Rate Applications,* as updated on July 12, 2018 and addended on July 15, 2019 ("Filing Requirements") as well as with the *Handbook for Utility Rate Applications* issued by the OEB in 2016.

1.2. OVERVIEW OF DOCUMENTS

The DSP consists of the following eight main sections:

Section 1 – Distribution System Plan Background provides background information relative to the contents of the document.

Section 2 – Overview of the Distribution System provides an overview of the assets and the context in which they are operated.

Section 3 – Asset Management Strategy & Objectives outlines Hydro Ottawa's Corporate Strategic Direction and the relationship between the Asset Management Objectives.

Section 4 – Performance Measurements for Continuous Improvement includes the qualitative assessments and quantitative metrics to monitor the quality of the planning process, the efficiency of implementing the plans, and the extent to which objectives are being met. In addition, it includes how the performance measurements affect the planning process and promote continuous improvement.

Section 5 – Asset Management & Capital Expenditure Process outlines Hydro Ottawa's Asset Management process, which is the systematic approach used to plan and optimize ongoing capital expenditures. It provides an understanding of how the Asset Management Process leads to the decisions that comprise the capital investment plan.

Section 6 – Asset Lifecycle Optimization describes how Hydro Ottawa uses its asset lifecycle optimization policies and practices to assess system renewal investments and make decisions on refurbishment versus replacement of assets. In addition, it summarizes Hydro Ottawa's approach to managing and mitigating asset risk.

Section 7 – System Capacity Assessment provides information on the capability of Hydro Ottawa's system to accommodate new load and Renewable Energy Generation ("REG") connections. This includes network constraints identified through the Regional Planning Process.

Section 8 – Capital Expenditure Plan outlines the planned investments for the next five years. Investments are derived from the Asset Management and Capital Expenditure planning processes and includes justifications of the investment decisions made.

The mapping of the sections within Hydro Ottawa's DSP to those identified in the Filing Requirements can be found in Appendix A of this Schedule.

1.3. KEY ELEMENTS OF THE DSP

Hydro Ottawa's capital investment plan is influenced by several key drivers, challenges, and trends that are unfolding within its operational and business environment. Among the major pressures on the distribution system, which are addressed through this plan, are the following:

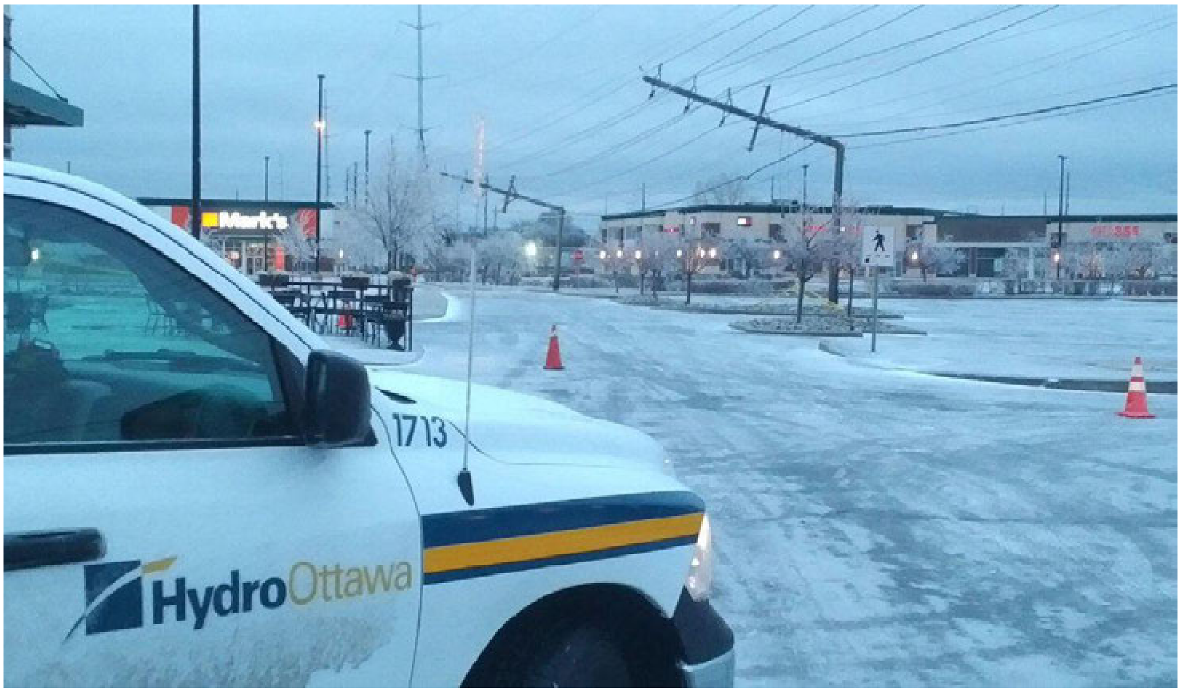
- **A Growing Community** – Growing electrical loads and system capacity constraints are driving the need to expand the capacity of the distribution system. This growth is driven by the development of residential subdivisions and business parks outside of the

Greenbelt and in historically rural lands, intensification in urban areas, and major local infrastructure projects such as Light Rail Transit and transit-oriented development.

- **Aging Distribution Assets** – A significant proportion of Hydro Ottawa's distribution system assets have reached or are approaching the end of their expected service life. For example, more than 20% of Hydro Ottawa's poles have exceeded their expected end-of-service life. These assets not only present an increasing failure risk, but also potential operational challenges resulting from obsolete and legacy equipment not meeting current standards or lacking replacement or repair components.

- **Climate Change and Adverse Weather** – The increased frequency of extreme weather has had significant impacts on Hydro Ottawa's operations and system – especially in 2018, when three major events within a six-month span caused considerable damage and heavily impacted spending on emergency replacement of assets. The effects of climate change are expected to be felt more acutely and frequently over the coming decades. For Hydro Ottawa, these impacts are reinforcing the continuation of existing adaptation measures that have already been implemented in response to past weather events, prompting review and implementation of new adaptations, and underscoring the need for investments to enable the renewal of aged overhead infrastructure.

Figure 1.1 – Broken Poles Caused by Ice Storm (2018)



- **Innovation** – The changing expectations of customers will require ongoing investment and innovation to provide them with the technologies and tools that will enable them to better understand, manage, and monitor their electricity consumption. Moreover, innovation in the planning and operation of the distribution system itself is needed in order to accommodate such trends as the growth of electric vehicles ("EVs") and customer-generated renewable electricity, and to respond to customer expectations for improved restoration times in the event of an outage. Enhanced automation in system operations and communications will be particularly critical objectives, in this regard.

- **Information Technology** – Hydro Ottawa must ensure its Information Technology ("IT") meets the needs of the business and its customers. Building upon the technology investments Hydro Ottawa made throughout 2016-2020, Hydro Ottawa plans to continue adopting innovative IT systems throughout 2021-2025 to solve business challenges, increase efficiencies, and enhance customer services. A central area of focus will be taking proactive steps to prevent cyber attacks that could impact the protection of customer information and distribution system reliability.

1.4. DSP PERIOD

The DSP provides capital expenditure plans and supporting information for the 2021-2025 period, along with Historical and Bridge Year information for 2016-2018 and 2019-2020, respectively.

1.5. VINTAGE OF INFORMATION

Since the distribution system is changing on a daily basis, all information and details provided have been updated as of December 31, 2018, unless otherwise stated, and should be considered as current.

1.6. OVERVIEW OF CUSTOMERS' PREFERENCES AND EXPECTATIONS

Based on results from a variety of customer engagement activities, Hydro Ottawa customers indicate that reliability should be maintained or improved, at minimal or no increased cost. As a result, Hydro Ottawa has created a capital plan that paces investments in order to minimize rate impacts while maintaining a focus on continuous improvement, efficiency, and productivity.

At a local level, customers are engaged through consultation sessions during the design phase of major projects to address any concerns in regards to potential impact to their property or neighbourhoods. These concerns are addressed in the final design of the project which minimizes the impacts raised by the customers in a cost effective manner.

Further details regarding Hydro Ottawa's engagement with customers, and how their input has been incorporated into the DSP, are available in section 1.10.1.

1.7. SOURCES OF COST SAVINGS AND PLANNING COORDINATION

Throughout the plan period and in the course of executing its planned work, Hydro Ottawa will continue to evaluate its operational efficiencies and seek ways to minimize and avoid costs. While continuing to minimize overall risk to Hydro Ottawa's strategic objective of delivering value to its customers. Examples of these initiatives are highlighted below, further examples can be found in Hydro Ottawa's Capital and Operating and Maintenance plans.

Coordinated Renewal – As part of the execution of its Station Renewal, Underground Renewal, and Overhead Renewal programs, Hydro Ottawa coordinates system investments where multiple adjacent systems are at or near the end of service life. This approach offers efficiencies and reduced customer impacts from the construction work.

Building on the benefits of this coordination, Hydro Ottawa also seeks cost saving opportunities through collaborations with various working groups and other local utilities, and with future plans identified through the internal planning process.

Non-Wires Alternatives – In step with provincial policy on electricity conservation, Hydro Ottawa seeks to leverage opportunities to pursue alternatives to infrastructure solutions and avoid/defer capacity enhancements, where feasible. Through the 2021-2025 period, Hydro Ottawa will be deploying a portfolio of measures in the Kanata North area to enable deferral of an additional transmission-connected station originally identified as being required through the Integrated Regional Resource Plan process. The deferral of this significant capital investment will be enabled through a mix of distribution enhancement and conservation measures. Deferring construction of an additional transmission-connected station allows the utility to minimize rate increases over the 2021-2025 period.

Enhanced Work Coordination – Over the course of 2015-2016, Hydro Ottawa introduced Mobile Workforce Management ("MWM"). This tool has been deployed across multiple groups in Operations (Collections, Metering, Forestry, Service trucks, Civil Inspection, etc.). The main strengths of the MWM system reside in its core capabilities to schedule and dispatch field work, including re-shuffling assignments to manage changes introduced during the day (e.g. cancellations and new high-priority work), and to enable communications through a mobile application to exchange information about work assignments, basic routing, work progress, and crew location. These strengths have resulted in improved work processes and productivity.

As the current tool has reached end-of-life and is no longer supported by the vendor, Hydro Ottawa will be replacing it with the new system in service by 2021. Through the implementation of the upgraded software, Hydro Ottawa will be seeking the increased functionality required to bring additional operational workgroups on to the scheduling platform. Furthermore, Hydro Ottawa will be aiming to drive productivity by sourcing a tool with improved scheduling policies and algorithms for routing (for example, using real-time and predictive traffic), the ability to bundle assignments by location, the ability to maintain dependencies between jobs, the ability to forecast more realistic completion times, and the ability to manage preferred execution times by area or work types (along with a variety of other criteria).

Planning Effectiveness – Hydro Ottawa's overall prioritization and optimization of distribution system expenditures is expected to drive value, including cost savings, over the long-term.

Through the inspection, testing, and maintenance planning and project prioritization process, Hydro Ottawa has developed a plan that paces spending while meeting the reliability requirements of the distribution system.

Through the Asset Management process outlined in section 5.1, Hydro Ottawa identifies the annual investments required to manage the risks associated with reliability, customer impact, safety, and environment while improving service to customers and providing increasing value to the shareholder. As described in section 5.2 Capital Expenditure Process, business cases are created to evaluate project alternatives thereby ensuring the optimum cost/benefit solution is identified for implementation. Annual expenditures are then paced to ensure timing of investments is optimized so as to maximize alignment with the achievement of Hydro Ottawa's strategic objectives.

Figure 1.2 – Planned Insulator Replacement on 27.6 kV Pole Line

1.8. CHANGES IN THE DSP

Refinements to Hydro Ottawa's Asset Management process have been focused on increasing the quantity and quality of data, establishing and documenting asset management processes, optimizing project prioritization, and improving workflow efficiency. Described below are key changes to the utility's Asset Management process that have been implemented since Hydro Ottawa's last rebasing application.[1]

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive-Rate Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

ISO 55001 Certification

As stated in Hydro Ottawa's *2016-2020 Strategic Direction,* the utility is committed to becoming a "leading partner in a smart energy future" and to continue creating value "for our shareholder, our customers and our community through excellence in the delivery of electricity and related services." In support of this vision and the utility's core mandate, Hydro Ottawa has committed to adopt the ISO 55001 Asset Management Standard as part of continual improvement in asset management.

The Asset Management System, which establishes an Asset Management framework, is used by the organization to direct, coordinate, and control asset management activities. It incorporates interrelated and interacting elements to establish an asset management policy, asset management objectives, and the overarching processes necessary to achieve those directives. The framework also strengthens the strategic asset decision-making processes by striving to do the following: balance the weighting of cost, risk and asset performance that meet or exceed service level expectations of customers; comply with the terms of applicable acts, licences and codes; improve asset value and resource efficiency; and minimize health, safety and environmental impacts.

As part of the ISO 55001 compliance initiative, Hydro Ottawa has formalized its asset management strategies in its Strategic Asset Management Plan ("SAMP"). The SAMP, found in Attachment 2-4-3(G) sets a clear and overarching framework for Hydro Ottawa's Asset Management System, documenting the strategies to achieve its asset management objectives and describes how these objectives support the corporate strategy. The SAMP guides the Asset Management Plans which have been developed for each major asset class. Each Asset Management Plan is a multi-year plan which includes specific activities, strategies, and timeframes required to achieve Hydro Ottawa's asset management objectives while describing what resources will be required for implementation.

Budget Change Request Process

Electronic change requests have been implemented in Copperleaf C55, Hydro Ottawa's investment optimization software. A change request is initiated if a project manager's budget forecast exceeds a threshold determined to have an impact on the overall sustainment budget. Once initiated, the change request must be approved by the appropriate level of authority depending on the amount of the variance. This process ensures that financial changes during project execution remain aligned with Hydro Ottawa's Asset Management Process.

Asset Inspection Scope

Hydro Ottawa continues to refine the statements and scopes of work that define specific inspection and testing activities used to collect data needed to assess the condition of its assets. This data is crucial to effectively identify assets that pose an increased level of risk to the continued reliability of Hydro Ottawa's distribution system. Specific improvements include:

- Alignment of inspection and testing activities to conform with data requirements for Hydro Ottawa's Asset Condition Assessment ("ACA") framework;
- Increased implementation of digital data capture forms to allow for accessibility and transferability between systems of the information; and
- Adoption of new inspection and testing programs for gas insulated pad-mounted switchgear and secondary pedestals.

Geographic Information System Data Improvements

Since Hydro Ottawa's previous rebasing application, continued effort has been made to improve the data available in the Geographic Information System ("GIS"), both in terms of quality and quantity.[2] Goals and benefits of these efforts include:

- Decrease in field visits required to identify or verify asset properties on-site, which improves labor efficiency;

[2] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB 2015-0004 (April 29, 2015).

- Increasing availability of asset condition data for risk based asset condition modelling;
- Elimination of overlaps between planned programs of inspection and ad-hoc requests, reducing the frequency an asset is inspected within a given inspection period;
- Easier identification of system needs and prioritization of investments; and
- Improved ability to use automated tools for engineering analysis.

Digital and Paperless Processes

In 2018, Hydro Ottawa implemented the use of Bluebeam® Revu®, design review software, to increase efficiency in drawing feedback and approval processes. Rather than printing and mailing drawings, the software allows drawings to be shared online thereby decreasing the time required to complete the design approval process. Efficiencies gained through this digital process have been further bolstered with the integration of other technologies such as the ike-gps. This tool allows for the collection of poleline data seamlessly, efficiently and consistently from the field, and ultimately enables design and engineering analyses which accurately reflect field conditions.

Capital Program Restructure

Since its previous rebasing application, Hydro Ottawa has restructured its capital budget to better align with the definitions set out in the Filing Requirements.[3] Appendix C of this Schedule shows a comparison between the two structures.

At the Capital Program level, the main changes are as follows:

- The Metering Program was moved to System Service, since the main driver of gaining the ability to remotely disconnect and reconnect the meter better aligns with the System Efficiency driver under System Service Investment category.

[3] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

- The Distribution Assets Program was divided into two programs (Overhead Distribution Assets Renewal and Underground Distribution Assets Renewal) to facilitate spending tracking for each asset category type.
- The Station Enhancements program was moved to System Service, since the projects created under this program better align with drivers under System Service.
- The Station Capacity Program was renamed to Capacity Upgrades Program in order to include both Station Capacity Upgrades and a new Budget Program called Distribution Capacity Upgrades, which was created in 2018.
- The Plant Failure Program was renamed to Corrective Renewal.

At the Budget Program Level, the main changes are as follows:

- The Distribution Plant Failure and Station Plant Failure Programs have been restructured into two new programs – Emergency Renewal and Critical Renewal. These two programs will reallocate work into a common classification of failed equipment (typically, but not necessarily, resulting in an outage) and those that may still be providing service, but no longer meet their designed requirements be it for safety, environmental, or reliability reasons.
- As of 2018, no new projects have been allocated to the Line Extensions Program. Instead, line extensions that are built to increase capacity are allocated to the Distribution Capacity Upgrades Program. Line extensions that are built to improve reliability are allocated to the Distribution System Reliability Program.

1.9. ASPECTS CONTINGENT ON ONGOING AND FUTURE ACTIVITIES

Regional Planning

The last Integrated Regional Resource Plan (“IRRP”) cycle for the Ottawa area was completed in 2015 and the Regional Infrastructure Plan (“RIP”) in 2016. Through the 2016 RIP, Hydro Ottawa has a number of station projects identified in the forecast period whose costs are dependent on the outcome of Hydro One Networks Inc.’s (“HONI”) evaluation and estimating process – i.e. Connection and Cost Recovery Agreements ("CCRA"). Please refer to sections 8.4 and 8.5 of the Capital Expenditure Plan for more details on the forecasted expenditures.

Hydro Ottawa is currently engaged in the latest IRRP cycle for the Ottawa area, the results of which are not yet final. A number of regional and bulk system needs are currently being studied to determine optimal solutions. This cycle is expected to be completed in the first quarter of 2020. Hydro Ottawa's five-year investment plan incorporates required projects to address the near-term and medium-term regional needs identified below. These investments will remain subject to change through the finalization of the IRRP and subsequent RIP processes.

The near-term and medium-term needs identified in the 2019 IRRP scoping assessment are as follows:

1) Supply capacity for South Nepean region
2) Additional capacity in the Kanata North region
3) Additional capacity in the Leitrim/Russell region
4) Additional 230kV/115kV transformer capacity at Merivale TS
5) Additional supply capacity for circuit L2M
6) Bilberry Creek TS end of life station refurbishment/retirement
7) M30A and M31A 230kV circuits overload
8) Restoration Needs at:
    a. Circuits M4G & M5G
    b. Circuits D5A & B5D
    c. Breaker Failure at South March SS L6L7
9) Downtown Cables at end of life

1.10. COORDINATION WITH THIRD PARTIES

Hydro Ottawa understands that planning and coordinating investments in isolation will only lead to inefficiencies, increase project costs, and negatively affect customer service. Thus, Hydro

Ottawa recognizes that coordinating and incorporating input from third parties is an essential aspect of its investment planning process.

1.10.1. Customer Consultations

Hydro Ottawa leverages a mix of ongoing and specific engagements with its customers to ensure that customer preferences and expectations are fully understood, and to ensure these are integrated into the utility's activities and plans. For a comprehensive summary of the tools, activities, and interactions which comprise the utility's toolkit for customer engagement, please see Exhibit 1-2-1: Customer Engagement Overview. In addition, information from the surveys that are regularly administered by Hydro Ottawa to gauge customer satisfaction and expectations is, likewise, included in section 4.1.1 of this Schedule.

Through the development of the DSP, customer engagement activities have been leveraged to direct the development of capital plans and to validate their components.

Community Open Houses

Engaging the customer on major projects is an important part of the project execution process. Hydro Ottawa regularly hosts Community Open Houses for major projects with the purpose of informing the public and obtaining feedback on how the project should proceed.

Promoting customer engagement has facilitated project improvements including the installation of natural and aesthetic barriers, adjustment to equipment locations to minimize property impacts, and project specific noise mitigation strategies, including the use of noise barriers or adjustments to the work schedule.

Hydro Ottawa plans to continue to hold Community Open Houses for major projects identified in this plan.

Customer Consultation on 2021-2025 Rate Application

In early 2019, Hydro Ottawa engaged Innovative Research Group ("Innovative Research"), a national consulting firm with expertise in public opinion research and experience in energy policy to collaboratively design, test, and implement a strategy for engaging customers on its 2021-2025 rate application proposals.

An iterative, two-phase customer engagement process was undertaken, with the following five key principles adopted in order to maximize effectiveness of the process:

- Ensure all Hydro Ottawa customers have an opportunity to be heard
- Ensure a representative sample of customers engaged
- Create an open, voluntary process to allow any customer the opportunity to provide comment
- Focus on the key outcomes and customer preferences
- Inform customers about the distribution system and electricity industry

Phase I

Phase I of the Customer Engagement process surveyed Hydro Ottawa's residential and small business customers. The purpose of this survey was to gather feedback and insights on priorities, preferences and needs from low-volume customers. The information collected through this survey helped Hydro Ottawa's planners and engineers inform the design of its DSP and Business Plan, which were shared in draft with customers in Phase II.

Among each customer type, Innovative Research conducted parallel telephone and online surveys through Phase I. This methodology enabled Innovative Research to establish baselines and develop weights that allowed Hydro Ottawa to move to an online methodology for its low-volume customer engagement program for Phase II.

This initial customer engagement yielded the following findings:

- The clear majority of residential and small business customers are satisfied with the current service they receive;

- Despite being the top priorities, customers do not simply expect Hydro Ottawa to focus exclusively on price and reliability; and

- Among competing priorities, price, reliability, and investing in new technology are the top three priorities for both residential and small business customers.

Phase II

Phase II provided additional insight about customers' needs and preferences prior to the completion of the business plan. The purpose of Phase II was threefold:

- To confirm customer needs, preferences, and priorities identified in Phase I;

- To solicit customer feedback on the content of Hydro Ottawa's proposed plans and the subsequent rate impact, including customer preferences toward particular capital programs where trade-offs on pacing existed; and

- To solicit customer feedback on Hydro Ottawa's planning development process, including the customer engagement process.

The Phase II approach involved an online workbook, available in English and French that gathered input from any interested residential, small business, or mid-market customers.

Customers were provided specific information about Hydro Ottawa's planning process, how it solicited feedback from customers, and information about Hydro Ottawa's cost benchmarking performance. The results of the Phase I engagement were summarized and customers were again asked to rank priorities to evaluate if the needs and preferences that informed the business plan had changed. Program-specific information, including activities, outcomes, and bill impacts were shared in respect of trade-offs where customer input was sought. In addition, customers participating in the online workbook were shown the estimated net bill impact of their trade-off choices and allowed to change their responses if desired.

In addition to the workbook, Focus Groups and Workshops were held to further solicit feedback. For the Low-volume customers, Hydro Ottawa held consultation sessions with general service and residential customers, who were recruited from a randomly generated list provided by the utility. A workshop was held with the mid-market, general service greater than 50 kW customers in Ottawa. Customers were randomly selected and screened.

There were 17,210 residential and 307 small business respondents to the survey. The majority of respondents, when considering investment areas individually, supported increased investment in overhead renewal, underground renewal and reliability investments. However, when asked for their views in regards to the draft plan 48% of residential and 47% of small business identified that “Hydro Ottawa should maintain the forecasted annual increase to deliver a program which delivers on the stated priorities.” A further 35% of residential and 29% of small businesses expressed support for further improvements in service, even if this entailed further rate increases.

Mid-market participants who attended expressed concern over the current rate increases being proposed, and were open to potential decreases in service reliability if it would reduce the forecasted increases in the bill. This feedback has emphasized the importance of a balanced plan – with a continued focus on efficiencies and a strategy to maximize the impact of investments to match residential customer expectations, without further increasing rate pressures on business customers.

1.10.2. Regional Planning Process

The IRRP is developed by a working group, comprised of the Independent Electricity System Operator ("IESO"), transmitter, and local distribution companies ("LDCs") which work together to develop a plan that integrates a variety of resource options to address the electricity needs of the region. The Ottawa Region working group holds several meetings throughout the year to discuss progress on the study, and consists of the IESO, Hydro Ottawa, HONI and Hydro One Distribution. The IRRP process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria, and develops integrated solutions to address any needs that are identified. Potential solutions may include the following: conservation, demand management, distributed generation, large scale generation, transmission, and distribution. Hydro Ottawa has provided IESO with an updated long term load forecast for Hydro Ottawa regions, which is provided in Appendix E. The forecast outlines several transmission and distribution stations that will exceed their capacity limitations within the near, medium, and long-term. Hydro Ottawa also contributes to the IRRP by identifying feasibility limitations within the planning area that may not be known to the working group (i.e. Greenbelt, rivers, highways, etc.). The IRRP is designed to address emerging needs of the regional utilities, and to identify cost-effective and viable solutions.

The first IRRP for the Ottawa area began in 2011, with the IESO leading the process. The IRRP was finalized in April 2015, with the RIP issued shortly thereafter in December 2015. In April 2016, the IESO issued a hand off letter to HONI and Hydro Ottawa, thereby initiating development work on near and mid-term transmission solutions to meet the identified needs.

The latest IRRP for the Ottawa area, planned for completion in the first quarter of 2020, is in the final stage for evaluation of solutions to identified needs. The IESO, Hydro Ottawa and HONI recently discussed forecasted growth across Hydro Ottawa's service territory, focusing on Kanata North and South-East Gloucester. These areas have served as the IRRP focus due to existing capacity constraints on both Hydro Ottawa and HONI's systems, which are set to increase as a result of future planned residential and commercial developments.

Please see section 1.9 above for additional information on the near-term and medium-term needs identified in the 2019 IRRP scoping assessment.

1.10.3. Other Utility & Stakeholder Coordination

City of Ottawa's Renewable Energy Strategy – Energy Evolution

In 2015, the City of Ottawa initiated the development of a formal renewable energy strategy, designated as "Energy Evolution."[4] Energy Evolution is aimed at managing energy consumption, promoting the use of renewable energy, and advancing local economic development opportunities in Ottawa. The strategy has specific deliverables for the short, medium, and long-term (2020, 2031, and 2050 respectively). These deliverables are intended to align with the City's official target to reduce greenhouse gas ("GHG") emissions by 80% below 2012 levels by 2050.

City Council approved Phase 1 of Energy Evolution in December 2017. Phase 1 focuses primarily on renewable energy generation opportunities and includes a three-year action plan with over 30 initiatives that are targeted for completion in partnership with community stakeholders.

In conjunction with its approval of Phase 1, City Council formally directed the initiation of plans for Phase 2, with a focus on reducing energy use in the building and transportation sectors. A final strategy and action plan for Phase 2 is scheduled to be presented to City Council for approval in the first quarter of 2020.

Hydro Ottawa has been actively engaged in the Energy Evolution initiative since its inception and has taken the strategy's goals into consideration in the development of the DSP. Where appropriate, the DSP highlights planned actions and expenditures that are complementary to

[4] https://ottawa.ca/en/living-ottawa/environment/climate-change-and-energy/energy-evolution.

Energy Evolution's objectives. For example, the expansion of station capacity can support increased accommodation of renewable energy projects through such measures as the installation of transformers which are designed to enable reverse-flow capabilities.

City of Ottawa Development Application Circulations

The City of Ottawa's process to circulate development applications allows Hydro Ottawa to provide comments regarding upcoming developments and plan distribution system upgrades as required. The City of Ottawa notifies utilities and the public of different types of applications:

- Site Plan Control
- Zoning By-Law Amendment
- Official Plan Amendment
- Demolition Control
- Plan of Condominium
- Plan of Subdivision
- Community Design Plans
- Road Closure
- Heritage Applications to be considered by Council

During the comment period, Hydro Ottawa provides comments to inform developers on the processes required to protect its distribution infrastructure and guarantee a safe job site. Additionally, development applications provide information with regards to future growth, including its location, size and timeline for completion. In order to accommodate the anticipated load growth, estimates obtained via the development application process permit Hydro Ottawa to proactively plan for any required distribution upgrades and to coordinate any transmission upgrades with HONI and the IESO.

City of Ottawa Utility Coordinating Committee

The Utility Coordinating Committee ("UCC") provides a forum for communication between invited utilities and the City of Ottawa in order to ensure safe and efficient management of the infrastructure within road allowances and other rights-of-way. Every fall, Hydro Ottawa provides the road authority with its proposed major works plan for the following year to maximize efficiency through improved construction scheduling coordination, damage prevention initiatives, and development of standards. The primary functions of the committee are the following:

- Jointly plan construction activities
- Set technical standards
- Protect plant
- Provide a quick communication network
- Maintain a central registry
- Resolve disputes
- Assist the road authority with proposed utility installation permit processes

The committee members are: City of Ottawa, Hydro Ottawa, HONI, Heavy Construction Association, Enbridge Gas Distribution, Birch Hill Telecom, Bell Canada, Rogers Cable Communications, Telus Communications, and Allstream.

Ottawa Light Rail Transit

The first stage of the Ottawa Light Rail Transit ("LRT") system became operational in September 2019, and construction of Stage 2 of the Ottawa LRT system will also commence in 2019. The Stage 2 project will extend the electrically-powered Ottawa LRT Confederation Line and diesel-powered Trillium Line further across the city.

As the licensed distributor servicing the majority of the proposed LRT expansions, Hydro Ottawa has been actively engaged in the project. The utility's role includes developing an electrical servicing strategy for future stations and for consideration of Hydro Ottawa plant relocations that may be required where conflicts exist. The utility collaborates with the City and project contractors on relocation plans, ensuring that both Hydro Ottawa and the City's requirements are met.

The impacts and planning considerations of LRT construction have been incorporated into the development of the DSP, where appropriate. For example, the station capacity required to support the constructed and forecasted LRT loads have been included in the utility's system capacity planning.

CEATI Distribution Programs

The Centre for Energy Advancement through Technological Innovation ("CEATI") provides technology solutions to electrical utility participants who collaborate to advance the industry. Advancements are made by networking, sharing information, industry benchmarking and cost-sharing on asset technical projects. Hydro Ottawa participates in several CEATI programs such as Protection & Control, Distribution Line Asset Management, and Station Equipment Asset Management. Cost sharing with other power distribution utilities to solve technical issues allows Hydro Ottawa to enhance the system and provide higher levels of reliability at minimal cost. Program specific conferences occur on an annual or biannual basis depending on the program.

1.10.4. Energy Resource Facility Generation Investment Coordination

As per the Filing Requirements, the IESO Comment Letter outlines the IESO's assessments of an electricity distributor's Energy Resource Facility ("ERF") Investments Plan, including:

- Whether the distributor has consulted with the IESO, or participated in planning meetings with the IESO;
- The potential need for coordination with other distributors and/or transmitters or others on implementing elements of the ERF investments; and
- Whether the ERF investments proposed in the DSP are consistent with any RIP.

The IESO Comment Letter will be appended to Hydro Ottawa's DSP once the IRRP is completed.

1.11. GRID MODERNIZATION

Hydro Ottawa's approach to grid modernization is centered on the customer. Modernization is one of the ways the utility ensures that its system and services continue to meet the evolving needs and preferences of customers, and that Hydro Ottawa delivers on its commitment, as described in the *2016-2020 Strategic Direction*, to becoming a "leading partner in a smart energy future." In addition, results from the customer consultation that was undertaken to inform the utility's 2021-2025 rate application showed that investing in new technology is one of the top three priorities for both residential and small business customers.

With this customer focus, the utility's approach to grid modernization is focused on enhancing the customers' ability to produce, store, and export energy onto the grid, exploring new transaction interfaces with customers, deploying monitoring and control to improve reliability while gaining operational efficiencies, and growing electrical demand from EVs. Concurrently, this approach also seeks to ensure that the grid is resilient and able to withstand growing cyber security and adverse weather stressors.

Table 1.1 below maps the alignment of Hydro Ottawa's grid modernization activities to Ontario's Long Term Energy Plan ("LTEP").

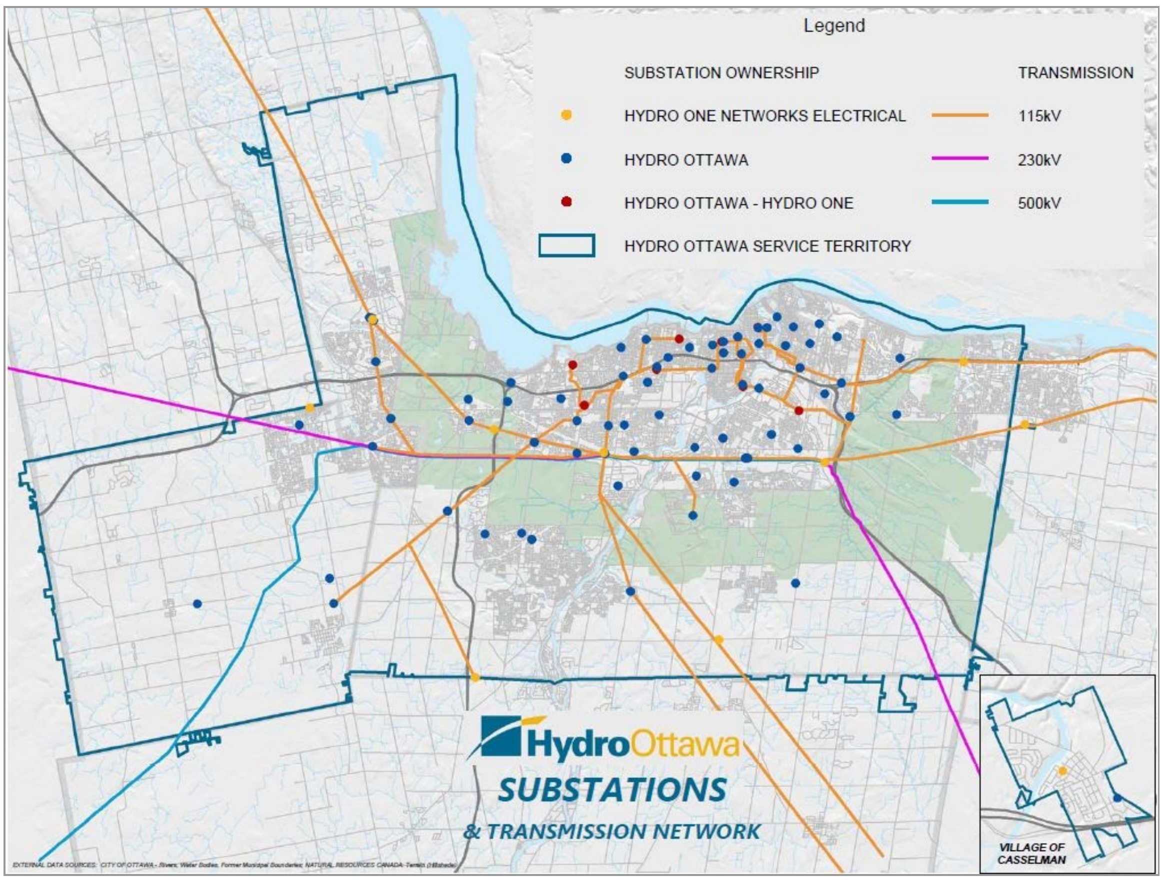
Table 1.1 – Hydro Ottawa Response to Key LTEP Initiatives

Key LTEP Initiatives	Hydro Ottawa Response and Proposed 2021-2025 Initiatives
Ensuring Flexible Transmission Energy System	Hydro Ottawa actively participates in the Regional Planning process and supports the flexible energy system as it relates to transmission. Please see section 1.10.2
Electrification of Transportation - Innovating the Future	Hydro Ottawa Investments are focused on determining and preparing for the impact of large scale penetration of EVs. Please see section 8.1.6.4
Grid Modernization- Innovating the Future	Hydro Ottawa grid modernization plans are focused on improving Distribution Automation, and operational technology to increase dynamic operation of the grid, and progress to a self-healing grid. Please See section 8.3.4.6-8.3.4.10 Hydro Ottawa through its Smart Grid projects such as MiGen is investing to explore tools and market models that support transactive future marketplace, to support the system and customers needs. See section 8.4.3.6
Distributed Energy Resources - Innovating the Future	Hydro Ottawa is focusing on advancing the capability to connect DER, in the course of its other renewal and modernization activities, and building platforms to support control and monitoring of DERs connected to the Distribution System. See section 8.1.6.2
Enhancing Reliability - Improving Value and Performance for Customers	Hydro Ottawa's System Renewal and System Service investments are targeted to maintain and enhance reliability performance, overall, and for identified areas that are experiencing below average reliability performance. See section 8.4.3.5.
Cybersecurity - Improving Value and Performance for Customers	Hydro Ottawa has integrated Cybersecurity into its information Technology and Operation Technology procurement, and is taking a proactive approach to fully secure against cyber threats. Please see Attachment 2-4-3(E): Material Investments
Strengthening the Commitment to Energy Conservation and Efficiency	Hydro Ottawa considers the existing and future Conservation and Demand Program for all capacity and renewal projects. See section 5.3.
Responding to Extreme Weather Events	Hydro Ottawa is investing in resiliency initiatives to mitigate the impacts of adverse weather. See section 8.1.6.3
Supporting Regional Solutions and Infrastructure	Hydro Ottawa is engaged in regional planning, and has incorporated capital investments reflective and responsive to regional planning activities that impact its service area. Please see section 8.1.6.1

2. OVERVIEW OF DISTRIBUTION SYSTEM

This section provides an overview of the features of Hydro Ottawa's distribution service area, including regional factors, such as weather and high-level asset demographics. A map depicting Hydro Ottawa's service territory is shown in Figure 2.1.

Figure 2.1 – Hydro Ottawa Service Territory

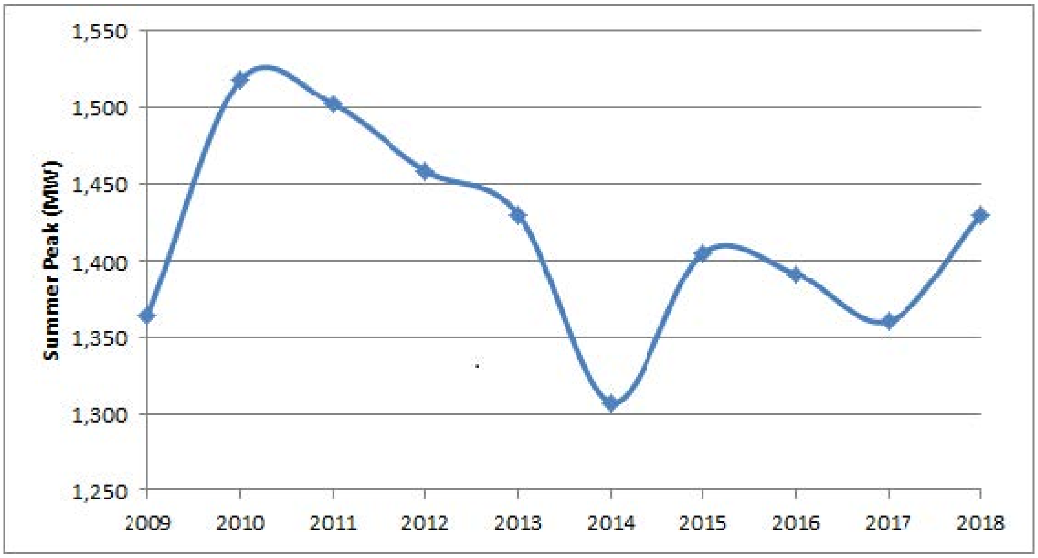


2.1. FEATURES OF THE DISTRIBUTION SERVICE AREA

Hydro Ottawa was formed in November 2000, following the amalgamation of five municipally-owned electric utilities (Gloucester Hydro, Goulbourn Hydro, Kanata Hydro, Nepean Hydro and Ottawa Hydro) from the former region of Ottawa-Carleton and the restructuring of the Ontario electricity sector as a result of the *Electricity Act, 1998*. In 2002, Casselman Hydro was acquired by Hydro Ottawa and joined the amalgamated utility. The amalgamation of the six distinct utilities resulted in an overall diverse system, with multiple service voltages comprising assets stemming from a variety of procurement and construction standards. Since amalgamation, Hydro Ottawa has focused on consolidating the systems and standards with common processes.

As of the end of 2019, Hydro Ottawa distributes electricity to approximately 340,000 metered customers within the City of Ottawa and the Village of Casselman. The service area covers 1,116 square kilometers and is supplied by an even mix of overhead and underground distribution lines. In 2018, Hydro Ottawa purchased a total of 7,446 gigawatt hours of electricity from the provincial grid to supply to customers. The Hydro Ottawa system peaks in the summer at a level that has remained relatively constant (maximum of 1,518 MW in 2010 and minimum of 1,308 MW in 2014) over the past decade. While population growth continues to increase, reductions from conservation programs, improvements in appliance efficiencies, and the installation of ERFs have offset the demand requirements of intensification. As the City grows, former rural areas fed by long distribution lines are becoming urban centres. This has created a new dynamic of customer requirements for higher reliability. Figure 2.2 depicts the net system summer peak (i.e. including embedded generation) over the last 10-year period.

Figure 2.2 – Net System Summer Peak (2009-2018)



Distribution expansion within Hydro Ottawa's service territory is impacted by both natural and constructed barriers including the Rideau River, the Greenbelt, and 400-Series highways, which limit distribution connectivity in some areas of the system. As a result, system planning must consider these barriers when identifying routing for distribution circuitry and evaluating capacity options.

Large segments of the system were constructed in the 1960s, 1970s, and 1980s, with a typical expected service life for these assets on the order of 50 years. Consequently, a considerable proportion of the system has exceeded or is approaching its anticipated end of life. These aging assets pose an increasing failure potential, and without corrective actions, will impact the utility's ability to maintain system reliability and minimize unplanned renewal cost in the future.

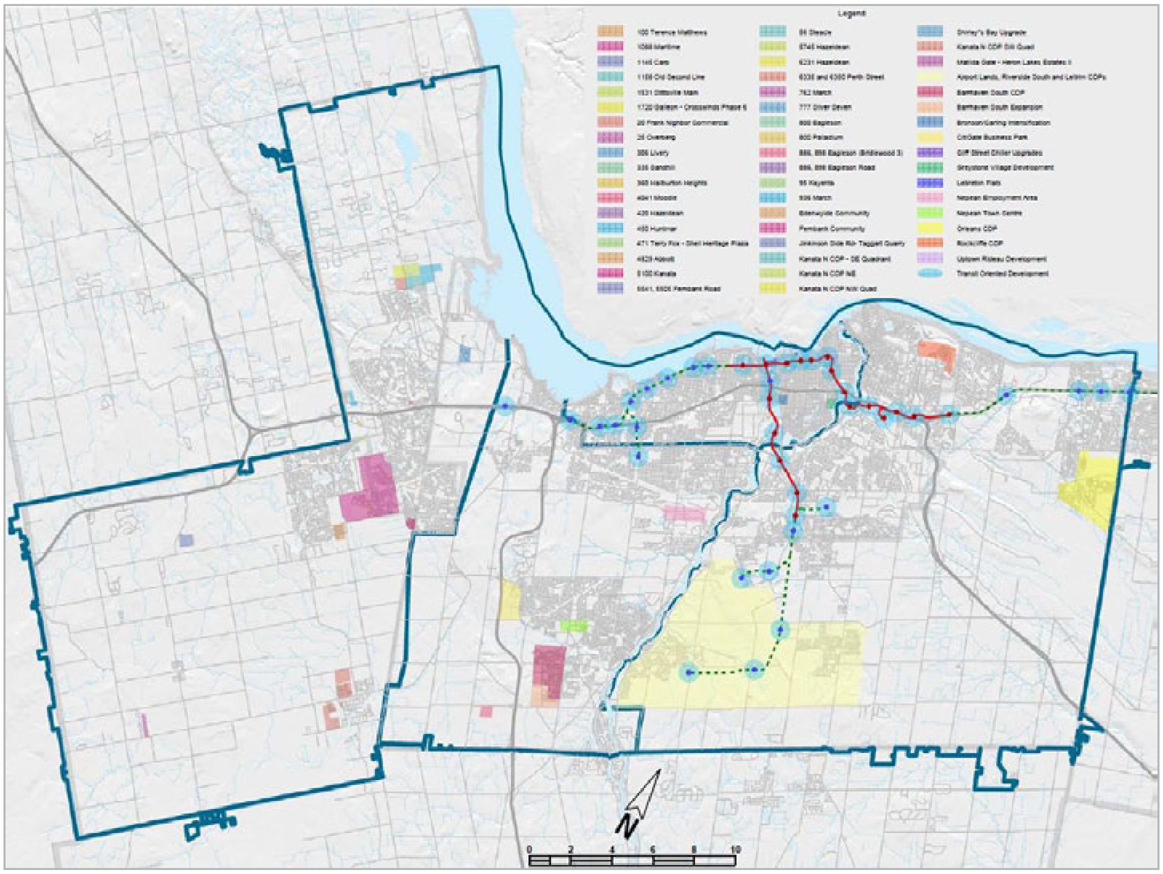
Overall, the City of Ottawa continues to grow in population and developed lands. The Ottawa-Gatineau population has consistently grown by 22,000 (1.5%) residents annually since 2015 (see Table 2.1 below). On the Ottawa side, this development is primarily focused in five regions: the Downtown Core, Nepean & Riverside South, South Kanata & Stittsville, the Village of Richmond, and Orleans. This growth is being seen through the development of new mixed commercial/residential communities, intensification of existing communities, and major projects like the Ottawa LRT system. The location of major growth areas is shown in Figure 2.3.

Table 2.1 – Ottawa-Gatineau Population and GDP Growth

		2015	2016	2017	2018	2019	2020	2021
Population	($‘000s)	$1,336	$1,360	$1,388	$1,409	$1,429	$1,447	$1,466
	(%)	*1.12%*	*1.79%*	*2.03%*	*1.55%*	*1.39%*	*1.30%*	*1.27%*
GDP	($’000,000s)	$65,041	$66,629	$68,806	$69,994	$71,515	$72,892	$74,351
	(%)	*1.86%*	*2.44%*	*3.27%*	*1.73%*	*2.17%*	*1.93%*	*2.00%*

*Source: Conference Board of Canada. Figures are from Q4 in the year cited.

Figure 2.3 – Primary Areas of Growth in Hydro Ottawa's Service Territory



2.2. SYSTEM CONFIGURATION

Hydro Ottawa's distribution system has diverse characteristics, which have endured since the amalgamation of the six former municipal utilities. The system has six different distribution operating voltages that are constructed in a mix of overhead and underground systems. The majority of the underground infrastructure is located in the downtown and suburban areas.

The stations supplying the service area are a mix of Hydro Ottawa-owned and HONI-owned stations and transformers. Formerly, HONI owned all transmission-connected transformers supplying Hydro Ottawa-owned breakers at the low voltage side to distribute electricity throughout the service area. The current practice for newly built transmission-connected stations is for Hydro Ottawa to construct and own all equipment.

Table 2.2 below shows the length of overhead and underground lines in Hydro Ottawa's distribution system.

Table 2.2 – Length of Underground & Overhead Lines

Orientation	Total Length (km)	Total Length (%)
Underground	3,022	52.4%
Overhead	2,745	47.6%
TOTAL	**5,767**	**100%**

Table 2.3 below shows the number of circuits and length of overhead and underground cables per voltage level in Hydro Ottawa's distribution system.

Table 2.3 – Number & Length of Circuits by Voltage Level

<table>
<tr><th>Voltage Level</th><th>Number of Circuits</th><th>Total Overhead (km)</th><th>Total Underground (km)</th></tr>
<tr><td>4.16 kV</td><td>280</td><td>620</td><td>278</td></tr>
<tr><td>8.32 kV</td><td>115</td><td>687</td><td>507</td></tr>
<tr><td>12.43 kV</td><td>6</td><td rowspan="2">459</td><td rowspan="2">918</td></tr>
<tr><td>13.2 kV</td><td>314</td></tr>
<tr><td>27.6 kV</td><td>51</td><td>785</td><td>1,312</td></tr>
<tr><td>44 kV</td><td>17</td><td>194</td><td>7</td></tr>
<tr><td>TOTAL</td><td>783</td><td>2,745</td><td>3,022</td></tr>
</table>

Table 2.4 below shows the number of transformer stations in Hydro Ottawa's service territory per voltage level.

Table 2.4 – Number of Transformer Stations

Secondary Voltage Level	# of Stations	# of Transformers Owned by Hydro Ottawa	# of Transformers Owned by HONI
4.16 kV	35	97	0
8.32 kV	24	42	2
12.43 kV	2	3	0
13.2 kV	12	2	23
27.6 kV	15	23	6
44 kV	3	0	6
TOTAL	**91**	**167**	**37**

2.3. AREA CONSIDERATION

The following examples outline some of the issues and concerns that are taken into consideration when planning the distribution system in Ottawa.

2.3.1. Physical and Administrative Barriers

Hydro Ottawa's service territory sits at the convergence of three major rivers: the Ottawa River, the Gatineau River and the Rideau River. The Ottawa River functions as the northern border of Hydro Ottawa's service territory, beyond being the province of Quebec. Hydro Ottawa is otherwise completely surrounded by HONI's service territory. The Rideau River and Rideau Canal, which by-passes unnavigable sections of the Rideau River, wind through the service area. Around the main urban area of the City of Ottawa is an extensive Greenbelt comprised of mostly forest, farmland and marshland. Outside of the Greenbelt, there are a number of rapidly growing suburban communities. Constructed barriers such as divided highways (417, 416 and 174) further subdivide the territory.

As the Nation's Capital, there are a number of federal lands in Hydro Ottawa's service territory which are managed by different government agencies. These federal lands can present an administrative barrier, which drive technical and administrative challenges in the construction and maintenance of distribution interconnections. These conditions can often result in increased cost and time required to create or augment new distribution interconnections within the service territory.

2.3.2. Soil Conditions

The Ottawa area soil conditions generally fall within two categories: till soils with loam to sandy loam texture, and clay soils. There are also extensive bogs within the region consisting of pockets of moist to wet soils. These conditions call for increased civil infrastructure (piling) beneath the civil footings to ensure the stability of structures, specifically within stations. The piling necessitates further excavation, resources, material and design, and therefore higher costs. Due to the shallow bedrock there can be increases in costs associated with boring or excavating (e.g. with the installation of poles, ducts, or piling to support civil structures). In the west area of the City, there are regions of exposed sedimentary bedrock.

2.3.3. Seismic Zone

Ottawa sits within Zone 4 for Seismic Acceleration (0.16-0.23g) and Zone 2 for Seismic Velocity (0.0-0.11m/s). Ottawa falls within the Western Quebec seismic zone which sees on average one earthquake every five days.[1] This condition requires civil footings and foundations to be designed and constructed to withstand these higher seismic levels. Larger foundations and footings require more reinforcing steel (rebar), larger excavations, and more concrete, contributing to increases in capital expenditures.

The seismic zone also requires that additional steel cross bracing is designed and installed on all structures. The additional bracing results in larger design, fabrication, and installation costs than that of a zone of lower seismic activity.

2.4. CURRENT AND FUTURE CLIMATE

In comparison to other major Ontario cities (with the exception of Sudbury), Ottawa is characterized by having generally lower wind speeds and colder winters with higher snowfall.

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[1] Natural Resources Canada, *Earthquake Zones in Eastern Canada:* http://www.seismescanada.rncan.gc.ca/zones/eastcan-en.php#WQSZ.

Hydro Ottawa strives to complete capital work year-round. However, work must be scheduled to accommodate the winter months in which there are more challenges to overcome in the field (e.g. snow removal) before work can commence.

The data presented in the following charts represent the Climate Normals from 1981-2010 for major cities in the province, as recorded by the Government of Canada.

Figure 2.4 – Daily Maximum Temperature

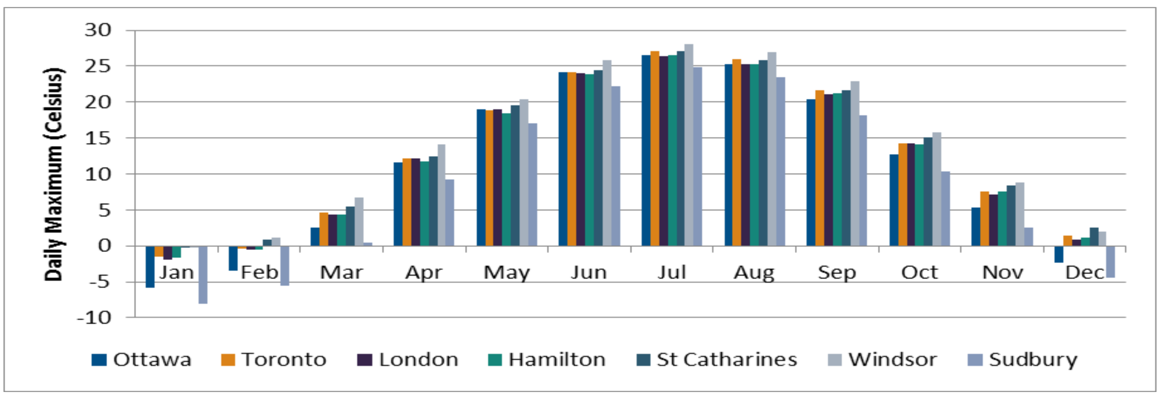


Figure 2.5 – Daily Minimum Temperature

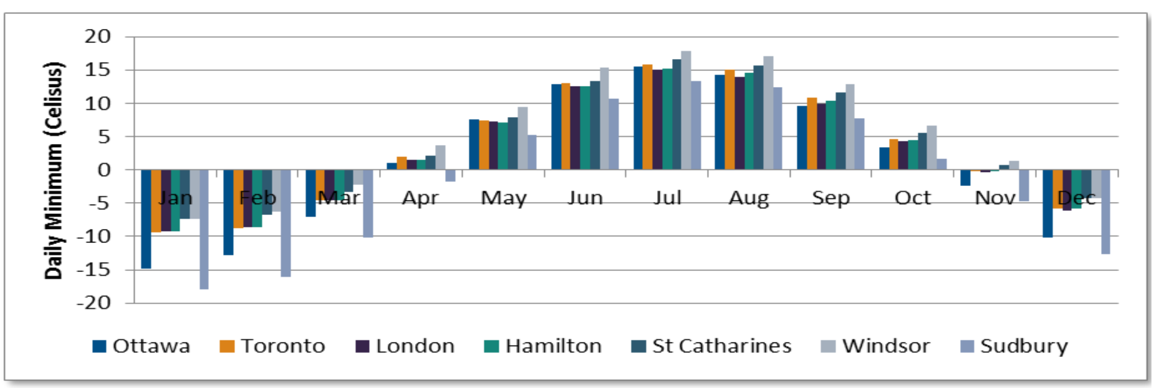


Figure 2.6 – Rainfall

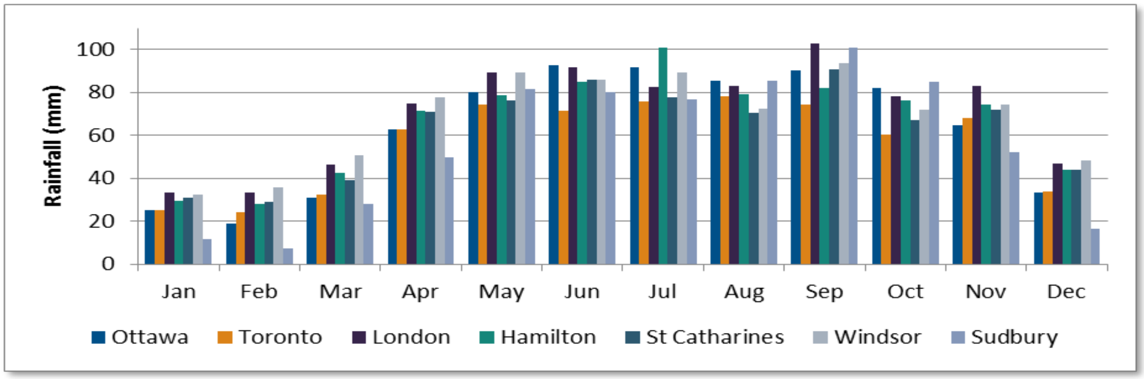


Figure 2.7 – Snowfall

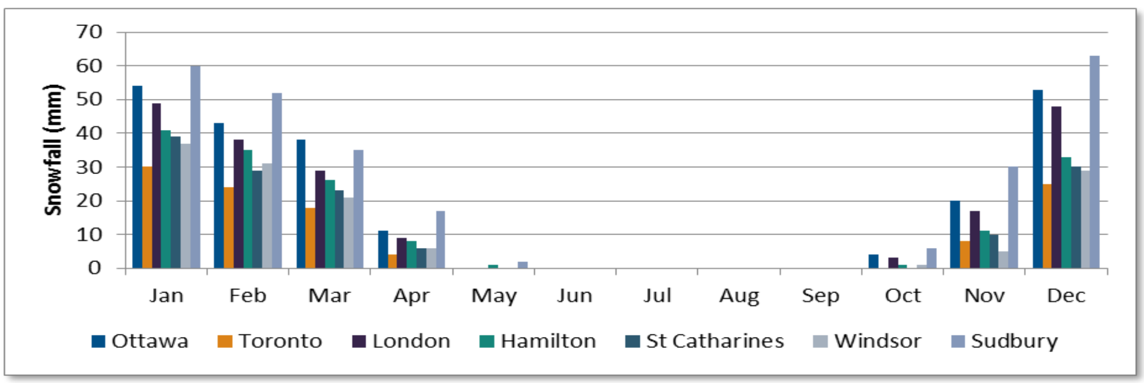
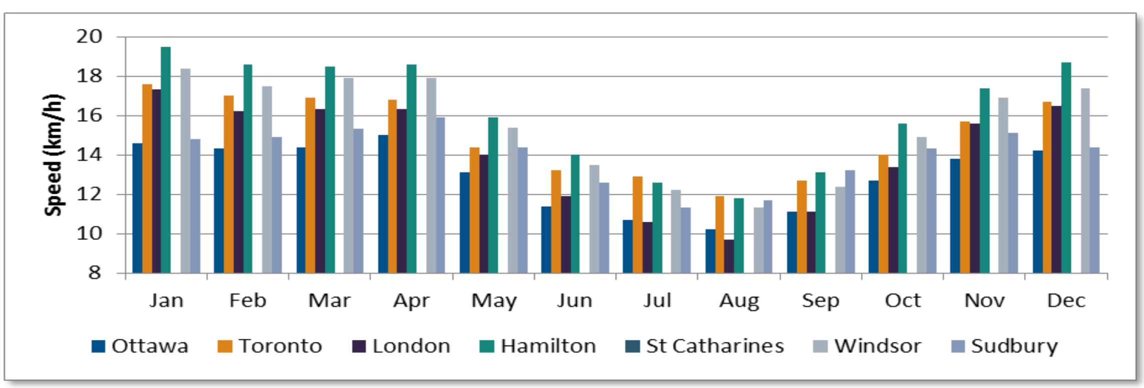


Figure 2.8 – Wind Speed



Temperature Profile

The Ottawa region temperature profile requires that equipment operate under a temperature range of -40 to +40 degrees Celsius. Various pieces of equipment, such as those containing inert gasses, require extra heaters to ensure reliable operation at the lower end of this temperature range. The requirement of additional heaters on equipment typically results in design modifications and the procurement of non-standard equipment.

Ice Accumulation & Snow Loading

Due to the amount of snowfall and ice accumulation experienced in Ottawa, civil structures (structural steel) must be able to withstand a significant amount of snow and ice build-up without impacting structural integrity. This requires that the specific alloys chosen must be of high quality and thus increases the cost of fabrication. Hydro Ottawa follows Canadian Standards Association ("CSA") and American Society for Testing and Materials ("ASTM") standards in order to ensure that structures are able to withstand winter conditions.

Substations are classified as "post-disaster buildings" as defined by the Ontario Building Code. The Ontario Building Code Supplement SB-1 lists the weather design criteria for buildings and structures, including snow load.

Another impact of the harsh winters is an increased use of road salt which can lead to premature rusting of equipment located along the road right of way. The salt spray from roadways increases the need to repaint and repair rusted underground and overhead equipment. Salt contamination on porcelain insulators can lead to pole fires and flashovers. Insulator washing is necessary to mitigate the risk of these failure modes.

2.4.1. Future Climate Projections

Weather patterns in the region are changing as a result of climate change and will ultimately result in Hydro Ottawa needing to adjust operations and infrastructure. Projections of the 2050s climate parameters in this section were prepared by Risk Science International for Hydro Ottawa as part of a Climate Vulnerability and Risk Assessment that was commissioned by the utility (see Attachment 2-4-3(H): Distribution System Climate Risk and Vulnerability Assessment). These forecasts are based on a “business as usual” climate scenario, which the Intergovernmental Panel on Climate Change (“IPCC”) refers to as the Representative Concentration Pathway (“RCP”) 8.5. Based on this scenario, it is assumed that global carbon emissions will continue to rise until 2100. Current estimates of GHG emissions are still close to following the RCP 8.5 path and thus this is considered to be conservative but realistic at this time. Details of Hydro Ottawa’s climate adaptation plans can be found in section 8.1.6.3.

Temperature

The climate models project 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. The warming of the climate system is also leading to important changes in temperature extremes. For example, 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 and is expected to increase in the future.

Other warming trends expected for the region under current emissions rates include:

- An increase in the number of days per year where the temperature reaches above 25ºC an average of 99 times per year up from 62-63 times per year as a baseline)
- An increase in the number of days per year where the temperature reaches above 30ºC (an average of 42 times per year up from 14-15 times per year as a baseline)
- A decrease in the number of days per year at or colder than -35ºC (an average probability of 3% of occurrence per year declining to 0.1% chance of probability).
- The annual number of freeze-thaw cycles is projected to decrease under climate change, from a baseline (1981-2010) mean of ~76 cycles per year to 59-60 cycles per year by the 2050’s. 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 2.9 – Pole Replacement Following 2018 Ice Storm

Precipitation

The Ottawa region has experienced an overall increase in annual precipitation, with total precipitation increasing 25.9 mm at the Ottawa Airport during the 1981-2010 time period. Future climate projections indicate an increase in precipitation for all seasons in the coming decades.

More importantly, the short duration-high intensity ("SDHI") rainfall event – i.e. a rainfall threshold of 50 mm in 1 hour – is expected to increase in annual probability from 1% today to 4.5% by 2050. SDHI events are more likely to result in flooding as stormwater infrastructure is overwhelmed by the sheer volume of water being deposited.

Over the next few decades, a slight decline in precipitation is expected during the summer months and an increase in precipitation during the winter and spring seasons. This means drier summers and wetter winters, and when rain or snow does fall, it is likely to be more variable and shorter, meaning intense rainfall or snow events are likely to be more common by the end of the century. The decline in winter precipitation means that declines in snowfall as a result of climate change are expected. More ice storms and freezing rain are also anticipated, as temperatures fluctuate around zero degrees. While the frequency of these events is projected to increase under climate change, large magnitude events will continue to be relatively rare.

Wind

The frequency of straight-line wind events with wind gusts that are greater than 60 km/hour are projected to increase from 14-15 times per year to 16 times per year by the 2050s. High straight-line wind gust events where the winds exceed 80 km/hour are projected to remain steady with approximately one to two instances per year. Damaging straight-line wind events, in the form of microbursts, can result in more damage than tornadoes as the winds can be stronger and affect a much larger area than a tornado. These events tend to occur during lightning storms.

Tornadoes

It is conservatively estimated that the annual probability of an Enhanced Fujita ("EF") scale category 1 or greater tornado impacting Hydro Ottawa's service territory could increase from 14.6% to 18.2% by the 2050s. Although the probability of a tornado event occurring remains low over the next century, a tornado can result in considerable damage to infrastructure.

Lightning

Estimates of increases in lightning frequency for the region indicate that lightning activity could be expected to increase by about 12% (per degree Celsius of warming), with about a 50% rise over the 21st century. It is projected that flash density in the region will increase in annual frequency from 1.1% to 1.5% by 2050. Furthermore, the length of the higher frequency lightning season is also expected to increase with warming under climate change.

Fog

Fog in the winter months promotes aerosolizing of salts (e.g. road salt) which can result in corrosion to Hydro Ottawa's infrastructure and cause pole fires and flashovers. 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. During this baseline, there is an annual probability of 37% for a winter with 50 or more fog days. Days with winter fog are likely to increase under climate change as winter temperatures warm, increasing moisture availability and promoting more evaporation in the region.

3. ASSET MANAGEMENT STRATEGY & OBJECTIVES

3.1. CORPORATE STRATEGIC OBJECTIVES

Hydro Ottawa's *2016-2020 Strategic Direction* sets the organization's overarching objectives, which, in turn, drive the Asset Management Process and planning practices. This framework provides context for Hydro Ottawa's Strategic Asset Management Plan ("SAMP") and DSP, and is referenced throughout both documents.

One of the central challenges facing Hydro Ottawa and other utilities is the need to invest heavily in the replacement and modernization of aging and deteriorating infrastructure without putting upward pressure on customer rates, which continue to rise due to increased electricity commodity prices. In this context, achieving efficient and effective operations has never been more important to the utility. Hydro Ottawa must continually find ways to work smarter and more efficiently – and the utility is doing just that.

Strategy

The essence of Hydro Ottawa's business is to put the customer at the centre of everything we do. Reorienting our activities around the customer was the primary goal of our *2016-2020 Strategic Direction*, and customer centrality continues to drive our business strategy. The utility believes that a sharp focus on the value we provide to our customers will generate positive results in all areas of performance – financial strength and business growth, operational efficiency and effectiveness, and contributions to the well-being of the community.

A core premise of the *2016-2020 Strategic Direction* is that the electricity service model is in the midst of significant transformation – taking on a more decentralized, customer-centric, technologically-advanced, and environmentally-sustainable form. The transition to a more customer-driven and customer-centric model of electricity will present opportunities for energy providers that are able to innovate, and challenges for those that fail to adapt. Hydro Ottawa's strategy for responding to this emerging landscape involves the following core elements:

- Taking customer experience to the next level;
- Continuing to achieve strategic growth;
- Ensuring access to capital for growth;
- Making sure the utility has the right skill sets and organizational capacity to deliver on existing and new business lines;
- Continuing to enhance operational performance, including productivity and safety;
- Continuing to build public confidence and trust; and
- Being ready to embrace change and disruption in the industry.

Hydro Ottawa's aim is to be the trusted energy advisor for our customers – large and small – and our community. As the energy needs and options of our customers and our community evolve, and as signature projects and developments proceed, Hydro Ottawa will play a leading role in helping the City to transition to a smart energy future.

The utility will also continue to grow shareholder value, maintaining a focus on strategic business growth within core areas of strength.

Taken as a whole, Hydro Ottawa believes this strategy for the utility's future presents a balanced program for solid performance, adaptation to a changing business environment, and sustainable and profitable business growth.

Mission

To create long-term value for our shareholder, benefitting our customers and the communities we serve.

Hydro Ottawa is both a community asset and an investment for our shareholder, the City of Ottawa. As a community asset, our purpose is to provide efficient and reliable services and a first-class customer experience to our customers, and to continue to be a strong strategic partner with the City, helping to deliver on its economic development and environmental agendas. As an investment, our purpose is to provide stable, reliable and growing returns, and to increase shareholder value both in the short- and long-term.

Vision

Hydro Ottawa – *a leading partner in a smart energy future*

Guiding Principles

Hydro Ottawa is committed to creating long-term value in a manner that will withstand the test of public scrutiny and inspire confidence and trust. To that end, the utility strives to achieve excellent operating and financial results while abiding by professional standards of conduct. Hydro Ottawa is guided not only by legal obligations, but also by best governance and business practices, and standards established by independent agencies. These expectations provide the foundation for our commitment to all of our stakeholders, and are reflected in our organizational values, our Code of Business Conduct, and our operating policies and procedures.

Organizational Values

Hydro Ottawa is committed to an organizational environment that fosters and demonstrates ethical business conduct at all levels and reflects our shared values of teamwork, integrity, excellence and service. Every employee must lead by example in this endeavour.

Commitment to our Stakeholders

Hydro Ottawa takes into account the interests of all our stakeholders including employees, customers, suppliers, our shareholders, and the communities and environment in which we operate.

- **Employees** – The quality of our workforce is our strength and we will strive to hire and retain the best-qualified people available and maximize their opportunities for success. Hydro Ottawa is committed to maintaining a safe, secure and healthy work environment enriched by diversity and characterized by open communication, trust, and fair treatment.

- **Customers** – Our continued success depends on the quality of our customer interactions, and we are committed to delivering value across the entire customer experience. We are honest and fair in our relationships with our customers, and provide reliable, responsive and innovative products and services in compliance with legislated rights and standards for access, safety, health and environmental protection.

- **Suppliers & Contractors** – We are honest and fair in our relationships with our suppliers and contractors and purchase equipment, supplies and services on the basis of merit, with a preference for local procurement. We pay suppliers and contractors in accordance with agreed terms, encourage them to adopt responsible business practices, and require them to adhere to our health, safety and environment standards when working for Hydro Ottawa.

- **Community & the Environment** – We are committed to being a responsible corporate citizen and will contribute to making the communities in which we operate better places to live and do business. We are sensitive to the community's needs, and dedicated to protecting and preserving the environment where we operate.

- **Shareholder & Other Suppliers of Finance** – We are financially accountable to our shareholders and to the institutions that underwrite our operations, and communicate to them all matters material to our organization. We protect our shareholder's investment, and manage risks effectively. We communicate to our shareholder all matters that are material to an understanding of our corporate governance.

Four Key Areas of Focus (Corporate Strategic Objectives)

Hydro Ottawa's success in the past has been achieved by focusing on four critical areas of performance – the utility's four Key Areas of Focus.

Figure 3.1 – Corporate Strategic Objectives

In each of these areas, Hydro Ottawa has set one overarching objective:

- **Customer Value**: We will deliver value across the entire customer experience by providing reliable, responsive and innovative services at competitive rates;

- **Financial Strength**: We will create sustainable growth in our business and our earnings by improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people;

- **Organizational Effectiveness**: We will achieve performance excellence by cultivating a culture of innovation and continuous improvement; and

- **Corporate Citizenship:** We will contribute to the well-being of the community by acting at all times as a responsible and engaged corporate citizen.

3.2. ASSET MANAGEMENT OBJECTIVES

Hydro Ottawa has structured its asset management processes for Distribution Assets to align with best practices described in the ISO 55001 Asset Management Standard. A cross-functional team from the organization has developed and supports the implementation of the plan to meet Hydro Ottawa's five Asset Management Objectives, which are outlined in Table 3.1.

Table 3.1 – Asset Management Objectives

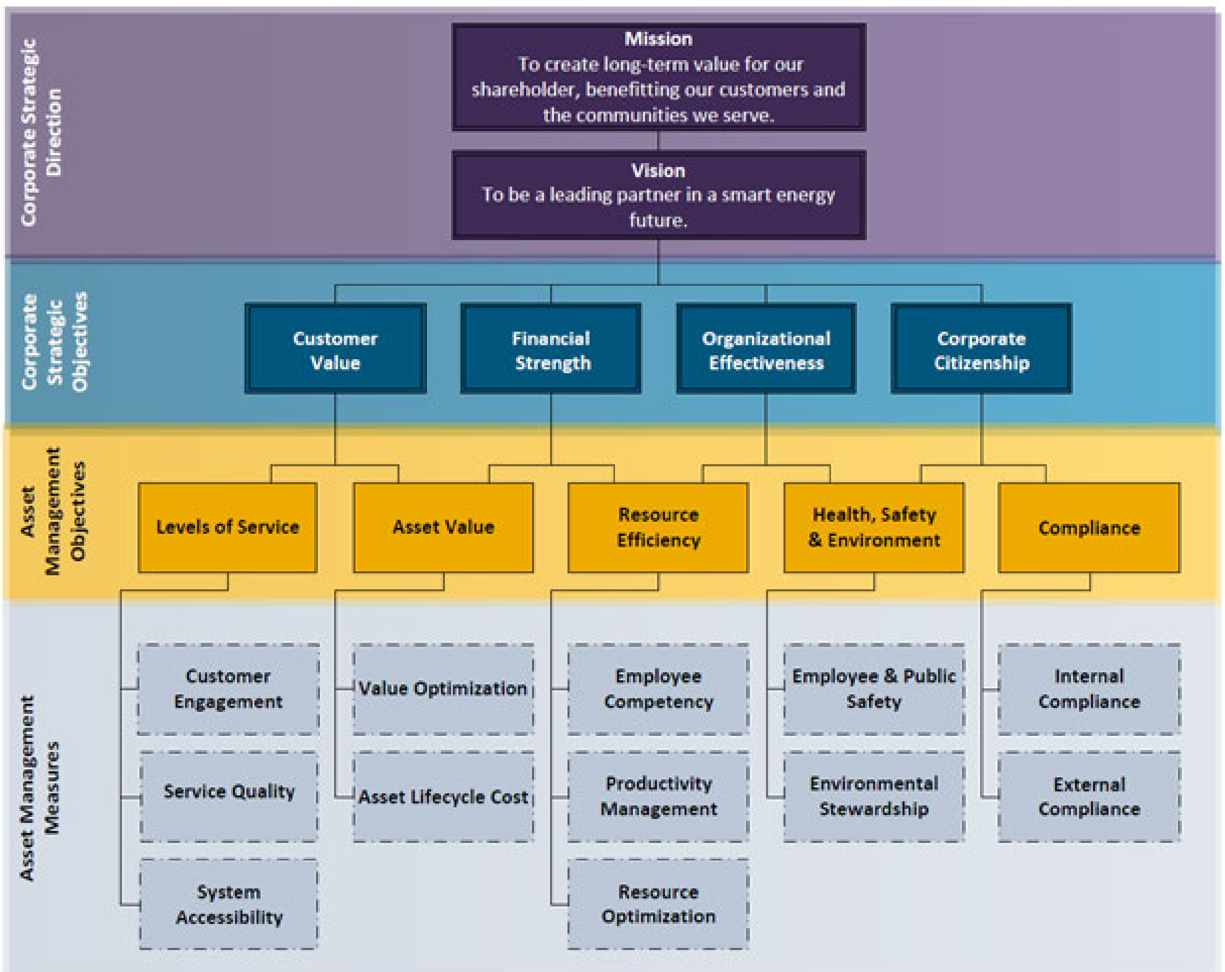
Asset Management Objective	Description
Levels of Service	To maintain and enhance leading performance of the distribution system through improving electrical service and alignment with customers' expectations
Asset Value	To maximize the realization of value from distribution system assets over their entire lifecycle through managing risks and opportunities
Resource Efficiency	To maximize economic efficiency by minimizing costs associated with maintaining and operating the distribution system
Health, Safety & Environment	To minimize employee and public health and safety risks and environmental risks from distribution system activities
Compliance	To maintain compliance with all internal and external requirements while managing the distribution system

The Asset Management Objectives have been identified as drivers in the success of the Corporate Strategic Objectives. The successful delivery of these objectives is implemented through Hydro Ottawa's Asset Management System, Asset Management Process, and the utility's portfolio of capital, operational, and maintenance projects.

The success of the Asset Management Objectives is expressed in terms of Asset Management Measures. These are specific goals which are directly impacted by the work carried out under the Asset Management Process. The evaluations of the Asset Management Measures are used to prioritize projects as described in the process outlined in section 5 Asset Management & Capital Expenditure Process.

The alignment and interplay between the Corporate Strategic Direction and Objectives through to the Asset Management Objectives and Measures is shown in Figure 3.2.

Figure 3.2 – Corporate Strategic Direction & Asset Management Objectives



4. PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

Hydro Ottawa monitors and tracks performance measurements to identify risks and opportunities for continuous improvement.

This section will cover the following:

- Distribution System Planning Process Key Performance Indicators
- Unit Cost Metrics
- Historical Reliability Performance Analysis
- Historical Performance Impact on DSP
- Realized Efficiencies Due to Smart Meters

4.1. SYSTEM PLANNING PROCESS KEY PERFORMANCE INDICATORS

Hydro Ottawa uses Key Performance Indicators ("KPIs") to measure and support continuous improvement in Customer Oriented Performance, Cost Efficiency & Effectiveness, Asset Performance and System Operations Performance. These KPIs are quantitative measures and align with Hydro Ottawa's Asset Management Objectives, and by extension, with Hydro Ottawa's Corporate Strategic Objectives. These measures are used to monitor the effectiveness of Hydro Ottawa's planning processes, efficiencies in carrying out work, as well as identifying shortfalls and areas for continuous improvement.

Table 4.1 below summarizes the KPIs by Category, Asset Management Objective, and Sub-Category, and the corresponding section where the detailed description and historical performance can be found.

Table 4.1 – System Planning Process Key Performance Indicators by Category

Category	Asset Management Objective	Sub-Category	KPIs
4.1.1 Customer Oriented Performance	Levels of Service	4.1.1.1 Customer Engagement	a. Customer Satisfaction b. Staff Knowledge c. Staff Courtesy d. First Call Resolution e. Residential & Small Commercial Satisfaction f. Commercial Satisfaction g. Staff Helpfulness h. Value for Money i. Customer Loyalty
		4.1.1.2 System Reliability	j. System Average Interruption Frequency Index (SAIFI) k. System Average Interruption Duration Index (SAIDI) l. Customer Average Interruption Duration Index (CAIDI) m. Feeders Experiencing Multiple Sustained Interruptions (FEMI)
		4.1.1.3 System Power Quality	n. System Average Root Mean Square Variation Frequency Index (SARFI)
4.1.2 Cost Efficiency & Effectiveness	Compliance	4.1.2.1 Cost Efficiency	o. Cost Efficiency
	Resource Efficiency	4.1.2.2 Labour Utilization	p. Productive Time q. Labour Allocation
4.1.3 Asset Performance	Asset Value	4.1.3.1 Defective Equipment Contribution to SAIFI	r. System Average Interruption Frequency Index – Defective Equipment ($SAIFI_{DE}$)
	Health, Safety & Environment	4.1.3.2 Public Safety Concerns	s. Public Safety Concerns (PSC)
		4.1.3.3 Oil Spilled	t. Litres Annual Oil Spilled u. Cost of Annual Oil Remediation
4.1.4 System Operations Performance	Levels of Service	4.1.4.1 Stations Capacity	v. Stations Exceeding Planning Capacity w. Stations Approaching Rated Capacity
		4.1.4.2 Feeder Capacity	x. Feeders Exceeding Planning Capacity y. Feeders Approaching Rated Capacity
		4.1.4.3 System Losses	o Losses

The following sections describe the KPIs used by Hydro Ottawa to monitor the quality of the planning process and the efficiency with which the plans are implemented and the extent to which the planning objectives have been met.

4.1.1. Customer Oriented Performance

Hydro Ottawa's KPIs surrounding Customer Oriented Performance align with the asset management objective for Levels of Service, which is to "maintain and enhance leading performance of the distribution system through improving electrical service and alignment with customers' expectations." Specifically, Hydro Ottawa continuously seeks feedback from customers on their satisfaction with the services provided by the utility. The customer satisfaction levels are greatly impacted by the distribution system's service reliability which is integral to all work undertaken as part of system planning. Hydro Ottawa continually assesses system reliability, and where gaps are found, implements appropriate actions to address the issues.

4.1.1.1. Customer Engagement

Customer value is at the core of Hydro Ottawa's Corporate Strategic Objectives and asset management objectives, and customers are engaged continuously to ensure their feedback is appropriately incorporated into planning of the distribution system. Annually, the utility engages customers with two surveys: a Touch Logic Survey and a Customer Satisfaction Survey (referred to as the SIMUL Survey). The results of these surveys provide Hydro Ottawa with KPIs used to identify areas of improvement and benchmark the utility's accomplishments against results of other utilities.

Touch Logic Survey

The Touch Logic survey is an automated survey sent to customers who have previously called the customer hotline. There are four KPIs evaluated for this survey (see Table 4.2), each measured as a percentage of customers who indicated they were neutral or satisfied with their service.

- Customer Satisfaction – the customer's overall level of satisfaction with the call;
- Staff Knowledge – the customer's assessment of the knowledge of the call centre staff;
- Staff Courtesy – the customer's assessment of the courtesy of the call centre staff; and
- First Call Resolution – the ability of the staff to deal with the customer's issue.

Table 4.2 – Touch Logic Survey Results

KPI	Target	2014	2015	2016	2017	2018
Customer Satisfaction	**90%**	88%	90%	89%	87%	78%
Staff Knowledge	**90%**	92%	92%	93%	90%	90%
Staff Courtesy	**90%**	93%	93%	94%	92%	91%
First Call Resolution	**85%**	84%	85%	85%	84%	86%

The number of Touch Logic survey questions changed from six to four in late 2018 to better reflect the call centre performance. The questions previously used were too ambiguous and did not properly reflect customer satisfaction.

Hydro Ottawa uses the results from this survey to help assess customers' level of satisfaction with their interaction with Hydro Ottawa's call centre. In 2019, Hydro Ottawa will begin conducting email and web chat surveys to further improve this process.

SIMUL Survey

Hydro Ottawa's SIMUL survey captures customer service satisfaction numbers in five different categories:

- Residential and small commercial
- Commercial
- Staff Helpfulness – the helpfulness of staff who dealt with you
- Value for money
- Customer Loyalty – satisfied, would continue if given a choice, would recommend

Hydro Ottawa tracks the percentage that identify they are satisfied with the utility in each of these categories and sets a target to equal or better than the provincial average in each year (see Table 4.3).

Table 4.3 – SIMUL Survey Results

KPI		2014	2015	2016	2017	2018
Pre-Survey Residential & Small Commercial (Target >90%)	Results	83%	87%	81%	90%	94%
	Ontario Results	83%	86%	81%	85%	91%
Pre-Survey Commercial (Target >90%)	Results	-	-	-	90%	94%
	Ontario Results	-	-	-	90%	93%
Staff Helpfulness (Target >80%)	Results	73%	75%	81%	74%	65%
	Ontario Results	65%	67%	69%	66%	64%
Value for Money (Target = 2% better than Ontario)	Results	61%	63%	57%	66%	75%
	Ontario Results	63%	62%	58%	57%	71%
Customer Loyalty - Satisfied (Target = 35%)	Results	24%	23%	25%	33%	47%
	Ontario Results	27%	28%	30%	32%	36%

Feedback from these surveys is incorporated into Hydro Ottawa's planning process, and ultimately forms the basis of plans which address customer needs and service offerings. These results are compiled with the Voice of the Customer program to enable Hydro Ottawa to adapt processes and procedures in a timely manner in response to changing customer needs and expectations.

4.1.1.2. System Reliability

Hydro Ottawa tracks system reliability performance using four indicators: System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), Customer Average Interruption Duration Index ("CAIDI") and Feeders Experiencing Multiple Sustained Interruptions ("FEMI"). More detailed information regarding historical reliability performance can be found in section 4.3 - Historical Reliability Performance Analysis.

System Average Interruption Frequency

This index represents the average frequency of sustained interruptions per customer and is defined as follows:

$$SAIFI = \frac{Total\ number\ of\ customer\ interruptions}{Total\ number\ of\ customers\ served}$$

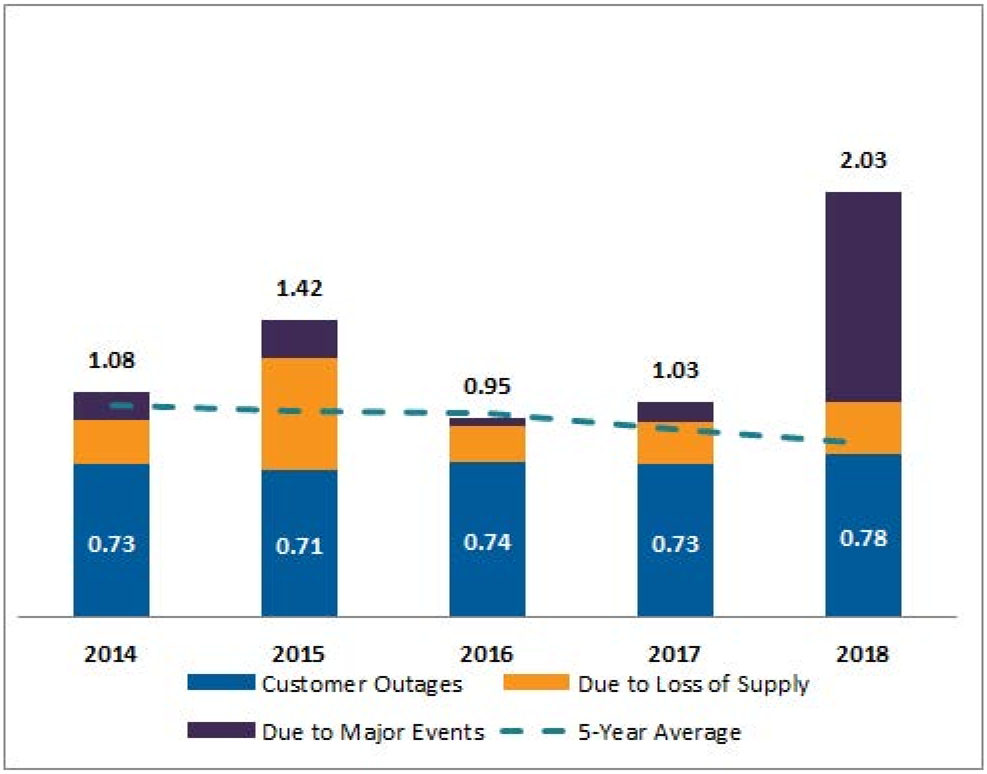
This index is reported both including and excluding Loss of Supply ("LoS") and Major Event Days ("MEDs").

Hydro Ottawa's target is to achieve or better the historical five-year average, excluding MEDs and LoS. This aligns with the OEB's distributor-specific target for reliability performance (see Table 4.4 and Figure 4.1).

Table 4.4 – SAIFI Reliability Performance

Metric		2014	2015	2016	2017	2018
SAIFI	All Interruptions	1.08	1.42	0.95	1.03	2.03
	Excluding LoS	0.86	0.75	0.78	0.83	1.19
	Excluding LoS & MEDs	0.73	0.71	0.74	0.73	0.78
	5-Year Historical Average	1.02	0.99	0.98	0.90	0.83
	Target Met	●	●	●	●	●

Figure 4.1 – SAIFI Reliability Performance



The reliability performance measure of SAIFI has been stable over the last five years (with LoS and MEDs excluded). The previous five years have all featured achievement of the target of the historical five-year average.[1]

Interruptions due to LoS and MEDs continue to have a large influence in maintaining a reliable system. Details of the historical MEDs can be found in section 4.3.2 - Major Events.

[1] For further details on how Hydro Ottawa's recent reliability performance compares favourably to other large electricity distributors in Ontario, please see Attachment 1-1-12(C): Electricity Utility Scorecard.

System Average Interruption Duration Index

This index represents the average interruption duration per customer and is defined as follows:

$$SAIDI = \frac{Total\ hours\ of\ customer\ interruptions}{Total\ number\ of\ customers\ served}$$

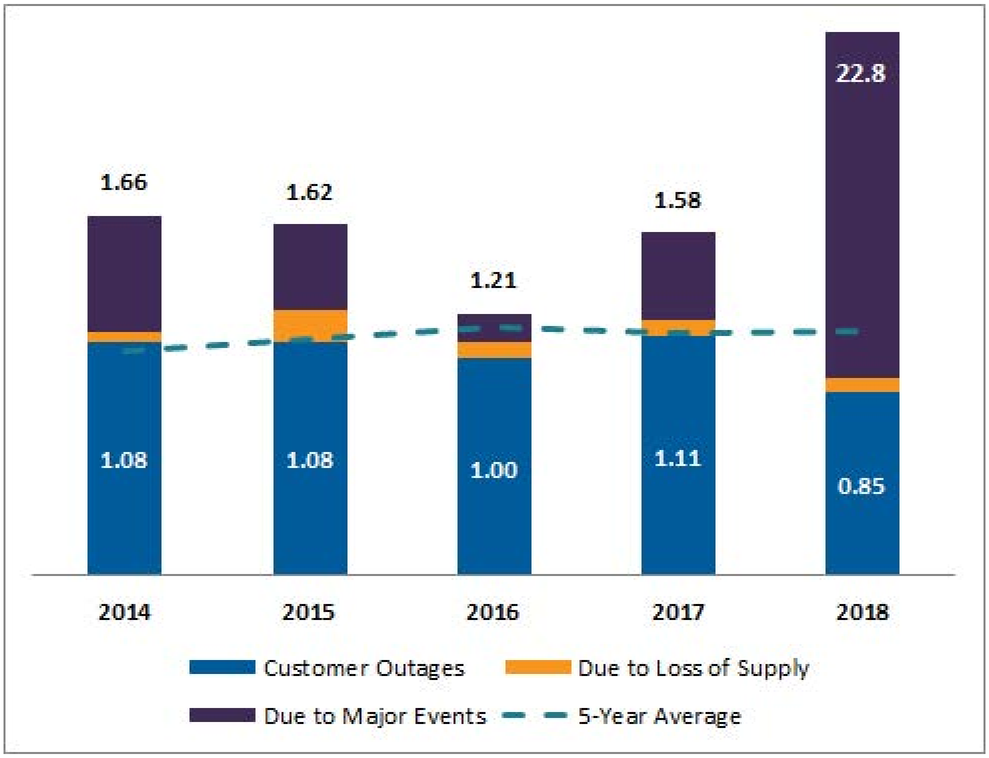
This index is reported both including and excluding LoS and MEDs.

Hydro Ottawa's target is to achieve or better the historical five-year average, excluding MEDs and LoS (see Table 4.5 and Figure 4.2). This aligns with the OEB's distributor-specific target for reliability performance.

Table 4.5 – SAIDI Reliability Performance

Metric		2014	2015	2016	2017	2018
SAIDI	All Interruptions	1.66	1.62	1.21	1.58	22.83
	Excluding LoS	1.59	1.15	1.13	1.51	3.54
	Excluding LoS & MEDs	1.08	1.08	1.00	1.11	0.85
	5-Year Historical Average	1.04	1.09	1.15	1.12	1.13
	Target Met					

Figure 4.2 – SAIDI Reliability Performance



The reliability performance measure of SAIDI has been stable over the last five years (with Los and MEDs excluded), with particularly exceptional performance in 2018. The previous five years have all witnessed the achievement of the target of the historical five-year average, with the exception of 2014, where the SAIDI value excluding LoS and MEDs exceeded the five-year average by 0.04.

Interruptions due to MEDs continue to have a large influence in maintaining a reliable system. Details of the historical MEDs can be found in section 4.3.2 - Major Events.

Customer Average Interruption Duration Index

This index represents the average time required to restore power per sustained interruption and is defined as follows:

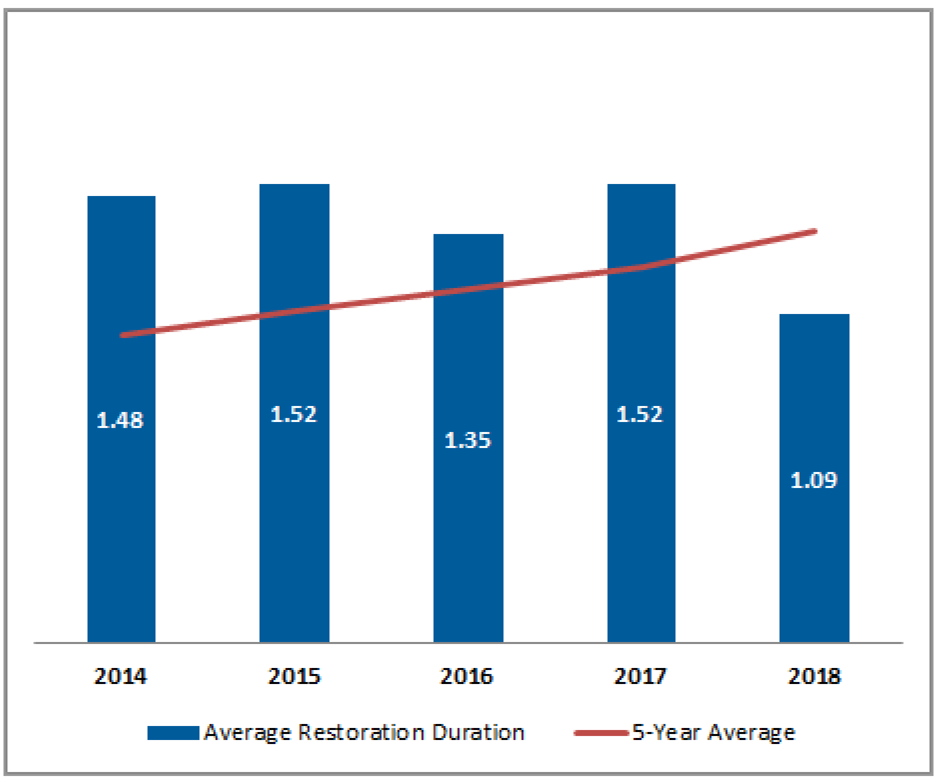
$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{Total\ hours\ of\ customer\ interruptions}{Total\ number\ of\ customer\ interruptions}$$

This index is reported excluding LoS and MEDs (see Table 4.6 and Figure 4.3).

Table 4.6 – CAIDI Reliability Performance

Metric		2014	2015	2016	2017	2018
CAIDI	Excluding LoS & MEDs	1.48	1.52	1.35	1.52	1.09
	5-Year Historical Average	1.02	1.10	1.17	1.24	1.36

Figure 4.3 – CAIDI Reliability Performance



Hydro Ottawa monitors the annual trend of CAIDI performance to evaluate potential concerns with restoration efforts. From 2014-2017, the CAIDI metric has been higher than the five-year average. Hydro Ottawa continues to target initiatives to reduce restoration times. In 2018, this is reflected in a significant reduction in the CAIDI metric.

Figure 4.4 – Outage Caused by Tree Falling onto Overhead Line

Feeders Experiencing Multiple Sustained Interruptions

The Feeders Experiencing Multiple Sustained Interruptions ("FEMI"$_n$) index represents the number of feeders experiencing sustained (greater than one minute) interruptions greater than or equal to value n; current reporting is done for n=10 – i.e. the count of feeders that have seen 10 or more sustained interruptions. Hydro Ottawa targets a $FEMI_{10}$ less than or equal to 10.

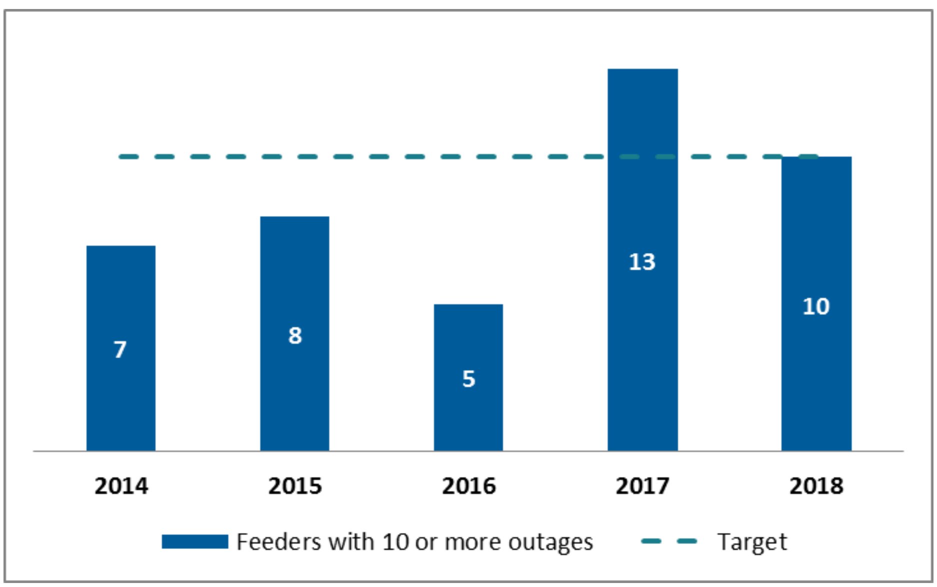
FEMI is used as a customer centric representation as it provides an indication as to which regions have seen reduced service quality. $FEMI_{10}$ is reported excluding Scheduled Outages, LoS, and MEDs.

Table 4.7 and Figure 4.5 show the historical system performance for FEMI.

Table 4.7 – FEMI Reliability Performance

Metric	Target	2014	2015	2016	2017	2018
FEMI	**10**	7	8	5	13	10

Figure 4.5 – FEMI Reliability Performance



On average, Hydro Ottawa has been achieving its targets for FEMI. Hydro Ottawa tracks and evaluates feeders that affect the performance of the FEMI metric monthly at its Reliability Council, to identify projects to improve the reliability of these parts of the distribution system.

Hydro Ottawa will continue to evaluate the performance of feeders that appear in the FEMI metric to ensure customer reliability is maintained.

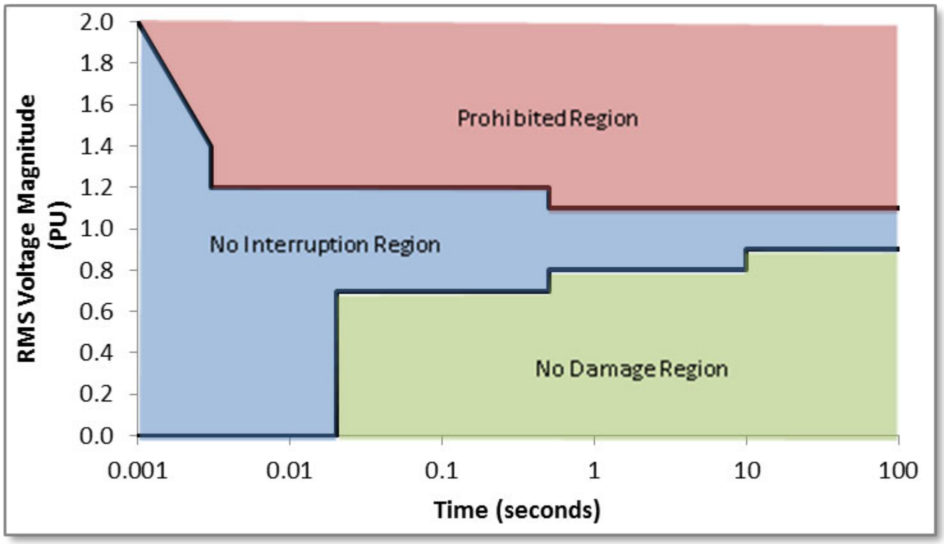
4.1.1.3. System Power Quality

Hydro Ottawa continuously monitors the quality of power supplied to its customers to ensure that it is meeting its required levels of service. This quality of power is based on industry standards for the delivery and use of power. With customer equipment becoming more sensitive to variations in the supplied power, monitoring the quality of this power has become an important factor in the levels of service provided.

System Average RMS Variation Frequency Index

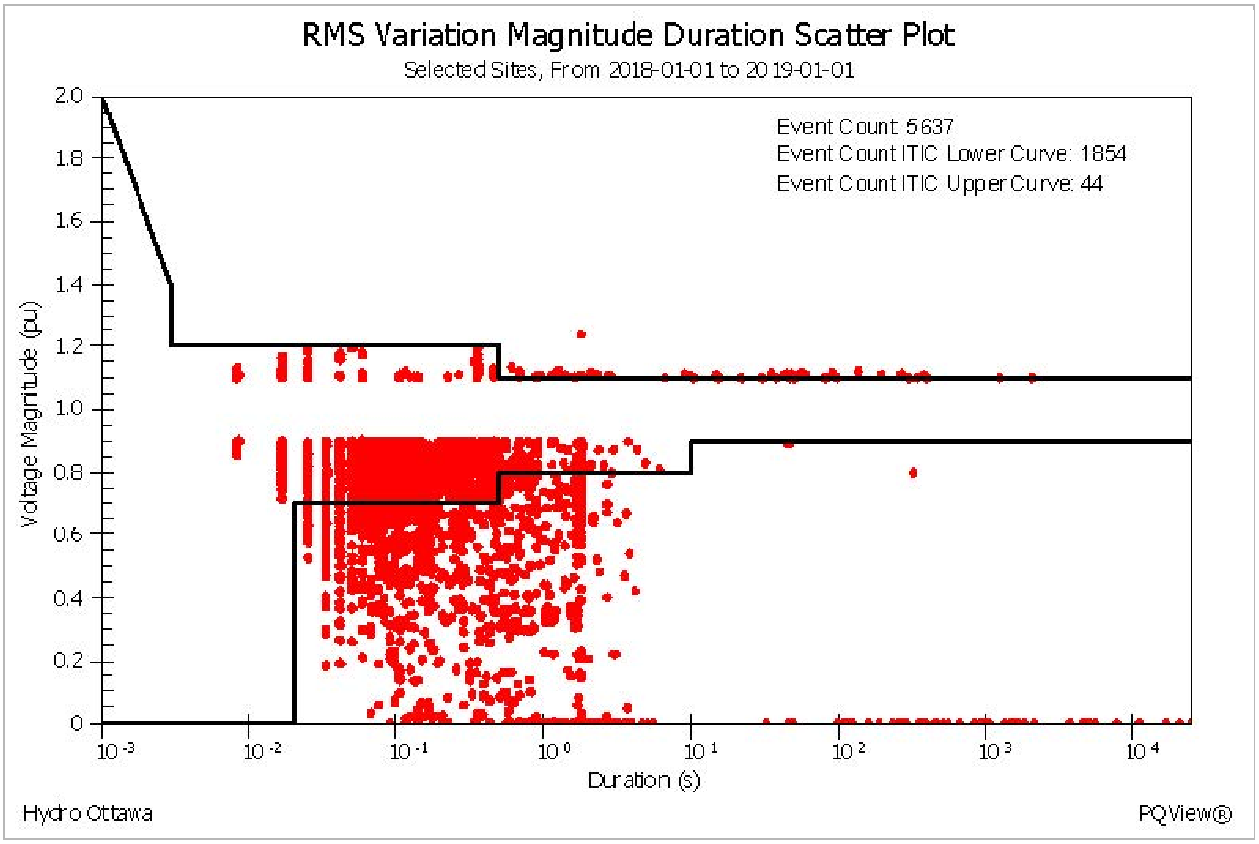
The System Average Root Mean Square ("RMS") Variation Frequency Index ("SARFI") is an indicator of system power quality which measures the average number of voltage sags or swells on the system. This index looks specifically at SARFI events that are caused by Hydro Ottawa or occur on the distribution system (i.e. excluding events originating from the transmission system or other third parties). Poor voltage is considered to be outside ±6% of the system nominal voltage and it is Hydro Ottawa's objective to maintain voltage within these tolerances and below the prohibited region of the Information Technology Industry Council ("ITIC") curve, as shown in Figure 4.6. The target is to identify areas of concern and implement corrective measures as soon as possible.

Figure 4.6 – Information Technology Industry Council Curve



As indicated in Figure 4.7, there were 5,637 events recorded in 2018. Of these, 44 fell within the prohibited region. Of the 44 prohibited events, five were due to events on Hydro Ottawa's system. There were no known customer impacts from these short duration RMS events. Hydro Ottawa continues to track and monitor SARFI events.

Figure 4.7 – 2018 Power Quality Events ITIC Curve



4.1.2. Cost Efficiency & Effectiveness

Annually, Hydro Ottawa determines the cost efficiency and labour utilization KPIs to report on the progress, efficiency, and effectiveness of its planning processes, as well as the efficiency of executing those plans. This helps to drive continuous improvement at the utility.

4.1.2.1. Cost Efficiency

On an annual basis, Hydro Ottawa uses cost efficiency as a means to monitor and report on the progress of carrying out the identified projects within the plans. This enables Hydro Ottawa to ensure the utility continues to deliver value to customers by demonstrating that it is effective in executing the capital projects deemed essential to the continued reliable operation of the distribution system.

Cost Efficiency

Cost efficiency is a measure of all planned capital projects, classified as either system renewal or system service investment categories, but excludes projects deemed as either system access or general plant and all emergency work. It is defined as the ratio of the amount of budget allocated for planned capital activities to the actual expenditures, per year. The formulation utilized appears below.

$$Cost\ Efficiency\ (\%) = \frac{Actual\ SS\ \&\ SR\ Expenditures}{Budgeted\ SS\ \&\ SR\ Expenditures} \times 100$$

Execution of planned capital projects are monitored through Hydro Ottawa's financial system. Deviations from the projected budget are administered via change request that is subject to approval on a case-by-case basis. Representatives from scheduling, construction, engineering, and design groups meet on a bi-weekly basis to prioritize and administer on-going and upcoming work. The target of the cost efficiency indicator is to achieve 100% completion of the annual planned work within the approved budget.

The yearly Cost Efficiency is shown in Table 4.8.

Table 4.8 – Cost Efficiency

KPI	Target	2014	2015	2016	2017	2018
Cost Efficiency	100%	94%	94%	94%	95%	113%

Between the years 2014 and 2017, inclusive, the targeted value for this KPI was not achieved due to re-tasking of resources to address equipment failures. In 2018, the target was exceeded due to scope changes on large projects late in the year with insufficient time to adjust other projects and programs to align with the planned budget.

4.1.2.2. Labour Utilization

On an annual basis, Hydro Ottawa uses the labour utilization KPIs to monitor and report the progress, efficiency and effectiveness of carrying out plans, as well as identifying shortfalls as areas for continuous improvement. This measure enables the utility to demonstrate efficient use of its resources through good stewardship.

Hydro Ottawa monitors labour utilization performance using productive time and labour allocation KPIs.

Productive Time

The definition of productive time is the ratio of total regular hours charged to a work order (billable) and total regular hours available per year. The formulation used appears below.

$$\textit{Productive Time} = \frac{\textit{Percent of Billable Hours}}{\textit{Total Regular Hours}}$$

This KPI is influenced by hours allocated for training, vacation, and sick time; further it does not account for work completed using overtime. Table 4.9 shows the trend of productive time for the last five years.

Table 4.9 – Productive Time

KPI	Target	2014	2015	2016	2017	2018
ProductiveTime	74%	71%	74%	74%	73%	72%

The decrease in KPI observed in 2017 and 2018 is largely due to an increase in requests for extended sick leave for surgical procedures.

4.1.2.3. Labour Allocation

The definition of labour allocation is the ratio of the percentage of labour hours used to execute capital activities and the amount of total productive time (as defined above). The intent of this

KPI is to measure the proportion of time spent on capital activities, as per annual work plans, versus time used for OM&A activities. The formulation used appears below.

$$Labour\ Allocation = \frac{Percent\ of\ \ Labour\ Time\ on\ Capital\ Activities}{Total\ Productive\ Time}$$

Labour allocation can be affected by an increase in labour hours needed to perform operations and maintenance ("O&M") activities associated with supporting aging infrastructure, resulting in a reduction in available for capital projects. Table 4.10 shows how this KPI trends for the previous five years.

Table 4.10 – Labour Allocation

KPI	Target	2014	2015	2016	2017	2018
Labour Allocation	61%	60%	61%	62%	60%	58%

The reduction observed in 2018, over 2017, results primarily from an increase in mutual aid responses undertaken in that year.

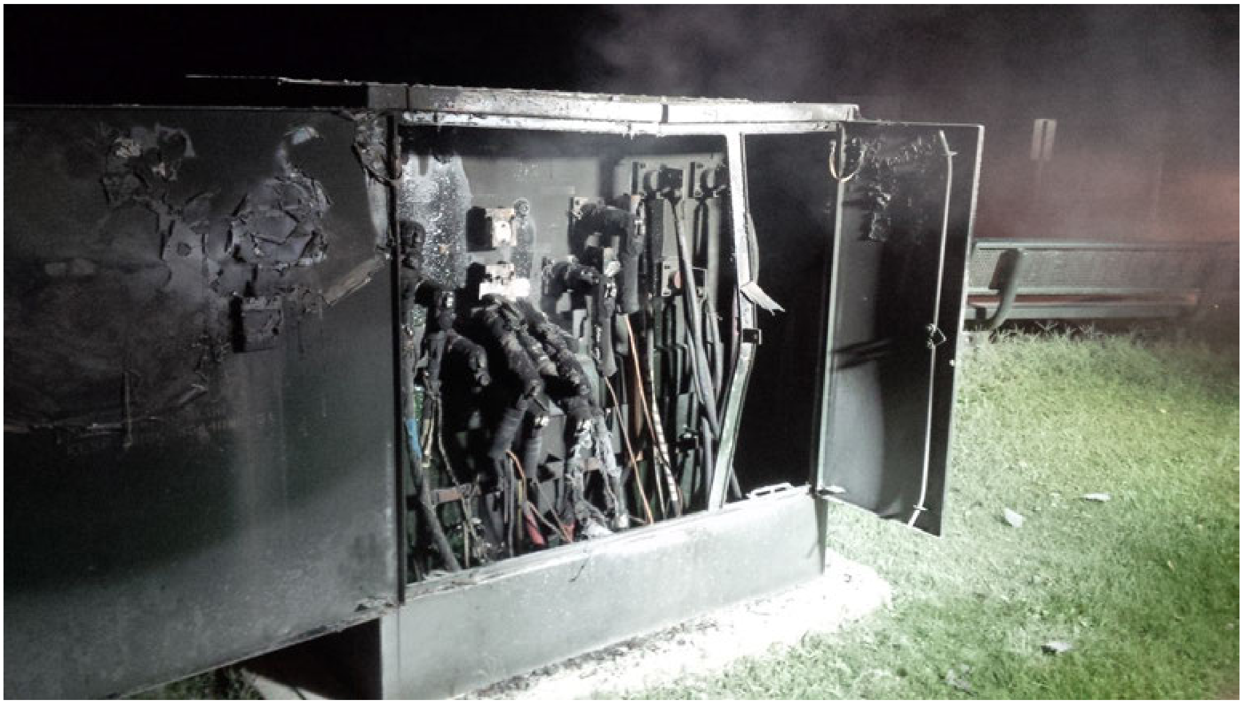
4.1.3. Asset Performance

Hydro Ottawa tracks asset performance through three metrics: defective equipment contribution to SAIFI, public safety concern notifications, and oil spilled incidents. Altogether, these metrics help Hydro Ottawa deliver on its asset management objectives. This section details these three metrics, and provides insight as to why these metrics are important tools used to mitigate risks in the distribution system.

4.1.3.1. Defective Equipment Contribution to SAIFI

The SAIFI metric is used by Hydro Ottawa to improve its levels of service, asset value, resource efficiency and compliance objectives. It allows Hydro Ottawa to identify assets that cause multiple outages and better focus its attention on issues directly affecting customers.

Figure 4.8 – Catastrophic Failure of a Three-Phase Transformer



This KPI tracks the contribution of defective equipment outages by asset class to the overall SAIFI (including MEDs) for 100 customers (SAIFI x 100). Hydro Ottawa's objective is to reduce the number of customer interruptions caused by defective equipment from year to year on a rolling basis. The yearly target is set by the average of the previous five years.

Each asset class contributes to the overall SAIFI reliability metric. Table 4.11 below details the contribution of each asset class to the SAIFI x 100.

Table 4.11 – Defective Equipment SAIFI per 100 Customers

Asset – SAIFI x 100	Target	2014	2015	2016	2017	2018
Overhead System Assets	10.13	12.73	7.89	6.70	13.69	9.58
Station System Assets	1.77	0.33	2.28	1.88	0.20	3.65
Underground System Assets	11.17	13.28	14.89	9.26	5.09	13.26

Customer interruptions due to Overhead System Assets and Underground System Assets have exhibited a relatively constant and decreasing trend, respectively, over the 2014-2018 period. Despite this positive trend, 2018 performance for Underground System Assets failed to meet the target. This was driven by aged XLPE cable failures in the Orleans area. Targeted cable renewal and expansion of the renewal program are required to ensure the positive trend is maintained.

Station System Assets performance failed to meet the target in 2018, and exhibits a slight overall increasing trend over the 2014 to 2018 window. These observations are not currently reflected in any current asset trends requiring specific interventions, as the 2018 performance was the result of a single, repairable transformer outage at Fallowfield station.

4.1.3.2. Public Safety Concerns

Public Safety Concerns

The public concerns metric is used by Hydro Ottawa to deliver on its health, safety, and environment objectives. This metric allows Hydro Ottawa to review public safety concerns on an annual basis and to identify any existing assets that may pose similar risks.

Table 4.12 shows the annual safety concerns recorded by Hydro Ottawa. The goal is to reduce this metric to zero. Hydro Ottawa works proactively to respond and undertake corrective action where required for all Public Safety Concerns received. There is no consistent trend or underlying cause for the Public Safety Concerns raised over the 2014-2018 window.

Table 4.12 – Public Safety Concerns

KPI	Target	2014	2015	2016	2017	2018
Public Safety Concerns	0	8	2	1	1	2

4.1.3.3. Oil Spilled

Litres of Annual Oil Spilled & Cost of Annual Oil Remediation

The annual oil spilled metric is used by Hydro Ottawa to improve its health, safety, and environment objectives. It allows Hydro Ottawa to track the amount of oil spilled into the environment as well as the annual cost of oil remediation.

Table 4.11 shows the annual litres of oil spilled into the environment, as well as the remediation costs. The target is to have no oil spills and zero cleanup costs.

Table 4.13 – Annual Oil Spills

KPI	Target	2014	2015	2016	2017	2018
Oil Spilled (litres)	0	958	1,133	824	1,119	1,475
Oil Remediation ($'000s)	0	695	609	799	733	1,083

Hydro Ottawa reports to the Ministry of the Environment, Conservation and Parks on the volume of oil spilled and the cost of remediation. Hydro Ottawa performs routine inspection programs on oil filled equipment and actively manages replacements to mitigate the environmental impact of oil spills.

4.1.4. System Operations Performance

Hydro Ottawa's KPIs surrounding System Operations Performance align with Asset Management Objectives for Levels of Service and Asset Value. Specifically, Hydro Ottawa monitors the operational performance of the system by tracking annual levels of station capacity, feeder capacity and system losses. This information is used to identify potential equipment upgrades ensuring that adequate capacity is available during normal system conditions and for reliable operation during system contingency in order to meet the levels of service expected by Hydro Ottawa's customers. In addition, these KPIs allow the identification of stations and feeders operating above or approaching its design ratings in order to implement the appropriate actions required to maximize the value of the distribution system assets throughout its lifecycle.

4.1.4.1. Stations Capacity

To improve System Accessibility, Stations Capacity KPIs are tracked to provide insight for larger medium- and long-term capacity needs, as well as smaller capacity deficits that may be solved through load transfers.

Figure 4.9 – Station Transformer at Terry Fox MTS

System Service projects are initiated to address issues and negative trends. Projects, in order of increasing complexity and cost, include extending distribution ties to other stations with available capacity, upgrading an existing station's planning capacity, or construction of a new station. The following KPIs quantify capacity risks through demand comparisons to a station's planning and equipment ratings and by determining if stranded load is possible during an N-1 contingency.

Stations Exceeding Planning Capacity

This KPI is defined by the percentage of stations with a summer peak operating above 100% of their planned capacity rating, as shown in the equation below.

$$Stations\ Exceeding\ Capacity\ (\%) = \frac{\#\ of\ Stations\ Exceeding\ Planning\ Capacity}{\#\ of\ Total\ Stations} \times 100\%$$

The planned capacity rating is defined as the sum of either the transformers' 10 day Limited Time Rating ("LTR") or the allowable top load rating if there is no published LTR for the remaining transformers following a single contingency loss of the largest element within the station (N-1 contingency). An N-1 contingency for a station is defined as the loss of the largest transformer within the station. For stations with a single supply and a single transformer, feeder ties from adjacent stations are used to provide contingency backup and the planning capacity rating is considered to be the rated capacity of the single unit (10 day LTR or allowable top load rating if there is no published LTR).

System capacity has not been added at the same rate as load growth in the City of Ottawa. This has resulted in 16% of the stations owned by Hydro Ottawa operating above their planning capacity rating set to ensure that adequate capacity is reserved for reliable operation during system contingency, as shown in Table 4.14 below.

Table 4.14 – Stations Exceeding Planning Capacity

KPI	Target	2014	2015	2016	2017	2018
SEPC %	≤5%	14%	13%	10%	9%	16%
Count		13	11	9	8	15

Hydro Ottawa has undertaken significant station expansion and upgrade projects which has demonstrated improvement in stations operating within their planning capacity ratings. In 2011, 24% of stations were operated beyond their planning capacity rating. This percentage has gradually declined to 9% in 2017. The proportion of stations exceeding their planning rating increased in 2018 to 16%. Further information on these stations can be found in section 7.1.1. There are near-term projects underway to address capacity limitations at seven of 15 stations exceeding planning ratings, which will return the SEPC % to a decreasing trend by 2020.

Stations Approaching Rated Capacity

This KPI is defined by the percentage of stations at or above 100% of the station rated capacity, as shown in the equation below.

$$Stations\ Approaching\ Capacity\ (\%) = \frac{\#\ of\ Stations\ Approaching\ Rated\ Capacity}{\#\ of\ Total\ Stations}$$

The rated capacity is defined as the sum of the top rating (10-day LTR or allowable flat rating should an LTR not be published) of all transformers within the station. If the loading on a transformer exceeds this limit it will cause accelerated loss of life.

Similar to the Stations Exceeding Planning Capacity index, the index for Stations Approaching Rated Capacity has improved over the last five years, as shown in Table 4.15. In 2014, two stations were being operated at or beyond rated capacity. This number has since been reduced to zero.

Table 4.15 – Stations Approaching Rated Capacity

KPI	Target	2014	2015	2016	2017	2018
SARC %	0%	2.2%	1.1%	1.1%	0%	0%
Count		2	1	1	0	0

4.1.4.2. Feeder Capacity

Hydro Ottawa plans feeder capacity based upon coincident peak loading and single (N-1) contingency. Typically, feeders have contingency pairs so that for the loss of any one feeder the entire load can be recovered by its back-up, thereby reducing the number of switching operations (and time) for recovery of full load. With this arrangement the sum of the load on any one circuit and its back-up must be less than its 8-hour emergency rating. With this philosophy two key capacity ratings need to be considered: the numbers of feeders exceeding their planning capacity and the number of feeders approaching their rated capacity.

Feeders Exceeding Planning Capacity

This KPI is defined by the percentage of feeders with a summer peak operating above 100% of the planned capacity rating, as shown in the equation below.

$$Feeders\ Exceeding\ Capacity\ (\%) = \frac{\#\ of\ Feeders\ Exceeding\ Planning\ Capacity}{\#\ of\ Total\ Feeders} \times 100\%$$

The planned capacity rating for a feeder takes three factors into consideration:

- **Coordination with lo-set instantaneous protection:** Under normal pre-contingency operating conditions, a feeder cannot be loaded above a level that would result in the lo-set instantaneous protection preventing feeder restoration (see the description below for Cold Load Pick Up).

- **Feeder Cold Load Pick Up ability:** Outage analysis indicates that the cold-load and hot-load pick up phenomenon results in loading factors approximately twice pre-contingency feeder loading at 0.2 seconds (trip time setting for lo-set instantaneous protection). See Table 4.16 for cold load pick up factors.

- **Short term (8-hour) egress cable overload capabilities:** Under normal pre-contingency operating conditions, a feeder cannot be loaded above the nominal capacity rating of the egress cable. In addition, a feeder must be capable of backing up neighbouring feeder(s) in the event of failure of supply of the neighbouring feeder or other contingency conditions. For purposes of providing back-up ability, Hydro Ottawa assumes that a feeder will be required to operate in the abnormal configuration with post-contingency loading levels for up to eight hours.

Table 4.16 – Cold Load Pick Up Factors

Voltage (kV)	Lo-set Inst. Pick Up (A)	Cold Load Factor	Feeder Load Limit (A)
4.16	1000	2	300
8.32	1200	2	300
12.47	1100	2	350
13.2	1350	2.5	400
27.6	1275	2.5	350

Table 4.17 – Cable Ratings

Voltage (kV)	Typical Egress Cable	Design Rating (A)	8hr Rating (A)
4.16	5kV 4/0 Cu PILC, buried in duct	285	330
8.32	15kV, 500 MCM Cu XLPE, direct buried	675	870
12.47	15kV, 500 MCM Cu XLPE, direct buried	675	870
13.2	15kV 500 MCM Cu PILC, duct bank	425	510
27.6	29kV, 750 MCM Al XLPE, duct bank	450	620
27.6	29kV, 1000 MCM Al XLPE, duct bank	500	685

Given the constraints outlined in Table 4.17, the rating limits presented in Table 4.18 below are used based on feeder egress cable type.

Table 4.18 – Cable Planning Ratings

Voltage (kV)	Typical Egress Cable	8-hour Loading Limit (A)	Cold Load Limit (A)	Planning Limit (A)*	Limiting Factor
4.16	5kV, 4/0 Cu PILC	330	300	300	Coordination between Lo-set instantaneous protection and cold/hot load pick-up
8.32	15kV, 500 MCM Cu XLPE	870	300	300	Coordination between Lo-set instantaneous protection and cold/hot load pick-up
12.47	15kV, 500 MCM Cu XLPE	870	350	350	Coordination between Lo-set instantaneous protection and cold/hot load pick-up
13.2	15kV 500 MCM Cu PILC	510	400	255	Ability to provide adequate back-up capability for neighbouring circuits
27.6	29kV, 750 MCM Al XLPE	620	400	310	Ability to provide adequate back-up capability for neighbouring circuits
27.6	29kV, 1000 MCM Al XLPE,	685	400	340	Ability to provide adequate back-up capability for neighbouring circuits

*Planning Limits may change from above based on specific feeder configurations.

Feeders exceeding their planning ratings are within target (≤ 10%), as shown in Table 4.19. Careful review and planning is being undertaken to ensure adequate backup is maintained to allow for secure and reliable delivery of power for customers.

Table 4.19 – Feeders Exceeding Planning Capacity

KPI	Target	2014	2015	2016	2017	2018
FEPC %	≤10%	2.5%	1.4%	1.6%	2.0%	2.8%
Count		19	11	13	17	22

Feeders Approaching Rated Capacity

This KPI is defined by the percentage of feeders at or above 90% of the rated capacity.

$$Feeders\ Approaching\ Capacity\ (\%) = \frac{\#\ of\ Feeders \geq 90\%\ of\ Rated\ Capacity}{\#\ of\ Total\ Feeders} \times 100\%$$

The rated capacity is defined as the egress cable 8-hour loading limit. If the circuits are loaded above this limit for longer than eight hours it will cause overheating and accelerated loss of life.

From 2015-2017, there were no feeders operated above 90% of their rated capacity, as shown in Table 4.20. In 2018, one feeder from Fallowfield station operated at 95% of its rated capacity. Feeder capacity needs in this area will be addressed with the construction of the new Cambrian Municipal Transformer Station ("MTS").[2]

Table 4.20 – Feeders Approaching Rated Capacity

KPI	Target	2014	2015	2016	2017	2018
FARC	0%	0.1%	0%	0%	0%	0.1%
Count		1	0	0	0	1

4.1.4.3. System Losses

Hydro Ottawa records and monitors annual system losses aiming to maintain losses within acceptable levels. An increasing trend in losses would trigger identification of investment needs to reduce losses in the system in order to meet set out levels of service.

System Losses

Distribution System losses are defined in the *Distribution System Code* as: "energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows." Table 4.21 shows the historical performance over the last five years.

Table 4.21 – System Losses

KPI	Target	2014	2015	2016	2017	2018
Losses %	≤ 4.00%	2.71%	3.32%	3.04%	2.97%	3.20%

[2] Cambrian MTS was previously named South Nepean MTS.

Losses remained below the target of 4%. Hydro Ottawa continues to work to reduce system losses through better system planning and by upgrading or replacement of equipment.

4.2. UNIT COST METRICS

The unit cost metrics identify the associated capital and O&M costs that Hydro Ottawa has incurred per customer, kilometers of line, and peak capacity, as prescribed in Appendix 5-A of the Chapter 5 Filing Requirements (see Attachment 2-4-3(C)). Table 4.22 lists the various unit costs and indicates that Hydro Ottawa's per unit costs in 2018 were above the five-year average.

Table 4.22 – Unit Cost Metrics (as per Appendix 5-A)

Metric Category	Metric	1-Year Cost (2018)	5-Year Average (2014-2018)
Cost	Total Cost per Customer	$803	$664
	Total Cost per km of Line	$46,678	$38,634
	Total Cost per MW	$186,762	$158,146
CAPEX	Total CAPEX per Customer	$544	$412
	Total CAPEX per km of line	$31,616	$23,970
O&M	Total O&M per Customer	$259	$252
	Total O&M per km of line	$15,062	$14,663

In addition to these metrics, Hydro Ottawa has sought to enhance its evaluation of unit costs through the commissioning of a dedicated benchmarking report on unit cost performance. The utility retained a third-party expert to compare the utility's unit costs in select asset categories and operations, maintenance and administration ("OM&A") programs to a sample group of peer utilities. On the whole, Hydro Ottawa compared favourably to the peer group. For information on this unit cost report, please see Exhibit 1-1-12: Benchmarking. The report in its entirety can be viewed in Attachment 1-1-12(B): Hydro Ottawa Unit Costs Benchmarking Study.

4.3. HISTORICAL RELIABILITY PERFORMANCE ANALYSIS

Hydro Ottawa's objective is to improve the System Reliability Performance Indicators from year to year. Hydro Ottawa utilizes its Capital Expenditure Process (outlined in section 5.2) to enhance its ability to prioritize the replacement of end-of-life assets. Testing, inspection, and maintenance programs, as defined in section 6.2, will continue to be essential to ensure equipment continues to operate as expected and to identify corrective actions to be performed. The utility continually assesses new ways of operating to increase system resilience, and reduce restoration times.

Details of Hydro Ottawa's historical reliability performance metrics can be found in section 4.1.1.2 - System Reliability.

4.3.1. Reliability Performance by Cause Code

Hydro Ottawa records all outage causes and monitors the primary causes for trends. Hydro Ottawa follows the OEB's definitions for primary causes as defined in the *Electricity Reporting and Record Keeping Requirements* ("RRRs"). Where trends are identified, Hydro Ottawa performs detailed analysis into the root causes to assess risk and identify investment needs.

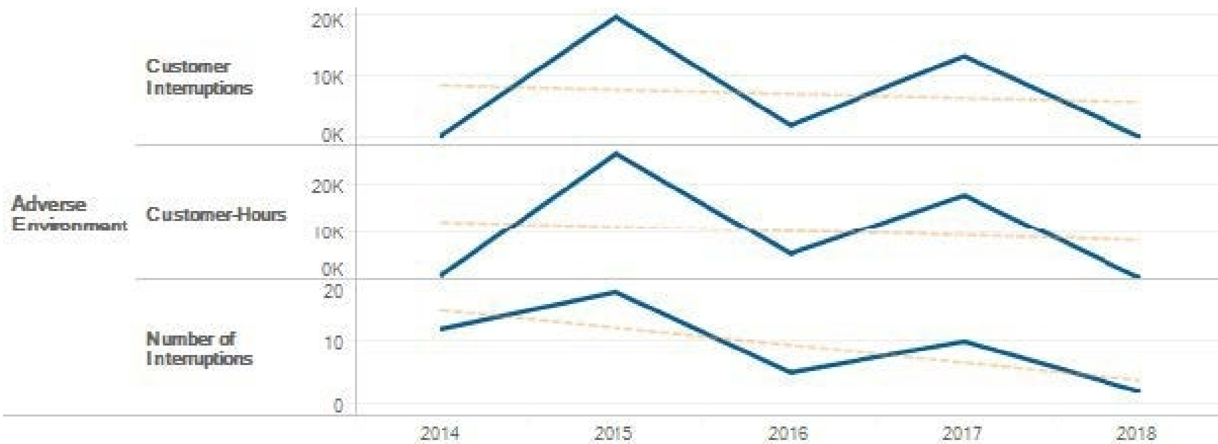
Table 4.23 below captures the historical outage information by primary cause.

Table 4.23 – Reliability Performance by Cause Code

Primary Cause		2014	2015	2016	2017	2018
Adverse Environment	Number of Interruptions	12	18	5	10	2
	Customer Interruptions	287	19,935	1,960	13,338	167
	Customer-Hours	870	26,612	5,389	17,794	378
Adverse Weather	Number of Interruptions	72	29	40	67	101
	Customer Interruptions	43,110	6,715	17,467	27,839	113,916
	Customer -Hours	117,892	8,693	35,612	93,957	727,176
Defective Equipment	Number of Interruptions	276	210	200	364	369
	Customer Interruptions	88,483	82,008	58,747	62,993	89,393
	Customer -Hours	120,603	113,818	94,802	109,659	133,733
Foreign Interference	Number of Interruptions	146	124	155	163	186
	Customer Interruptions	27,097	16,547	32,989	36,021	33,803
	Customer -Hours	28,608	23,829	35,659	36,999	38,512
Human Element	Number of Interruptions	24	19	20	33	31
	Customer Interruptions	32,295	34,456	27,288	38,459	21,144
	Customer -Hours	38,396	36,966	5,624	42,095	14,676
Lightning	Number of Interruptions	37	17	32	33	27
	Customer Interruptions	29,279	11,957	24,130	15,711	21,822
	Customer -Hours	77,122	23,319	18,739	6,919	22,298
Loss Of Supply	Number of Interruptions	28	24	11	17	52
	Customer Interruptions	71,072	214,891	58,466	66,181	278,727
	Customer -Hours	23,371	148,471	26,002	23,557	6,436,022
Scheduled Outage	Number of Interruptions	1,068	1,200	1,031	863	762
	Customer Interruptions	24,851	34,162	31,446	20,436	20,103
	Customer -Hours	76,844	101,699	97,984	62,770	40,273
Tree Contacts	Number of Interruptions	73	99	88	191	157
	Customer Interruptions	15,652	16,253	26,006	39,675	54,923
	Customer -Hours	24,950	25,578	58,121	115,929	183,236
Unknown/Other	Number of Interruptions	34	52	37	39	49
	Customer Interruptions	11,751	18,802	32,593	17,961	43,021
	Customer -Hours	18,575	10,639	16,156	10,625	19,463

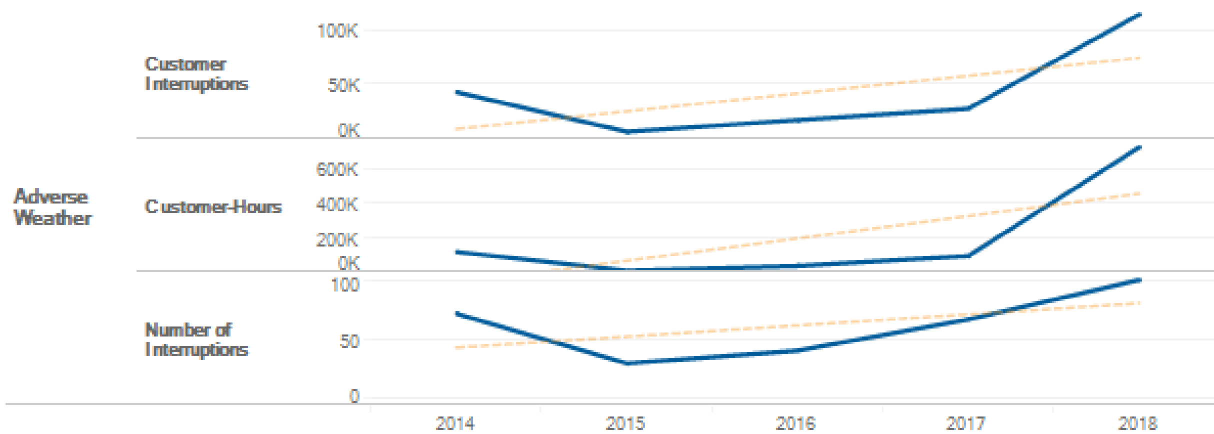
Outages due to Adverse Environment are on a declining trend over the last five years, as seen in Figure 4.10 below. Historical outages have been largely due to pole fires occurring as a result of salt contamination on insulators from the City of Ottawa winter de-icing efforts. Hydro Ottawa has mitigated these risks by performing a bi-annual insulator wash program to clean insulators of salt and other contamination. In addition, renewal and replacement of insulators with polymer insulators which are less susceptible to this failure mode continues to reduce the overall risk profile.

Figure 4.10 – Adverse Environment Historical Trend



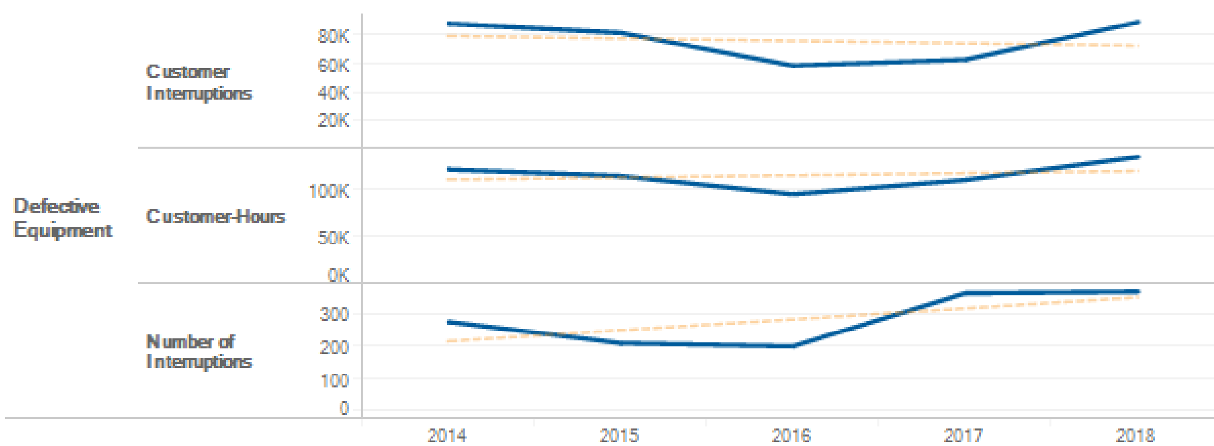
Outages due to Adverse Weather are on an increasing trend over the last five years, as seen in Figure 4.11 below. Historical outages have been largely due to high winds and freezing rain weather. Many of the extreme weather events have resulted in the classification of MEDs as further defined in section 4.3.2. Hydro Ottawa is evaluating the impact and risk of future climate changes on its assets.

Figure 4.11 – Adverse Weather Historical Trend



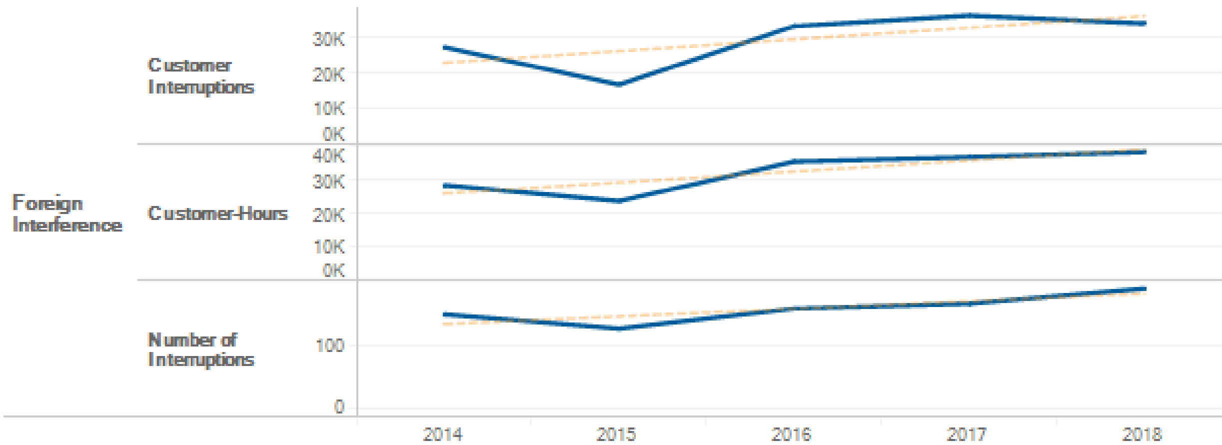
Outages due to Defective Equipment are on an increasing trend over the last five years. However, the impact of these outages on number of customers interrupted and customers-hours are relatively constant, as seen in Figure 4.12. Hydro Ottawa has been mitigating risk due to asset failures by prioritizing renewal investments and targeting asset classes having a higher impact.

Figure 4.12 – Defective Equipment Historical Trends



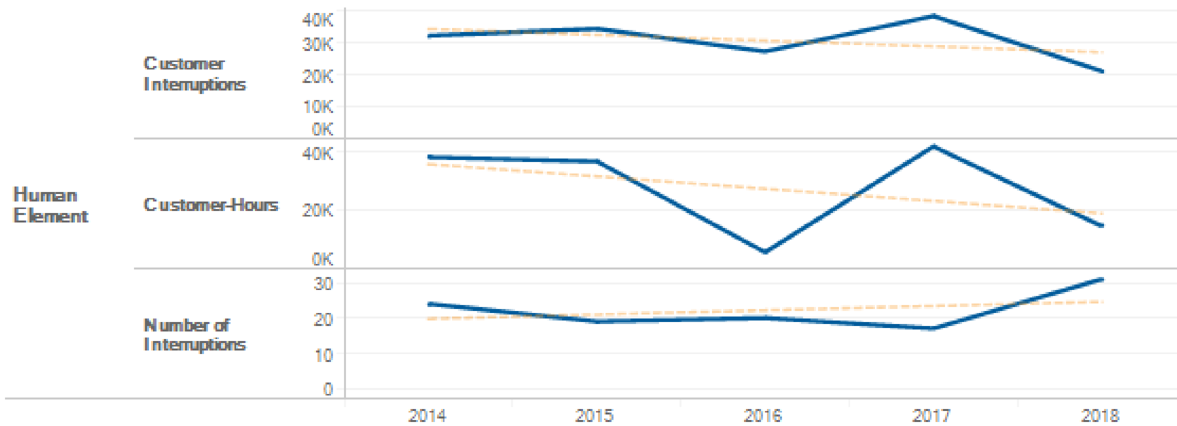
Outages due to Foreign Interference exhibited an increasing trend over the last five years, as seen in Figure 4.13 below. However, the 2013 number of Foreign Interference interruptions were nearly equivalent to the 2018 outcome, suggesting a long-term level trend. Historical outages have been largely due to animal contacts and foreign objects contacting the lines. Hydro Ottawa's standard for new construction requires the incorporation of animal guards. In addition, legacy construction is being retrofitted in a targeted and prioritized manner.

Figure 4.13 – Foreign Interference Historical Trends



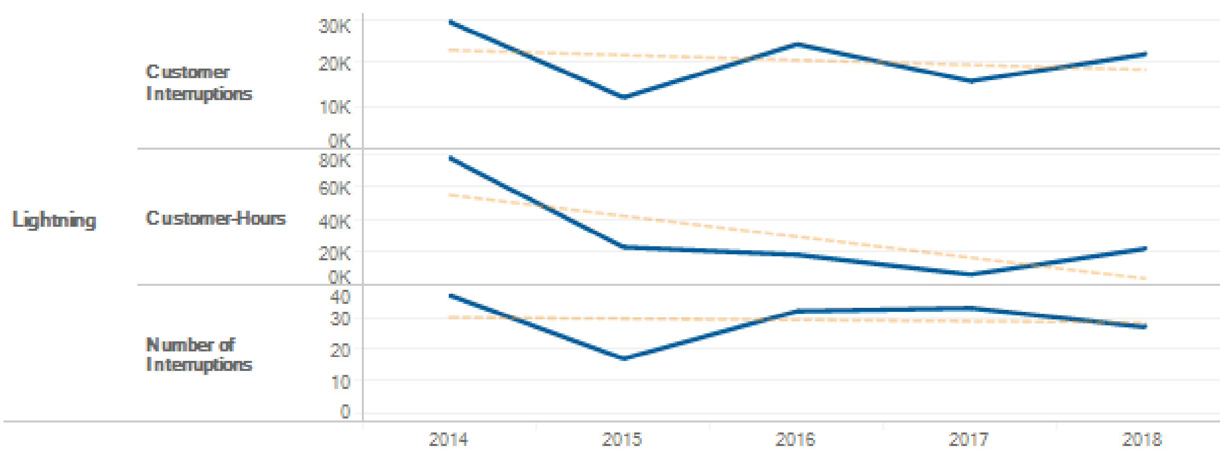
Outages due to Human Element are on a relatively constant trend over the last five years. However, the impact of these outages are on a declining trend, as seen in Figure 4.14 below. Historical outages have been largely due to incorrect records and switching errors. Each incident is reviewed and appropriate actions such as records updates, procedural changes, or staff training are undertaken to prevent reoccurrence.

Figure 4.14 – Human Element Historical Trends



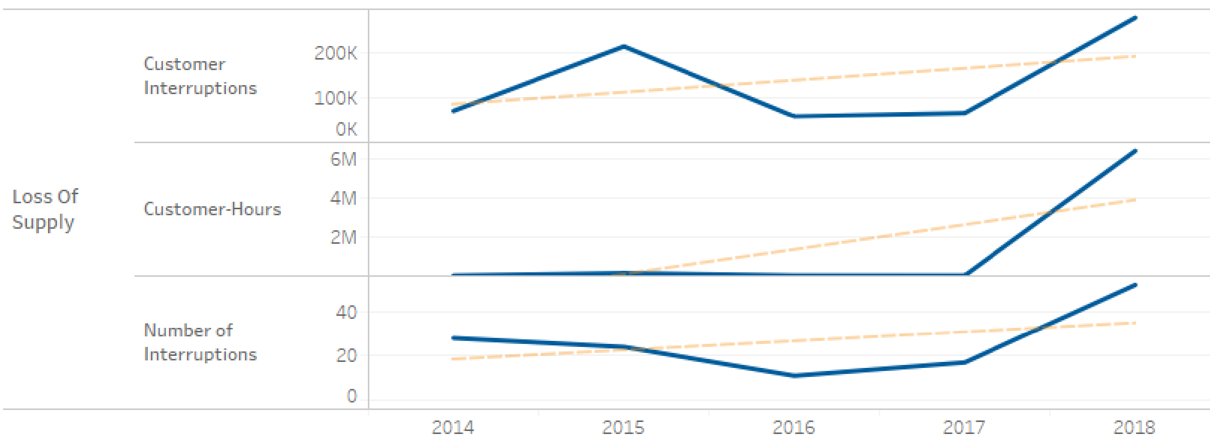
Outages due to Lightning are on a constant trend. However, the impact is on a declining trend, as seen in Figure 4.15. Hydro Ottawa mitigates sustained outages through its system design and application of lighting protection and shielding.

Figure 4.15 – Lightning Historical Trends



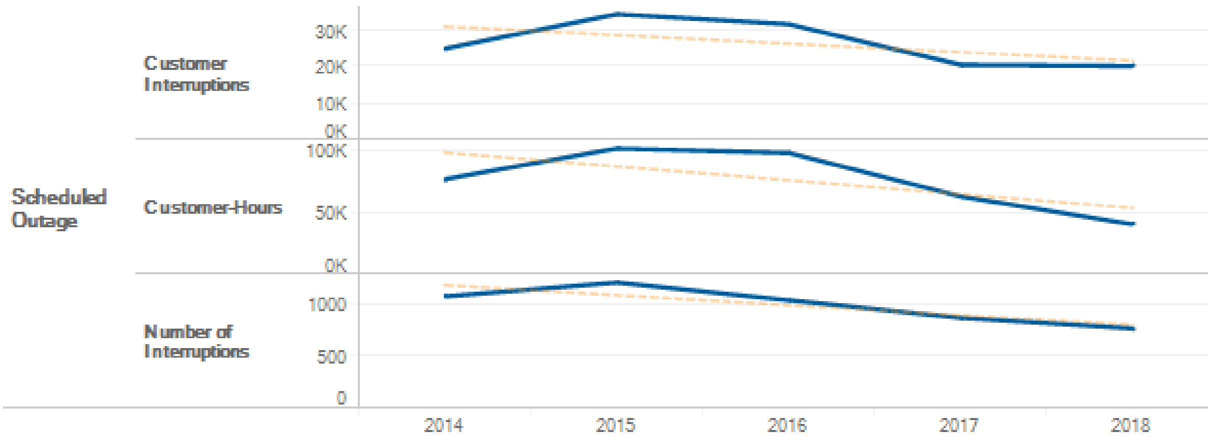
Outages due to LoS increased significantly in 2018. This was largely attributable to the tornado event that occurred in September 2018. From 2014-2017, LoS had a relatively constant frequency and customer impact. Hydro Ottawa works proactively to identify and address supply reliability issues whether working with the transmitter, Hydro One Networks Inc. ("HONI"), to address supply issues, or mitigating their impact through distribution interties.

Figure 4.16 – Loss of Supply Historical Trends



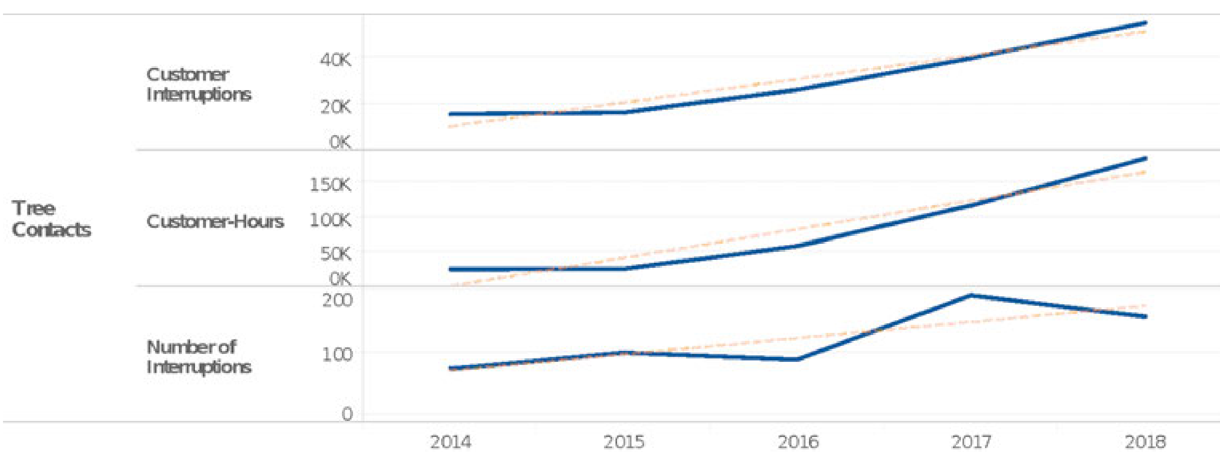
Outages due to Scheduled Outages are on a declining trend over the last five years, as seen in Figure 4.17 below. Hydro Ottawa has made the effort to reduce the impact on customers when planning outages. This includes installing temporary switches and using live-line techniques to minimize the number of customers affected.

Figure 4.17 – Scheduled Outage Historical Trends



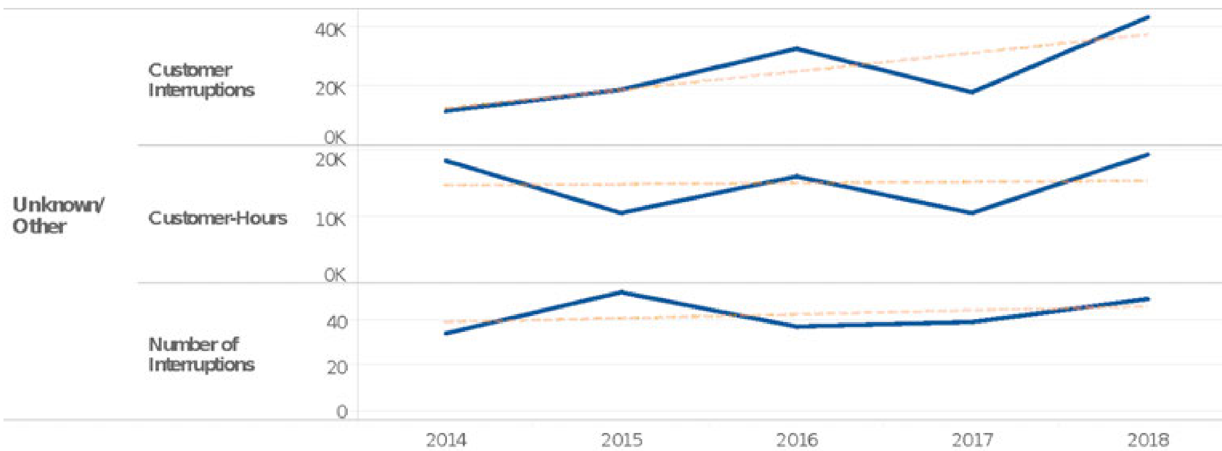
Outages due to Tree Contacts are on an increasing trend over the last five years, as seen in Figure 4.18. The increasing trend is attributed largely to an increase in large tree limbs, and full trees falling into wires from outside the powerline corridor, typically as a result of extreme weather events. Hydro Ottawa has reviewed and continues to evaluate the performance of its vegetation management program. The utility is increasingly working with customers to address risk trees outside the trim zones wherever possible.

Figure 4.18 – Tree Contact Historical Trends



Outages due to Unknown/Other are on a slightly increasing trend over the last five years, as seen in Figure 4.19. Hydro Ottawa strives to identify the root causes of outages through line patrols and fault point analysis.

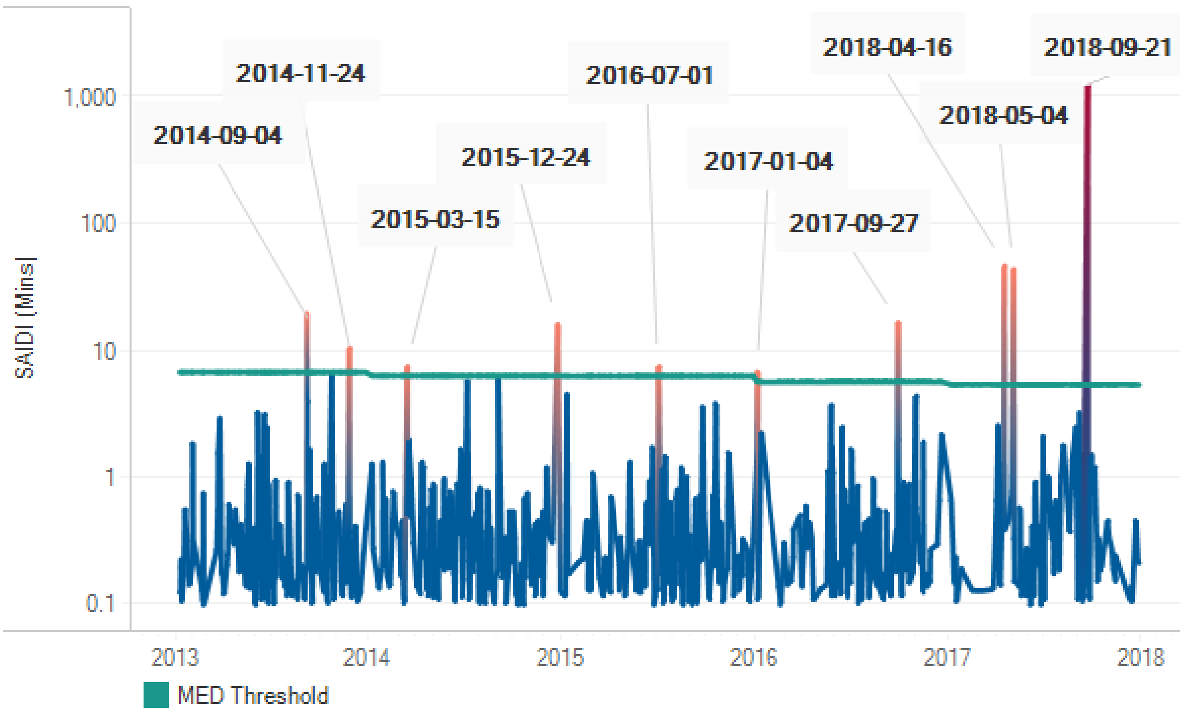
Figure 4.19 – Unknown/Other Historical Trends



4.3.2. Major Events

Hydro Ottawa uses the IEEE standard *"1366 – IEEE Guide for Electric Power Distribution Reliability Indices"* to identify MEDs. The threshold for the classification of a MED each year is based on the previous five years of daily SAIDI values. Over the last five years, Hydro Ottawa has experienced 10 MEDs, as illustrated in Figure 4.20 below. There was a notable increase in the severity of MEDs in 2018, relative to the preceding four years.

Figure 4.20 – Major Event Day Threshold



A description of each MED over the last five years can be found below in Table 4.24.

1 **Table 4.24 – List of Major Event Days**

Date	Event Description
2014-09-04	On September 4th, 2014, a lightning storm hit the City of Ottawa affecting 26,890 customers for a total of 106,189 customer-hours.
2014-11-24	On November 24th, 2014, high winds caused outages to 13,565 customers for a total of 56,298 customer-hours.
2015-03-15	Hydro Ottawa experienced an MED due to pole fires that caused 2 large outages and affected 15,864 customers for a combined total of 40,487 customer hours. The larger of the two outages was a result of a HONI pole that caught fire and caused a loss of supply to Hydro Ottawa customers in the south end of the City. The second outage was a result of a Hydro Ottawa pole catching fire in the core of the City. Both outages were restored within 5 hours.
2015-12-24	Hydro Ottawa experienced an MED primarily due to two large events that affected 42,401 customers for a combined total of 87,025 customer hours. The first large event was a defective egress riser cable at Nepean TS which caused an outage on the 22M28 and A9M2 44kV sub-transmission lines that affected 4,477 customers for a combined total of 11,791 customer hours. The second large event was the loss of HONI`s S7M 115kV transmission line due to extreme wind that affected 34,297 customers for a combined total of 70,730 customer hours. Extreme winds caused a number of other smaller outages to customers across the service territory. All customers affected were restored by the end of day on December 24th.
2016-07-01	The Ottawa area experienced high winds and lightning which caused multiple outages throughout the city. The high winds caused trees and branches to fall, breaking conductor and poles, which resulted in lengthy restoration efforts. Many lightning events also caused circuits to trip momentarily and some remained off until crews could assess if any damage was present. A total of 12,297 customers were affected during this event.
2017-01-04	Hydro Ottawa's service territory experienced a mix of heavy wet snow and freezing rain. The result was many downed trees and limbs making contact with the distribution system. Restoration efforts were prolonged due to clearing of vegetation prior to restoring. A total of 19,130 customers were affected during this event.
2017-09-27	A micro-burst of wind hit just west of downtown Ottawa resulting in many downed trees and limbs making contact with the distribution system and some broken poles. Restoration efforts were prolonged due to clearing of vegetation prior to restoring. A total of 11,391 customers were affected during this event.
2018-04-16	Hydro Ottawa's service territory experienced freezing rain and windy conditions resulting in outages across the city. A total of 55,101 customers were affected during this event.
2018-05-04	Heavy wind gusts across the service territory caused multiple outages from falling trees and broken pole lines. A total of 63,869 customers were affected during this event.
2018-09-21	Tornadoes (class EF-2 and EF-3) with winds up to approximately 260 km/h touched down in the Ottawa area which caused extensive damage to pole lines and station equipment. Approximately 216,000 customers were affected during this event.

Figure 4.21 – Downed Pole Line Following September 2018 Tornado Event

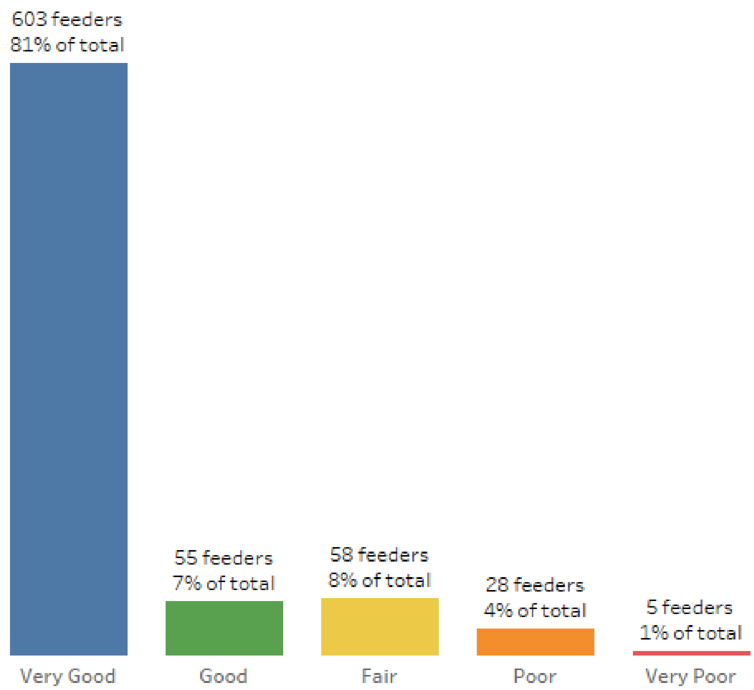
4.3.3. Worst Feeder Analysis

Annually, Hydro Ottawa reviews the performance of its feeders with respect to their impact on customer interruptions, customer hours, and frequency of outages. A Feeder Performance Index ("FPI") for each feeder is derived from these criteria and is assigned a ranking. This condition ranking allows for annual performance review and trending while identifying which feeders would most benefit from targeted investments.

Feeders identified as having "Very Poor" performance will be reviewed and have an action plan developed to identify recommendations for improvements. The performance of these feeders will be tracked for a period of five years. If a feeder continues to perform poorly in following years, another review will be performed to ensure that the recommendations and actions have appropriately addressed the issues identified.

As outlined in Figure 4.22, there were five feeders identified as having "Very Poor" performance in 2018. This represents 1% of all feeders. Long-term and short-term fixes to the reliability of these poor performing feeders are implemented through the Worst Feeder Betterment Program.

Figure 4.22 – 2018 Feeder Condition



4.4. HISTORICAL PERFORMANCE IMPACT ON DSP

Hydro Ottawa uses the KPIs, as described in section 4.1 above, to measure continuous improvement in Customer Oriented Performance, Cost Efficiency & Effectiveness, Asset Performance, and System Operations Performance. These KPIs are quantitative measures used to monitor the effectiveness of Hydro Ottawa's planning processes, efficiencies in carrying out work, as well as to identify shortfalls and areas for continuous improvement.

Customer Oriented Performance

Hydro Ottawa continuously seeks feedback from customers on their satisfaction with the services provided by the utility. This feedback is greatly impacted by the distribution system's service reliability. Based on historical performance of Customer Oriented KPIs, Hydro Ottawa has made the following changes:

- The Touch Logic survey questions changed from six to four questions in late 2018 to better reflect the call centre performance.
- Based on 2017 FEMI results, Hydro Ottawa initiated investment projects to address the causes of outages, such as localized cable replacement, overhead switch replacement, targeted vegetation management, and the installation of line spacers.
- In alignment with the majority of residential and small business customers having expressed support for an accelerated approach to investments in both the overhead and underground distribution system, Hydro Ottawa plans to continue focused investment in the pole and cable renewal programs.

Asset Performance

Asset Performance metrics help Hydro Ottawa deliver on its asset management objectives. Based on historical performance of Asset Performance, Hydro Ottawa has made the following changes:

- Defective Equipment Contribution trends are reviewed on an annual basis to establish a target for the frequency and the quantity of assets to be replaced.
- Increased frequency of customer interruption due to cable failure is driving increased investment in the cable renewal program.
- Recent Oil Spilled trends are showing more leaking residential underground transformers, which have increased the cost of remediation. This emphasizes the importance of active inspection and replacement of underground transformers to mitigate this environmental impact.

System Operation Performance

Hydro Ottawa monitors the operational performance of the system to identify potential equipment upgrades, thereby ensuring that equipment operates within design ratings and adequate capacity is available. Based on historical performance of System Operations metrics, Hydro Ottawa has made the following changes:

- From 2015-2017, Fallowfield MTS was the one station approaching rated capacity. As a result, plans were put in place to transfer load to adjacent stations in order to decrease loading levels in the short term. The construction of the new station in the South Nepean area will bring loading at this station within acceptable levels.
- Plans for addressing stations and feeders exceeding planning capacity are described in section 7 - System Capacity Assessment.

4.5. REALIZED EFFICIENCIES DUE TO SMART METERS

Hydro Ottawa began the deployment of smart meters in 2006 and concluded in 2010. The smart meter network provides several key advantages over the older mechanical meter fleet, as described below.

4.5.1. Monthly Billing Cycles

The largest advantage of smart meters is that Hydro Ottawa now receives daily meter reads for every meter in its fleet. This has facilitated the move to monthly billing cycles as opposed to billing every two months. This increases Hydro Ottawa's level of customer service by smoothing out the billing cycle and improving the predictability of customers' bills. Customers are able to adjust consumption patterns based on load changes on a monthly basis rather than bi-monthly.

4.5.2. Meter Health Monitoring

Smart meters provide daily reports on meter health statistics enabling Hydro Ottawa to identify defective meters as the failures occur. Historically, a slow or failed mechanical meter may not have been detected until it was retrieved for reverification (an event which may not occur for several years). This contributes to Hydro Ottawa's financial strength and security by ensuring that the meter fleet is accurately measuring power distribution. Ensuring that the meter fleet is functioning properly improves confidence on the part of customers that they are being billed appropriately. Table 4.25 identifies the number of meter and metering installation defects that Hydro Ottawa has discovered through these remote meter health reports.

Table 4.25 – Metering Irregularities Discovered Via Smart Meter Reporting

Type of Defect	2014	2015	2016	2017	2018
Defective Primary Fuses	11	19	13	14	17
Unmetered Power Diversion	0	2	1	0	1
Defective Meters	701	652	604	663	538

4.5.3. Outage Management Functionality

Due to an early adoption of the provincial smart meter initiative, Hydro Ottawa's smart meters have very limited last gasp functionality. In 2006, the self-reporting technology offered limited functionality. As such, Hydro Ottawa relies on alternate outage management tools to determine the scope and magnitude of outages. However, the System Office has the ability to routinely call, or "ping", individual meters to assess the effects of restoration efforts. A meter response indicates the repair was successful, no response indicates that there may be additional issues with the supply. Planned implementation of a Distribution Management System incorporating improved communication links to collectors will allow groups of meters to be called simultaneously and enable a more expedient confirmation of the extent of an outage. Furthermore, strategic installation of meters with last gasp functionality will allow Hydro Ottawa to leverage the self-diagnostic technology while avoiding a full scale replacement.

4.5.4. Smart Meter Data and Analytics

A significant advantage of smart meters is the amount of data that they provide. Hydro Ottawa has developed analytical tools to assess system performance. Smart meter data enables access to transformer and circuit loading patterns with granularity down to an hourly interval.

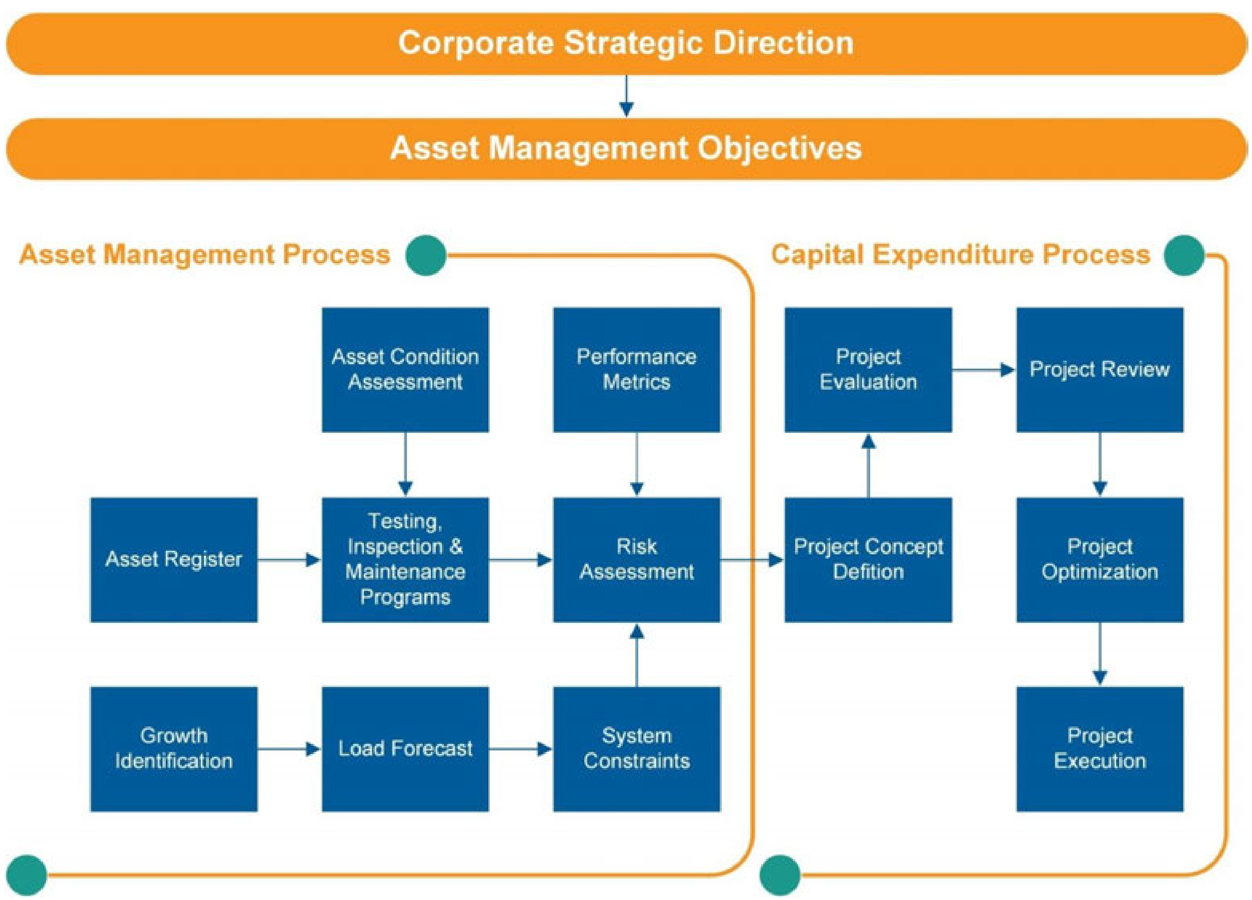
Hydro Ottawa has developed tools that aid in the detection and prediction of unmetered power diversion, abnormal voltage profiles and system losses. The utility identified a signature pattern for failed primary meter fuses. An algorithm uses this signature to flag suspect fuses on a weekly basis which are then investigated. Hydro Ottawa has discovered many defective primary metering fuses which otherwise may have gone undetected for several years and which may have ultimately resulted in significant financial losses.

5. ASSET MANAGEMENT & CAPITAL EXPENDITURE PROCESS

This section speaks to the components of Hydro Ottawa's Asset Management and Capital Expenditure processes which are used to translate the asset and system needs into investments that will deliver on the Asset Management Objectives. For each process, details are provided on the tools and methods used, inputs and outputs of information, and how opportunities are identified to coordinate for cost effectiveness from good planning.

Hydro Ottawa's Asset Management and Capital Expenditure Processes are shown in Figure 5.1.

Figure 5.1 – Asset Management & Expenditure Process



5.1. ASSET MANAGEMENT PROCESS

The Asset Management Process is rooted in understanding the current and future risks of the assets and systems. Starting with the translation of *2016-2020 Strategic Direction* into Asset Management Objectives (see section 3 - Asset Management Strategy & Objectives for more details), Hydro Ottawa's Asset Managers identify the requirements for data collection, analysis, and risk assessment. Information flows from an established Asset Register to evaluate each asset to determine potential risks and opportunities for investments.

The sub-sections below outline the main components of the Asset Management Process:

- Asset Register
- Asset Condition Assessment
- Testing, Inspection & Maintenance Programs
- Service Quality
- Growth Identification
- Load Forecast
- System Constraints
- Risk Assessment & Review

5.1.1. Asset Register

Hydro Ottawa maintains electronic repositories to store its technical, testing, inspection and maintenance information, and geographic data for most of its distribution and station assets (buildings and other non-power delivery assets are excluded). These repositories allow the data to be collected, reported, and queried in a manner that enables efficient dissemination and reporting of information on Hydro Ottawa's assets.

The system of record for Hydro Ottawa's power delivery assets is the Geographical Information System ("GIS"), based on Intergraph's G/Technology platform. With minor exceptions (i.e. secondary conductors in the downtown core), it forms a complete repository of Hydro Ottawa's assets used within its stations and distribution system. These exceptions do not reduce the effectiveness or usability of GIS as they are few in number and typically do not bring additional clarity during analysis. The missing data can be readily retrieved elsewhere if the need arises.

Hydro Ottawa's GIS is used to store, query, and provide reports to enable the analysis and development of investment plans. The data kept in the system is continuously improved through feedback from field staff and data collected through inspection programs. Using a graphical interface, it enables users to view distribution assets on a geo-referenced map showing location, technical nameplate data, and assess their relationship to other nearby assets, including electrical connectivity and relation to civil structures. Further, this system is used by resources in the field while collecting asset condition data before storing it within the same repository.

For Hydro Ottawa's Station assets, the PowerDB system is used for the collection of testing, inspection, and maintenance data as it allows for more complex collection forms. Technical data is stored through customized forms for each asset class and maintenance activity. This technical data can then be exported for further analysis, and is used as input into the health index formulation for specific assets described in section 5.1.2. The geographic information on each station is stored in the GIS. For more information about the Power DB and GIS databases, please refer to Appendix D of Hydro Ottawa's Strategic Asset Management Plan (Attachment 2-4-3(G)).

5.1.2. Asset Condition Assessment

Hydro Ottawa uses health index scores for its assets to rate their condition and indicate a probability of failure. The utility consulted with industry experts in the development of its scoring formulation, which is a weighted addition of a number of degradation factors to determine an overall health index score. The health index is an indicator of an asset's condition and remaining life and is assigned a score from 100 to 0. A new asset will have a health index of 100, while an asset in very poor condition would have a health index below 30.

Table 5.1 below presents the health index ranges, corresponding asset condition, and the required action generally associated with each health index.

Table 5.1 – Asset Condition Based on Health Index

Health Index	Condition	Description	Requirements
85–100	Very Good	Some aging or minor deterioration of a limited number of components	Normal maintenance
70–85	Good	Significant deterioration of some components	Normal maintenance
50–70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on criticality
30–50	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate considering risk and consequences of failure
0–30	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk; replace or refurbish based on assessment

To determine the health index for a given asset, a mathematical formulation specific to the asset under consideration is used to convert various data points that describe the asset's condition down to a single value. These values are then used to prioritize asset replacement, when warranted, and can also be used to determine the probability of instantaneous failure associated with each asset. The probability of failure is determined through a series of lookup tables that equate asset condition to its instantaneous probability of failure.

Hydro Ottawa has assessed the maturity of its Asset Condition Assessment implementation by a third party. The summary of this assessment can be found in Attachment 2-4-3(M): Asset Condition Assessment - Third Party Review. Overall, the third party found that Hydro Ottawa's ACA framework utilized robust formulations that are in alignment with best practices, and that it was tightly integrated with Hydro Ottawa's broader Asset Management related processes, procedures, and outcomes.

5.1.3. Testing, Inspection, & Maintenance Programs

Hydro Ottawa's planned testing, inspection, and maintenance programs are the utility's primary means of collecting condition data used to calculate the health index of assets and to identify corrective actions to ensure continued reliable operation.

Hydro Ottawa's planned programs can be divided into three groups:

1. **Predictive**: assessing the condition of the asset
2. **Preventative**: maintaining the condition of the asset
3. **Corrective**: improving the condition of the asset

Predictive programs collect technical details, testing, and inspection data used to identify assets in need of corrective actions while determining the asset's overall condition. These programs use a combination of inspection techniques depending on the asset type being considered and the failure mode(s) that pose an increased risk to safety, reliability, or the environment. The deployment of communication and sensors on certain new or upgraded assets provides the ability to monitor the condition of assets and collect operational data in real-time. This can reduce or eliminate the need for predictive programs to collect asset data. Furthermore, the ongoing monitoring can support the eventual transition from time-based to condition-based maintenance. Details of Hydro Ottawa's implementation of cost effective modernization of the distribution system can be found in section 5.5.

Preventative programs maintain the existing condition of the asset. Some asset types require regular maintenance activities that are time-based, while other assets are maintained after a certain number of operations to ensure that it will continue to operate as designed. These activities include cleaning, tensioning, tightening, calibrating, and realigning various components.

Corrective programs improve the condition of the assets by repairing, replacing, or refurbishing various defective or degraded components. This mitigates the need for replacing the asset by extending the expected operational life.

Details of Hydro Ottawa's asset specific testing, inspection, and maintenance practices can be found in section 6.2 - Asset Lifecycle Optimization Policies & Practices.

Information collected through the inspection, maintenance, and testing programs is stored in the Asset Register as defined in section 5.1.1.

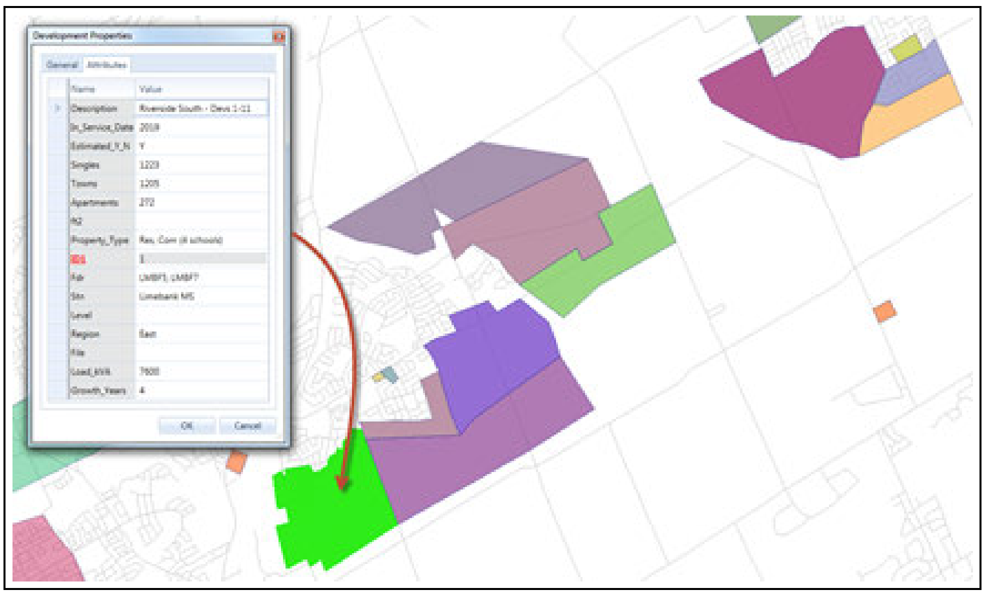
5.1.4. Growth Identification

An important predecessor to load forecasting is the ability to identify areas of potential load growth. To ensure that Hydro Ottawa can continue to supply existing and new growth through its service territory, two primary processes are used to identify growth: the City of Ottawa's development application process and Hydro Ottawa's service request process.

Hydro Ottawa is actively engaged in the City of Ottawa's development application process which allows for input and understanding of the City's land use policy through the Official Plan and supporting plans such as community design plans, transportation master plan, and infrastructure master plan. Changes to land use policy will typically have a long-term impact (i.e. greater than five years) on growth opportunities and be more wide reaching throughout the City of Ottawa. Hydro Ottawa is also actively engaged in the implementation of the land use policies by reviewing site plans, subdivision plans, and zoning amendments. Proposals from the implementation of the land use policies are typically short-term (one to two years) to medium-term (two to five years), and are localized to specific areas of the City.

Hydro Ottawa captures this information through GeoMedia, a GIS tool used to record sources of growth and track the progress of current developments, as shown in Figure 5.2 below. The mapping tool plots the impacted area of developments discovered through the growth identification process and stores key information on when the developments will impact the system. This information includes the impacted feeder and station, an estimated in-service date, anticipated load, and the number of years for which the growth is expected to increase. The information stored within the GeoMedia database is then extracted on an annual basis from which station growth forecasts are created and system sustainment projects are created.

Figure 5.2 – GeoMedia Growth Forecasting Database



The service request process consists of developers requesting connection to Hydro Ottawa's system. These can range from general services and residential services to commercial service and large developments. These developments include connection requests for projects previously identified through the development application process.

Hydro Ottawa works closely with developers within its service territory to support early identification of required service size and timing of line additions or expansion within these growth areas. This engagement enables these developments and supports Hydro Ottawa load forecasting for capacity investment planning.

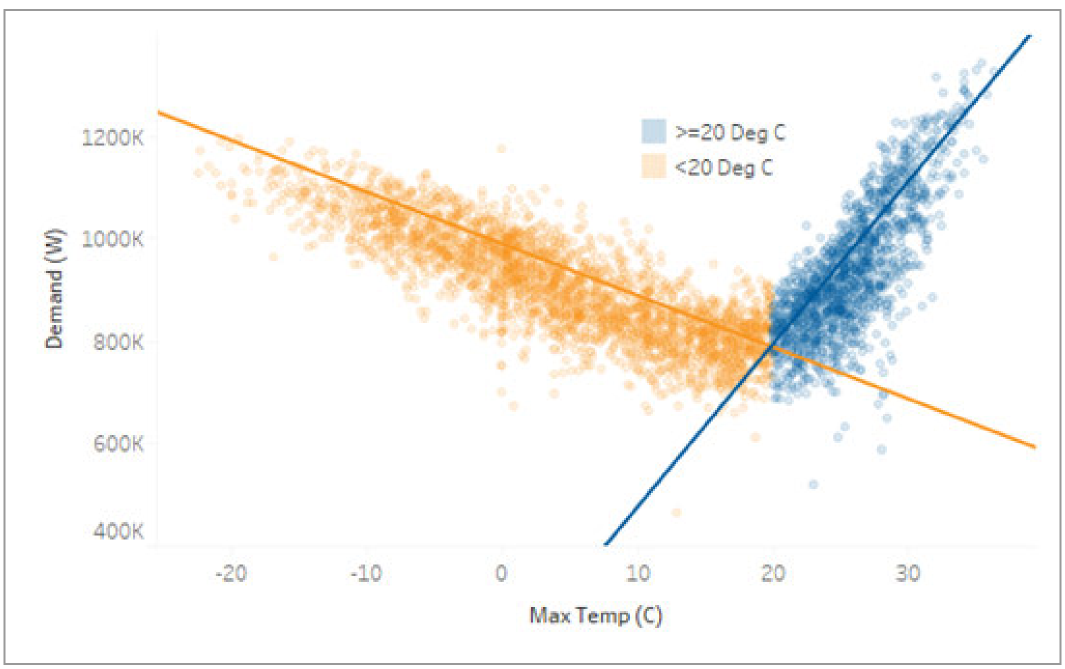
Details about identified load growth can be found in section 7.2 - Ability to Connect New Load.

5.1.5. Load Forecast

Using information from identifying growth opportunities, load forecasting identifies how load will increase at the system level. Forecasted load is established at the feeder level and aggregated by station on an annual basis to evaluate the loading impact with respect to equipment limitations and system constraints.

The forecast baseline is first established from weather normalized historical system coincident peak loading to reflect the expected load on an average peak weather day. As seen in Figure 5.3 below, historical maximum daily temperature is correlated with the system loading for that particular day. Hydro Ottawa uses historical data from 2007 to present day to develop the correlation. Each load forecast then accounts for the growth identified in aggregate to the baseline based with their estimated load, energization date, and impacted supply feeder.

Figure 5.3 – Weather Loading Correlation



To ensure system adequacy, a 1-in-10-year weather factor is applied to the forecast to represent the expected load on a system peak day with a temperature anticipated only once every ten years. The 1-in-10-year factor ensures the network can withstand expected peak temperatures without exceeding system constraints. It also allows the scheduling and implementation of system investment plans to address capacity and reliability needs without compromising resiliency of supply.

Details about load forecasting can be found in section 7.2 Ability to Connect New Load.

5.1.6. System Constraints

The distribution system is designed and planned to supply existing and future customers reliably while conforming to system design constraints. These constraints include equipment thermal and short-circuit limitations, power quality, and restoration capability standards. System constraints must be considered in the design of the transmission supply network, station equipment, and distribution feeder configuration.

Due to the large load and number of customers impacted by transmission system failures, the transmission system is constrained by standards designed to ensure a high level of reliability. Transmission reliability standards are defined by the IESO within the Ontario Resource and Transmission Assessment Criteria ("ORTAC"). Projects to address transmission system constraints are often driven by growth within the distribution system. Hydro Ottawa provides the IESO with updated growth forecasts for the distribution system on an annual basis to help identify and address transmission capacity and ORTAC constraints.

Hydro Ottawa's station planning criteria dictates a constraint to the worst case N-1 contingency scenario. This loading limit is determined as the sum of the transformer capacities after the loss of the largest transformer within an individual station. Transformer summer 10-day LTR ratings are used as the top rating if available on the nameplate. The 10-day LTR rating is the loading supplied by the transformer over a 10-day period while sustaining less than 1% loss of life, assuming peak summer temperatures and a typical daily loading profile. The highest fan rating is used in cases where the summer 10-day LTR rating is not specified by the transformer manufacturer. Hydro Ottawa designs stations to be limited by the transformation; hence cable, bus and breaker thermal ratings within the station should exceed the transformer ratings. In the case of a single transformer station, the station is limited by load transferring capacity to neighbouring stations via feeder ties.

At the feeder level, the system is constrained by conductor thermal limitations and voltage drop. Each feeder is planned to supply connected customers and/or back up other connected feeders in an N-1 contingency while remaining under the thermal limitation of the conductor. On the 4kV system this is achieved by having a dedicated backup feeder available at the station, while for all other systems this is achieved through feeder ties. Feeder planning loading limits are listed in section 4.1.4.2. Additionally, conductor properties, size of loads, and location of loads may lead to voltage drop concerns. Feeders must be configured to deliver voltage levels within the limits stated in CSA CAN3-C235-83.

Constraints of various equipment types are determined by the equipment properties information stored in Hydro Ottawa's Asset Register. Projects and operation guidelines are created to address equipment forecasted to exceed their constraints.

5.1.7. Performance Metrics

Hydro Ottawa monitors the performance of its assets and systems to ensure the successful delivery of its Asset Management Objectives. Continuous improvement is achieved through the use of Key Performance Indicators ("KPIs"). Performance targets that are either not met will trigger a review to determine root cause and potential remedial actions.

Details of Hydro Ottawa's performance metrics can be found in section 4 - Performance Measurement for Continuous Improvement.

5.1.8. Risk Assessment

The Risk Assessment process looks to identify and quantify all the needs of the system in order to meet the Asset Management Objectives. By evaluating the condition of its assets, growth opportunities and constraints on the system, and the system performance, Hydro Ottawa can establish the potential risks and opportunities to begin to identify the investment requirements.

The utility has established a risk register for assessing, monitoring, and mitigating risks that are present in the system as well as identifying opportunities.

5.1.8.1. Risk Register

Risks and opportunities associated within Hydro Ottawa's Asset Management System and asset management activities (at a system or asset class level) are identified by employees and communicated to the respective section Manager and/or the Asset Management Council ("AMC"). In addition, Hydro Ottawa's Internal Audit, Risk and Advisory Service group and external audits identify risk and opportunities through applicable audits and reporting. The Asset Manager ensures that routine risk and opportunity identification activities take place during AMC meetings. This includes identifying risks or opportunities over which Hydro Ottawa has control or can be expected to have an influence. These risks and opportunities, along with their rating and control actions, are recorded in Asset Management System Risk Register.

Risks and opportunities are linked to strategic and asset management objectives, and then scored with respect to impact and probability against the associated objective. To mitigate a risk or capitalize on an opportunity, control actions are assigned for each risk or opportunity, and at least one AMC member is assigned to said risk/opportunity and control. The resultant risk or opportunity is then tracked, and once implementation of the control is complete, the residual score of the risk or opportunity is calculated and approved by the Asset Owner.

5.1.8.2. Program and Asset Analytics

Hydro Ottawa aims to maximize asset value by determining optimal asset replacements and capital and operations and maintenance ("O&M") solutions (e.g. by comparing costs and benefits and mitigating risks). Analysis is performed at both an Asset Program Replacement Level and through Project Optimization, as described in the Strategic Asset Management Plan (Attachment 2-4-3(G)).

Program Analytics

Program level replacement policies for each asset can be found in Attachment 2-4-3(E): Material Investments. Analysis is performed to determine the optimal replacement policy based on a number of factors, including the following:

- Asset type
- Current asset demographics and expected service life
- Probability of failure curve (by asset type)
- Asset condition
- Asset consequence of failure
- Cost effectiveness of different replacement policies

Project Optimization

Hydro Ottawa utilizes the asset investment planning and management software tool C55 to evaluate and optimize projects to create a plan that balances performance, risk, and cost. This process is described in more detail in section 5.2.2 Project Evaluation.

5.1.8.3. System Constraints

Risks associated with Hydro Ottawa's ability to service new customers due system constraints are evaluated through a regional system study, as detailed in section 7.0 - System Capacity Assessment. By identifying and forecasting load growth against system constraints, Hydro Ottawa can identify investment timing requirements. Alternative solutions for addressing the identified risk are reviewed and evaluated as part of the regional system study and take into account both short-term and long-term needs in order to optimize investment plans.

5.1.8.4. Performance Metrics

The evaluation of performance metrics can identify risks to Hydro Ottawa's Asset Management Objectives. Metrics not meeting their desired targets will raise awareness for a more detailed analysis into the issues present. Results from this analysis are evaluated to determine if proposing investments will mitigate the risk and bring the metric into a desired tolerance in an acceptable time frame.

5.2 CAPITAL EXPENDITURE PROCESS

Hydro Ottawa's Capital Expenditure Process, as shown in Figure 5.1 above, includes phases which are executed following the Asset Management Process:

- Project Concept Definition
- Project Evaluation
- Project Review
- Project Optimization
- Project Execution

5.2.1. Project Concept Definition

The Project Concept Definition phase gathers all internal and external drivers to describe the needs of the company's organizational environment. Concept projects and project alternatives are created to meet requirements, mitigate or remove risk, and meet Asset Management Objectives. Table 5.2 outlines the description of the drivers by Investment Category. The Investment Categories are:

- System Access (section 8.2)
- System Renewal (section 8.3)
- System Service (section 8.4)
- General Plant (section 8.5)

Table 5.2 – Driver Description

Investment Category	Driver	Description
System Access	Customer Service Request	Customer request for new connection (load or generation)
	Third Party Requirements	Request by a third party for plant relocation or upgrade to an existing service
	Mandated Service Obligation	Regulatory requirement to maintain distribution licence under the OEB's Distribution System Code or requirement as per Hydro Ottawa's Conditions of Service
System Renewal	Assets at End of Service Life i. Failure ii. Failure Risk iii. Substandard Performance iv. High Performance Risk v. Functional Obsolescence	i. Asset no longer meets functional requirements ii. Asset is at risk to no longer meet functional requirements iii. Asset still meets functional requirements; however, falls below standards for operability or efficiency iv. Asset is at risk of failure in a way that can cause harm or damage to other equipment or assets or would put the distribution system in a detrimental state v. Asset is functionally obsolete with no spare parts, tools, and/or software to continue operation
System Service	Capacity Constraint	Requirement for additional capacity (station transformation or circuit) due to planned or realized load increases
	Reliability	Requirements driven by poor distribution system performance such as abnormally (high) duration or frequency of interruptions
	System Operability	Requirements for improved system operability and visibility
General Plant	System Capital Investment Support	• Capital contributions to HONI for connection projects • Requirement for fleet/vehicle acquisition
	System Maintenance Support	Requirement for tools and associated equipment
	Business Operations Efficiency	Requirements for Information Technology software and systems
	Non-System Physical Plant	Building infrastructure requirements

5.2.1.1. System Access

System Access investments are obligated activities. For this reason the investments are not prioritized through the Asset Management and Capital Expenditure Processes, but rather prioritized based on resources and working with the requesting party.

Customer Service Request

Customer Service Requests arise from the needs of load or generation customers for new connections. For example, this includes servicing for new commercial buildings, residential subdivisions, or generators, and encompasses any system expansion required to supply the site of development.

Third Party Requirements

Third Party Requirements are initiated from requests received for the relocation or upgrade (modifications) of assets or infrastructure (e.g. pole relocation for road widening).

Mandated Service Obligations

Mandated Service Obligations are requirements of a distributor as defined by the *Distribution System Code* ("DSC") as well as any additional obligations as defined by Hydro Ottawa's Conditions of Service.

5.2.1.2. System Renewal

Assets at End of Service Life

Hydro Ottawa's system assets range in age from new to over 50 years old. The management of these assets are critical to providing safe, reliable, and efficient electricity distribution services to customers.

Hydro Ottawa regularly assesses its asset replacement strategy through the risk assessment process identified in section 5.1.8. The objective is to confirm that the assets deliver the required functions at the desired level of performance and that this level of performance is sustainable for the foreseeable future, while staying within the acceptable levels of risk.

Areas which are addressed in Hydro Ottawa's asset replacement strategy review are the financial, technical, and management elements needed for making sound, innovative, or best practice asset management decisions.

Hydro Ottawa looks ahead 20 years with a focus on the first five years. For the initial five-year period, most of the specific planned projects have been identified – and if not, program level spending needs have been identified. Beyond this period, the required program level spending needs have been identified based on the long-term sustainment needs. Based on long-term trends, current asset demographics, known asset issues, or needs on the system, it is likely that new and planned projects will evolve through the forecasted period.

The intent of the asset replacement strategy is to optimize the lifecycle costs for each asset class (including procurement, design, operation, maintenance, renewal, and disposal) to meet reliability service targets and future demand. Each year, the aim is to improve the plan by taking advantage of new information and changing technology.

The following list describes the key variables that are used to inform the Asset Lifecycle Optimization:

- Testing, inspection, and maintenance records to inform condition
- Asset demographic and nameplate information
- Asset failure statistics – number of failures and frequency by asset type (SAIFI)
- Financial useful lives
- Financial records – cost per replacement.

The following list describes the outcome of the Asset Lifecycle Optimization:

- Recommended asset replacement rates, refurbishment, and associated annual spend
- Asset condition (health index)
- Projected failure rates based on spending/replacement levels

5.2.1.3. System Service

Capacity Constraints

Hydro Ottawa routinely assesses the capability and reliability of the distribution system in an effort to maintain adequate and reliable supply to customers. Where gaps are found, appropriate plans for additions and upgrades are developed, which are consistent with all regulatory requirements for the connection of customers and with due consideration for safety, environment, finance, and supply system reliability/security. Hydro Ottawa summarizes the results of this capacity planning process in section 7 - System Capacity Assessment in which the short-term and long-term capacity needs for the service territory are identified.

In this regard, the supply needs in the service territory have been assessed to determine if additions and/or upgrades are required to maintain adequate and reliable/secure system capacity. Hydro Ottawa is composed of several subsystems which are segregated by operating voltage and geographical boundaries. The capacity planning process reviews and summarizes the existing and future constraints for each subsystem, identifying short-term and long-term projects. Forecasted growth, asset replacement schedules, and reliability are all factors in planning the system.

The following describes the key variables that are used to inform the capacity planning process:

- Historical station transformer loading from the system-wide annual peak day (weather normalized and adjusted to a one-in-ten year peak for forecasting)
- Historical feeder loading from the system-wide annual peak day (weather normalized and adjusted to a one-in-10 year peak for forecasting)
- Station, station transformer, and feeder planning capacity and ratings;
- Asset condition
- System configuration and operating characteristics (and restrictions)
- Number of Hydro Ottawa customers
- Historic energy purchased and delivered
- Summer and winter peak load

- City of Ottawa Official Plans and Community Development Plans
- Land use designation and population and employment projections
- Known developments through conversation with developers and City staff
- Energy Resource Facility connections and capacity
- Station capacity to connect generation and plans in place to address any restrictions
- Details and plans resulting from the Integrated Regional Resource Planning ("IRRP") process with the IESO and HONI
- Details relating to Connection Cost Recovery Agreements ("CCRAs") with HONI for station or transmissions projects

For more detail refer to section 7 - System Capacity Assessment.

Reliability

Hydro Ottawa continuously assesses the distribution system's service reliability. Where issues are found, appropriate actions are identified to address these concerns. Service reliability is integral to all work undertaken as part of system planning and asset management. The reliability planning process provides a platform for thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

Reliability driven projects are those which are designed to reduce outage frequency or duration. Automation is a key reliability initiative. In general, work considered as part of the system reliability plan includes the following:

- Deployment of remote sensors
- Deployment of remotely operable and autonomous devices
- Deployment of field devices to provide fault indications locally
- Supporting technologies to automation (i.e. communication & SCADA)
- Modifications of existing installations to address specific interference (i.e. animal guards, circuit spacing)

The reliability planning process may point to asset replacements that may be required. Successful lifecycle management of Hydro Ottawa's assets has a direct impact on system reliability. These activities focus on assets that are optimally maintained throughout their life, asset replacement prior to failure, and system planning to increase operability and reduce downtime.

The following describes the key variables that are used to inform the reliability planning process:

- Historical outage statistics (primary cause, secondary cause, duration, number of customers affected, circuit affected, station affected, date of interruption);
- Power quality measures (System Average RMS Frequency Index – voltage sags and swells); and
- Worst Feeder evaluation.

The following describes the results of the reliability planning process:

- Projects to improve the Worst Feeders reliability performance
- Initiatives to improve overall reliability (specific to top three causes of interruption from the previous year)
- Details on automation plans and how they will impact reliability

System Operability

Hydro Ottawa routinely reviews the existing system to identify opportunities for Distribution Enhancement projects that reduce operational constraints and improve system operability. Efficiency driven projects are those which are designed to reduce restoration times and decrease the number of personnel required for routine switching.

The following describes the variables that are used to identify areas that benefit from projects related to operational efficiency:

- Frequency of historical switching operations (often or never used)
- Criticality of connected load circuits (sub-transmission, critical infrastructure)
- Location of equipment (such as main switching centres or distribution trunk ties)
- Historical restoration issues (grading, vegetation, secure locations)

The following describes the results of the reliability planning process:

- Critical switches identified for upgrades to remote operable units
- Decommissioning redundant/unused legacy equipment from the system upon renewal
- Relocation of equipment or normal-open points

5.2.1.4. General Plant

General Plant investments follow a similar approach to the Asset Management and Capital Expenditure Processes, but are not evaluated within Copperleaf C55, Hydro Ottawa's investment optimization software. This is due to their large nature, generally spanning several years. They are instead, initiated and justified with detailed business cases.

As directed in Attachment 1-1-9(A): Corporate Memorandum - 2020-2025 Priorities and Budget Guidelines, all capital investment by the utility should provide for customer growth and the replacement of aging infrastructure to maintain plant reliability as per the needs analysis documented in the DSP. Capital investment key considerations include, but are not restricted to, the following:

- Affordability;
- Reliability;
- Efficiency, cost-effectiveness, and enhanced preparation for technological changes;
- Planned investments related to accommodating the connection of renewable energy generation;
- Planned investments for the development and implementation of the smart grid to support grid modernization and expenditures as required by legislation;

- Provision of more customer choice and addressing customers' preferences and expectations; and
- Coordination of infrastructure planning with customers, the transmitter, other distributors, and the IESO or other third parties where appropriate.

All new information technology ("IT") requirements must first be supported by IT Project Requests and submitted as a joint application between the requesting Division and the IT Prime Contact. This ensures the project is in line with the company priorities as well as the Information Management/Information Technology Strategy.

For development of the 2021-2025 budget, customers were engaged through the customer survey process. The results below reflect the robust support expressed by customers for innovation,General Plant, and technology investments.

- Innovation: 75% of customers support Hydro Ottawa's strategy of "leading change and engaging in industry pilots," whereas customers are split on whether Hydro Ottawa should limit expenditures in this category to service today's customers and existing needs.
- General Plant: 83% of customers feel that Hydro Ottawa should make the necessary investments to manage the distribution system efficiently and reliably. In addition, 83% feel that Hydro Ottawa should make investments in fleet on a vehicle-by-vehicle basis based on a set criterion.
- Finding efficiencies through technology investments: 85% support Hydro Ottawa's view on technological investments. Those that do are split on what should be prioritized – improvements or lowering distribution rates.

All technology investments will be evaluated through a Business Benefits Realization process. The results are measured against the objectives to ensure the benefits were achieved through the investments.

System Capital Investment Support

System Capital Investment Support captures the requirements for capital contributions to HONI for transmission-connection projects as well as for Hydro Ottawa fleet acquisition.

System Maintenance Support

System Maintenance Support covers the requirements for tools and associated equipment used by Hydro Ottawa crews.

Business Operations Efficiency

Business Operations Efficiency is the requirement for IT software and systems used to support daily business activities.

Non-System Physical Plant

Non-System Physical Plant captures the life cycle requirements for buildings.

5.2.2. Project Evaluation

The Project Evaluation phase creates business cases in support of the project alternatives. Each alternative is valued based on Hydro Ottawa's Corporate Strategic Objectives using the Value Model, described below, in order to assess the project's alternatives based on their value. The evaluation of project alternatives is completed within Copperleaf's industry leading Asset Management software, C55.

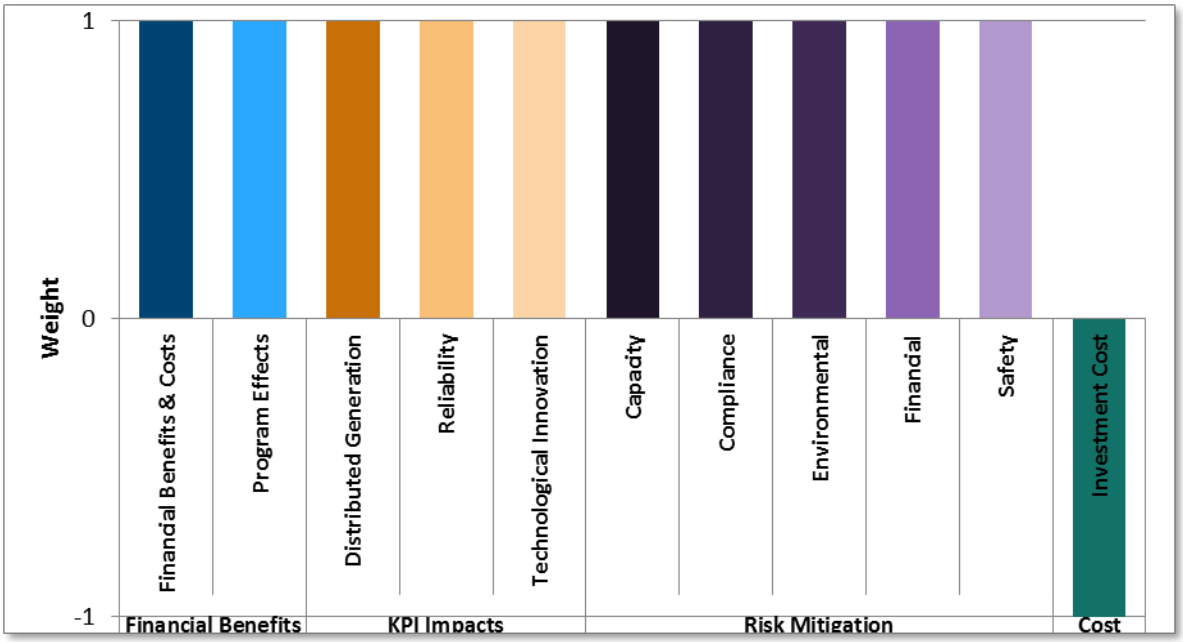
Project concepts and their alternatives are then reviewed to determine if they are mandatory projects. Mandatory projects are typically dictated through the DSC or the *Electricity Act, 1998*. They range from customer connections to line relocations. These projects are prioritized if they help address immediate concerns to health and safety, the environment, or alleviate constraints to the operation of the system. These projects may move directly to the Execution phase, potentially taking precedence over planned projects and causing deferral or delays. Otherwise, the projects make their way into the Project Review phase before being prioritized.

Project alternatives are then scored by identifying their risk and/or benefit as it relates to Hydro Ottawa's Asset Management Measures through the use of the Value Model. The evaluation Value Model is comprised of 11 Value Measures grouped into four Value Categories, as follows:

- Financial Benefits
    - Financial Benefits & Costs
    - Program Effects
- Key Performance Indicator ("KPI") Impacts
    - Distributed Generation
    - Reliability
    - Technological Innovation
- Risk Mitigation
    - Capacity
    - Compliance
    - Environmental
    - Financial
    - Safety
- Cost
    - Investment Cost

Each of the Value Measures is normalized to the same scale where one value point is equal to approximately $1,000. This means that within the Value Function, each of the Value Measures (except Investment Cost) is weighted with the same value of +1. Investment Cost is a negative contributor to the Value Measure, and as such, is weighted with a value of -1, as shown below.

Figure 5.4 – Value Category Weighting



The Value Measures for each project are computed for each year (the benefits or risks in one year can be different than the next – for example, the risk of a poor condition asset failing increases with time). They are then converted into a single number by taking the present value back to the current fiscal year using the system defined discount rate (5.89%). This means that if a project has a negative value, the cost of the project outweighs its benefits.

The following sections outline the details for the calculation of each of the Value Measures.

5.2.2.1. Financial Benefits

Financial Benefits & Costs

The Financial Benefits & Costs are computed in dollars and then normalized to the Value Measure by dividing by 1000.

This Value Measure is calculated using the following equation, the components of which are defined in Table 5.3 below:

$$Financial\ Benefits\ \&\ Costs\ = (CLAB)(HLR) + (OLAB)(HLR)(10) + CCST + (OCST)(10) - (OADD)(10)$$

Table 5.3 – Financial Benefits & Costs Variables

Variable Name	Description
CLAB	Capital Labour Saved (hours)
OLAB	O&M Hours Saved (hours)
HLR	Hourly Labour Rate (dollars/hour)
CCST	Other Capital Cost Savings (dollars)
OCST	Other O&M Savings (dollars)
OADD	Additional O&M Costs resulting from this investment (dollars)

- Hourly labour rate (“HLR”) is $80/hours; and
- O&M Costs are weighted at 10:1 to Capital Costs.

Program Effects

Program Effects utilizes the results of the Program Analytics (see section on Project Optimization), and is incorporated into the project value, where applicable.

5.2.2.2. KPI Impacts

Distributed Generation

Hydro Ottawa prioritizes Energy Resource Facility (“ERF”) investments based on customer requests and follows regulated timelines for response and connection.

Hydro Ottawa strives to integrate all proposed residential and commercial customer generation projects into the grid. Several projects are proposed every year. Hydro Ottawa works with project managers and the customer to integrate the proposed generation into the distribution system. The process for accepting these projects involves the following: analyzing the generation capacity of the connecting feeder and interface transformer; verifying that the relevant station transformer can accept reverse flow; ensuring that the short circuit changes and voltage fluctuations will cause no material impact on either the distribution or transmission grid; and reviewing the proposed single line diagram, electrical protection scheme, and site plan for adherence to all Hydro Ottawa, ESA, and IESO standards and requirements. In the event that the proposed generation connection is not possible, Hydro Ottawa works with the customer to provide a solution. This solution may involve expanding the distribution system to meet customer needs or relocating the project to a more fitting property. Where work on the distribution system is required for the connection, the project is coordinated to ensure regulatory timelines are met while optimizing crew time.

Hydro Ottawa also prioritizes investments within its system which help to enable the connection of ERFs. If a given project benefits the ability to connect ERFs, then 30 value units are applied to aid in prioritization.

Reliability

The following information is collected specific to each investment:

Table 5.4 – Reliability Variables

Variable Name	Description / Question Answered
FAIL	How many failures per year will be avoided by implementing this investment? (based on historic rates of failure)
PEAK	For each of the failures, what would be the expected peak load lost, or in the case of redundant equipment, the peak load at risk? (kW)
DUR	What is the average duration of the outage caused by the failures? (hours)
DURR	If this is redundant equipment, and there is a failure, what is the duration of the period for which redundancy will be lost? (hours)
NCUS	What is the average number of customers impacted by each failure?
TYPE	Customer Type: ● Residential ● Mixed Residential / Commercial or ● Commercial / Industrial
WORS	Has this feeder been identified on the Worst Performing Feeder Report in the past 2 years, OR has this area been identified as an area of concern?

The Reliability measure is then calculated through a sequence of steps:

5.2.2.3. Customer Interruption Cost

Costs associated with interruptions are assigned based on customer type and the frequency and duration of the interruption, as outlined in Table 5.5.

Table 5.5 – Customer Interruption Costs

Metric / Customer Type	Residential	Mixed Residential / Commercial	Commercial / Industrial
Frequency Cost per kW	2.00	20.00	20.00
Duration Cost per kWh	4.00	20.00	30.00

1. **Outage Duration**

The duration of the outage is computed as:

$$Duration = DUR + (0.05)(DURR)$$

Where,

- DUR represents the duration of the interruption that is experienced by the customer(s); and
- DURR represents the duration for which redundancy will be lost.

The time when redundancy has been lost has been included with an impact of 5% since it is possible that a second failure occurs during this time creating an interruption. Computing the likelihood of a secondary failure is complex and varies from situation to situation. Accordingly, 5% has been selected as a reasonable expectation, and has been used by Copperleaf at other utilities.

2. **Customer Cost of Outage Duration**

The Cost of Customer Minutes of Interruption is computed as:

$$cmiCost = (FAIL)(Duration)(60)(NCUS)(\frac{\$1}{min})$$

Where Duration is calculated in Step 2.

3. **Cost of Customer Minutes of Interruption**

The Cost of Customer Minutes of Interruption is converted to a cost using a factor of $1 per minute of interruption. This value has been derived using the figures for Mixed Residential / Commercial provided in Table 5.5 above, as follows:

$$Cost\ per\ minute = \frac{Duration\ Cost\ (\frac{\$}{kWh}) \times Power\ Consumption(kWh)}{60min}$$

$$Cost\ per\ minute = \frac{(20)(3)}{60}$$

$$Cost\ per\ minute = 1$$

Where,

- An assumed average consumption of 3 kWh has been used as derived Hydro Ottawa statistics from 2013 (7,570 GWh billed and 315,000 customers).

4. Frequency Cost

Frequency is computed as:

$$frequencyCost = (FAIL)(PEAK)(frequency\ cost\ per\ kW)$$

Where frequency cost per kW is defined in Table 5.5 above.

5. Duration Cost

Duration Cost is computed as:

$$durationCost = (FAIL)(PEAK)(Duration)(Duration\ cost\ per\ kWh)$$

Where,

- Duration is calculated in Step 2; and
- Duration cost per kW is defined in Table 5.5 above.

6. Reliability Cost

Reliability Cost is computed based on the highest of cmiCost, frequencyCost, and durationCost as:

$$reliabilityCost = max(cmiCost,\ frequencyCost,\ durationCost)$$

7. Reliability Value

Reliability Value is then computed from the Reliability Cost using:

$$reliability\ Value = \frac{reliabilityCost[1+(WORS)(0.25)]}{1000}$$

Where, if the feeder impacted has been identified as a Poor Performing Feeder, as defined in section 4.3.3 in the last two years or has been identified as an area of concern, the value is inflated by 25%. To convert the measure from dollars to units, the value is divided by 1000.

Technological Innovation

The Technological Innovation measure is computed as:

$$Technological\ Innovation = (10)(TI1)$$

Where,

Table 5.6 – Technological Innovation Variables

Variable Name	Question Answered	User Selection	Value
TI1	Does this investment introduce or apply new technology that has never been used at Hydro Ottawa before? (Does not include enhancements to existing technology)	Yes	1
		No	0

5.2.2.4. Risk Mitigation

The Value of Risk Mitigation is computed using the same methodology for all five Value Categories:

- Capacity
- Compliance
- Environmental
- Financial
- Safety

To compute the value, the Baseline Risk and the Residual Risk are specified and the Value is calculated as follows:

$$Value\ of\ Mitigated\ Risk = Baseline\ Risk - Residual\ Risk$$

Where, Baseline Risk is the risk present if the investment is not completed and Residual Risk is the risk present if the investment is completed.

For both the Baseline Risk and the Residual Risk, the Consequence and Probability are specified based on the Risk Categories and Probabilities (Table 5.7 and Table 5.8 below) and are converted to unit values using the Risk Matrix (Figure 5.5 below).

1 **Table 5.7 – Risk Categories**

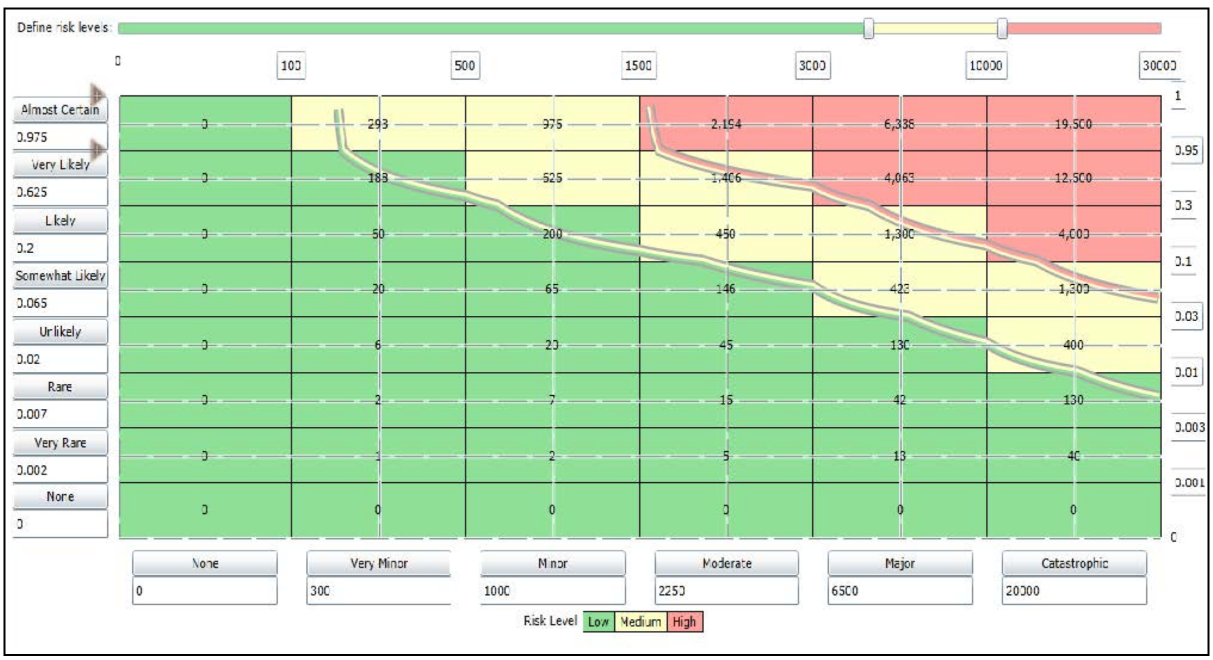
Risk Category	Consequence					
	Catastrophic	**Major**	**Moderate**	**Minor**	**Very Minor**	**None**
Capacity	Unable to service a new load	Can supply all load but exceeding thermal limits	Can supply all load but exceeding planning limits	N/A	N/A	Able to supply load without exceeding planning limits
Compliance	Federal/Provincial: Regulated (including OEB, CSA). Including voltages exceeding the standard levels defined in the Conditions of Service	N/A	Municipal: Regulated (local level through Municipal by-laws)	Corporate /Other: Corporate or other requirements, including replacement of recalled equipment, and equipment no longer operating as originally designed	Legislation Pending: May become regulated in the future (i.e. bills announced in parliament or pending legislation)	None: no corporate or legal requirements
Environmental	Release of more than 2000L of oil	Release of 1000L to 2000L or oil	Release of 200L to 1000L of oil	Release of 100L to 200L of oil	Release of less than 100L of oil	Immaterial consequence
Financial	>$10M annually	>$3M annually	>$1.5M annually	>$500k annually	>$100k annually	<$100k annually
Safety	Possibility of injury has been mitigated by operating restriction where the cost of those restrictions are >$10M or result in >10M CMI annually	Possibility of injury has been mitigated by operating restrictions where the cost of those restrictions are >$3M or result in >3M CMI annually	Possibility of injury has been mitigated by operating restrictions where the cost of those restrictions are >$1.5M or result in >1.5M CMI annually	Possibility of injury has been mitigated by operating restrictions where the cost of those restrictions are >$500k or result in >500k CMI annually	Possibility of injury has been mitigated by operating restrictions where the cost of those restrictions are >$100k or result in >100k CMI annually	Immaterial consequence

2

Table 5.8 – Risk Probability

Probability							
Almost Certain	**Very Likely**	**Likely**	**Somewhat Likely**	**Unlikely**	**Rare**	**Very Rare**	**None**
Imminent: >95% chance of occurring this year	Greater than 30% chance of event occurring this year	Greater than 10% chance of event occurring this year (e.g. 1 in 10 year event)	Greater than 3% chance of event occurring this year (e.g. 1 in 33 year event)	Greater than 1% chance of event occurring this year (e.g. 1 in 100 year event)	Greater than 0.3% chance of event occurring this year (e.g. 1 in 333 year event)	Greater than 0.1% chance of event occurring this year (e.g. 1 in 1000 year event)	Event unlikely to occur in next 1000 years

Figure 5.5 – Risk Matrix



To illustrate the use of the Risk Matrix, the replacement of a station-class transformer without modern oil containment by a station-class transformer with modern oil containment would mitigate a risk of 'Catastrophic' environmental consequence, with a probability from 'Very Rare' to 'Unlikely', depending on the age and condition of the asset. The replacement of a distribution-class transformer would mitigate the risk of 'Very Minor' consequence, with a probability from 'Rare' to 'Somewhat Likely', depending on the age and condition of the asset. Approximate annual risk mitigation scores for these scenarios would be 130 and 2, respectively. The two lines in Figure 5.5 above delineate the regions of each Risk Level in the Risk Matrix: Low, Medium, and High.

5.2.2.5. Cost

Investment Cost

The investment cost is entered in dollars and then normalized to the Value Measure scale by dividing by 1000.

5.2.2.6. Mandatory Compliance Investments

Investments that have been identified as mandatory or “must do” based on being an imminent safety or regulatory concern will be flagged and will pass through at the top of the optimization process. These investments will still be scored based on the Value Measures and will typically show mitigated risk under the Compliance or Safety category.

5.2.3. Project Review

During the Project Review phase, the valuation of each project is reviewed individually and compared to similar projects to ensure a consistent approach has been applied. As well, the relative ranking of projects, compared to one another, is assessed to validate that projects have been ranked according to expectations based on engineering judgement. If discrepancies are found, the project valuation will be corrected.

5.2.4. Project Optimization

The Project Optimization phase uses C55 to rank each project based on its value, as calculated through the Project Valuation phase. Constraints are then applied to create a detailed project list for Hydro Ottawa Executive Management Team approval.

Project Optimizer

The Optimizer algorithm within C55 selects the combination of projects that carry the highest overall value while fitting within specified constraints. The Optimizer takes the following as inputs:

- Project or program alternatives, including budgets and value (as calculated in the Execution Phase); and
- Constraints (dependencies, time horizons, financial, resource, etc.).

The goal of the optimization is to determine the optimal portfolio of projects which maximizes the value to the organization given a set of projects/programs within a set of constraints (e.g. budget envelope), and uses a Mixed Integer Linear Programming ("MILP") optimization engine enabling fast computation time.

Projects classified under the Pole Renewal and Underground Cable Renewal programs are optimized independently from all other projects. This is done to meet the replacement levels recommended by the Asset Management Plan for each asset type.

Project List

A Preliminary Project List is created based on the Optimization process and expert knowledge of the needs and impact of the proposed projects. This list is further refined based on known expenditure and resource constraints to create the Detailed Project List.

While it is preferred that the timing for all investments are based on this optimization, mandated investments will arise, typically due to external drivers, such as regulatory or legislative mandates or health and safety concerns. When such investments occur, they will have reasoning clearly documented and the impact to planned objectives will be reviewed.

The Detailed Project List of prioritized investments then moves on for approval from Hydro Ottawa's Executive Management Team and Board of Directors before proceeding to execution.

This ensures that Corporate Strategic Objectives are being met through the proposed investment plan. Constraints may be re-evaluated and updated to meet objectives or adjust the level of mitigated risk.

5.2.5. Project Execution

The Execution phase follows a Hydro Ottawa internal project management methodology called "Project Coach" which defines the core lifecycle for projects. Project Coach is based on the internationally accepted standard for project management: Project Management Body of Knowledge ("PMBOK") issued by the Project Management Institute.

Project Coach provides specific guidelines, procedures, work instructions, and industry best practices that will allow Hydro Ottawa personnel to perform project work in an efficient, effective, and high quality manner. Processes described in Project Coach are intended to be scalable and applicable to all projects, regardless of complexity. Through use of this tool, a consistent approach to planning, scheduling, and execution of projects can be implemented.

Project Coach describes six steps in the execution of the project:

1) **Planning & Project Initiation (Plan)** – The project charter, scope, and objectives are created. Key players take steps to initiate the project and engage any needed authorization.
2) **Design** – The project charter, scope, and objectives are reviewed and approved. Preliminary and detailed project design and estimates are created.
3) **Procurement & Circulation (Procure)** – The project design is approved. Material and services are procured.
4) **Scheduling (Schedule)** – The project is scheduled with key milestones and deliverable dates.
5) **Construction (Construct)** – The project is executed with a continuous review on progress and risk to completion.

6) **Closure (Close)** – The project documentation, financials, and reviewed lessons learned are completed. Feedback and lessons learned are registered and communicated for continuous improvement.

5.3. NON-DISTRIBUTION SYSTEM ALTERNATIVES

Hydro Ottawa was a key stakeholder in the IRRP process,, as developed by the IESO and updated by the OEB. The IRRP develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the ORTAC, and develops regionally integrated solutions to address needs that are identified. These include conservation, demand management, distributed generation, large-scale generation, transmission, and distribution. Hydro Ottawa continues to work with the IESO and HONI in developing optimal solutions to the transmission and bulk system needs within the Ottawa area. Please refer to section 1.10.2 for more details. The development of the next cycle of the IRRP began in 2018 and is expected to be completed in the first quarter of 2020.

5.4. CUSTOMER ENGAGEMENT ACTIVITIES

Hydro Ottawa undertakes numerous customer engagement activities to solicit feedback and keep customers informed about the work which may impact them.

Customer Satisfaction Survey

Each year, Hydro Ottawa engages an external research firm to conduct an annual Customer Satisfaction Survey. The survey helps the utility understand the satisfaction levels of Hydro Ottawa customers relative to Ontario comparators. It also reveals how customer perceptions, issues, and concerns are evolving over time. The types of questions posed to customers in this annual survey cover the following topics:

- LDC knowledge, integrity, involvement, and trust
- Overall customer satisfaction scores
- % of respondents indicating they had a blackout or outage in the past 12 months
- % of respondents indicating they had a billing problem in the past 12 months

- What customers think of electricity costs
- Level of customer engagement
- Company Image
- Customer view of importance to pursue implementation of the Smart Grid

The survey results factor into the setting of annual performance objectives and the establishment of relative priorities.

Interviews are conducted with a wide range of questions covering such topics as system reliability performance, investment to improve reliability, acceptable length of outages, design of the system (overhead versus underground), and willingness to pay more for system enhancements.

Based on survey results, Hydro Ottawa has created a capital plan that paces investments in order to minimize rate impacts, while continuously improving efficiencies and productivity with respect to distribution planning and implementation. Hydro Ottawa is continuing to improve capital project prioritization, specifically in the areas of data collection and risk management. Please see Attachment 1-2-1(C) and Attachment 1-2-1(D) for the results from Hydro Ottawa's 2018 Customer Satisfaction Survey, organized by responses from residential and small business customers and large commercial customers, respectively.

Hydro Ottawa also conducts monthly telephone surveys of customers who have recently called the utility's contact centre. This survey measures factors such as the following:

- Level of satisfaction with the Contact Centre
- Level of knowledge of the staff who dealt with the customer
- Level of courtesy of the staff who dealt with the customer
- The ability to deal with the customer's issue (First Call Resolution)

The use of these surveys helps to determine if Hydro Ottawa is improving performance, from the customer's perspective, year-over-year. Further, these surveys help identify emerging issues which influence planning and resolution priorities. Annual plans are more informed and aligned as a result of customer feedback generated from these two surveys.

Customer Consultations on Major Projects

Hydro Ottawa regularly consults customers with regards to major projects that will potentially impact customer property or neighbourhoods, such as cable replacement or distribution transformer replacement.

The consultation process first involves informing the potentially impacted customers of the pending work, followed by a customer open house aimed at creating open dialogue. During the open houses, Hydro Ottawa staff inform customers on the scope, schedule, and the general process to be undertaken to perform the work. It is also a venue for customers to provide their feedback and voice their concerns that staff can then immediately address. The open house strategy was developed based on feedback received from customers in the past and have since proven to enable a productive and successful project for both the customers and Hydro Ottawa. The utility Ottawa believes, as has been demonstrated through these sessions, that strong and open communication with customers is essential. Customers have commented that they appreciate these consultation sessions as they provide a forum for discussion and airing their concerns, while allowing Hydro Ottawa to inform them of project needs and the concept of reliability.

Participation with Electrical Contractors Association

Hydro Ottawa actively communicates with the Electrical Contractors Association ("ECA") of Ottawa to ensure strong communications between the utility and the numerous contractors that work in Ottawa. This need was identified by the ECA as part of the customer persona activity that Hydro Ottawa initiated in 2013. As a result, Hydro Ottawa now ensures any and all questions are answered and actively communicates new information to the ECA. Topics such as changes to the Conditions of Service are explained and discussed to ensure a clear understanding of requirements. Feedback received in this continuous manner allows Hydro Ottawa planners to better understand future needs, timing of developments and issues and concerns around design standards and planning practices.

Hydro Ottawa Website

Customers are solicited for their direct feedback on Hydro Ottawa's corporate website, as well as on the secured MyAccount customer portal. Customers can send in their complaints and inquiries, the resolution of which are tracked and managed by a complaint management application. The use of complaint management software helps Hydro Ottawa identify complaint trends and opportunities for improvement.

5.5. COST EFFECTIVE MODERNIZATION OF THE DISTRIBUTION SYSTEM

Hydro Ottawa takes advantage of opportunities that arise during system planning to implement cost-effective modernization of the distribution system in order to make it more efficient, reliable, and provide more customer choice. Such opportunities include the following:

- When replacing assets at the end of life, or evaluating projects to improve reliability, Hydro Ottawa incorporates new technology where appropriate, including:
    - Replacing end of life switches with smart, Supervisory Control and Data Acquisition ("SCADA")-controlled switches capable of remote operation thus reducing crew and truck time previously required for switching and power restoration.
    - Installing fault circuit indicators ("FCIs") based on past experience and evaluation of single line diagrams for ideal installation locations. The smart FCIs report is communicated back to the system office through the SCADA network, which provides indication to the operators as to the location of the fault, speeding up switching and restoration time by reducing the time spent on troubleshooting.
    - Through the use of these technologies a reduction of manual efforts is achieved, thereby creating better efficiencies and enhanced reliability. They also allow for

greater O&M savings than their initial investments, thus reducing the overall lifecycle cost.

- When station transformers are identified for replacement, the new units will have reverse flow capabilities to eliminate potential restrictions to connecting ERFs.
- The recent SCADA upgrade will facilitate the implementation of DMS and OMS in a single platform. This investment will enhance the efficiency and performance of the system operators in the control room by removing separate interfaces and incorporating SCADA, DMS, and OMS into a single view.
- Through their MyAccount online accounts, customers are able to download daily and hourly consumption data which facilitates their ability to make decisions about their electricity cost. (Residential customers are also able to use a mobile application for this purpose).

6. ASSET LIFECYCLE OPTIMIZATION

Hydro Ottawa manages its assets throughout their lifecycle to optimize the value they deliver over the period that they are in service. Hydro Ottawa's lifecycle optimization includes planning and design, installation and commissioning, operation and maintenance, and renewal and decommissioning.

This section will cover Hydro Ottawa's lifecycle optimization in the following subsections:

- Asset Demographics and Condition
- Asset Lifecycle Optimization Policies and Practices
- Asset Lifecycle Risk Management

6.1. ASSET DEMOGRAPHICS AND CONDITION

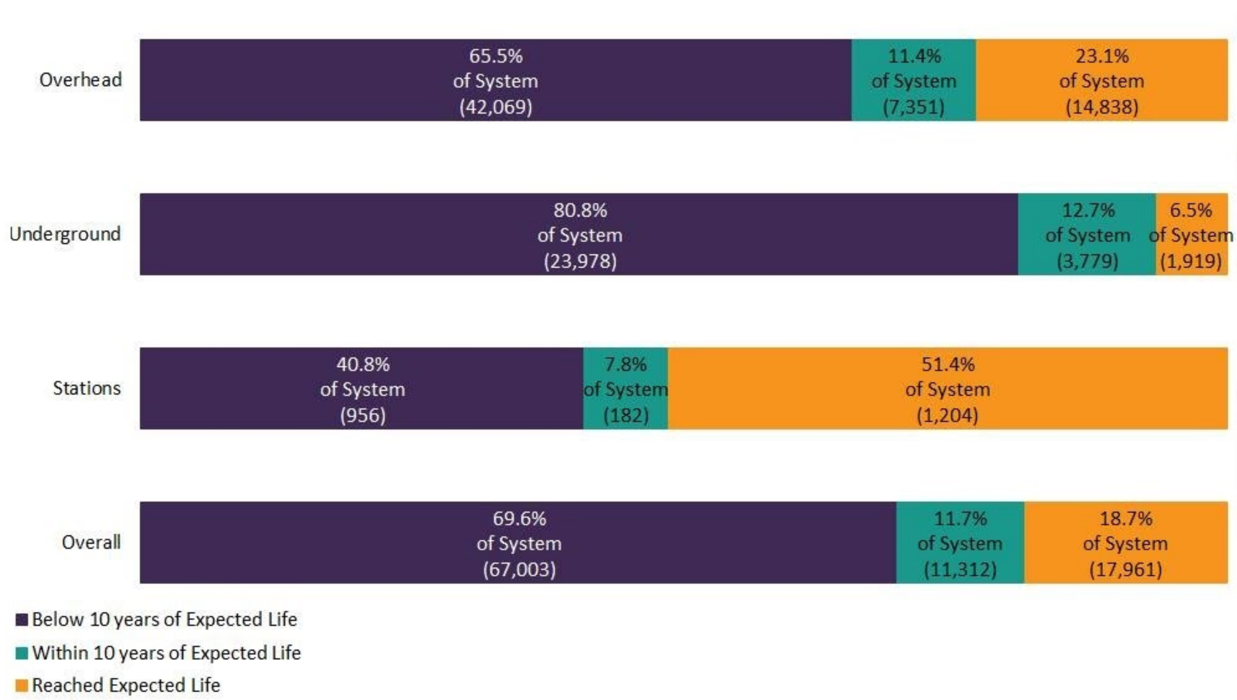
The following sections summarize the demographics and condition assessment for the major asset classes within Hydro Ottawa's system. Asset condition is based upon health index calculations which are unique for each asset class. Details of Hydro Ottawa's Asset Condition Assessment Process can be found in section 5.1.2. Details of the utility's System Renewal Investments can be found in section 8.3.

Hydro Ottawa manages assets in three main systems: Stations, Overhead, and Underground. Each system has distinct types of assets that are specific to the system and are subject to different types of risks. Managing assets within each system allows for the coordination of activities and investments.

Hydro Ottawa's overall asset demographics, as seen in Figure 6.1 below, show that a large portion of the asset population has reached its expected service life. For example, 19% of all assets have reached their expected service life and now pose a higher risk of failure. An additional 12% of assets are within 10 years of reaching their expected service life.

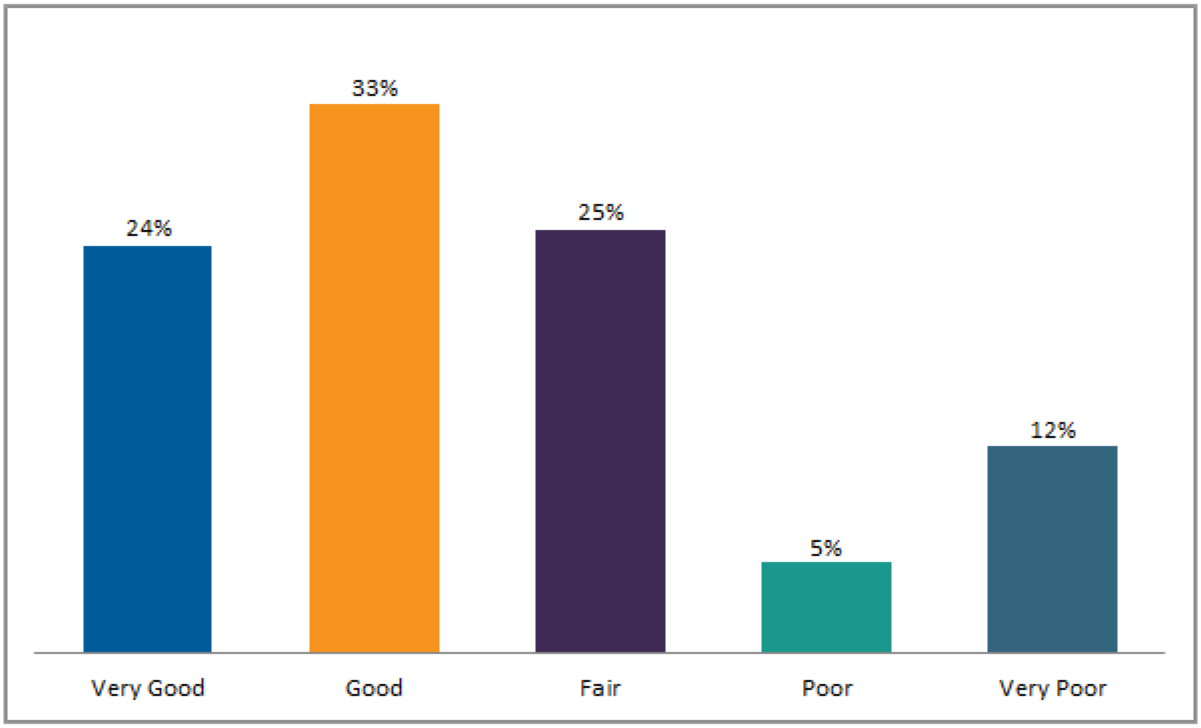
A large portion of station assets have reached the end of their expected service life. However, there are no station assets in Poor or Very Poor condition. Continued condition monitoring of assets, including dissolved gas analyzers and temperature monitoring, is being used to assess the health of aging assets. Station assets are continuously inspected and maintained as part of Hydro Ottawa's station equipment maintenance programs in order to identify any developing deficiencies before the asset fails.

Figure 6.1 – Overall Asset Age Demographics



Hydro Ottawa's overall asset condition ratings are summarized in Figure 6.2 below. As indicated, there are 17% of assets in Poor or Very Poor condition. Hydro Ottawa's asset investment and maintenance programs are targeted to minimize assets in these conditions in order to mitigate the potential risk of failure.

Figure 6.2 – Overall Asset Condition



The following sections detail the demographics and condition of each asset class.

6.1.1. Station System Assets

Hydro Ottawa station assets are an important part of delivering power to customers. These assets are located within the fence of an electrical station. Out of the 91 stations that service Hydro Ottawa's customers, Hydro Ottawa fully owns 73. Hydro Ottawa and Hydro One Networks Inc. ("HONI") jointly own 12 stations. These stations consist of various assets, some owned by HONI, and others owned by Hydro Ottawa. HONI wholly owns six stations that supply Hydro Ottawa customers. A list of these stations and their ownership is provided in Appendix B: Hydro Ottawa Station Table.

6.1.1.1. Station Transformers

Station transformers are one of Hydro Ottawa's most critical asset classes due to the ability to affect thousands of customers. Hydro Ottawa owns 167 station transformers which operate at various voltages, connected to either Ontario's electric transmission grid or connected to the local sub-transmission system. Hydro Ottawa also supplies distribution stations and customers through 37 station transformers owned and maintained by HONI. Hydro Ottawa does not manage HONI-owned station transformers. Figure 6.3 and Table 6.1 below detail the various components of a station transformer.

Figure 6.3 – Station Transformer

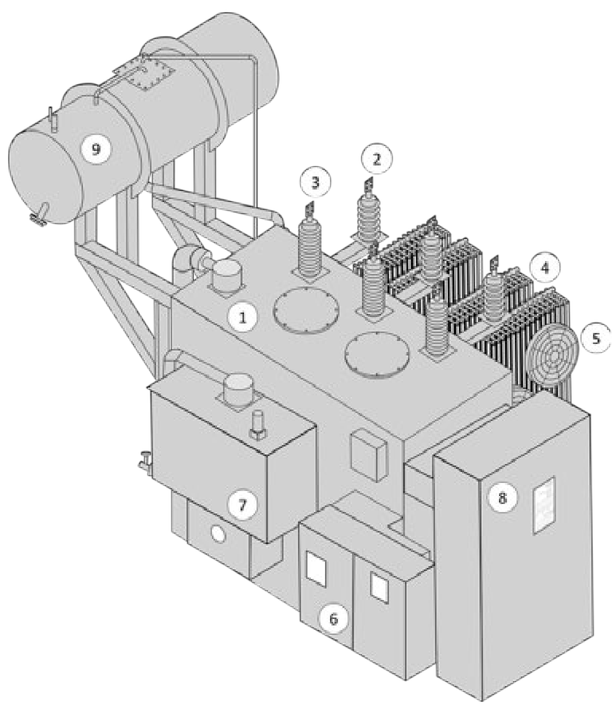


Table 6.1 – Station Transformer Components

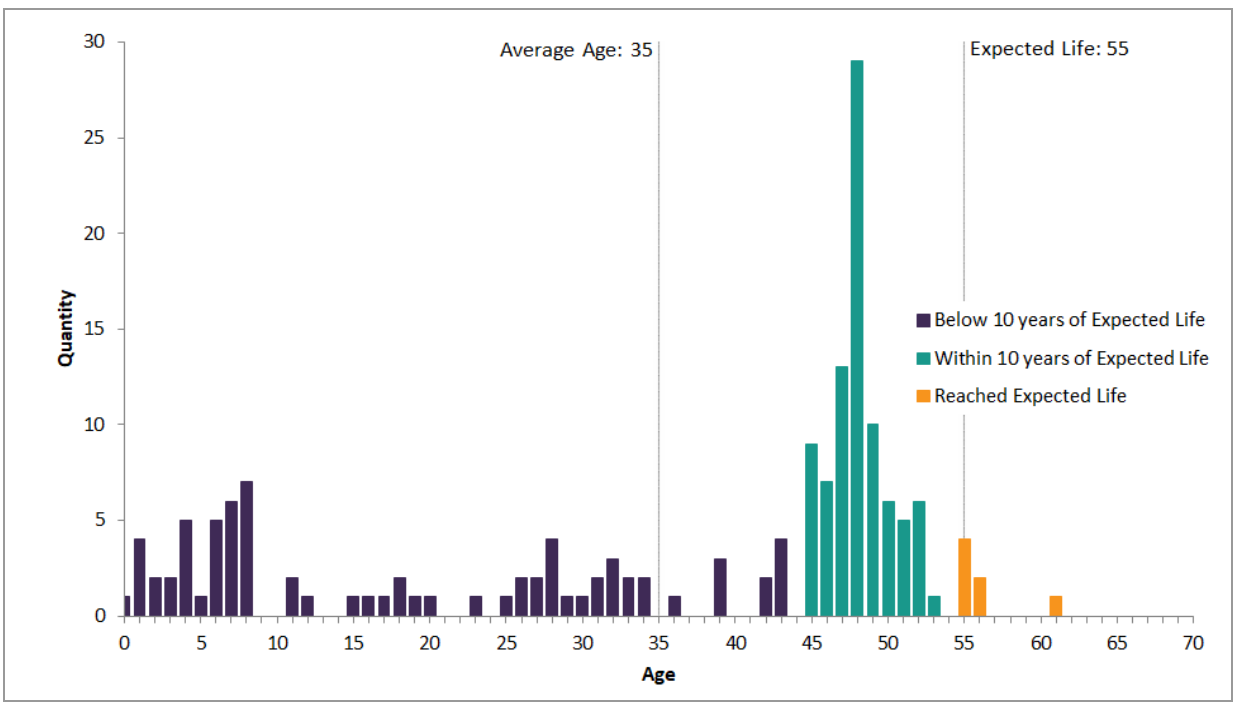
Figure Number	Component	Function
1	Enclosure	Station transformer enclosures maintain isolation of the high and medium voltage equipment from outside sources while ensuring security from the public for increased safety. Additionally, the enclosure protects the inside equipment from damage and increases system reliability by isolating it from weather, animals and contaminants.

Figure Number (Cont'd)	Component (Cont'd)	Function (Cont'd)
2	Surge Arrestors	Station surge arresters protect the system and equipment by suppressing voltage surges from various causes (e.g. lightning).
3	Bushings	Station transformer bushings support an insulated flow of current from the connecting conductors to the inside connections through the grounded enclosure.
4	Radiators	The radiators external to the station transformer's core support the asset's successful operation through cooling of the oil using natural convection. As warm oil flows up into the radiator, cooler oil flows back into the transformer. The management of station transformer temperature is vital to ensuring it can support the designed transformation capacity without degrading internal components over its lifecycle.
5	Fans	The cooling fans further support the oil cooling mentioned above as the fanned air cools the oil travels within the radiators. These fans allow a station transformer to achieve increased electrical transformation capacity through managing the temperature. Fans are typically controlled on and off through relays at specific temperature thresholds.
6	Control Cabinet	A station transformer's control cabinet encloses and protects various monitoring and protection systems (described below) from damage by isolating it from weather, animals, contaminants and the public.
7	Tap Changer	The on-load tap changer is used to regulate the voltage of the station transformer by changing the transformer's winding ratio. The tap changer can rotate up or down to either increase or decrease the ratio. This ensures that the voltage supplied by the station is constant, even in cases where the incoming voltage is too high or too low. This results in high-quality power being distributed from the station into the distribution network.
8	Bushing Enclosure	The bushing enclosure is used on station transformers with side mounted bushings, typical for connecting underground conductors. The bushings and cables are contained within the metal enclosure which protects them from the outdoor elements described by the station transformer enclosure above.
9	Conservator	The conservator tank provides space for a station transformer's oil to expand and contract as the transformer's load increases and decreases. When electrical load increases, the transformer's temperature rises causing the oil to expand into the conservator tank. When the load decreases, the temperature decreases causing the oil to contract and flow down from the conservator into the main tank. This separation also ensures oxidation occurs in the conservator and not in the main transformer tank. Hydro Ottawa also installs fully sealed station transformers which do not use a conservator tank.
Not Shown	Monitoring and Protection Systems	Monitoring and protection systems are used to ensure that a station transformer operates to its full expected life safely. Various sensors are used to measure temperature, gas accumulation and pressure. The results control cooling systems on the transformer, signal alarms to system operators and operate breakers to isolate and protect the transformer. Additionally, the results are used to drive maintenance or renewal activities.

Figure Number (Cont'd)	Component (Cont'd)	Function (Cont'd)
Not Shown	Online Dissolved Gas Analyzer	Online dissolved gas analyzers continuously monitor gas accumulation in the station transformer's oil to ensure operation over its lifecycle. If a transformer experiences a fault, various gases accumulate in the transformer oil. Tracking the rate of change of these gases can provide an early indication of developing faults in a transformer.
Not Shown	Core, Windings, Oil	A station transformer's core, primary and secondary windings and oil insulation are sealed within the transformer's enclosure. These elements work together to convert supplied electricity from a high or medium voltage to outgoing electricity at a lower voltage through the use of electrical and magnetic induction. This allows for electricity to be stepped down from a transmission or sub-transmission voltage to a distribution voltage for economic delivery throughout Hydro Ottawa's service territory.

The average age of Hydro Ottawa's station transformers is 35 years; Figure 6.4 illustrates the population demographics.

Figure 6.4 – Station Transformer Age Demographics

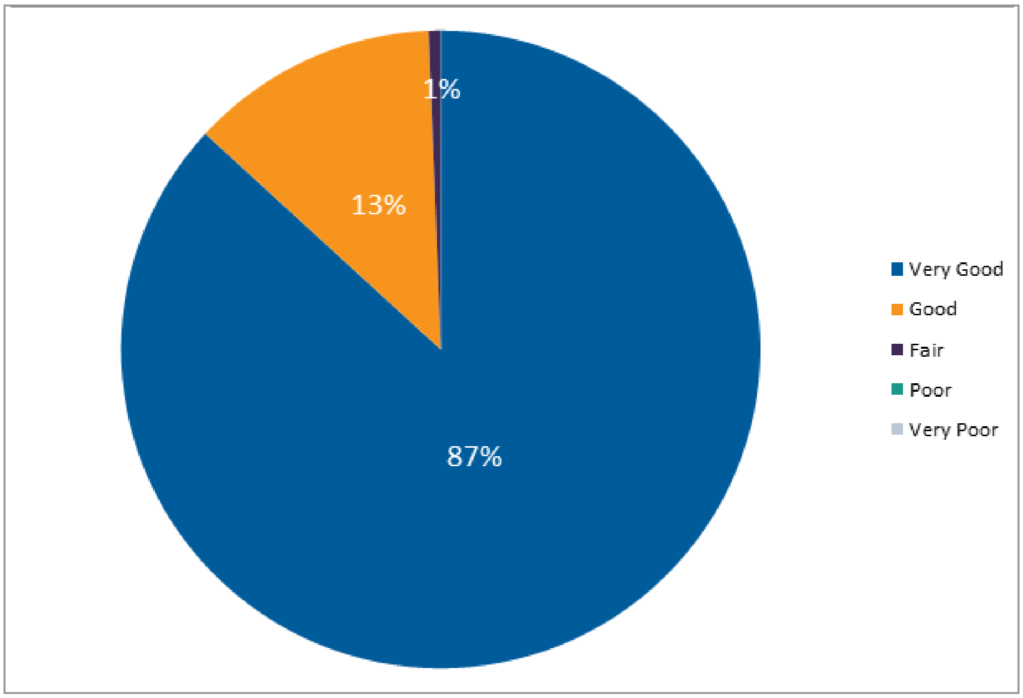


The expected service life of station transformers, where the probability of failure is approximately 1.5% or greater, is an age of 55 years. There are seven transformers that have reached the expected service life and 86 within 10 years of their expected service life.

Figure 6.5 – 28 kV Station Transformer at Terry Fox MTS

The health index of a transformer is determined through various criteria such as visual inspections, power factor tests, load history, infrared scanning, oil analysis (dissolved gas analysis and degree of polymerization), as well as additional criteria for on-load tap changers if applicable. The resultant health index is a condition rating from Very Good to Very Poor. This rating is an accurate representation of the current condition of the transformer and is used to drive maintenance and renewal programs. Hydro Ottawa has an active maintenance and monitoring program for its station transformers given their criticality in the system. A summary of known Hydro Ottawa's station transformer conditions is shown in Figure 6.6. The majority of station transformers are in Good or Very Good condition as a result of proactive preventative maintenance practices and ongoing monitoring, including Dissolved Gas Analysis.

Figure 6.6 – Station Transformer Condition Demographics



6.1.1.2. Station Switchgear

Hydro Ottawa owns and maintains switchgear assemblies in 85 stations, which include Hydro Ottawa-owned stations, as well as stations with shared ownership with HONI. The station switchgear asset class consists of breakers, switches, bus insulation, support structures, protection and control systems, arrestors, control wiring, ventilation, and fuses. Figure 6.7 and Table 6.2 below detail the various components of a station switchgear lineup.

Figure 6.7 – Station Switchgear and Breakers

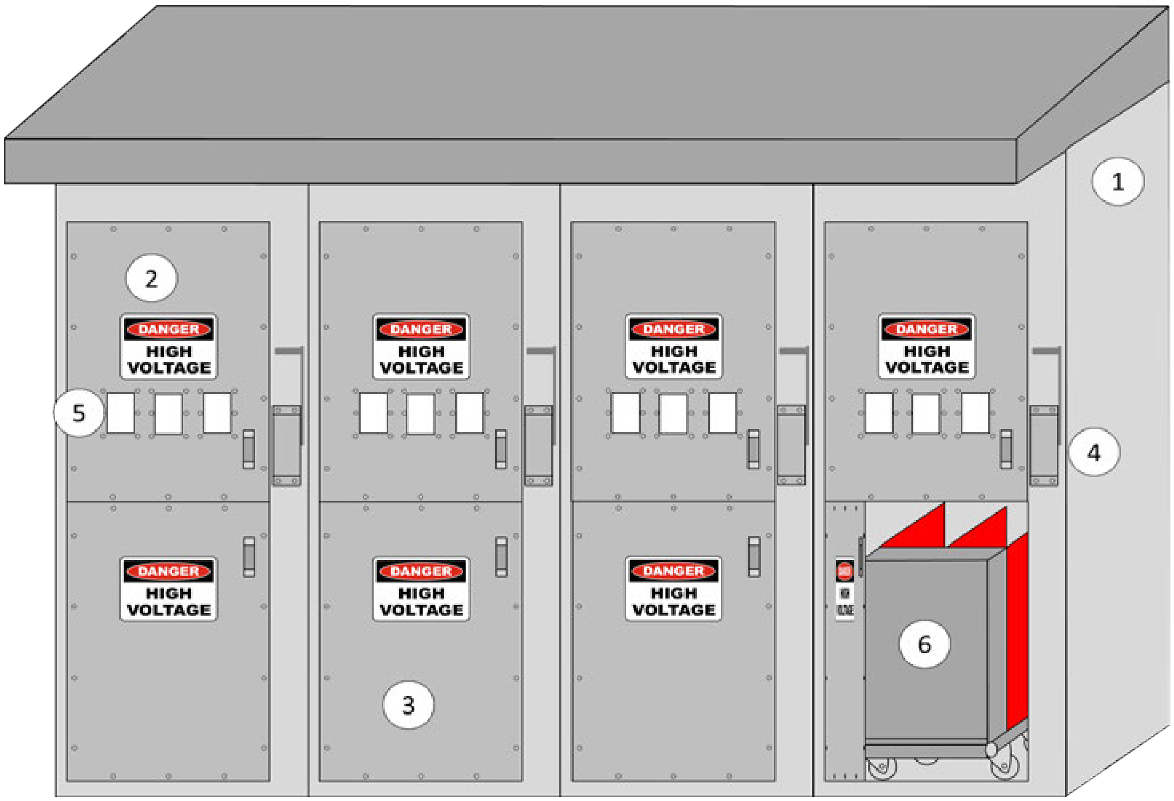


Table 6.2 – Station Switchgear and Breaker Components

Figure Number	Component	Function
1	Enclosure/ Plenum	Enclosures maintain isolation of the medium voltage and high voltage equipment from outside sources and provide a barrier between energized equipment and the persons at the station. Additionally, the enclosure protects the inside equipment from damage and increases system reliability by creating a barrier. Finally, the enclosure houses the insulation, bus bars, switches, breakers, control cabling and isolation pieces of the switchgear. The plenum is part of the arc resistant design of a switchgear, which services to strategically direct and contain the forces associated with an arc flash to avoid catastrophic failure of the enclosure of the switchgear.
2	Control Cabinet	The control cabinet houses all of the low voltage and control signals, such as instrument transformer feedback, that are used to operate and provide communication signals from breakers.
3	Breaker Door	The breaker door isolates the breaker from the medium voltage equipment and provides a mechanism for removing breakers for isolation from the attached bus.
4	Breaker Switch	The breaker switch is used to open and close the circuit breaker's connection to the bus, housed within the switchgear.
5	Switchgear Window	Breaker windows allow a view into the switchgear enclosure for inspection and to visually identify connected or disconnected breakers.
6	Circuit Breaker	The circuit breaker is a protection and isolation device used to connect an electrical bus to a feeder or another electrical bus. Circuit breakers are rated for a specific current at which they will open, breaking load, as a protection device. The circuit breaker can be activated locally or remotely, and via other protective relays that can be wired into the control cabinet and breaker trip circuit.

Figure 6.8 – Station Switchgear at Woodroffe TS

Due to the different expected operating life of each breaker type, it is more appropriate to break out station breakers per type, rather than as one asset group, Figures 6.9 to 6.12 below illustrate the population demographics of each type. The expected service life of air breakers is 42 years, and the average age is 47. The expected service life of oil breakers is 55 years, and the average age is 54. The expected service life of gas (SF6) breakers is 51 years, and the average age is 24. The expected service life of vacuum breakers is 46 years, and the average age is seven. There are 532 breakers that have reached their expected service life, and 49 that are within 10 years of their expected service life.

Figure 6.9 – Station Air Breaker Age Demographic

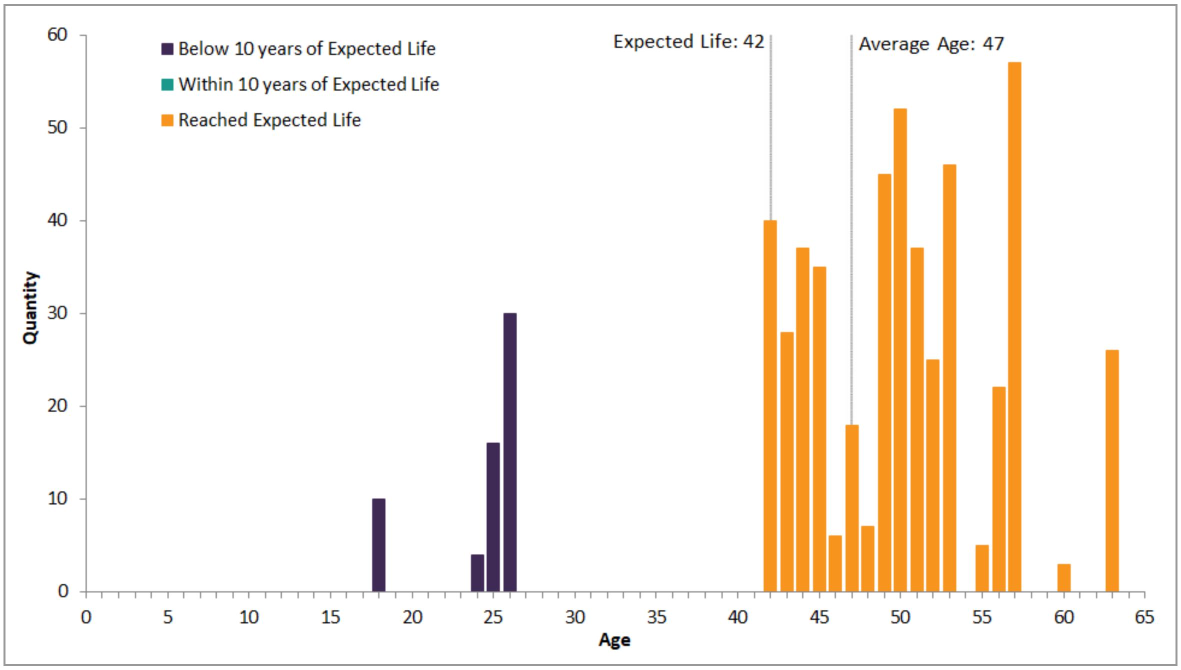


Figure 6.10 – Station Oil Breaker Age Demographic

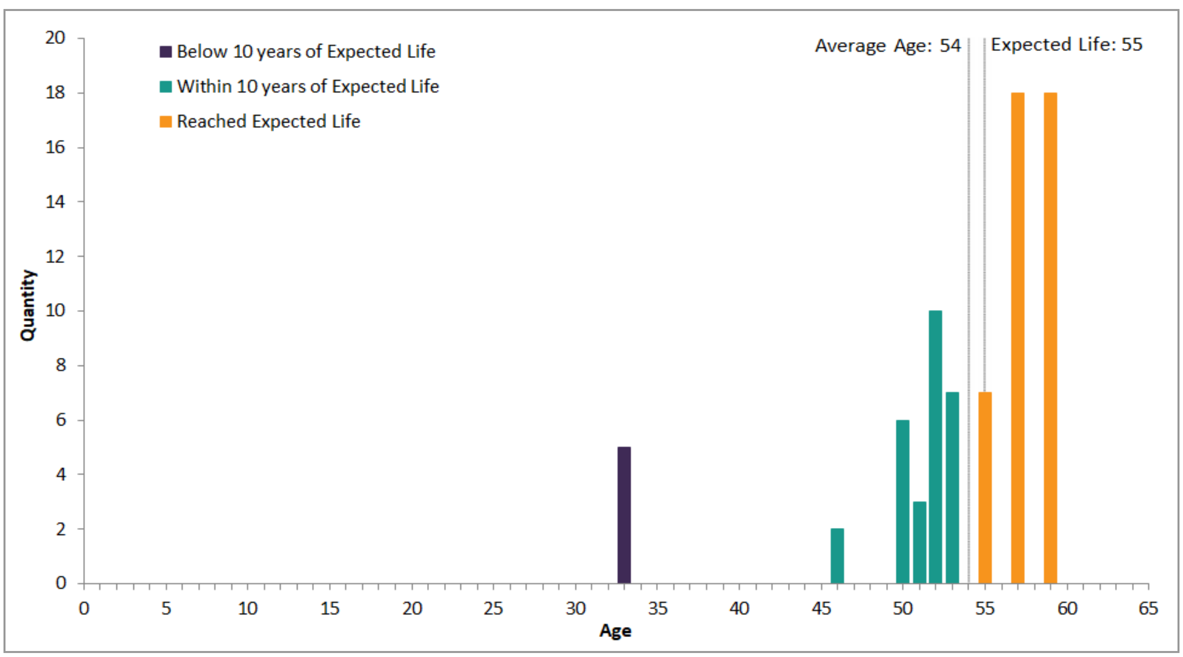


Figure 6.11 – Station Gas Breaker Age Demographic

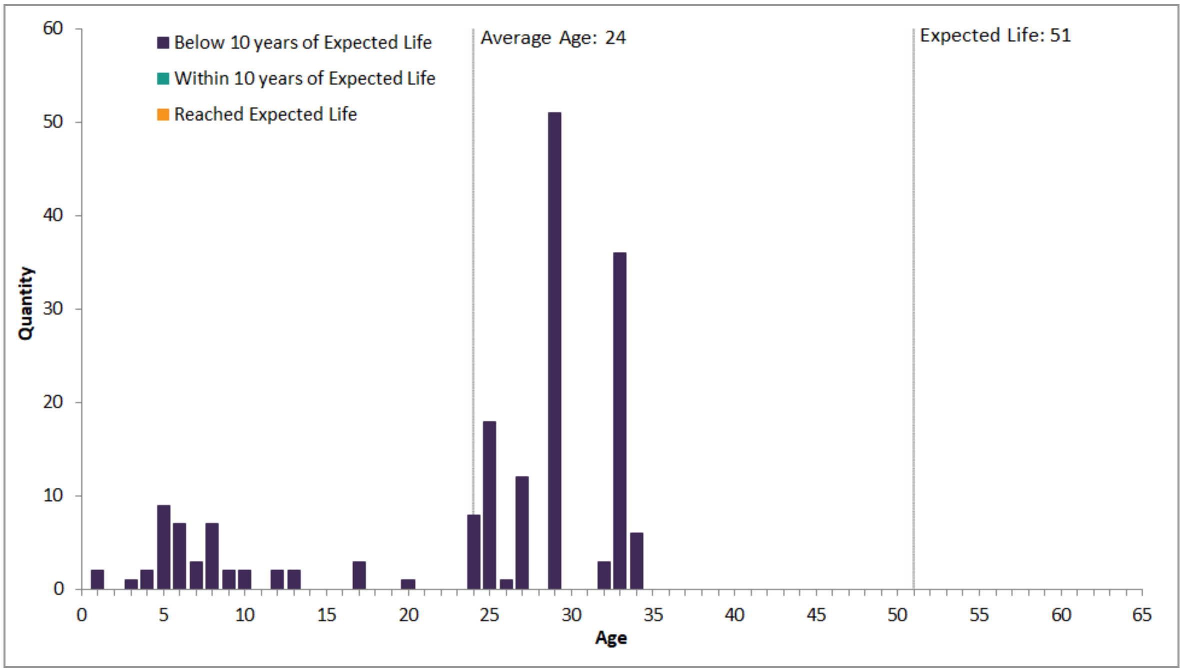
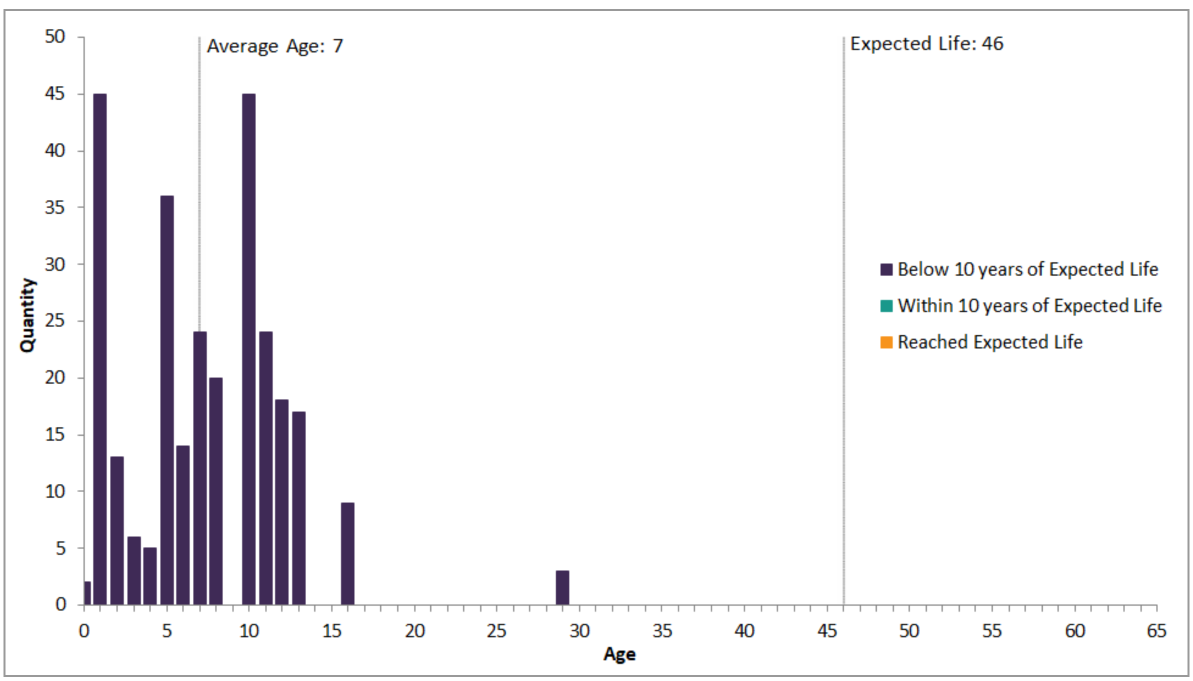
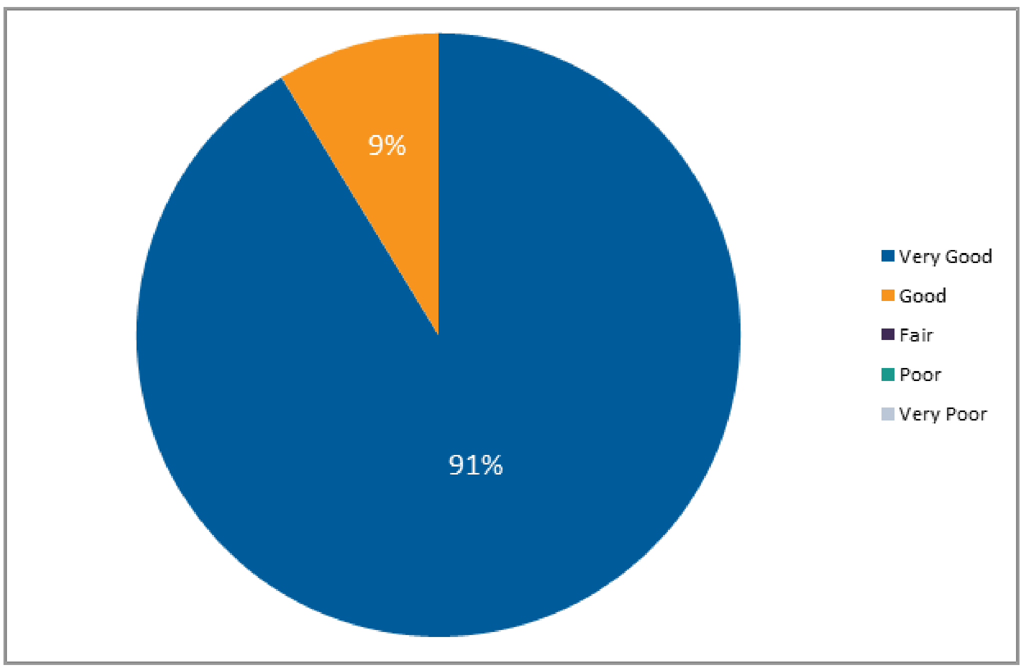


Figure 6.12 – Station Vacuum Breaker Age Demographic



The health index for Station Switchgear takes into account the many functional and supporting parts of the equipment. A qualitative assessment of the equipment condition, based on subject matter experience, is done on the switches, breakers, bus, insulation, and supporting structures. The equipment is then reviewed for functional obsolescence and the availability of spare parts. The health index is calculated using this information and the age of the equipment. A summary of known Hydro Ottawa's station breaker conditions is shown in Figure 6.13. The majority of station breakers are in Good or Very Good condition as a result of proactive preventative maintenance practices and ongoing inspection.

Figure 6.13 – Station Breaker Condition Demographics



6.1.1.3. Station Batteries

Hydro Ottawa's station batteries and chargers asset class provide power for operating station breaker trip and closing coils, DC lights, and relays when the station service power is lost. Hydro Ottawa owns 63 station battery banks and chargers within its stations. Figure 6.14 below illustrates a station battery bank. Table 6.3 below lists its components.

Figure 6.14 – Station Batteries

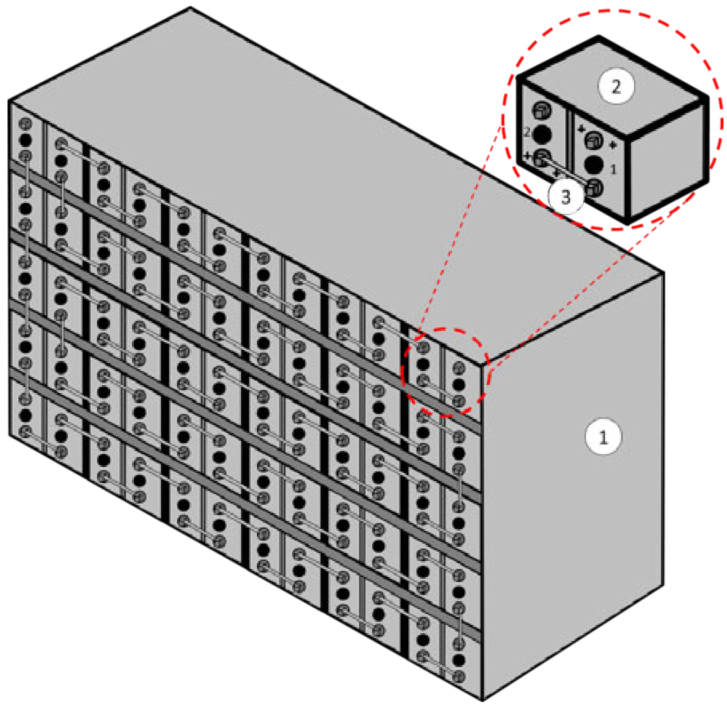


Table 6.3 – Station Battery Bank Components

Figure Number	Component	Function
1	Battery Bank	The battery bank serves as the power source for DC systems in substations, which includes equipment such as relays and tripping coils. The bank supplies these systems and allows for their continued function when there is an electrical interruption.
2	Battery Cell	Battery cells independently hold charge and provide a specific voltage to be used in summation for the battery system. Individual battery cells can be replaced eliminating the need for replacement of the whole battery bank.
3	Battery String Connection	Battery string connections allow for battery cells to be connected in series, creating a sum voltage of all cells connected that is equal to the nominal rating of the battery.
Not Shown	Battery Charger	Battery chargers supply electricity to the battery cells to ensure they are able to support the connected DC systems. The charger also provides alarms in the case of abnormal conditions.

Due to the different expected operating life of each battery type, it is more appropriate to break out batteries per type, rather than one asset group. Figure 6.15 and Figure 6.16 illustrate the population demographics for each battery type. Vented lead acid (“VLA”) batteries have an expected operating life of 25 years, with an average age of eight years. Valve-regulated lead acid (“VLRA”) batteries have an expected operating life of 15 years, with an average age of six years. There are no batteries that are past their expected service life and six batteries that are within 10 years of their expected service life.

Figure 6.15 – Station VLA Battery Bank Age Demographics

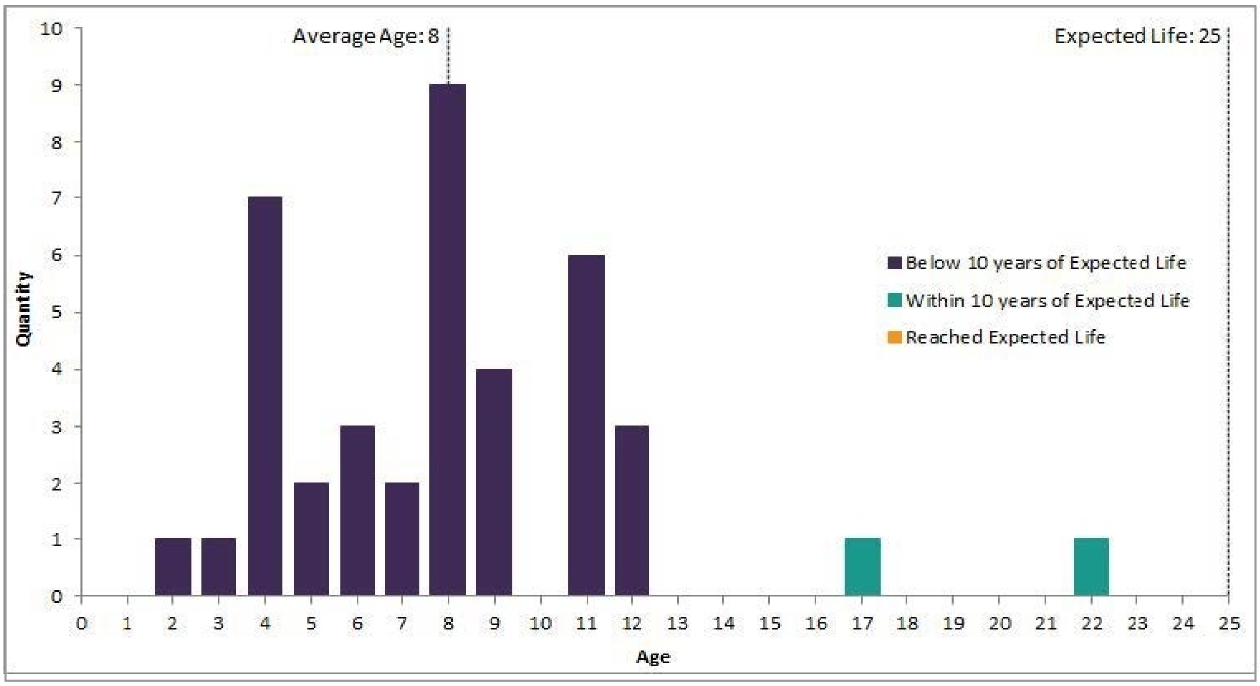
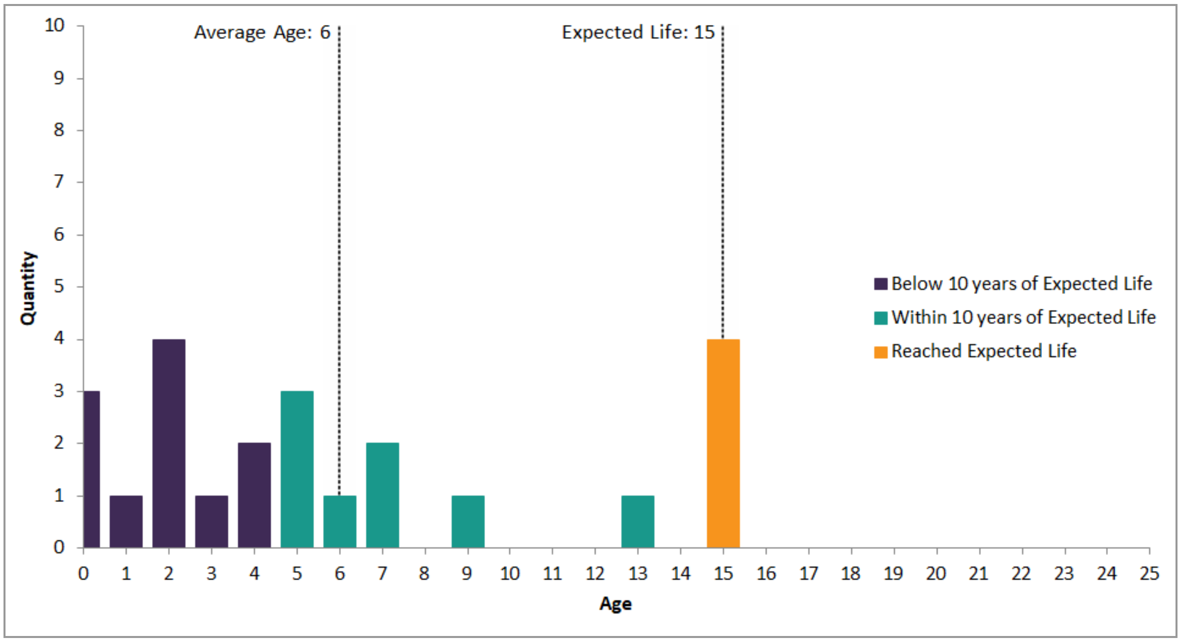


Figure 6.16 – Station VRLA Battery Bank Age Demographics



6.1.1.4. P&C

Hydro Ottawa's Protection & Control ("P&C") equipment facilitates the control and monitoring of the distribution system. Of the components contained within the P&C asset class, protective relay has a proactive testing and maintenance program. Hydro Ottawa owns 1,006 station protective relay sets. Figure 6.17 below illustrates two main types of protection relays, Electromechanical (left) and Microprocessor (right). Table 6.4 below lists their components.

Figure 6.17 – Station Protective Relays

Table 6.4 – Protection Relay Components

Figure Number	Component	Function
1	Time Dial	The time dial is used to vary the operating time of the relay. By changing the timing, various protection devices can coordinate with each other.
2	Instantaneous Trip Setting	The instantaneous trip setting is a value in amperes that when exceeded, will initiate an immediate trip output from the relay. The tripping of the relay is used to protect downstream equipment from electrical damage and maintain public and employee safety.
3	Tap Trip Setting	The tap trip setting is a value in amperes that when exceeded, will initiate a trip output from the relay following the specified curve associated with the relay and settings. The tripping of the relay is used to protect downstream equipment from electrical damage and maintain public and employee safety.
4	Induction Disc	The induction disc begins rotating when the amperage exceeds the trip setting and initiates the tripping of the relay and protective device. The time required for the disk to spin and trip the contact is set by the time dial.
5	Breaker Status	Breaker status lights provide feedback as to the breaker position.
6	Display	The display shows settings and provides information on the relay's measurements, allowing for local control and troubleshooting of distribution system events and the minimization of outages.
7	Indicating Lights	Indicating lights provide various statuses related to the relay's status and operation.
8	USB & Communications Port	USB & communication ports are used for local connection and for local data transfer to and from relays.

Figures 6.18 through 6.20 below illustrate the population demographics of protective relay sets as well as shows their average age. The expected service life of protective relays is dependent on the relay type, and as such is 40 years for electromechanical, 15 years for electronic, and 25 years for microprocessor based relays.

Figure 6.18 – Station Electromechanical Relay Demographics

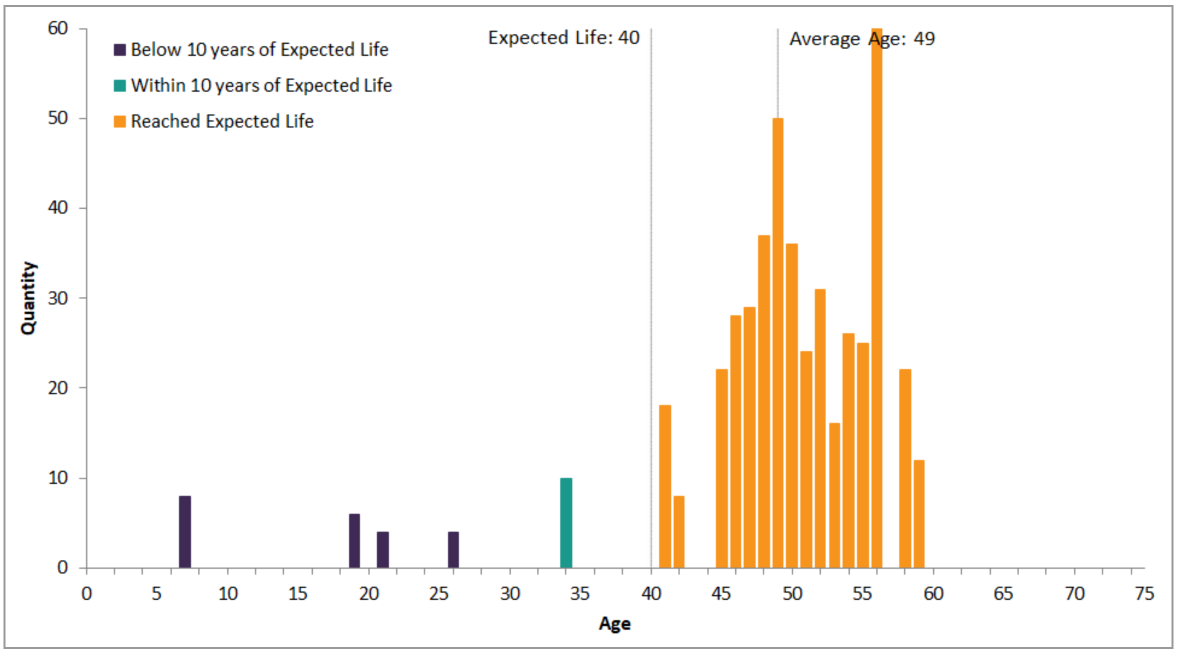


Figure 6.19 – Station Electronic Relay Demographics

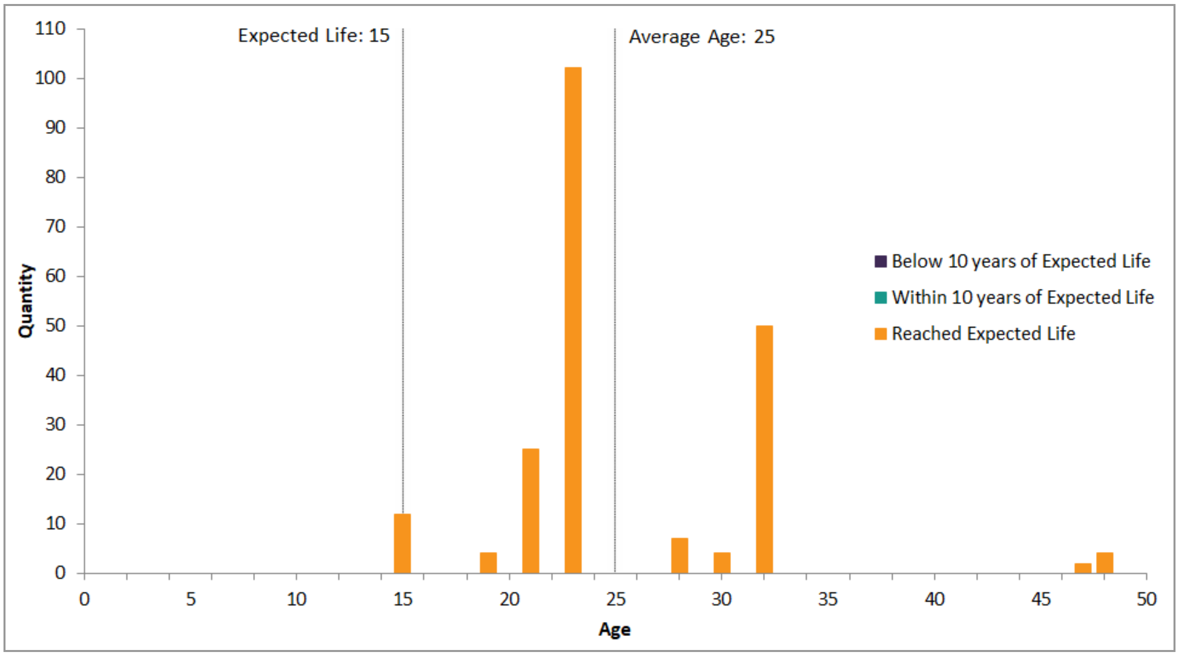
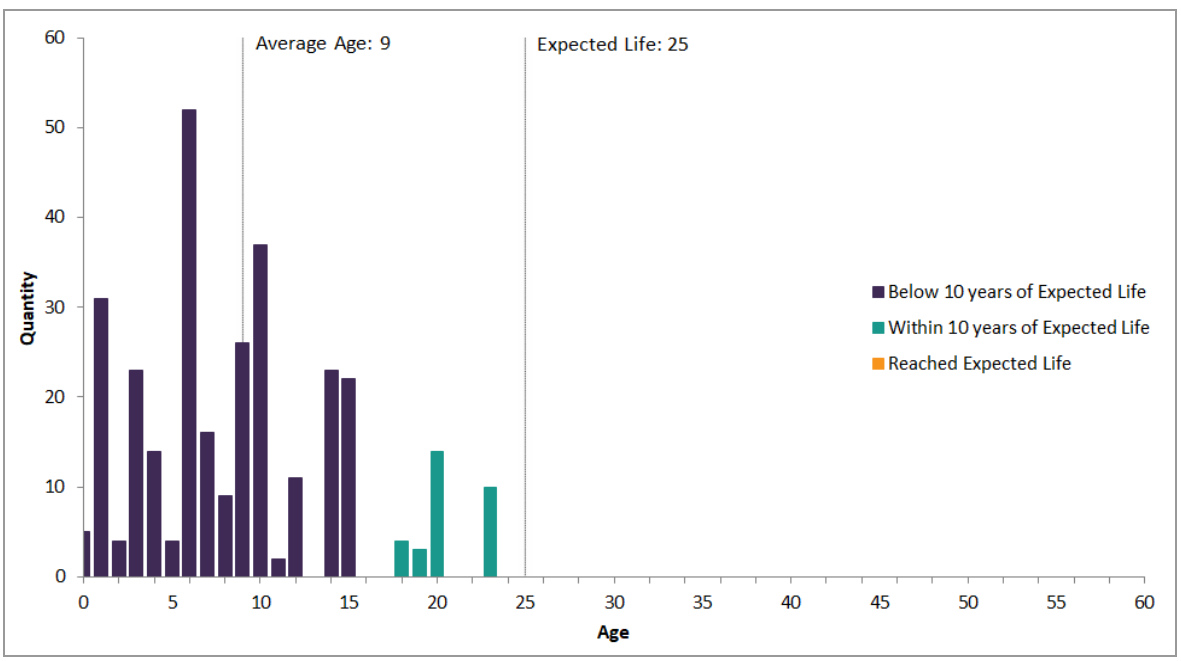


Figure 6.20 – Station Microprocessor Relay Demographics



6.1.2. Overhead System Assets

Hydro Ottawa overhead system assets are integral for the distribution of electricity. The overhead system is Hydro Ottawa's standard design for delivering power and can be located in a range of locations. Overhead system assets are broken into the following main asset classes:

- Distribution poles and fixtures
- Overhead distribution transformers
- Overhead distribution switches

6.1.2.1. Distribution Poles

Hydro Ottawa owns 47,506 wood poles[1] and 1,000 non-wood poles, and operates on an additional 13,781 wood and 338 non-wood poles owned by third parties. Figure 6.21 below illustrates a wood pole with all of the fixtures and overhead conductor system attachments. Table 6.5 below lists the individual components.

[1] Quantities of Hydro Ottawa owned wood and non-wood poles as of Jan 2, 2019.

Figure 6.21 – Distribution Pole with Fixtures and Overhead Conductor System

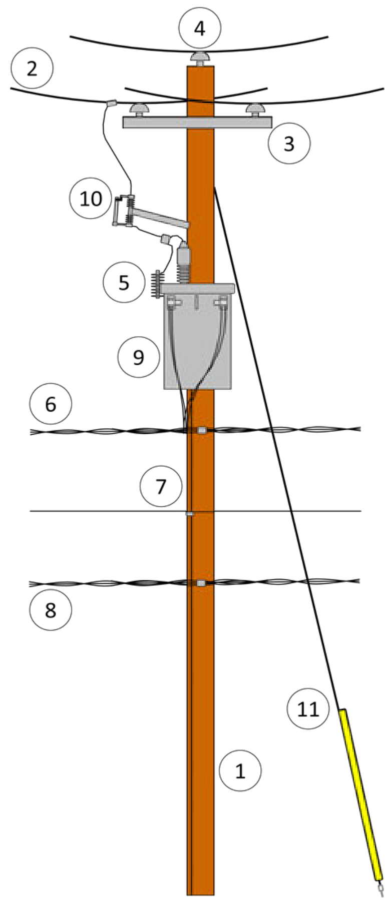


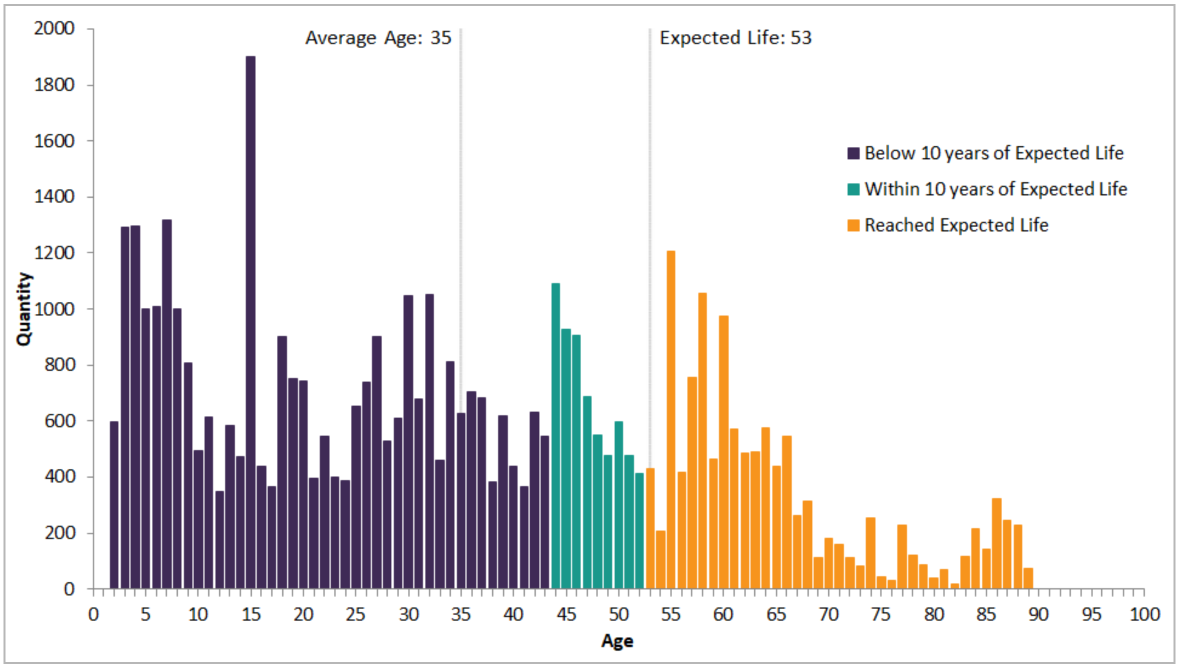
Table 6.5 – Pole Components

Figure Number	Component	Function
1	Poles	Poles support maintaining clearances for public and employee safety. They also support the transition of conductor between the overhead and underground electrical systems and equipment such as overhead switches, transformers, communication equipment and metering collectors.
2	Primary Overhead Conductor	Primary overhead conductor distributes electricity at medium voltages across the service territory. It also allows for a means of installing fault indicating equipment allowing for expedited fault finding and restoration.
3	Cross Arms	Cross arms support insulators and other electrical equipment such as overhead switches. They are also used as an anchoring point on dead-end poles.
4	Insulators	Insulators support overhead conductors while protecting equipment from the flow of current.
5	Surge Arrestors	Surge arresters protect the system and equipment by suppressing voltage surges from various causes (e.g. lightning).
6	Secondary Overhead Conductors	Secondary overhead conductor distributes low voltage electricity suitable for customer use.
7	Grounding Conductor	Grounding conductor allows for a low impedance path for current to ground to limit buildup of unsafe voltage on the electricity system and equipment.
8	Third Party Equipment	Poles support third party equipment such as telecom wires, signs and third party low voltage services (e.g. street lighting).
9	Overhead Transformer	Pole mounted transformers are described in section 6.1.2.2.
10	Fused Cut Out	Fused cutouts are described in section 6.1.2.3
11	Guy Wires and Anchors	Guy-wires and anchors support unbalanced lateral loading and can be used to support the pole under inclement weather. A high visibility plastic cover is used for public and employee safety.

Figure 6.22 – Installation of New Pole Line

The average age of this asset class is 35 years. Figure 6.23 below illustrates the population demographics. The expected service life of wood poles is 53 years. There are 12,089 poles that have already reached the end of their expected service life and an additional 6,128 poles within 10 years of the end of their expected service life.

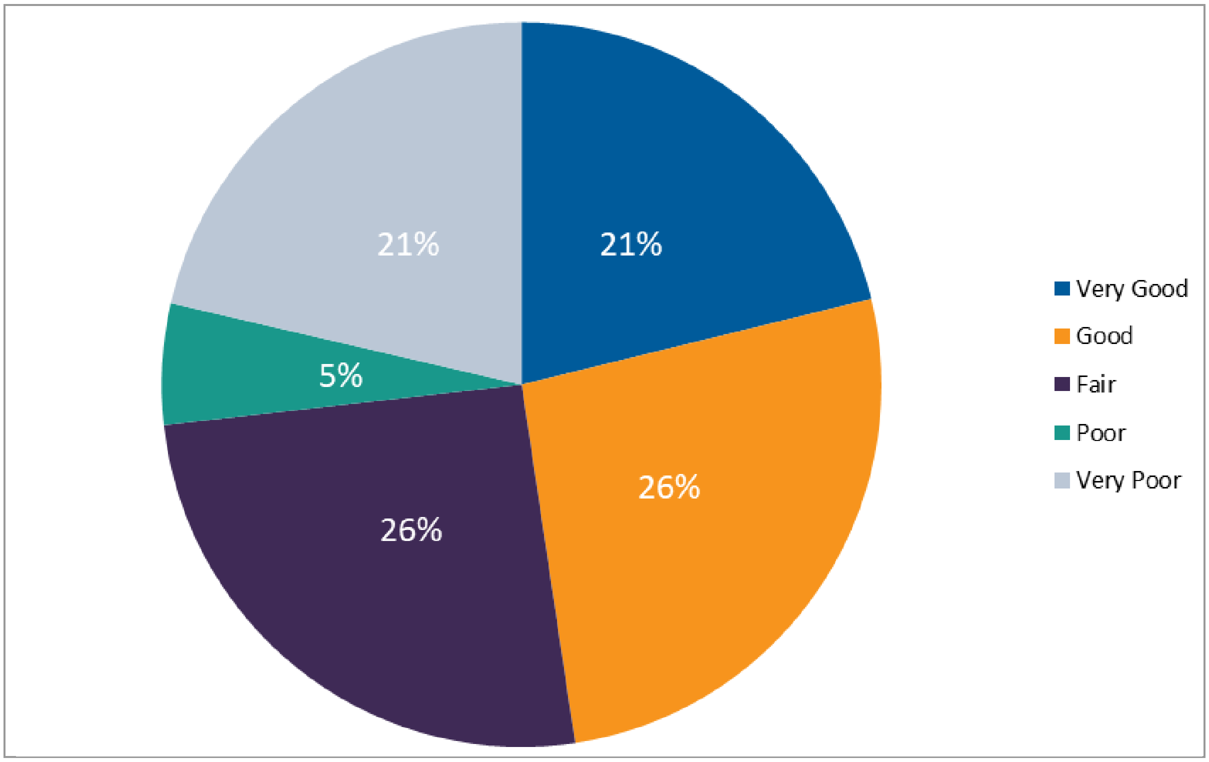
Figure 6.23 – Distribution Wood Pole Age Demographics[2]



The health index for wood poles is largely based on the estimated remaining mechanical strength in the pole's butt determined using resistograph measurements. Assessment of the pole's condition, and the condition of the ancillary equipment attached to it, are included as part of the process to identify candidate assets for corrective actions. A summary of known Hydro Ottawa's distribution pole conditions is shown in Figure 6.24 below.

[2] Datum of March 20, 2019 is used for age demographics.

Figure 6.24 – Distribution Wood Pole Condition Demographics



6.1.2.2. Overhead Transformers

Hydro Ottawa owns and operates 15,619 overhead transformers. These are installed in both front and rear lot to service customers. Figure 6.25 illustrates two types of overhead transformers (single phase (left) and three phase (right). Table 6.6 below lists its components.

Figure 6.25 – Overhead Transformer

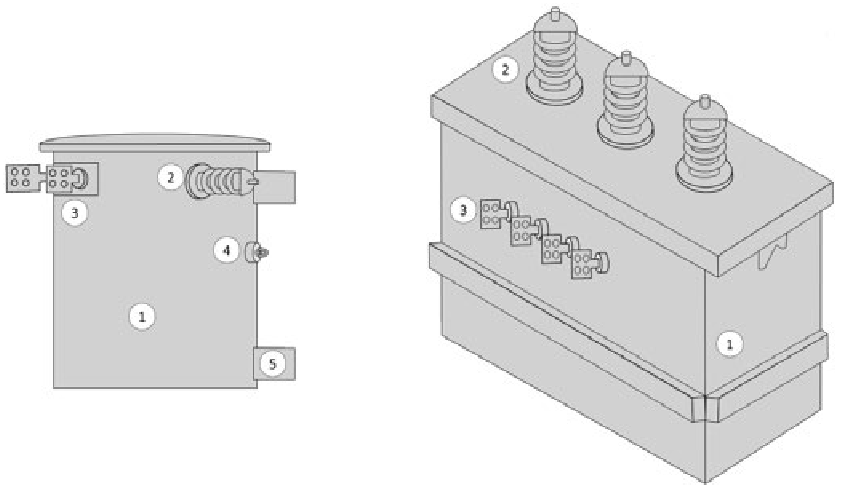


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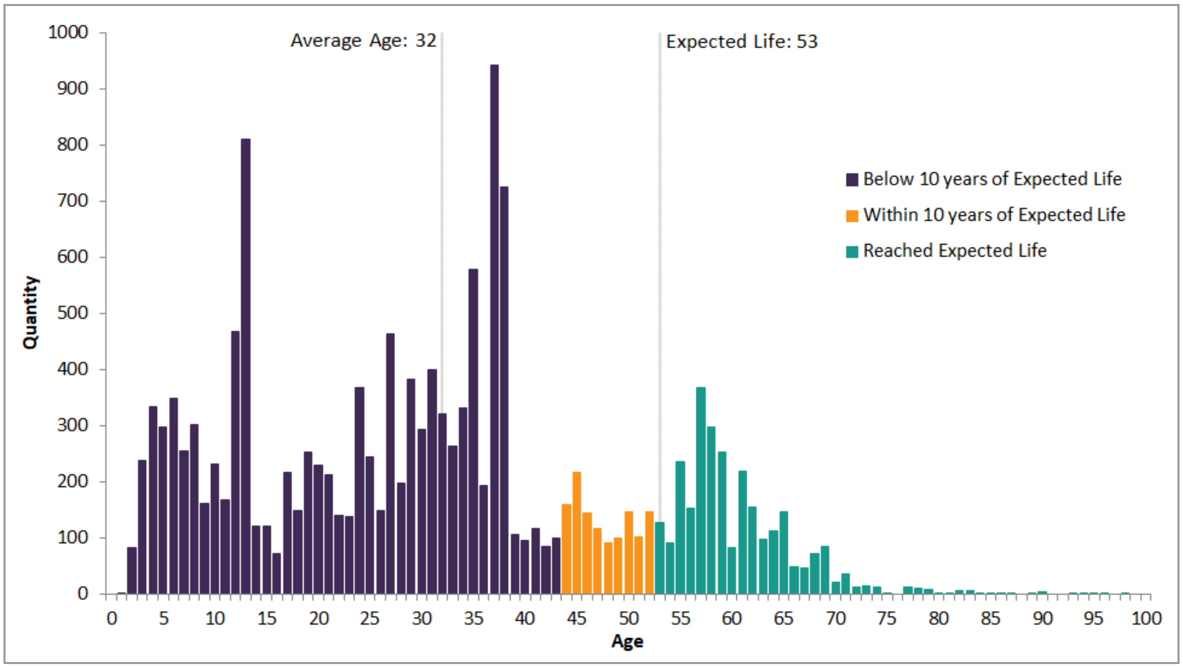
Table 6.6 – Overhead Transformer Components

Figure Number	Component	Function
1	Enclosure	Distribution overhead transformer enclosures maintain isolation of the medium and low voltage equipment from outside sources while ensuring security from the public for increased safety. Additionally, the enclosure protects the inside equipment from damage and increases system reliability by isolating it from weather, animals and contaminants.
2	Primary Bushing	Primary bushings support an insulated flow of current from the connecting primary overhead conductor to the inside connections through the grounded enclosure.
3	Secondary Bushings	Secondary bushings support an insulated flow of current from the inside connections through the grounded enclosure to the secondary conductor.
4	Tap Changer	The tap changer is used to regulate the voltage of the distribution overhead transformer by changing the transformer's winding ratio. The tap changer can rotate up or down to either increase or decrease the ratio. This ensures that the voltage supplied by transformer is constant, even in cases where the incoming voltage is high or low. This results in the distribution of high-quality power.
5	Hanging Lugs	Hanging lugs are used to mount distribution overhead transformers, such as to poles.
Not Shown	Ground Connection	The ground connection allows for a low impedance path for current to ground to limit buildup of unsafe voltage on the electricity system and equipment.
Not Shown	Surge Arrestors	Surge arresters protect the distribution overhead transformer by suppressing voltage surges from various causes (e.g. lightning).

Figure 6.26 – Installation of Overhead Transformer

The average age of this asset class is 32 years. Figure 6.27 below illustrates the population demographics. The expected service life of overhead transformers is 53 years. There are 2,749 transformers that have already reached the end of their expected service life, while an additional 1,223 overhead transformers are within 10 years of the end of expected service life.

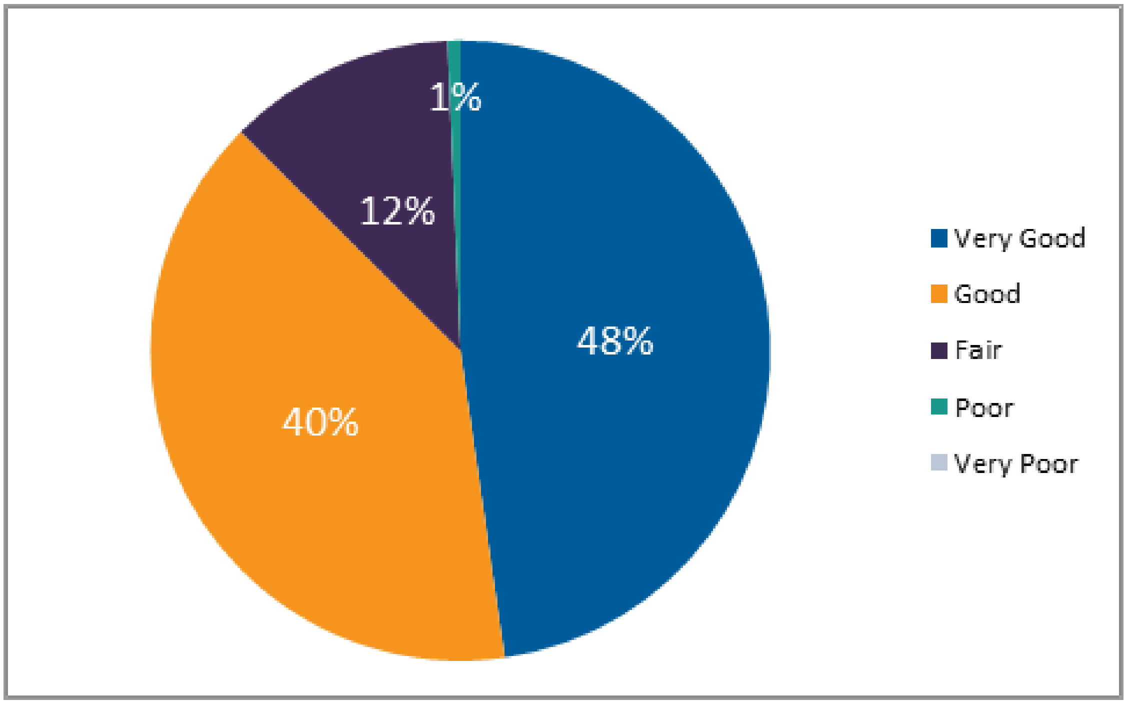
Figure 6.27 – Overhead Transformer Age Demographic[3]



The health index for overhead transformers is based on age and asset condition data collected from planned programs of inspection that use both visual and thermographic inspection techniques. A summary of known Hydro Ottawa's overhead transformer conditions is shown in Figure 6.28 below.

[3] Datum of January 29, 2019 is used for age demographics.

Figure 6.28 – Overhead Transformer Condition Demographic



6.1.2.3. Overhead Distribution Switches and Reclosers

Hydro Ottawa's distribution overhead switch and recloser asset class consists of all overhead load break switches, reclosers, fuse cut-outs and inline switches, with a primary voltage rating up to and including 44 kV. In general, the purpose of this asset class is to isolate faulted sections of Hydro Ottawa's distribution system; minimize the impact to customers; isolate sections of the distribution system to enable work to proceed while affecting the smallest part of the distribution system possible; isolate customers through requests; and provide backup supply from other feeder(s). Figure 6.29 below illustrates overhead switches and Table 6.7 below lists its components.

Figure 6.29 – Overhead Switch

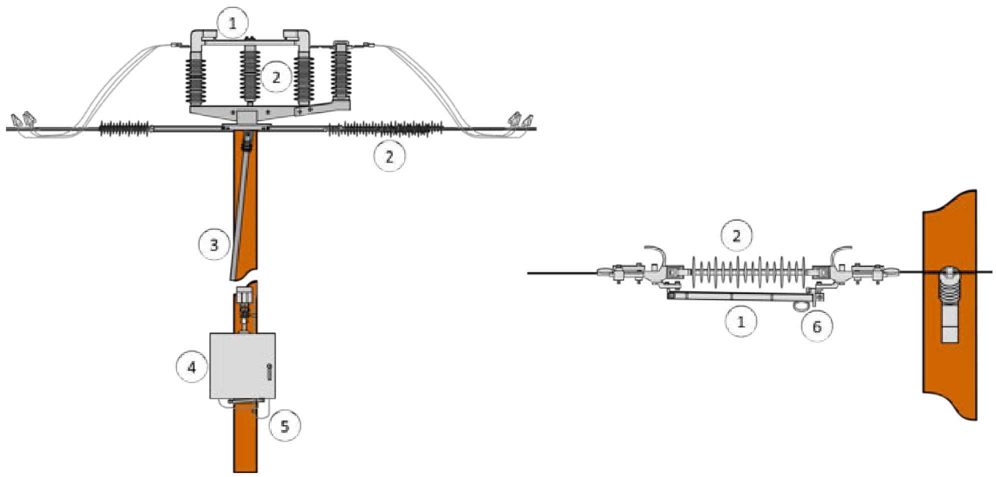


Table 6.7 – Overhead Switch Components

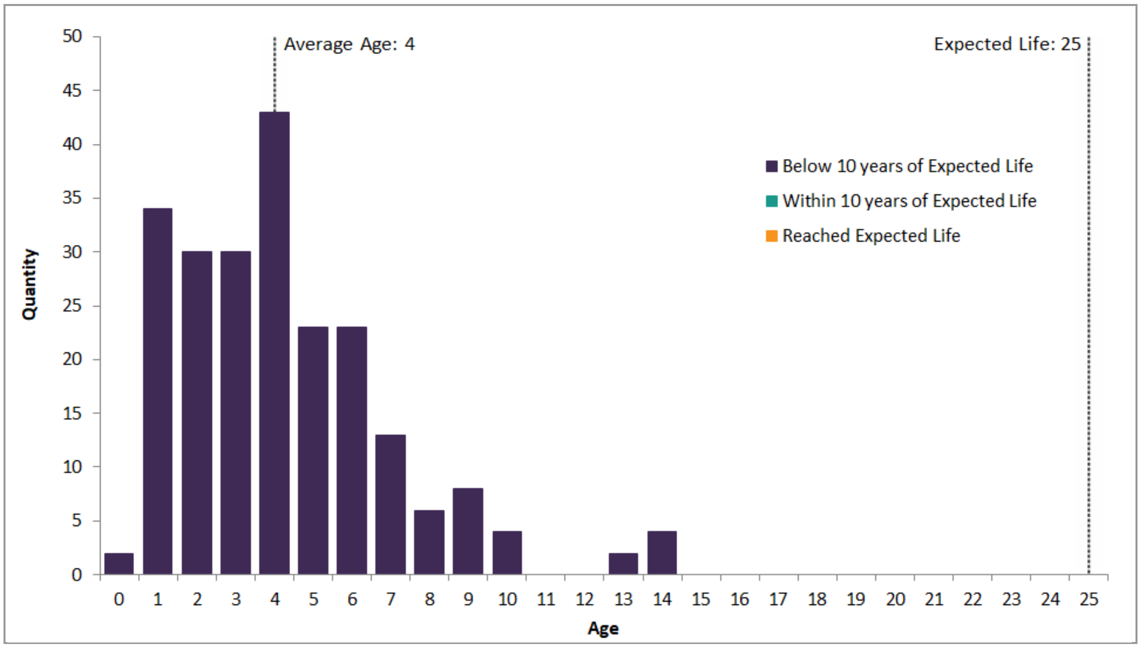
Figure Number	Component	Function
1	Solid Blade	The solid blade of an overhead switch allows the flow of current when closed and interrupts the flow of current when opened.
2	Insulator	Insulators support overhead conductors while protecting equipment from the flow of current.
3	Operating Pipe	Operating pipe is the mechanism that engages the solid blade to open or close allowing for switching from the ground versus the top of the pole.
4	Control Cabinet	Control cabinets house the low voltage equipment necessary to communicate with, monitor, and control motor operated switches.
5	Control Wire	Control wire connects the control cabinet to the overhead switch's motor.
6	Hot Stick Operating Hook	The hot stick operating hook is a mechanical access point to manually open an overhead switch using a hot stick tool.
Not Shown	Communication Device	A communication device is an antenna or modem that provides remote operability to an overhead switch through the use of the control box and overhead switch's motor.
Not Shown	Fused Cutout	Fused cut-outs allow the flow of current when the current flowing through the fuse is less than the rated value of the fuse. The fuse melts and breaks when the current flowing through the fuse exceeds the rated value.

Hydro Ottawa owns numerous types of overhead switches with different functionality dependent on the required application. Hydro Ottawa owns 34,991 sets (set refers to one or more switches operating in concert, but not necessarily mechanically connected) of distribution overhead switches throughout the service territory (26,958 in-line fuses and fused cut-outs).[4] Most of the utility's overhead switches, including in-line fuses and fused cut-outs, are subject to a proactive inspection program but are not subjected to proactive maintenance. Hydro Ottawa focuses its proactive inspection and maintenance programs on its 222 higher complexity switches and whose failure carries a greater impact, including the utility's overhead switches that are both loadbreak and gang operated.

The average age of Hydro Ottawa's overhead load break/gang operated switches with a known age is 4.3 years, Figure 6.30 below illustrates the population demographics for this asset class. The installation date is unknown for 53% of these assets. The expected life of overhead load break/gang operated switches is 25 years. All of these switches are below 10 years of their expected life.

[4] Datum of March 6, 2019.

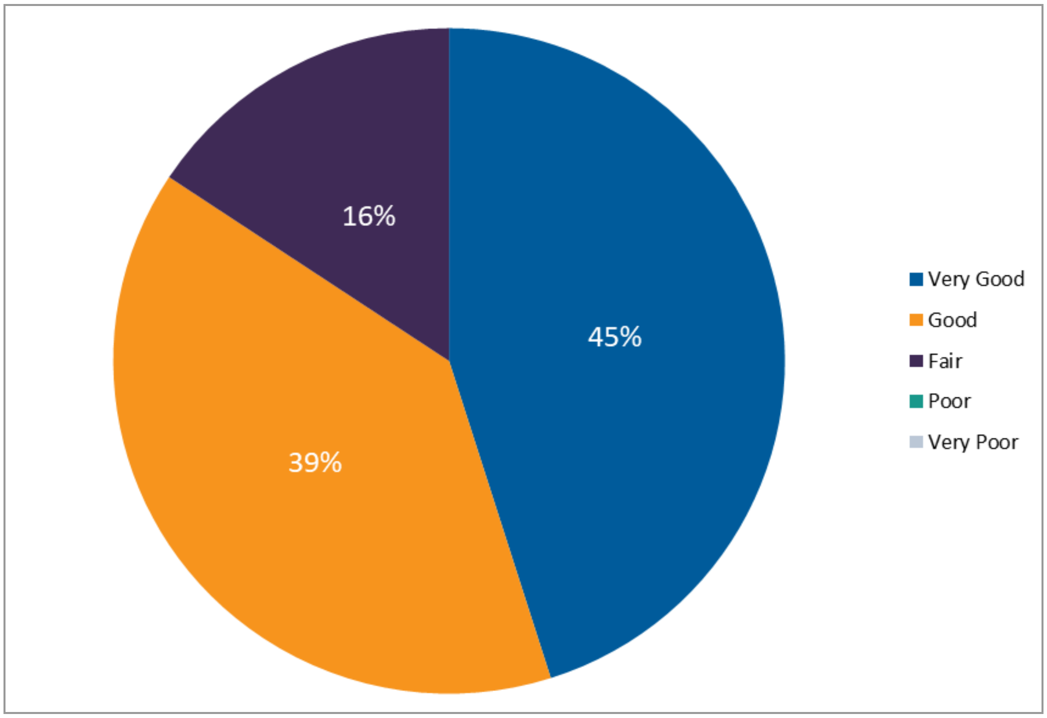
Figure 6.30 – Overhead Switch Age Demographics[5]



The health index for overhead complex switches is largely based on age and the results from thermographic scans. A complex switch is typically a three-phase gang-operated device that is capable of interrupting load. Other criteria include the condition of insulators, solid blades, and operating mechanism. A summary of known Hydro Ottawa's overhead switch conditions is shown in Figure 6.31 below.

[5] Datum of June 20, 2019 is used for the age demographics.

Figure 6.31 – Overhead Switch Condition Demographics



6.1.3. Underground System Assets

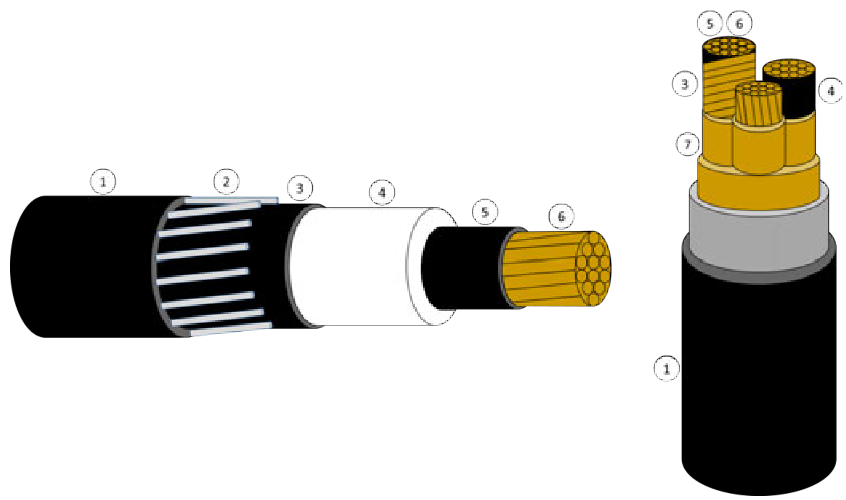
Hydro Ottawa underground system assets are integral for the distribution of electricity. The underground system consists of distribution assets and their respective supporting civil structures that enable delivery of energy to areas where the feasibility of the overhead system is reduced or where it is preferential to have increased aesthetics. Underground system assets are broken into the following categories:

- Distribution cables (PILC, polymer)
- Underground transformers
- Underground switchgear
- Vault transformers
- Underground Civil structures

6.1.3.1. Distribution Cables (PILC)

Hydro Ottawa owns and operates 367 km of triple conductor Paper Insulated Lead Cable ("PILC").[6] It was primarily installed in the core of Ottawa on the 13kV system and is some of the oldest cable in the service territory. Due to higher material costs, increasing procurement lead times, and the need for specialised trades, Hydro Ottawa is moving to phase out this type of cable with polymer insulated cable. Figure 6.32 illustrates both polymer (left) and PILC (right) underground cables. Table 6.8 below lists the individual components.

Figure 6.32 – Distribution Cable



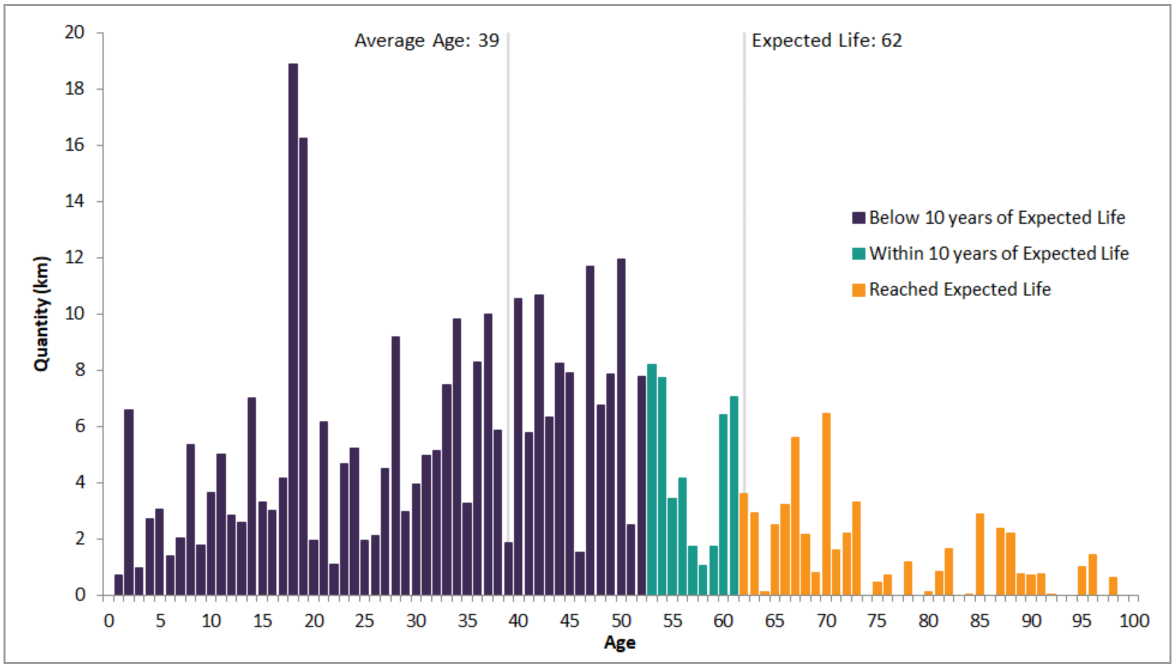
[6] Datum of February 5, 2019 is used in this instance.

Table 6.8 – Distribution Cable Components

Figure Number	Component	Function
1	Jacket	The cable jacket is an outer barrier that protects the cable from mechanical and moisture ingress.
2	Concentric Neutral	The concentric neutrals act as a shield and a neutral cable of carrying unbalance current.
3	Insulation Shield	The insulation shield ensures that unwanted electromagnetic interference is not transmitted along the cable and that excess energy is dissipated to ground properly.
4	Insulation	Insulation provides electrical and physical isolation between conductors and components of the cable.
5	Conductor Shield	The conductor shield protects individual conductors from electromagnetic interference.
6	Conductor	The conductor carries electrical current, and is a path for the flow of electricity from source to supply equipment, such as from transformers to customers.
7	Impregnated Paper Insulation	Impregnated paper insulation is an oil based type of insulation that provides electrical and physical isolation between conductors. This type of insulation is used for paper insulated lead covered cables.

The average age of Hydro Ottawa's PILC cable is 39 years, Figure 6.33 below illustrates the population demographics. The expected service life of PILC is 62 years. There are 52.2 km of PILC cable that has already reached the end of its expected service life and 41.5 km within 10 years of the end of its expected service life.

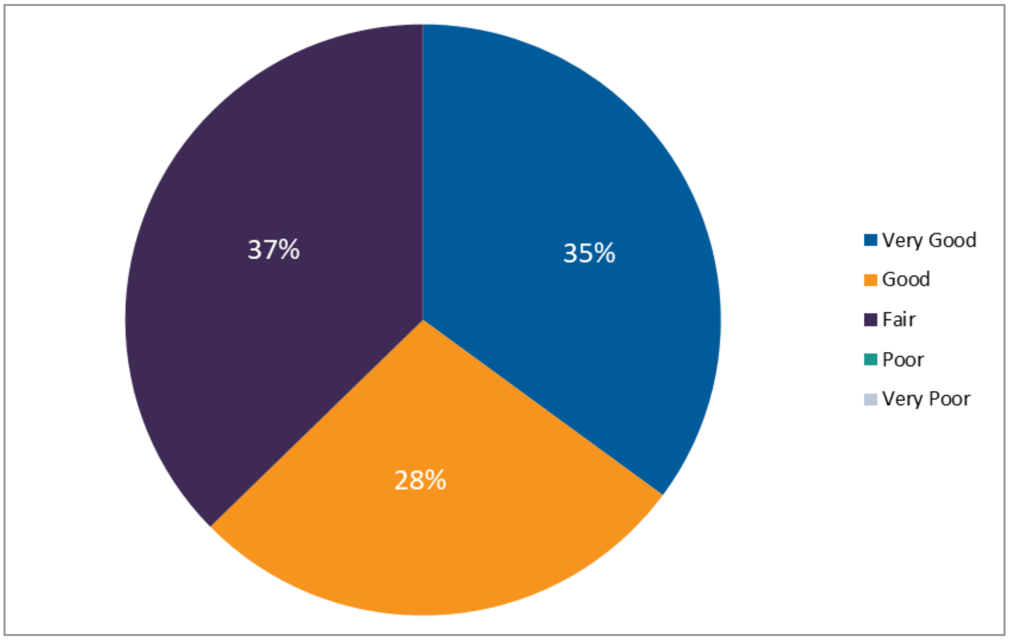
Figure 6.33 – Distribution Cable PILC Age Demographics[7]



The health index for PILC cables is based on a combination of age and failure rate. A summary of known Hydro Ottawa's distribution PILC cable conditions is shown in Figure 6.34 below.

[7] Datum of February 2, 2019 is used for age demographics.

Figure 6.34 – Distribution Cable (PILC) Condition Demographics



6.1.3.2. Distribution Cables (Polymer)

Hydro Ottawa owns and operates 2,578 km of single conductor polymer cable (Cross-Linked Polyethylene ["XLPE"], Ethylene Propylene Rubber ("EPR"), and Butyl Rubber).[8] The installation of this cable uses a mix of concrete encased duct, direct buried duct, and direct buried cable, which can add to the cost and labour requirements when replacing under planned and unplanned events.

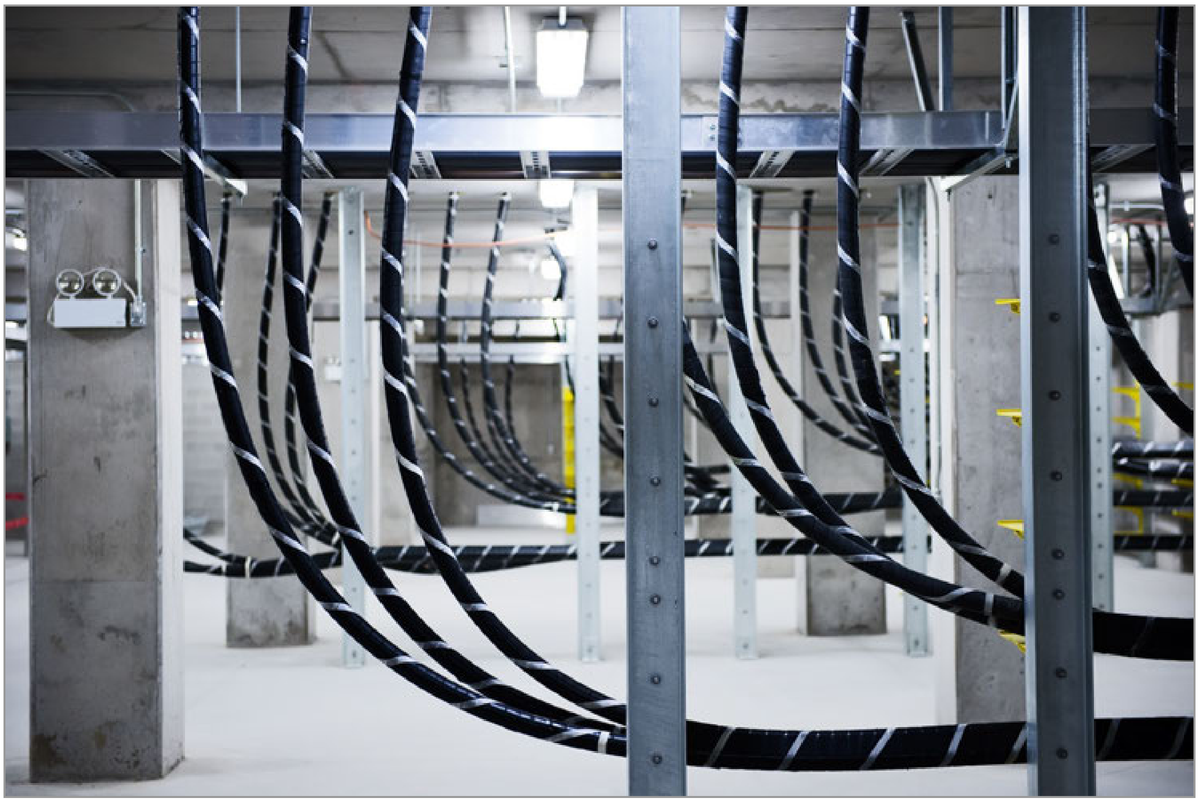
The vast majority of the underground polymer cable is XLPE. EPR makes up a small portion of underground cables and has only recently been introduced as a replacement for PILC cable as it is phased out. For this reason, the condition assessment of underground polymer cable is focused on testing of XLPE cable.

The average age of this asset class is 26 years. Figure 6.35 illustrates the population demographics. The expected service life of XLPE is 45 years. There is 813 km of XLPE cable

[8] Datum of February 5, 2019 is used in this instance.

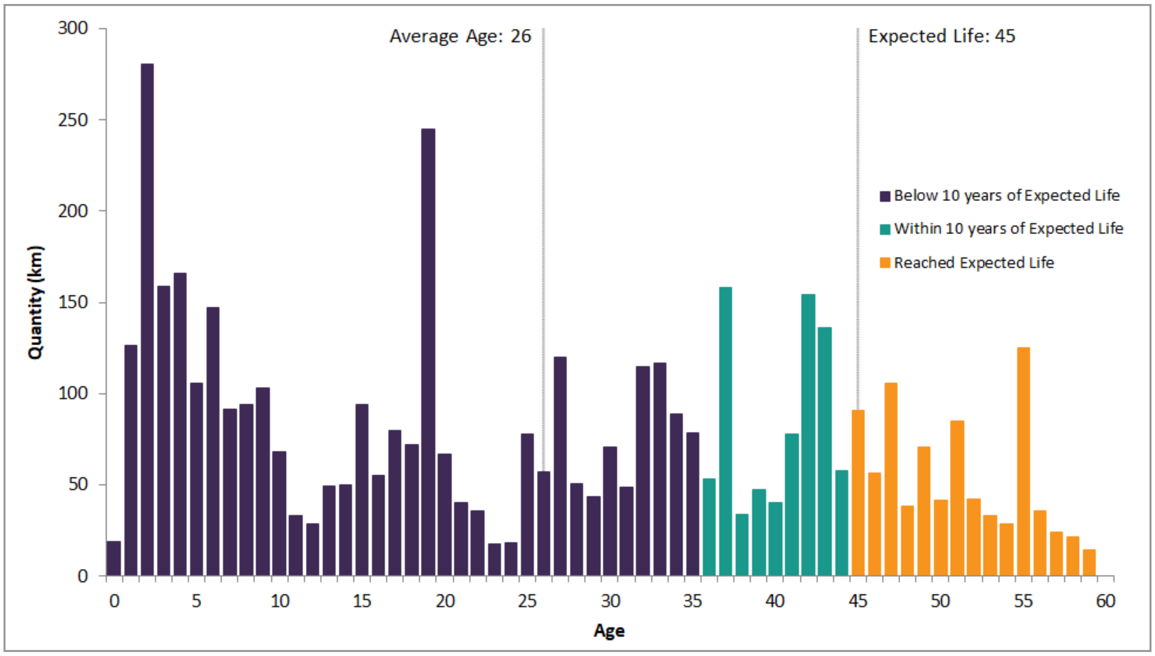
that has reached the expected service life and 758 km within 10 years of the end of its expected service life.

Figure 6.35 – Installation of XLPE Cable in a Station Basement



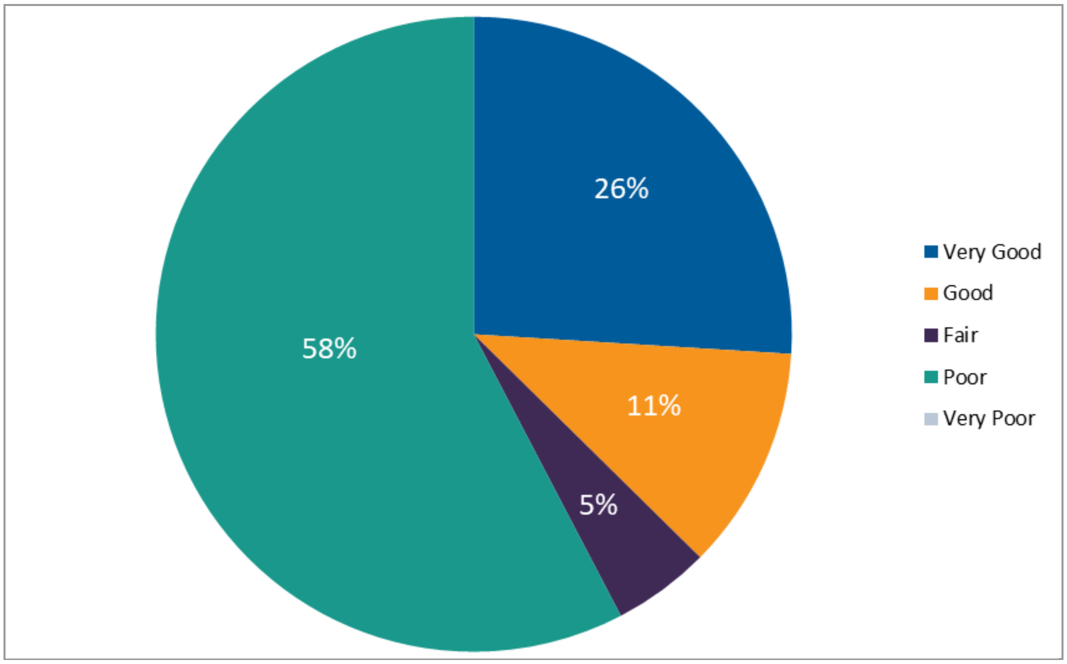
The health index for XLPE cables is based on a combination of age and failure rate. A summary of known Hydro Ottawa's distribution XLPE cable conditions is shown in Figure 6.36 below.

1 **Figure 6.36 – Distribution Polymer Cable Age Demographics**[9]

2 

[9] Datum of February 2, 2019 is used for age demographics.

Figure 6.37 – Distribution Polymer Cable Condition Demographics



6.1.3.3. Underground Transformers

Hydro Ottawa owns and operates 16,882 underground transformers.[10] These are installed in both front and rear lot to service customers. Figure 6.38 below illustrates two types of underground transformers: padmount transformers (left) and Kiosk transformers (right). Table 6.9 below lists the individual components.

[10] Datum of February 5, 2019 is used in this instance.

Figure 6.38 – Underground Transformers

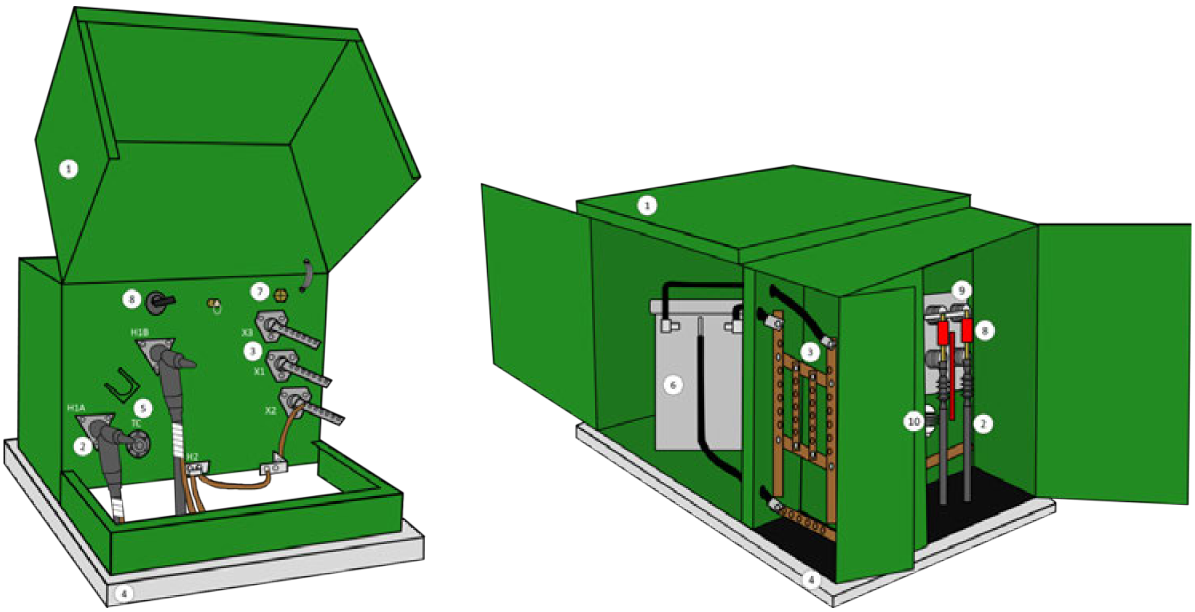


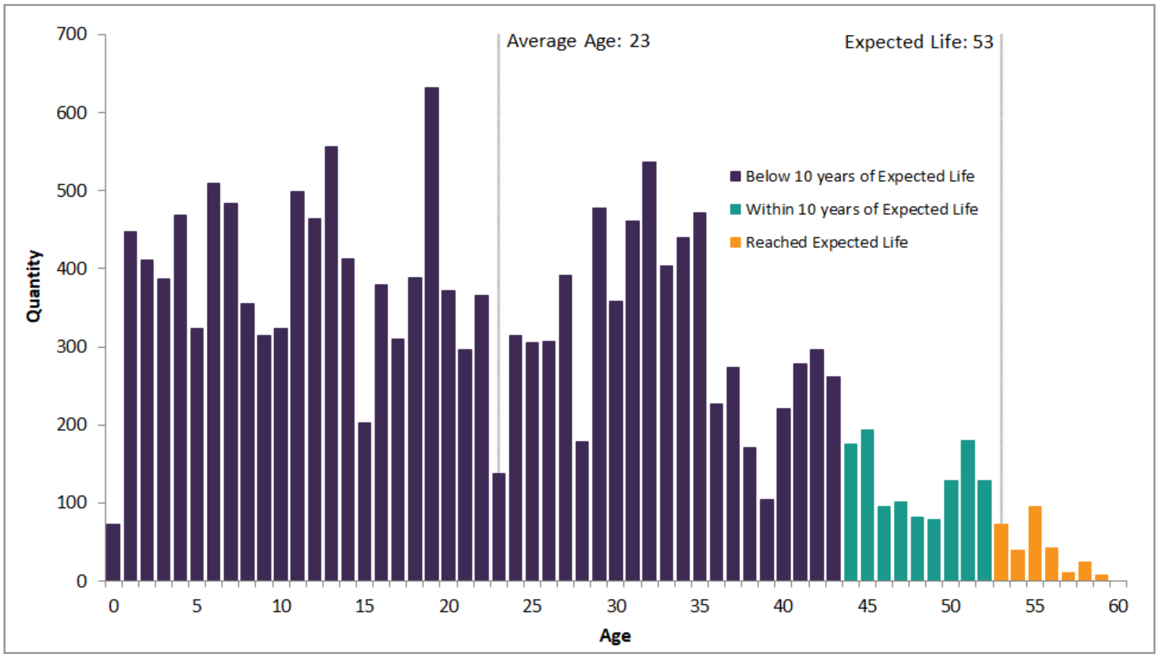
Table 6.9 – Underground Transformer Components

Figure Number	Component	Function
1	Enclosure(s)	Underground transformer enclosure(s) maintain a degree of protection for the medium voltage equipment from the environment while ensuring security from the public for increased safety. Additionally, the enclosure contains the insulating oil and increases system reliability by isolating it from weather, animals and contaminants such as road salt.
2	Primary Connections	Underground primary connections distribute electricity at medium voltages across the service territory. It also allows for a means of installing fault indicating equipment allowing for expedited fault finding and restoration.
3	Secondary Connections	Secondary connections allow for underground transformers to supply multiple customers from a single transformer. This provides increased asset value due to effective asset utilization.
4	Concrete Base	Concrete bases provide support for underground transformers by dispersing the weight over a large area. The base also provides space for cables to be routed to the primary and secondary connections.
5	Tap Changer	The tap changer is used to regulate the voltage of the underground transformer by changing the transformer's winding ratio. The tap changer can rotate up or down to either increase or decrease the ratio with the transformer isolated. This allows the voltage supplied by the transformer to be locally adjusted within the required range
6	Core & Windings	An underground transformer's core, primary and secondary windings and oil insulation are sealed within the transformer's enclosure. These elements work together to transform electrical power, stepping down from a distribution voltage to customer supply voltage using an electromagnetic circuit.
7	Oil Level Gauge	The oil level sight gauge allows visual confirmation of the level of oil insulation within the transformer tank.
8	Fuses	Fuses disconnect the transformer in response to failed equipment or transformer overloading. The operation of the fuses isolates the failed equipment and minimizes the reliability impact to Hydro Ottawa customers, and protecting equipment from further damage. Underground transformers may contain more than one type of protective fuse.
9	Insulators	Insulators support electrical conductors and connections, without conducting electricity.
10	Surge Arrestors	Surge arresters protect the system and equipment by suppressing voltage surges from various causes (e.g. lightning).

The average age of this asset class is 23 years. Figure 6.39 below illustrates the population demographics. The expected service life of underground transformers is 53 years. There are

290 underground transformers that have already reached the end of their expected service life and an additional 1,165 transformers within 10 years of the end of their expected service life.

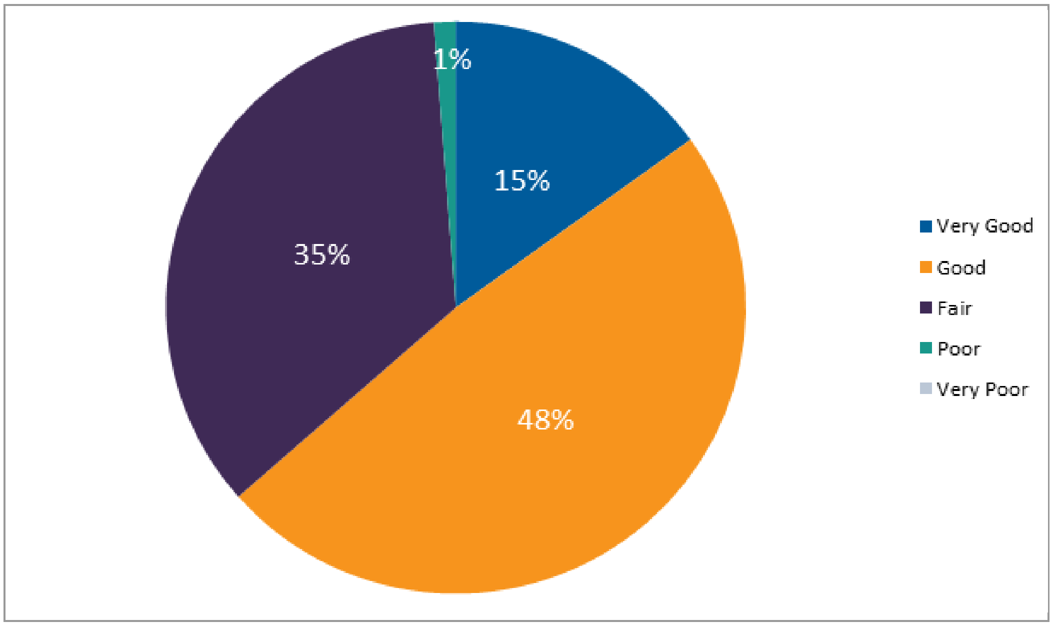
Figure 6.39 – Underground Transformer Age Demographics[11]



The health index for underground transformer is largely based on the visual and thermographic inspections. Other factors that influence the health index are the age, peak loading, and condition of the civil structure. A summary of known Hydro Ottawa's underground transformer conditions is shown in Figure 6.40 below.

[11] Datum of August 9, 2019 is used for age demographics.

Figure 6.40 – Underground Transformer Condition Demographics

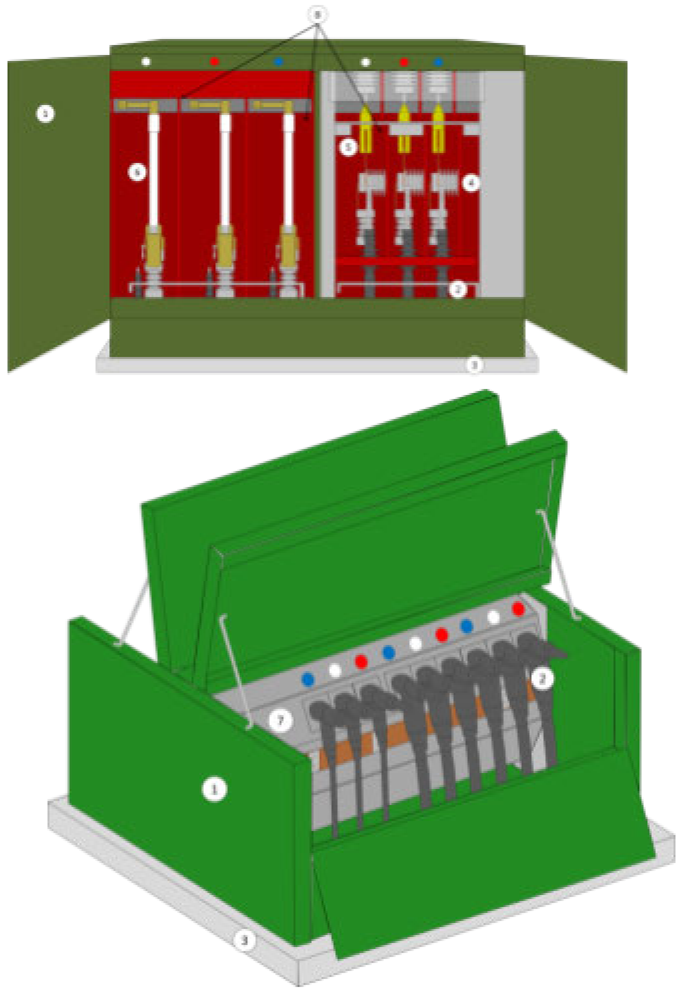


6.1.3.4. Underground Switchgear

Hydro Ottawa owns and operates 527 underground switchgear.[12] There are many different configurations and types of switchgear in service due to the amalgamation of the former utilities and their varying policies for servicing customers. Figure 6.41 below illustrates two common underground switchgear types: air insulated PMH (top) and SF6 insulated (bottom). The components are listed in Table 6.10 below.

[12] Datum of January 31, 2019 is used in this instance.

Figure 6.41 – PMH (top) and Vista (bottom) Underground Switchgear Types



1
Table 6.10 – Underground Switchgear Components

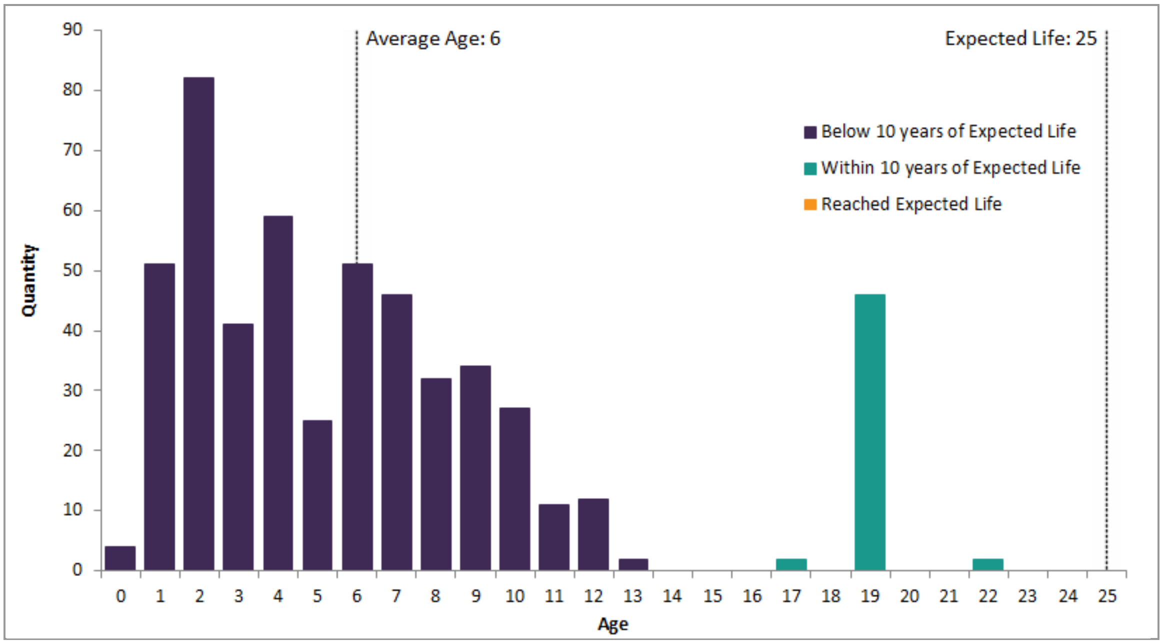
Figure Number	Component	Function
1	Enclosure	Underground switchgear enclosures maintain isolation of the medium voltage equipment from outside sources while ensuring security from the public for increased safety. Additionally, the enclosure protects the inside equipment from damage from external sources and increases system reliability by isolating it from weather, animals and contaminants, such as road salt.
2	Primary Conductor	Underground primary conductor distributes electricity at medium voltages across the service territory, connecting the supply system to the switchgear. Within an underground switchgear it provides for a contact point for installing fault indicating equipment allowing for expedited fault finding and restoration.
3	Concrete Base (Pad)	Concrete bases (pads) provide support for underground switchgear by dispersing the weight over a large area. The pad also provides a work area under the switchgear to perform cable work. The pad may also be coupled with a cable chamber (manhole) to allow for increased access to underground cables (described in the Civil Structure AMP).
4	Insulator	Insulators support electrical connections while protecting equipment from the flow of current.
5	Switch Blades	Switch blades allow for the continued flow of current while providing the ability to isolate or restore power to customers through switching. The switch blades also allow for isolating the system to enable work (Hydro Ottawa or third party requested).
6	Switch Fuses	Switch fuses disconnect the circuit in response to high current levels (fault conditions or overloading). Electrical faults result in increased current which can potentially be unsafe for the public, employees and connected equipment. The operation of the fuses isolates the failed equipment and minimizes the safety and reliability impact to Hydro Ottawa customers.
7	Vista Switchgear	The Vista switchgear is fully enclosed in a hermetically sealed enclosure, containing all of the operational functionality found within other underground switchgear (see 5 and 6 above) while providing a sealed environment for the internal equipment.
8	Barrier Boards (panels)	Barrier boards (panels) are used to separate the operable equipment within an underground switchgear. While providing additional dielectric insulation, the boards isolate the impact of failure on the adjacent mechanical devices. Additionally, the boards assist in guiding the operation of the specific phase devices.

2

Figure 6.42 – Typical Installation of a Vista Type Underground Switchgear

The average age of this asset class is six years, Figure 6.43 below illustrates the population demographics. The expected service life of underground switchgear is 25 years. There are 50 underground switchgear that are within 10 years of the end of their expected service life.

Figure 6.43 – Underground Switchgear Age Demographics[13]

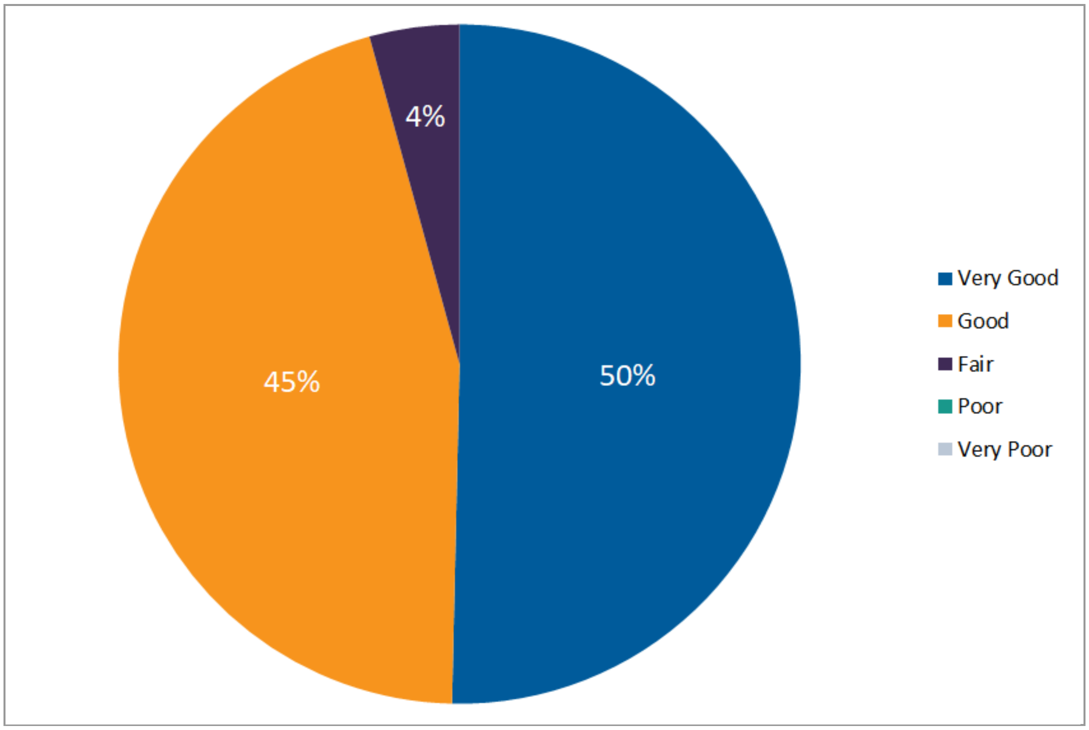


The health index for underground switchgear is largely based on age and the results from visual and thermographic inspections. Switchgear that contain SF6 gas have their health index largely based on the presence of gas leaks.

The condition assessment for underground switchgear is based on data collected from a planned program of inspection as well as installation age. Currently, Hydro Ottawa operates a planned program of inspection and maintenance for its switchgear on a three-year cycle. A summary of known Hydro Ottawa's underground switchgear conditions is shown in Figure 6.44 below.

[13] Datum of January 31, 2019 is used for age demographics.

Figure 6.44 – Underground Switchgear Condition Demographics



6.1.3.5. Vault Transformers

Hydro Ottawa's vault transformers are located in building vaults and typically service a single large customer. Currently Hydro Ottawa owns 3,652 vault transformers.[14] Figure 6.45 below illustrates a vault transformer and Table 6.11 below details the individual components.

[14] Datum of February 5, 2019 is used in this instance.

Figure 6.45 – Vault Transformer

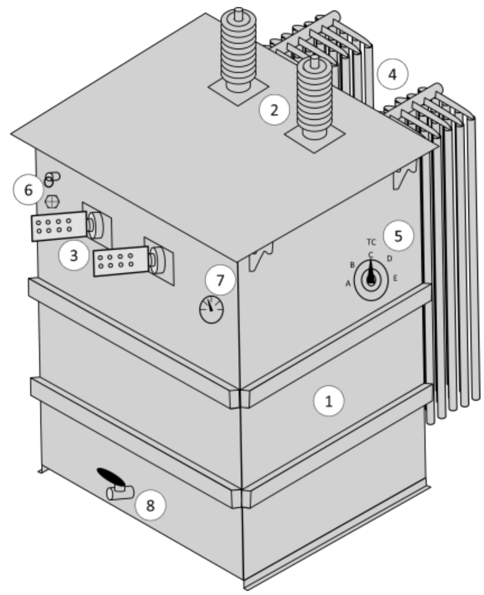
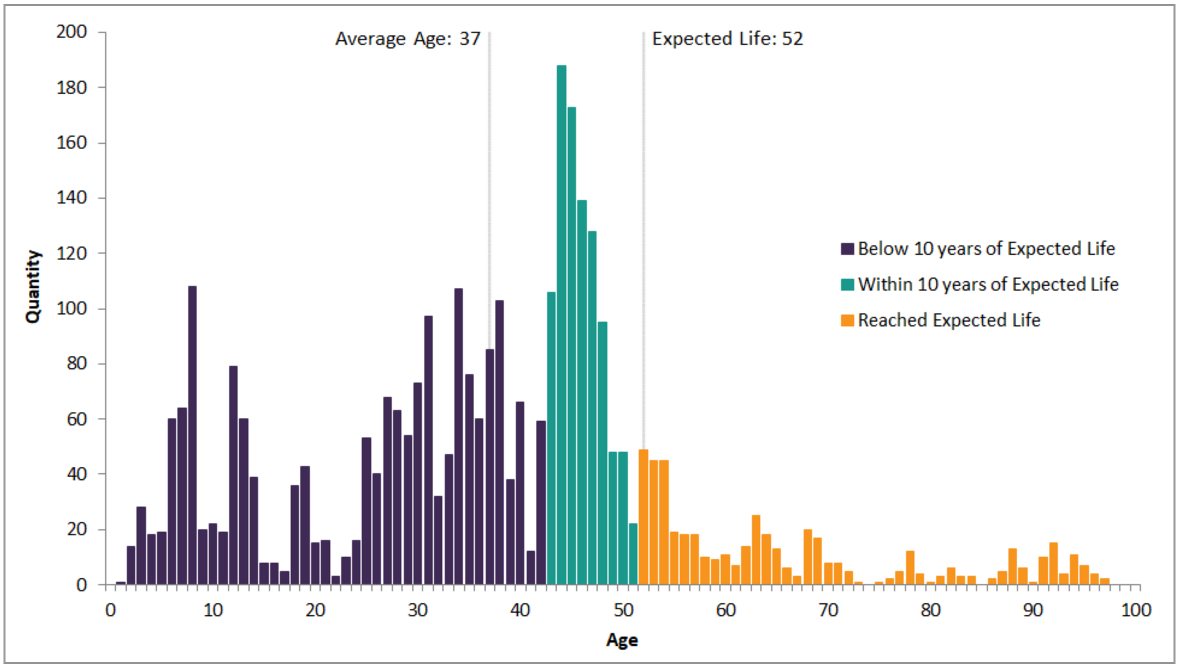


Table 6.11 – Vault Transformer Components

Figure Number	Component	Function
1	Enclosure	Vault transformer enclosures maintain isolation of the medium and low voltage equipment from the environment while providing a degree of personnel protection from the energized internal components. Additionally, the enclosure contains insulating oil.
2	Primary Bushing	Primary bushings support an insulated flow of current from the connecting primary conductor to the internal transformer connections through the grounded enclosure.
3	Secondary Bushings	Secondary bushings support an insulated flow of current from the inside connections through the grounded enclosure to the secondary conductor.
4	Cooling Radiators	Cooling radiators provide convection cooling for the transformer allowing for the efficient dissipation of cool air across the transformer to prevent overheating.
5	Temperature Gauge	Temperature gauge provides a measurement of the oil temperature of a vault transformer and can be used as an indication of vault transformer operating condition.
6	Pressure Relief Device	The pressure relief device is used to avoid pressure buildup inside the transformers, and acts as an exit point for oil if the internal pressure exceeds permitted safe level.
7	Liquid Level Gauge	The liquid level gauge provides a level measurement of oil within the transformer tank to ensure the adequate amount of oil exists to cool and insulate the transformer.
8	Drain	The drain allows the transformer oil to be removed from the tank for maintenance or in a proactive or reactive manner for testing.
Not Shown	Tap Changer	The tap changer is used to regulate the voltage of the distribution vault transformer by changing the transformer's winding ratio. The tap changer can rotate up or down to either increase or decrease the ratio. This ensures that the voltage supplied by transformer is constant, even in cases where the incoming voltage is too high or too low. This results in the distribution of high-quality power.
Not Shown	Ground Connection	The ground connection allows for transformer connection to ground electrode which; prevents voltage on transformer enclosure, provides an effective ground-fault current path which is essential for the operation of the overcurrent protection systems, and provides a reference for customer service voltage.
Not Shown	Core, Windings, insulating Oil	The transformer's core, primary and secondary windings and oil insulation are sealed within the transformer's enclosure. These elements work together to transformer the electrical power, stepping down from a distribution voltage to customer supply voltage using an electromagnetic circuit.

The average age of this asset class is 37 years. Figure 6.46 below illustrates the population demographics. The expected service life of vault transformers is 52 years. There are 489 vault transformers that have reached the end of their expected service life and an additional 947 transformers within 10 years of the end of their expected service life.

Figure 6.46 – Vault Transformer Age Demographics[15]



6.1.3.6. Underground Civil Structures

Hydro Ottawa's Underground Civil Structure asset class consists of duct banks, hand holes, and cable chambers forming a network through which cables may be installed. Distribution underground civil structures are used in areas where underground wiring is required which allows for ease of access and protection of electrical equipment. Figure 6.47 below illustrates a cable chamber and Table 6.12 below details the individual components.

[15] Datum of February 1, 2019 is used for age demographics.

Figure 6.47 – Cable Chamber

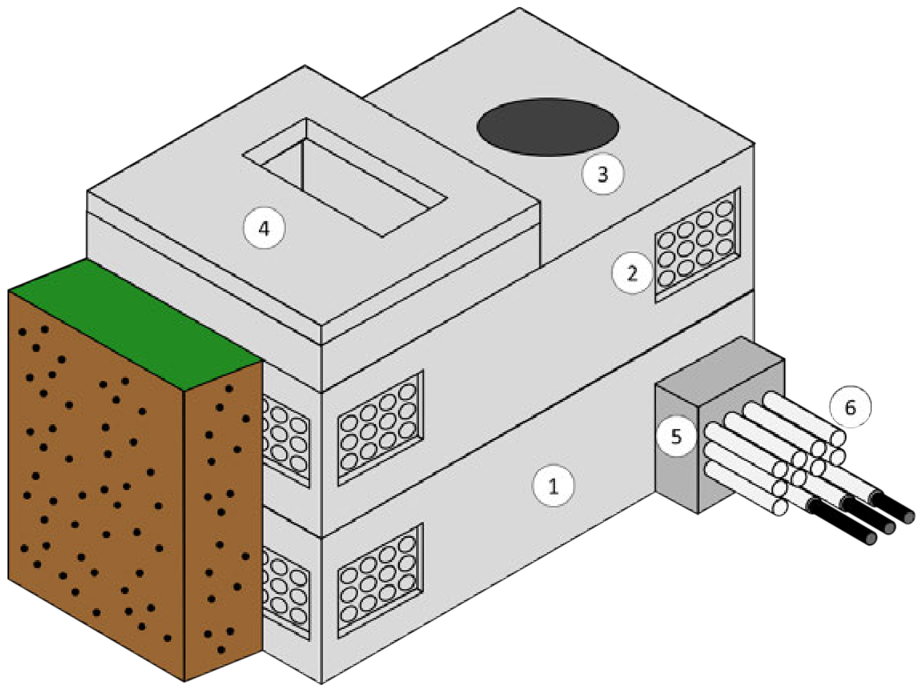


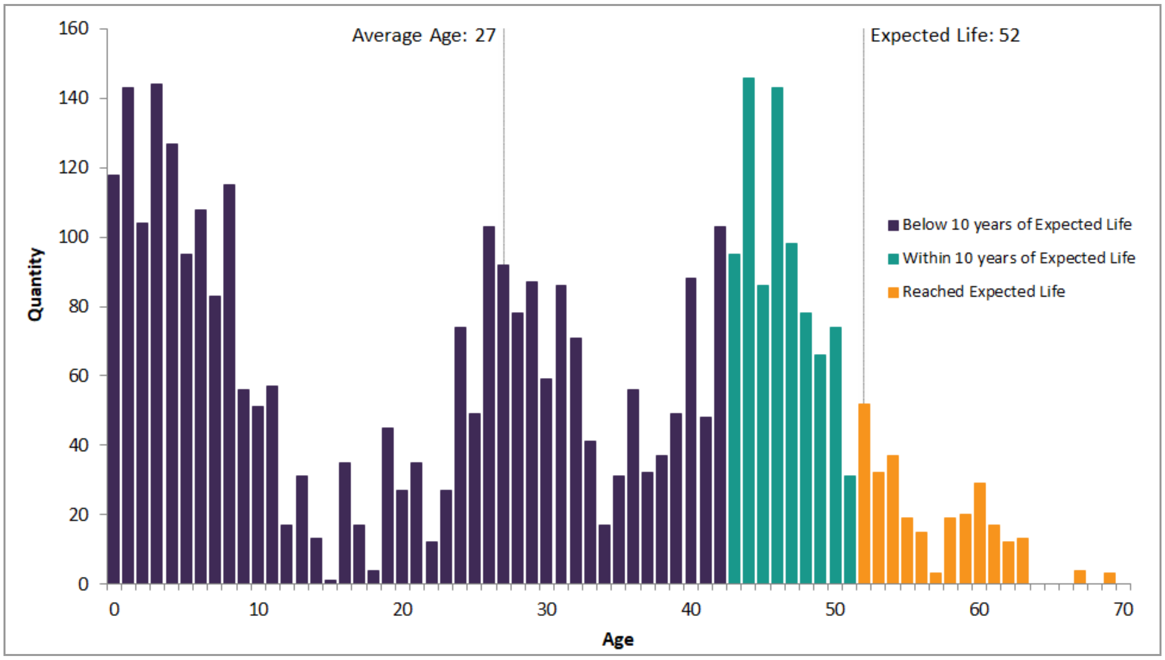
Table 6.12 – Cable Chamber Components

Figure Number	Component	Function
1	Cable Chamber	Cable chambers are used to protect other assets such as cable and submersible equipment from external damage and elements. The cable chamber also provides an area for cable splicing, cable pulling, and for replacement and repair without excavation.
2	Duct Windows	Duct windows are precast concrete structures used for installing new ducts within a cable chamber, while providing a space for future ducts and ease of future core drills.
3	Cable Chamber Entrance/Lid	The cable chamber entrance/lid allows access to within the cable chamber to gain access to underground assets and connections.
4	Equipment Pad	Pads support pad-mounted assets including transformers and switchgear. They also allow for bottom entry of equipment and equipment terminations.
5	Concrete Encased Duct Bank	Concrete encased duct banks support electrical conductors, protect ducts, and therefore the associated cables through a physical barrier preventing damage.
6	Duct	Duct supports and protects electrical conductors, while allowing for ease of pulling new cable

Figure 6.48 – Cable Splicing within a Cable Chamber

Currently Hydro Ottawa owns 3,878 cable chambers. The average age of this asset class is 27 years. Figure 6.49 below illustrates the population demographics. The expected life of cable chambers is 52 years. There are 275 cable chambers that have already reached the end of their expected life and an additional 817 cable chambers within 10 years of the end of the expected life.

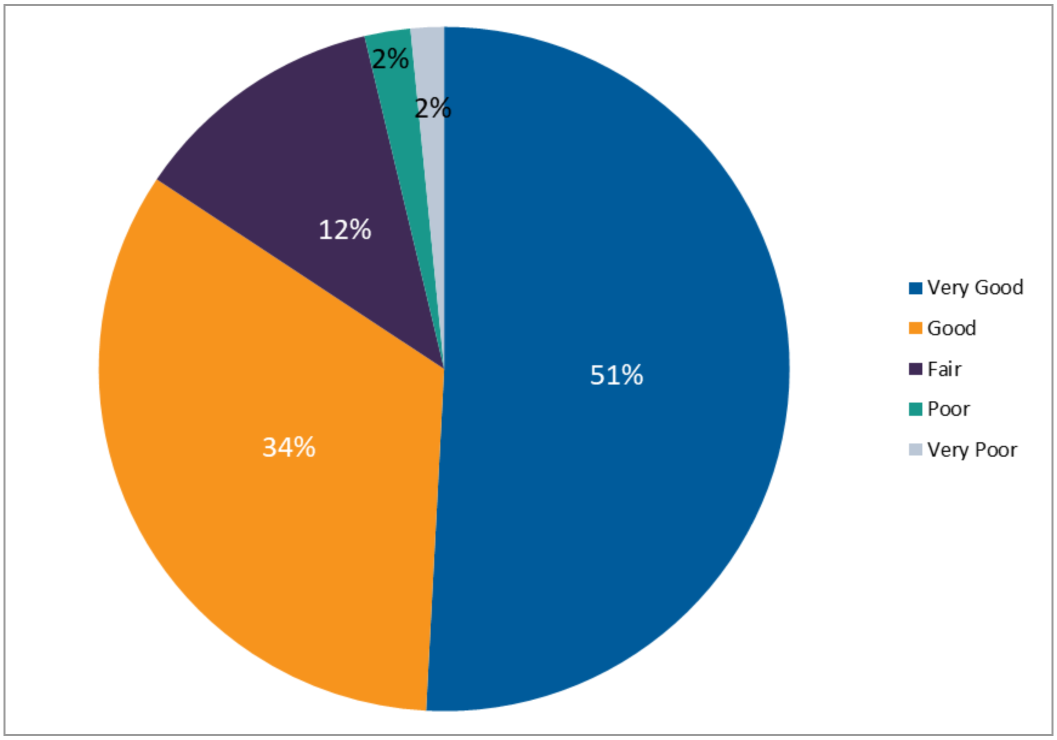
Figure 6.49 – Cable Chamber Age Demographics[16]



Hydro Ottawa operates a planned program of inspection for cable chambers based on a 10-year cycle. The health index for cable chambers is primarily based on visual inspections. A summary of known Hydro Ottawa's cable chamber conditions is shown in Figure 6.50 below.

[16] Datum of February 2, 2019 is used for age demographics.

Figure 6.50 – Cable Chamber Condition Demographics



6.2. ASSET LIFECYCLE OPTIMIZATION POLICIES & PRACTICES

Hydro Ottawa takes a full lifecycle approach to managing its assets by identifying opportunities to make improvements to the various aspects of the lifecycle. To achieve this, Hydro Ottawa updates design and installation standards, ensures efficient installation and commissioning practices, develops cost effective operation and maintenance, and prioritizes renewal investments.

This section addresses the following:

- Asset Replacement and Refurbishment Policies
- Testing, Inspection, and Maintenance Programs
- Asset Replacement Prioritization and Scheduling

6.2.1. Asset Replacement & Refurbishment Policies

Assets identified of needing corrective action are evaluated to determine the appropriate action. Options evaluated are Repair, Refurbish, or Replace. Hydro Ottawa performs a case-by-case analysis to determine the preferred alternative when corrective action is required. Factors such as the age, maintenance history, new standards, and availability of spare parts all influence the decision of whether or not to refurbish, repair, or replace the asset.

Repair actions are corrective interventions that involve the replacement of a minor component which can be obtained from stock materials or through manufacturer sourcing.

Refurbishment is expected to renew the asset and extend the expected service life. These actions are also used to defer the need for replacement to a time where efficiencies can be found by replacing other assets at the same time. Typically, Station assets, such as transformers and breakers, have been more economical to refurbish than Overhead and Underground assets.

Each asset identified for replacement is evaluated for opportunities for efficiencies by assessing the condition of the other assets in proximity that may need to be replaced concurrently; evaluating future growth and demand; and determining if decommissioning is an option.

6.2.2. Testing, Inspection & Maintenance Programs

To optimize asset lifecycle and manage risk, Hydro Ottawa uses various programs and activities to evaluate the performance and condition of its assets. The practices used to assess risk include non-destructive testing, and predictive and preventative maintenance which help drive corrective maintenance and capital investments. An overview of this process is available in section 5.1.3 - Testing, Inspection, & Maintenance Programs.

Most of Hydro Ottawa's asset maintenance activities are performed on a predetermined periodic schedule. The cycle period is selected based on various factors to address manufacturers' recommendations, regulatory requirements in the *Distribution System Code*, and/or internal experience and standards. Table 6.13 outlines the inspection and maintenance cycles of each program.

Table 6.13 – Maintenance Programs

	Activity Type	Cycle	Type
Stations	Station Inspections	Monthly	Predictive
	Thermographic Scans	Annually	Predictive
	Transformer Inspection	Annually	Predictive
	Transformer Oil Analysis	Annually	Predictive
	Transformer Maintenance	Every 3-5 Years	Preventative
	Transformer Tap changer Maintenance	Every 1-8 Years	Preventative
	Switchgear and Breaker Inspection	Annually	Predictive
	Switchgear and Breaker Maintenance	Every 4-6 Years	Preventative
	Battery Testing	Annually	Predictive
	Relay Maintenance	Every 4-6 Years	Preventative
Underground	Underground Switchgear Thermographic and Visual	Every 3 Years	Predictive
	Underground Distribution Transformer Thermographic and Visual	Every 3 Years	Predictive
	Vault Inspections	Every 3 to 6 Years	Predictive
	Switchgear CO_2 Washing	Every 3 Years	Preventative
	XLPE/TRXPLE Cable Testing	400 segments annually	Predictive
	Cable Chamber Inspections	10 Year	Predictive
Overhead	Overhead Thermographic Inspection	Every 3 Years	Predictive
	Vegetation Management	Every 2 to 3 Years	Preventative
	Pole Inspection	Every 10 years	Predictive
	Critical Switch Inspection	8 Years	Preventative
	Insulator Washing	Bi-Annual	Preventative

The following sections detail the testing, inspection, and maintenance practices for each asset type.

6.2.2.1. Station Transformers

Hydro Ottawa performs monthly station inspections where a visual inspection is performed to check for any deficiencies and initiate corrective actions.

Annually, Hydro Ottawa performs transformer inspection on every station transformer, which includes a detailed visual inspection, oil analysis, and infrared scans. The oil analysis includes a dissolved gas and oil quality analysis. Every five years, a furan analysis is performed to assess the degradation of the transformer's paper insulation.

Several major station transformers are also continuously monitored through the SCADA system to provide operational and asset condition related information. Various monitoring technologies have been added to station transformers due the consequences associated with a failure. These include online dissolved gas analysis ("ODGA"), winding and oil temperature, tap changer status, cooling fan status, and loading information. Warnings and alarms from these monitoring units allow Hydro Ottawa to identify the need for corrective actions with real-time data. It also ensures that the transformers are not overloaded or overheating, which causes the insulation to degrade and reduces their lifespans.

Figure 6.51 – Visual Inspection of a Station Transformer

Every three to five years, station transformers are isolated for preventive maintenance, which includes electrical testing and mechanical maintenance. Transformer tap changer maintenance intervals vary with the type: oil-filled tap changers with no oil filter are maintained every one to two years; oil-filled tap changers with an oil filter are maintained every two to four years; and vacuum tap changers are maintained every six to eight years.

6.2.2.2. Station Switchgear & Breakers

Hydro Ottawa performs monthly station inspections where a visual inspection is performed to check for any deficiencies and initiate corrective actions.

Annually, Hydro Ottawa performs switchgear inspection on every station switchgear, which includes a detailed visual inspection and infrared scans.

Every four to six years, preventative maintenance is performed on individual breakers. The breaker maintenance includes electrical, mechanical, and type-specific maintenance tasks to ensure the proper functioning of the breaker.

Every 10 years, detailed preventative maintenance is performed on the entire switchgear assembly. Switchgear maintenance includes detailed internal visual inspections, insulation resistance tests, and ensuring that there are no structural deficiencies, such as cracks, leaks or warped metal in the switchgear.

6.2.2.3. Station Batteries

Batteries are visually inspected as part of the monthly station inspections to check for any deficiencies and initiate corrective actions.

Annually, detailed predictive maintenance is performed on station battery banks. This includes a detailed visual inspection, infrared scan, as well as electrical and mechanical tests. Battery charger predictive maintenance consists of an annual visual inspection, electrical tests, as well as functional and alarm tests.

6.2.2.4. Relays

Every four to six years, Hydro Ottawa performs relay maintenance at every Hydro Ottawa station. Relay maintenance includes function testing, calibration of electromechanical relays, and protection setting updates, if required.

6.2.2.5. Distribution Poles

Hydro Ottawa inspects all of its distribution poles as part of multiple planned programs of inspection for overhead assets. This planned program of inspection subjects all of its distribution poles and associated attachments to both a visual and thermographic inspection on a rotating three-year cycle identifying candidate assets for corrective actions.

Hydro Ottawa also conducts a predictive maintenance program of detailed inspection of all poles on a 10-year cycle. The data collected from this program is used to assess the pole's condition and estimate remaining strength using the results of non-destructive resistograph drill tests.

6.2.2.6. Overhead Transformers

Hydro Ottawa inspects overhead transformers as part of multiple planned predictive maintenance programs. Transformers are inspected visually as part of the 10-year pole line inspection program and every three years as part of the infrared inspection program.

6.2.2.7. Overhead Switches

Hydro Ottawa inspects all of its overhead switches as part of multiple planned programs of inspection for overhead assets. This planned program of inspection subjects all of its overhead switches to both a visual and thermographic inspection on a rotating three-year cycle identifying candidate assets for corrective actions.

Hydro Ottawa also conducts a separate planned program of detailed inspection and maintenance (Critical Switch Inspection), based on a rotating eight-year cycle, on overhead load break gang operated switches. The detailed inspection is to address switches that have a higher reliability consequence. Inspections are performed in the air, in closer proximity to the switch's components, allowing for a more detailed inspection that could not be performed from the ground. Simultaneously, preventative maintenance is performed on the switch to ensure that it continues to operate as intended.

6.2.2.8. Distribution Cables

Hydro Ottawa annually tests a portion of its polymer cables using non-destructive testing technology to determine the cable's probability of failure resulting from water tree migration. The utility combines this information with feedback from utility staff, reliability data, and the cable segment's age to determine if the cable would be a candidate for replacement.

PILC cables are not subjected to a dedicated planned program of inspection or maintenance and is instead included as part of the inspection of underground civil structures. A visual inspection is performed on a 10-year cycle by qualified outdoor field staff which includes reviewing the cable condition, racking within the cable chamber, and duct allocation.

6.2.2.9. Underground Transformers

Hydro Ottawa inspects its underground distribution transformers annually on a three-year cycle. The inspection process uses a visual inspection to identify transformers with broken components or leaking oil. A thermographic inspection is also performed to identify defective transformer components including elbows, bushings, and fuses. This process identifies candidate transformers for corrective actions including mechanical repair and component replacement. When repair is not economical, the transformer is scheduled for replacement.

6.2.2.10. Underground Switchgear

Hydro Ottawa inspects and maintains all of its underground distribution switchgear on a planned basis. This planned program subjects all of its underground distribution switchgear to a visual and thermographic inspection based on a rotating three-year cycle. The maintenance of air insulated switchgear also includes cleaning of its internal mechanism. The visual inspection records demographic information and the current condition including the enclosure and civil base.

6.2.2.11. Vault Transformers

Hydro Ottawa inspects all of its vault transformers on a planned three-year cycle. This planned program subjects its vault transformers to a visual and thermographic inspection in addition to minor cleaning. The visual inspection records demographic information and the current condition.

Hydro Ottawa does not own the electrical supply room within customer-owned buildings. Deficiencies found that would affect the ongoing operations or identified safety risks are identified to the building owner to take corrective actions.

6.2.2.12. Underground Civil

Hydro Ottawa performs an inspection of its cable chambers on a 10-year cycle. The cable chamber inspection process involves a visual inspection and sounding test to assess the cable chamber's condition. The inspection includes reviewing the condition of the collar and lid, roof, and walls. Cable chamber components that pose an immediate risk to the public, workers, or reliability of the distribution system are identified for immediate corrective actions. If they pose a reduced risk, they are identified for planned corrective actions at a later date.

Through the use of experienced underground field workers, the electrical components installed within the cable chambers can be inspected and minor corrective actions addressed immediately. The visual inspection includes capturing information about the cable demographics, location of splices, and identification of duct allocation.

Other civil assets, including hand holes, ducts, and duct banks, are not subject to a planned program of inspection. Failures of these assets pose a reduced risk to the public and workers in the event of unforeseen failure.

6.2.3. Asset Replacement Prioritization & Scheduling

Hydro Ottawa manages its asset replacement prioritization and scheduling the same way it manages other types of investments. Details about this process can be found in section 5.2 - Capital Expenditure Process.

6.3. ASSET LIFECYCLE RISK MANAGEMENT

Hydro Ottawa identifies risk through its Asset Management Process and seeks to mitigate risk through Expenditure Process as defined in section 5 - Asset Management & Capital Expenditure Process.

In order to understand the long-term impact and risk of decisions, various investment scenarios are used by Hydro Ottawa to prioritize the needed investments to maintain or improve risk to a level that is acceptable to the organization. Details on how the utility has analysed the risk for selecting and prioritizing capital expenditures can be found in Attachment 2-4-3(E): Material Investments for each asset renewal program.

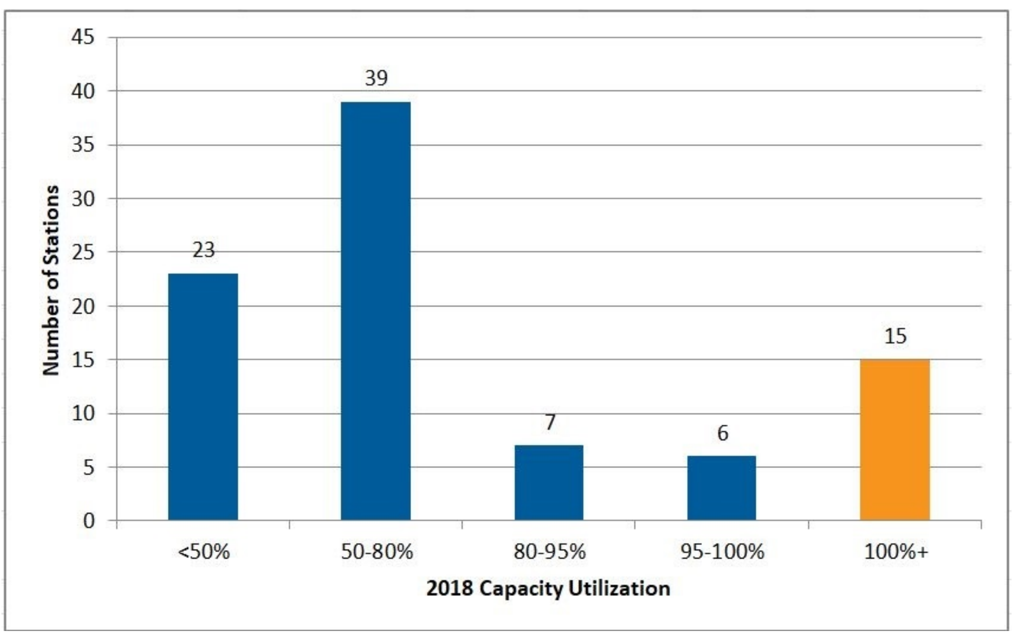
7. SYSTEM CAPACITY ASSESSMENT

This section outlines the degree of utilization of existing assets relative to the planning criteria as layout out in section 4.1.4 - System Operations Performance. In addition, it identifies the system capabilities and constraints to accommodate new load and Energy Resource Facility ("ERF") connections, as well as transmission network constraints identified through the Regional Planning Process.

7.1 CAPACITY OF THE EXISTING SYSTEM ASSETS

In 2018, 15 Hydro Ottawa stations were above their planning rating capacity and six were approaching planning capacity limitations as shown in Figure 7.1. None were above normal thermal limits. Stations above 100% of their planning capacity limit the flexibility of the system to manage abnormal system states including planned activities.

Figure 7.1 – Stations Capacity Utilization in 2018



7.1.1. Stations Exceeding Planning Capacity

Station planning capacity is defined in section 4.1.4.1 - Station Capacity. Station loading must be maintained within the planning capacity to allow for efficient transfer of load during an N-1 contingency, while respecting equipment ratings. Stations loaded above their planning capacity on the 2018 system peak day are shown in Table 7.1.

Table 7.1 – Stations Exceeding Planning Capacity

	Station	2018 System Peak Day Load (MVA)	Planning Capacity (MVA)	Planning Factor
1	Fallowfield MTS	50	25	201%
2	Merivale MTS	16	10	160%
3	Rideau Heights DS	18	12.5	143%
4	Marchwood MTS	43	33	129%
5	Manordale MTS	13	10	128%
6	Centrepointe MTS	17	14	119%
7	Vaughan UG	8	6.7	116%
8	Jockvale DS	14	12.5	115%
9	Hawthorne TS	123	110	111%
10	Bayshore DS	14	12.5	111%
11	Stafford Road DS	15	14	109%
12	King Edward TK	85	80	107%
13	Church AA	5	5	105%
14	Leitrim MS	25	25	102%
15	Kanata MTS	61	60.5	101%

Fallowfield Station in the South Nepean 28kV area continues to be above its planning capacity limitations. The construction of the new Cambrian Municipal Transformer Station (“MTS”) will allow offloading of Fallowfield and other stations in the South Nepean area. The new station will be energized in 2022.

Merivale and Rideau Heights Stations in the Nepean Core 8kV area continue to be above their planning capacity limits. A project to increase capacity at Merivale station is currently in progress and expected to be energized by the end of 2019, enabling a decrease of load at Rideau Heights station.

Kanata and Marchwood Stations are slightly above their planning rating. There is substantial growth expected in this area in the short to mid-term. Plans to bring additional capacity to this area are in place for the 2021-2025 period through distribution line extensions, load transfers to adjacent stations, and conservation and demand management ("CDM") demand reductions. Feasibility for a new station in the Kanata North area is being discussed in the current Integrated Regional Resource Planning ("IRRP") cycle. However, there are transmission constraints that will need to be addressed before a new transmission connected station can be built in this area.

Hawthorne Station was a new addition to the list in 2018. Hydro One Networks Inc. ("HONI") is currently replacing the transformers and increasing capacity at this station. The project was set to be completed by Q4 2019.

The other eight stations on the list have minor overloads in 2018 and they will continue to be monitored for future improvements. Plans for addressing the stations above planning capacity ratings are further discussed in section 7.2 - Ability to Connect New Load.

7.1.2. Stations Approaching Rated Capacity

Station rated capacity is defined in section 4.1.4.1 - Station Capacity. Transformer loading must be maintained within their thermal rated capacity in order to avoid any accelerated loss of life to the unit.

There were no stations loaded at or above their thermal rated capacity on the 2018 system peak day.

7.1.3. Feeders Exceeding Planning Capacity

Feeders planning capacity is defined in section 4.1.4.2 - Feeder Capacity. Feeders must be maintained within the planning capacity to allow for efficient load transfer during N-1 contingency situations, while respecting equipment ratings.

The feeders above 100% of their planning capacity on the 2018 system peak day are listed in Table 7.2. Plans for addressing the feeders above planning capacity ratings are discussed in section 7.2 - Ability to Connect New Load.

Table 7.2 – Feeders Exceeding Planning Capacity

	Station	Feeder	2018 System Peak Day Load (MVA)	Planning Capacity (MVA)	Planning Factor (%)
1	Russell TB	TB2JP (TB13)	8.7	5.8	149%
2	Fallowfield MTS	FAL02	22.9	16.3	141%
3	Jockvale DS	145F1	5.9	4.3	137%
4	Limebank MS	LMBF7	21.5	16.7	129%
5	Kanata MTS	624F1	16.4	13.1	125%
6	Startop MS	6F10	5.3	4.3	123%
7	Uplands MS	Q4801F8	18.0	14.8	122%
8	Ellwood MTS	ELW11	7.0	5.8	121%
9	Kanata MTS	624F5	15.0	13.1	114%
10	Kanata MTS	624F2	15.0	13.1	114%
11	Barrhaven DS	140F3	4.9	4.3	114%
12	Slater TS	630	6.6	5.8	113%
13	Rideau Heights DS	180F3	4.9	4.3	113%
14	Parkwood Hills DS	190F5	4.8	4.3	112%
15	Marchwood MS	MWDF4	14.4	13.1	109%
16	Albion TA	2206	11.8	10.7	109%
17	Riverdale TR	509	6.1	5.8	105%
18	Riverdale TR	TR2FB	6.1	5.8	105%
19	Janet King DS 28kV	JKGF4	16.8	16.3	103%
20	Rideau Heights DS	180F1	4.5	4.3	103%
21	Stafford Road DS	200F6	4.4	4.3	103%
22	Woodroffe TW	TW18	5.9	5.8	101%

7.1.4. Feeders Approaching Rated Capacity

Feeders rated capacity is defined in section 4.1.4.2 - Feeder Capacity. Feeder loading must be maintained within the rated capacity in order to avoid damaging equipment and causing an accelerated loss of life to cables or equipment.

Table 7.3 – Feeders Approaching Rated Capacity

	Station	Feeder	2018 System Peak Day Load (MVA)	Rated Capacity (MVA)	Capacity Factor (%)
1	Fallowfield MTS	FAL02	22.9	24.1	95%

There was one feeder loaded at 95% of the rated capacity on the 2018 system peak day. Load on the Fallowfield feeder will decrease once the Cambrian MTS is energized in 2022, enabling the transfer of load to the new Cambrian feeders.

7.2. ABILITY TO CONNECT NEW LOAD

Hydro Ottawa regularly assesses the capability and reliability of the distribution system in an effort to maintain adequate and reliable supply to customers. Where gaps are found, appropriate plans for additions and/or modifications are developed consistent with all regulatory requirements and with due consideration for safety, environment, finance, and supply system reliability/security. The factors determining constraints in the system are explained in section 5.1.6 - System Constraints.

In this regard, the supply needs have been assessed to determine if additions and/or modifications are required to maintain an adequate and reliable system capacity. The growth identification process is described in section 5.1.4 - Growth Identification.
Details from City of Ottawa plans used in the forecasting of expenditures are explained below.

City of Ottawa Growth Projections

Forecasts for population, household, and employment growth have been obtained from the summary of City of Ottawa Growth Projections for 2006-2031, and are shown in Table 7.4. The

City is in the early stages of updating the Official Plan, which will include updated growth projections. The update to the Official Plan is scheduled for adoption by the City Council in early 2021.

Table 7.4 – Projected Growth in Population, Households & Employment in the City of Ottawa (2011-2031)

Population				
Year	**2011**	**2016**	**2021**	**2031**
Total	923,000	976,800	1,031,300	1,135,800

Households				
Year	**2011**	**2016**	**2021**	**2031**
Total	381,800	413,000	443,600	497,400

Employment				
Year	**2011**	**2016**	**2021**	**2031**
Total	580,200	617,000	648,400	703,100

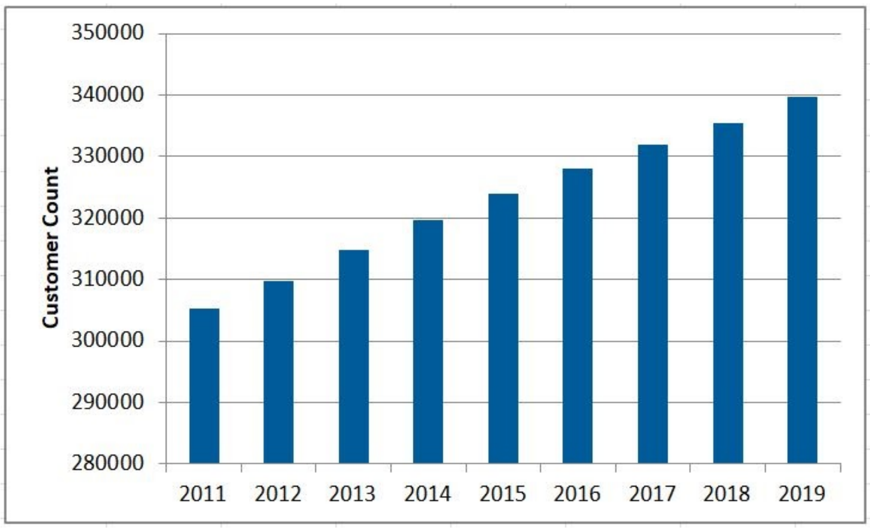
The growth within the City of Ottawa is expected to continue into the future. The total average annual growth rates from 2011-2031 are as follows:

- Population – 1.01%
- Households – 1.25%
- Employment – 0.87%

Hydro Ottawa has been experiencing a steady customer growth for many years. Customer counts from 2011-2018 are in alignment with forecasted population growth in the City of Ottawa Growth Projections for 2006-2031 at an annual growth rate of 1.19%, as shown in Figure 7.2.

Therefore, Hydro Ottawa expects the continuing trend of requests for connection of residential subdivisions and the associated mixed-use centres, along with employment centres.

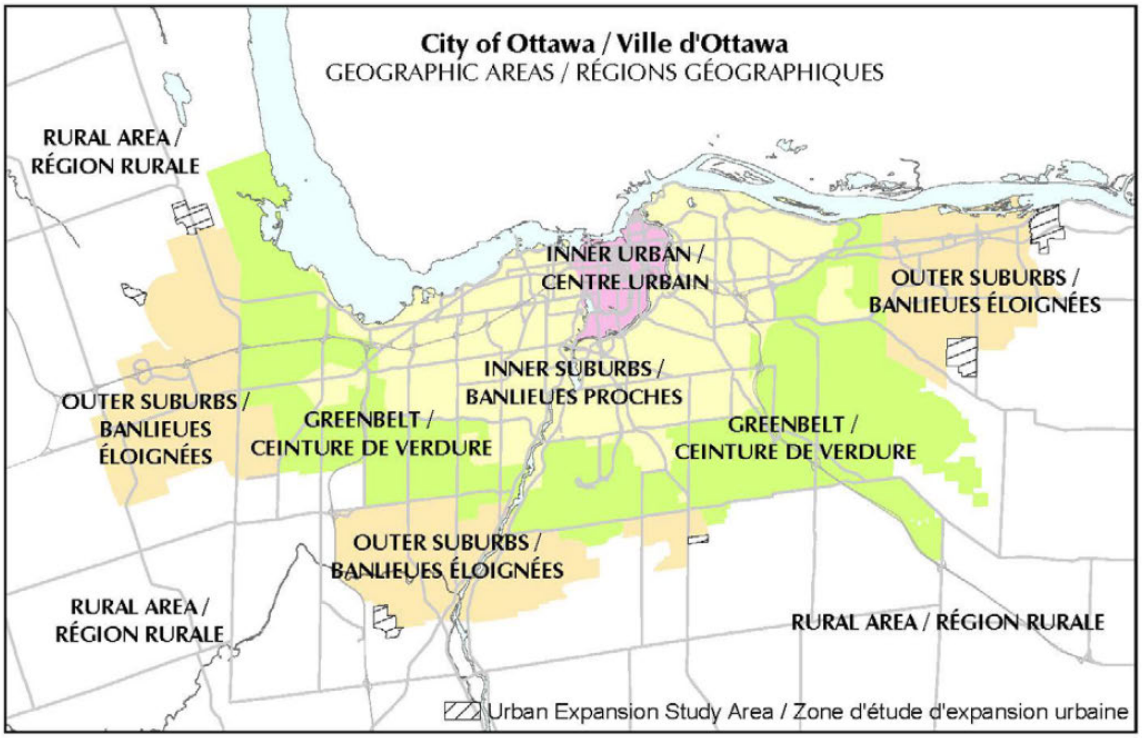
Figure 7.2 – Historical Customer Count



City of Ottawa Transportation Master Plan

The City of Ottawa's Transportation Master Plan identifies the transportation facilities and services that are required to meet the needs of the growing City. Hydro Ottawa utilizes this information to help forecast customer connection requests and to plan the sustainment of the distribution system. Figure 7.3 and Table 7.5 below depict the increasing requirements by region, within the City of Ottawa out to 2031.

Figure 7.3 – Location of Inner Area, Inner Suburbs & Outer Suburbs (City of Ottawa)



*Source: City of Ottawa Transportation Master Plan, 2013

Table 7.5 – Population & Employment: 2011 Actual & 2031 Projections

Area	Population			Employment		
	2011	2031	Growth and Distribution	2011	2031	Growth & Distribution
Inner Area	97,200	116,400	19,200 9%	170,600	201,800	31,200 23%
Inner Suburbs	432,500	459,300	26,800 13%	287,400	355,300	67,900 49%
Kanata/ Stittsville	105,200	162,000	56,800 27%	51,300	62,500	11,200 8%
Barrhaven	71,200	107,400	36,200 17%	11,100	21,800	10,700 8%
Riverside South/Leitrim	15,900	35,800	19,900 9%	4,000	7,800	3,800 3%
Orléans	108,200	143,400	35,200 16%	20,600	33,000	12,400 9%
Rural Ottawa	91,400	111,700	20,300 9%	20,000	20,900	900 1%
TOTAL	**922,000**	**1,135,900**	**213,900**	**564,900**	**703,200**	**138,100**

*Source: City of Ottawa Transportation Master Plan, 2013

Within the Transportation Master Plan, the City of Ottawa has developed an “Affordable Road Network” planned out to 2031. This “Affordable Road Network” is the prioritized City projects based on the expected funding levels, and as such, is used to forecast Hydro Ottawa’s Plant Relocation, Asset Renewal, and other line upgrades driven by transportation projects.

The “Affordable Road Network” projects have been broken out by phases, and are listed in Table 7.6 below, showing only those projects planned until 2025.

Table 7.6 – City of Ottawa Affordable Road Network - Projects by Phase (*)

Phase 1: 2014-2019		
Sector	**Project**	**Description**
Southeast	Airport Parkway (1)	Widen from two to four lanes between Brookfield Road and Hunt Club Road
East	Blackburn Hamlet Bypass Extension (1)	New four-lane road between Orléans Boulevard and Navan Road
East	Brian Coburn Boulevard Extension	New two-lane road (ultimately four-lane) between Navan Road and Mer Bleue Road
West	Campeau Drive	New four-lane road between Didsbury Road and Huntmar Drive
Rural	Country Club Road	New two-lane road between eastern terminus of Golf Club Way and Jenkinson Road
West	Earl Grey Drive Underpass	New underpass of Terry Fox Drive
Southwest	Greenbank Road Extension	New four-lane road between Cambrian Road and Jockvale Road
West	Old Richmond/West Hunt Club	Widen Old Richmond Road/ West Hunt Club Road from two to four lanes between Hope Side and Highway 416
West	Stittsville North-South Arterial (1)	New two-lane road between Fernbank Road and Abbott Street
West	Klondike Road	Urbanize existing two-lane rural cross section between March Road and Sandhill Road
East	Mer Bleue Road	Widen from two to four lanes between Brian Coburn Boulevard and Renaud Road
West	Palladium Drive Realignment	Realign in vicinity of Huntmar Road to new north-south arterial
Southwest	Strandherd Drive (1)	Widen from two to four lanes between Fallowfield Road and Maravista Drive

Phase 2: 2020-2025		
Sector	**Project**	**Description**
Southeast	Bank Street	Widen from two to four lanes between Earl Armstrong Road extension and south of Leitrim
East	Blackburn Hamlet Bypass Extension (2)	New four-lane road between Innes Road and Orléans Boulevard
West	Carp Road	Widen from two to four lanes between Highway 417 and Hazeldean Road
Southwest	Chapman Mills Drive	New four-lane road between Strandherd Drive and Longfields Drive
West	Eagleson Road	Widen from two to four lanes between Cadence Gate and Hope Side Road

Phase 2: 2020-2025 (Cont'd)		
Sector	**Project**	**Description**
Southwest	Jockvale Road	Widen from two to four lanes between Cambrian Road and Prince of Wales Drive
West	Kanata Avenue	Widen from two to four lanes between Highway 417 and Campeau Drive
West	Stittsville North-South Arterial (2)	New four-lane road between Palladium Drive (at Huntmar) and Abbott Street
Southeast	Lester Road	Widen from two to four lanes between Airport Parkway and Bank Street
Southwest	Strandherd Drive (2)	Widen from two to four lanes between Maravista Drive and Jockvale Road
East	Tenth Line Road	Widen from two to four lanes between Harvest Valley Road and Wall Road

*Source City of Ottawa Transportation Master Plan, 2013

City of Ottawa Community Design Plans

Hydro Ottawa also references published Community Design Plans ("CDPs") from the City of Ottawa to forecast future residential and mixed-use centres.

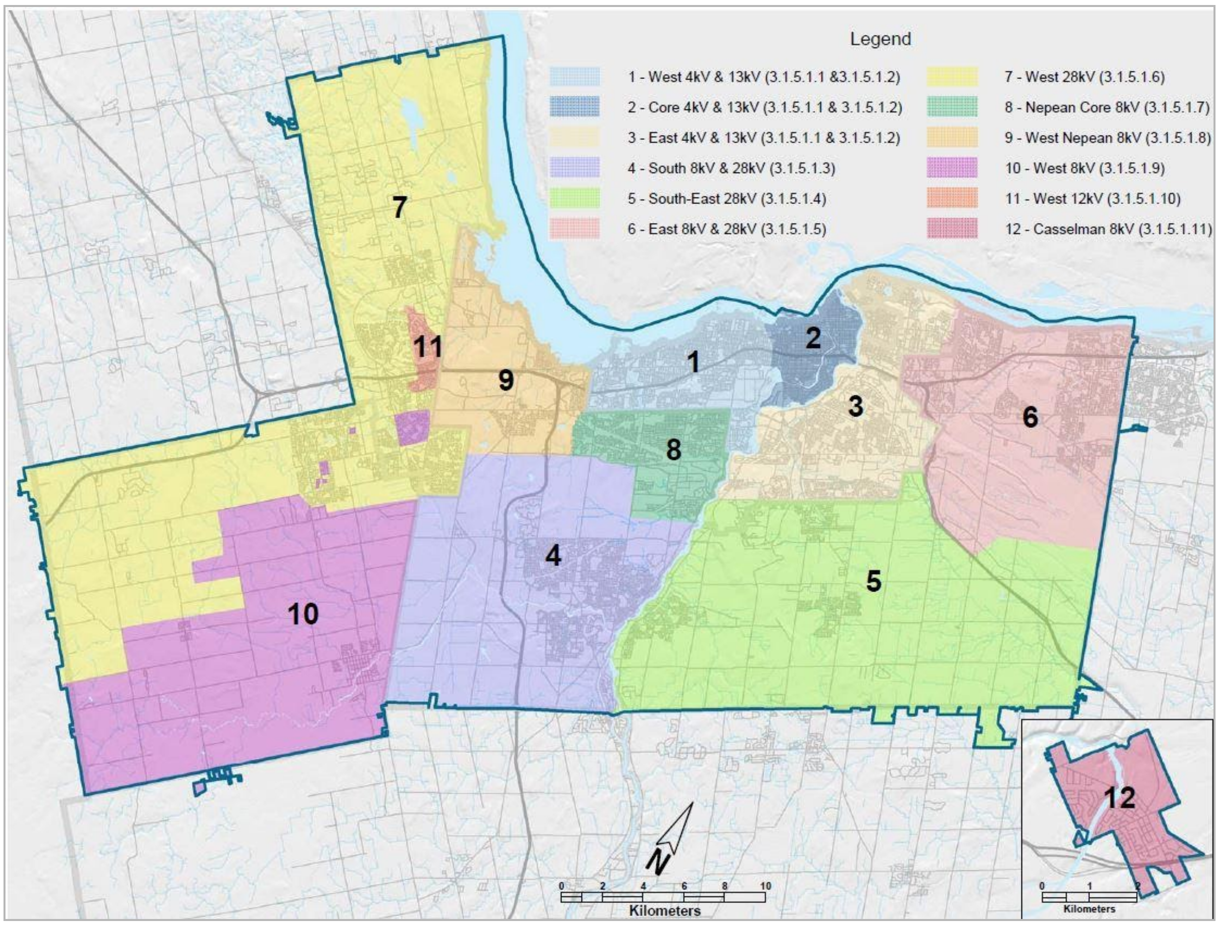
Currently, there are 35 CDPs published on the City of Ottawa's website which describe a mix of development types. A summary of the CDPs can be found in Table 7.7 below and is based upon information provided within each study plan.

Table 7.7 – City of Ottawa Community Design Plans Summary

Study	Study Area (ha)	GFA (ha)	No. Res. Units	Land Use Type
Barrhaven South CDP	500	188.9	6,862	Mixed-Use
Barrhaven South Expansion CDP	122	48.2	1,752	Mixed-Use
Bank Street CDP	101	39.9	990	Mixed-Use
Bayview Station District CDP	29.5	55	3,594	Mixed-Use
Beechwood CDP	22	6.5	819	Mixed-Use
Cardinal Creek Village Concept Plan	208	95	3,500	Mixed-Use
Carp Road Corridor CDP	2475	Not specified	0	Commercial
Village of Carp CDP	49.5	Not specified	543	Mixed-Use
Village of Constance Bay Community Plan	114	27.2	204	Mixed-Use
East Urban Community (Phase 1 Area) CDP	570	Not specified	3,498	Mixed-Use
East Urban Community (Phase 2 Area) CDP	240	Not specified	1,726	Mixed-Use
Fernbank CDP	674	310	11,000	Mixed-Use
Former CFB Rockcliffe CDP	131	45	5,350	Residential
Greely CDP	1276	87	729	Mixed-Use
Leitrim CDP	500	362.3	5,300	Mixed-Use
Mer Bleue CDP	160	113.7	3,000	Mixed-Use
Kanata North CDP	181	47.9	2,900	Residential
Kanata West Concept Plan	887	Not specified	5,000	Mixed-Use
North Gower CDP	278	208	520	Mixed-Use
Old Ottawa East CDP	158	Not specified	2,250	Mixed-Use
Orleans Industrial Park Study	316	18.7	0	Commercial
Richmond Road/Westboro CDP	270	111.7	2860	Mixed-Use
Riverside South CDP	1800	1450	18,300	Mixed-Use
Scott Street CDP	57.7	Not specified	1,500	Mixed-Use
South Nepean Town Centre CDP	165	35	11,000	Mixed-Use
Uptown Rideau CDP	21	43.1	2,500	Mixed-Use
Transit-Oriented Development (TOD) Plans	588	432	16,500	Mixed-Use
Village of Richmond CDP	879	3.5	2,700	Mixed-Use
Wellington Street West CDP	232	Not specified	950	Mixed-Use

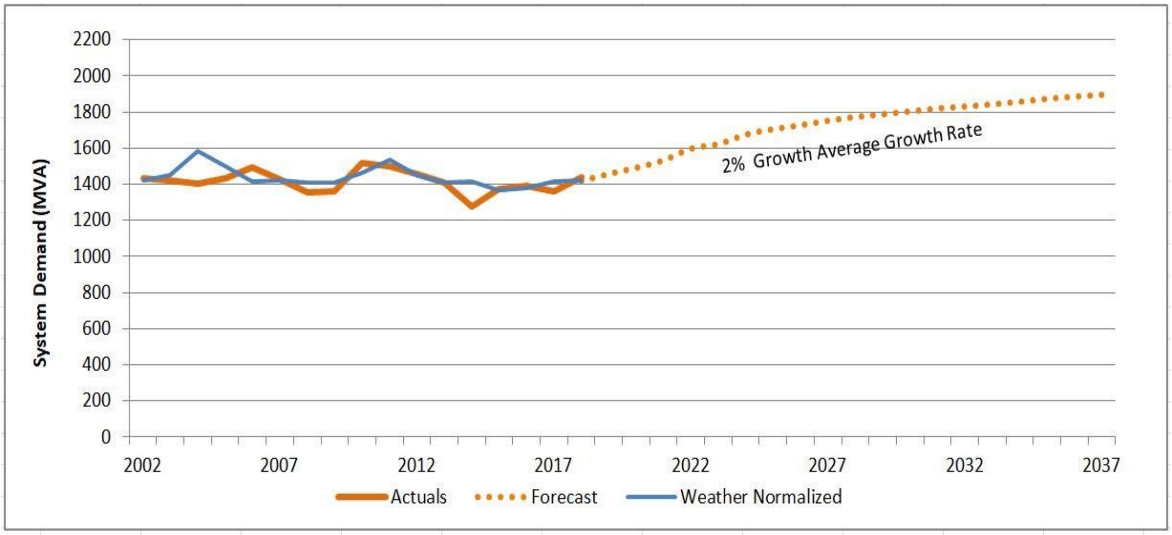
Hydro Ottawa's distribution system is composed of several subsystems, which are segregated by operating voltage, geographical boundaries, and pre-amalgamation utility demarcations, as shown in Figure 7.4. Each of these subsystems undergo an extensive review annually, as part of the capacity planning process, and a forecast is produced over a 20-year horizon.

Figure 7.4 – Hydro Ottawa Planning Regions



The forecast from the 2017 assessment was incorporated into the latest IRRP cycle. The expected growth for Hydro Ottawa's service territory included in the latest IRRP is shown in Figure 7.5. Over the next 20 years the system will see an average annual growth of 2%. Five-year and 10-year forecast growth rates are 4% and 3%, respectively.

Figure 7.5 – System Load Forecast



Despite steady customer and population growth, overall summer system peak load has remained relatively steady in recent years at approximately 1,400 MW as shown in Figure 7.5 below. However, Ottawa continues to experience high load growth in certain areas of the city primarily due to new residential developments in previously rural areas, infill and intensification in many established areas, as well as major projects like the Ottawa Light Rail Transit ("LRT") system. Rural areas experiencing growth are South Nepean, Kanata North, Leitrim, Riverside South, and Richmond South. Distribution lines and stations in these former rural areas are being pushed to their capacity limitations. Asset renewal and upgrades are required to meet the expected growth and maintain acceptable reliability levels in these growth areas.

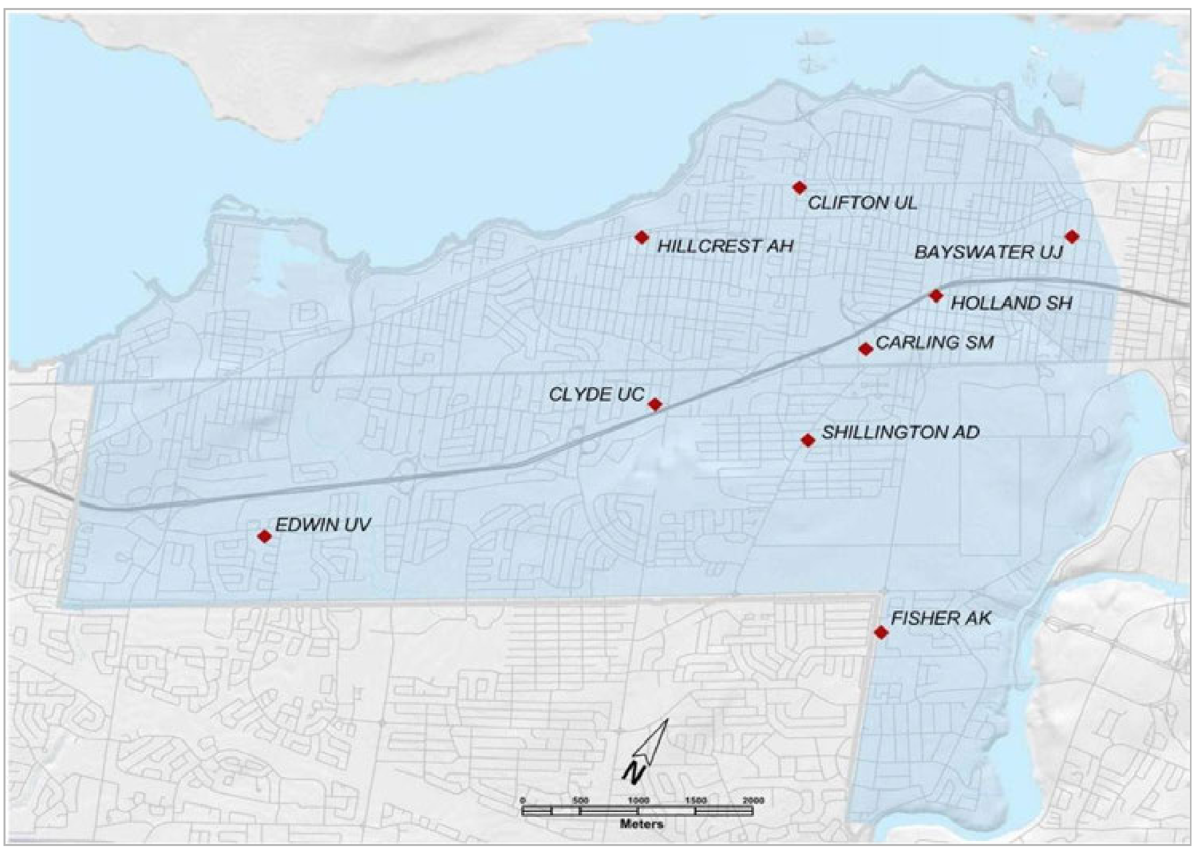
The following sections detail the forecasted subsystem needs.

7.2.1. 4 kV System

Hydro Ottawa 4kV supply region is comprised of three main areas: West 4kV, Core 4kV, and East 4kV as shown in Figure 7.6, Figure 7.7 and Figure 7.8 below, respectively.

1) The West 4kV supply region covers West of Rochester Street, East of Bayshore Drive, and North of Baseline Road. This region is supplied by Edwin DS, Shillington DS, Fisher DS, Clyde DS, Carling DS, Hydro Ottawa land DS, Hillcrest DS, Clifton DS, and Bayswater DS.

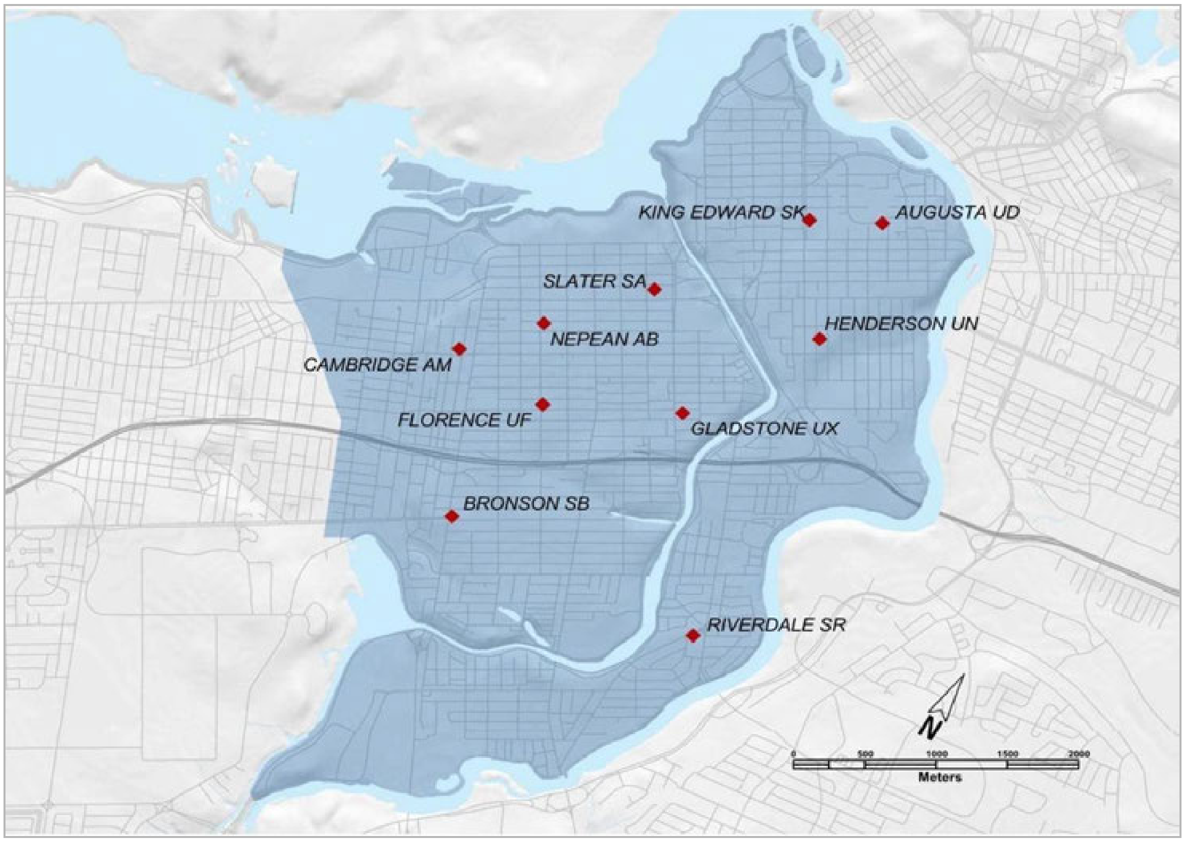
Figure 7.6 – West 4kV Supply Region



2) The Core 4kV supply region covers East of Rochester Street and is bounded West and North of the Rideau River. This region is supplied by Bronson DS, Nepean DS,

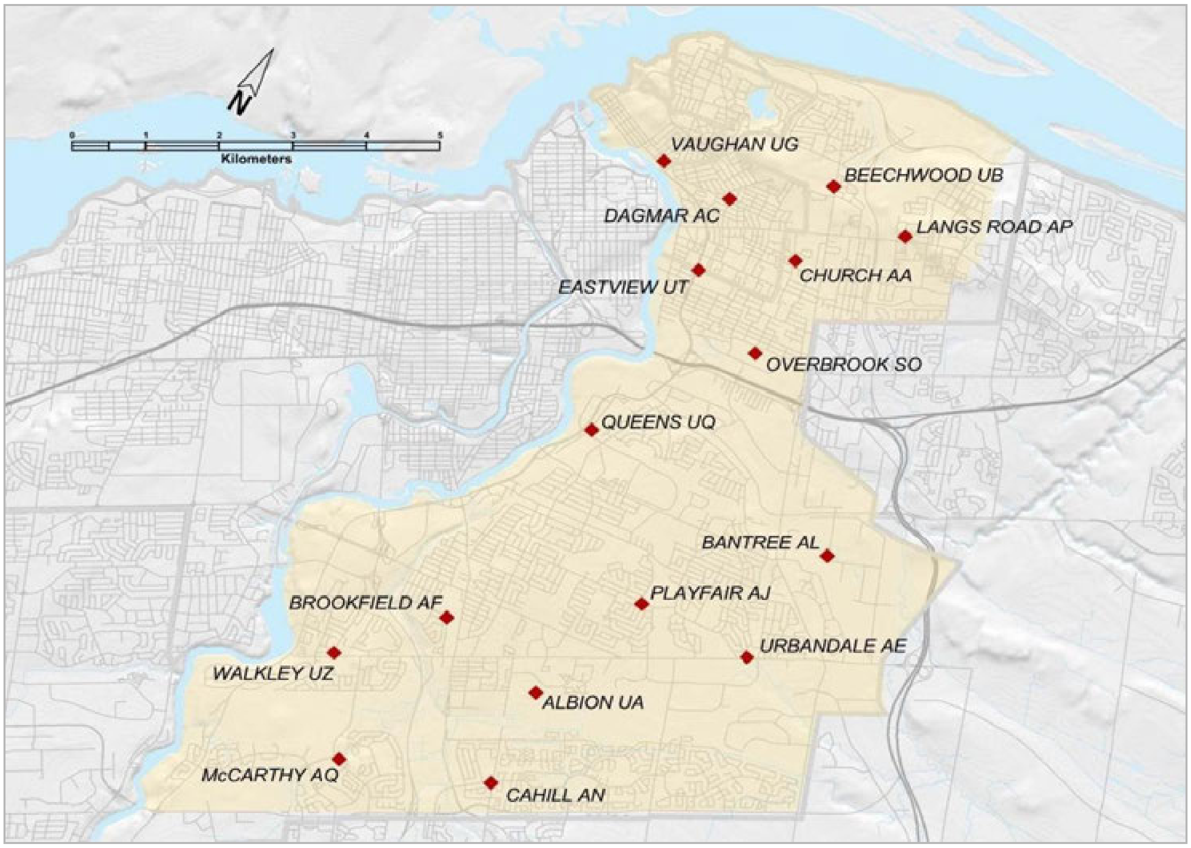
Gladstone DS, Augusta DS, Cambridge DS, Slater DS, Henderson DS, Florence DS, Riverdale DS, and King Edward DS.

Figure 7.7 – Core 4kV Supply Region



3) The East 4kV supply region covers West of Blair Road, East of the Rideau River, and North of Hunt Club Road. This region is supplied by Vaughan DS, Bantree DS, Albion DS, Eastview DS, Playfair DS, Cahill DS, Dagmar DS, Urbandale DS, McCarthy DS, Beechwood DS, Brookfield DS, Walkley DS, Queens DS, Langs Road DS, Overbrook DS, and Church DS.

Figure 7.8 – East 4kV Supply Region



These 4kV stations are supplied from twelve 13kV stations and provide electricity for the majority of the residential load in the region.

Through the Official Plan, the City of Ottawa is promoting new growth by means of intensification. Many new developments are converting from low-rise apartments to larger high density condos and apartment buildings. As a result, most of the 4kV stations are experiencing decreasing loads as customers upgrade their electrical supply and transfer to being supplied directly from the 13kV system.

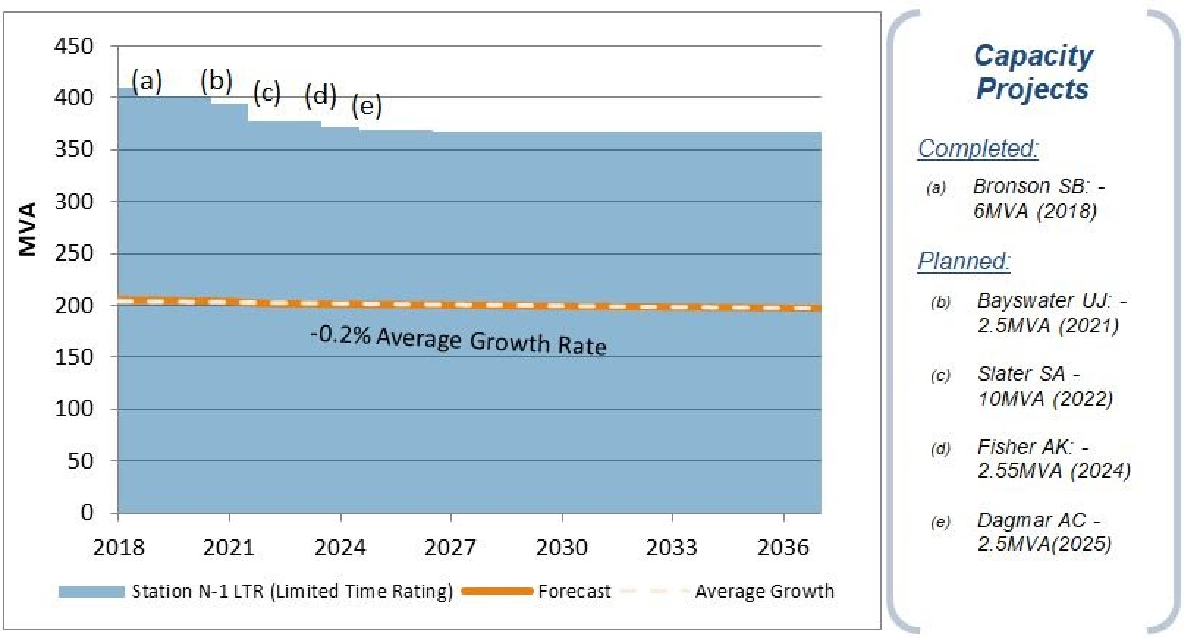
This decrease in load among the stations reduces their financial effectiveness due to the maintenance and replacement costs required that is independent of load. In areas that have seen a large transition of their load being supplied by 13kV stations and where the 4kV stations' equipment is approaching end of life, it may be financially advantageous to convert the existing customers to a 13kV supply while decommissioning the 4kV station.

Hydro Ottawa does not have a formal plan to phase out the 4kV system, but considers voltage conversion when evaluating station renewal options. Voltage conversion is favored over station renewal in cases where the cost to renew station assets exceeds the cost of upgrading the distribution assets to meet 13kV design requirements.

As assets in 4kV stations reach end of life and are identified for renewal, voltage conversion is evaluated on a case-by-case approach as a potential renewal option alongside full station asset replacement.

The forecasted 20-year load growth, along with planned station projects, is shown in Figure 7.9.

Figure 7.9 – East 4kV Supply Region



7.2.2. 8kV System

Hydro Ottawa 8kV supply system is comprised of five main areas:

1) Nepean Core 8kV System
2) West Nepean 8kV System
3) West 8kV System
4) Casselman 8kV System
5) East 8kV System

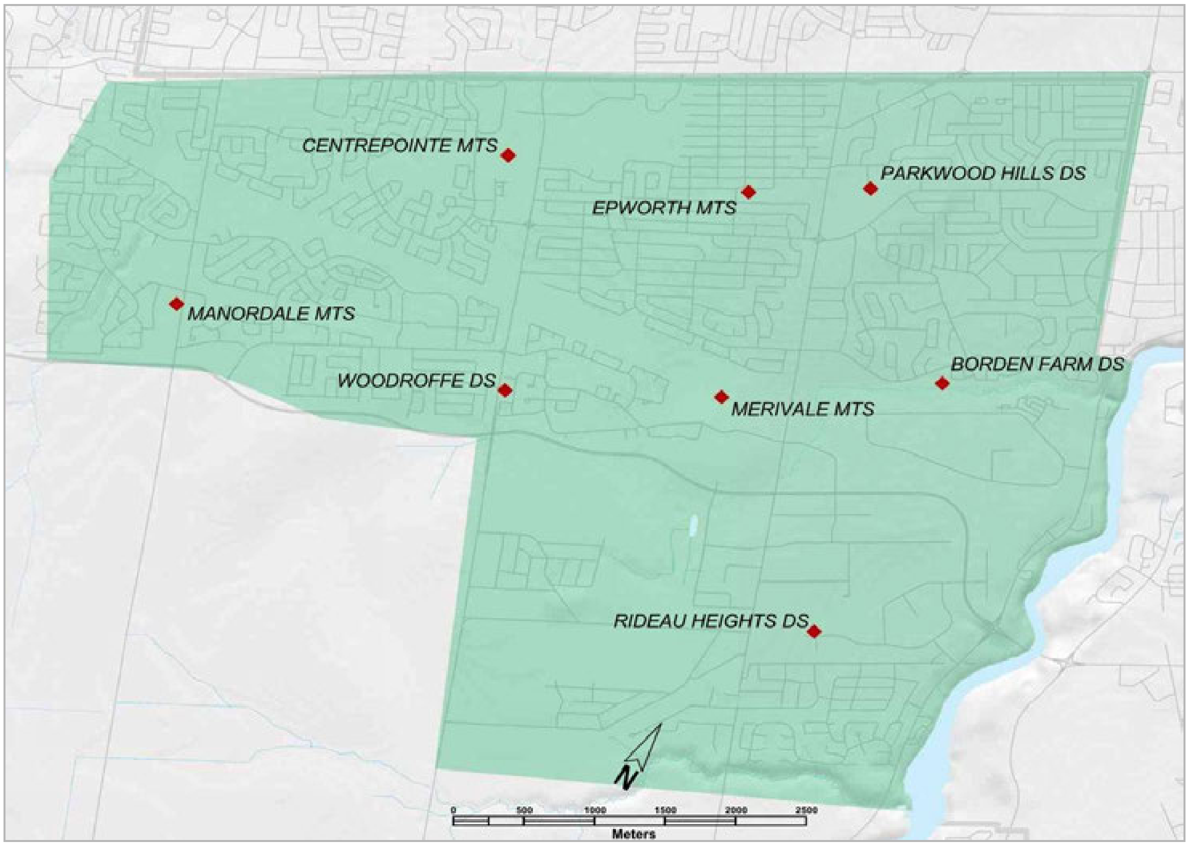
Seven out of the 24 8kV stations are supplied by the 115kV transmission system, one 8kV station is supplied by both 44kV and 115kV supplies, and the remaining 16 are supplied from three 44kV stations.

7.2.2.1. Nepean Core 8kV System

The Nepean Core 8kV supply region includes the northern portions of Nepean. This region is supplied by the Manordale MTS, Centrepointe MTS, Woodroffe DS, Epworth MTS, Merivale MTS, Parkwood Hills DS, Borden Farms DS, and Rideau Heights DS. Figure 7.10 below shows the supply region of the Nepean Core 8kV System.

Growth in the 8kV Nepean supply region is driven by ongoing commercial developments, which are focused in the Nepean Employment Area (located around Hunt Club Road between Merivale Road and Prince of Wales Drive).

Figure 7.10 – Nepean Core 8kV Supply Region



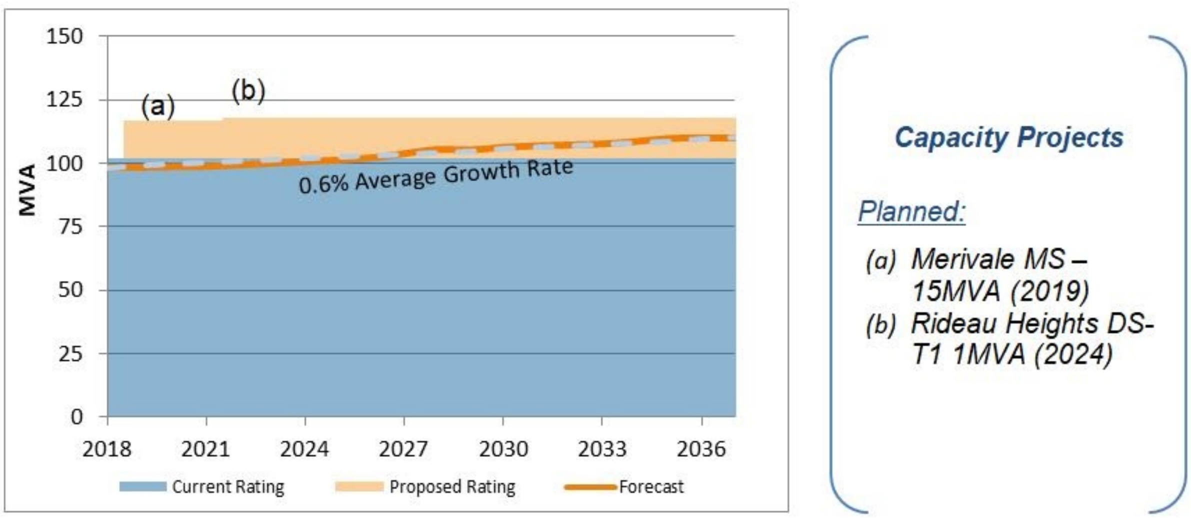
Overall, the existing 8kV Nepean area is operating at the planning capacity limitations with Centrepointe MTS, Merivale MTS, Manordale DS, and Rideau Heights DS operating above their planning capacity rating as shown in Table 7.1 above. The area of main concern is the Nepean employment area in which the trunk feeders are above or approaching their planning capacity limitations and the existing feeder interconnections are limited. Two feeders from Rideau Heights DS and one feeder from Parkwood Hills DS are on the list of feeders exceeding their planning capacity, as shown in Table 7.2 above.

Over the next 20 years, significant growth is expected for the employment area in the Nepean region. The transformers at Borden Farm DS were replaced recently adding 8MVA of additional capacity in this area. The Merivale station is undergoing a major rebuild which will bring 15MVA of additional capacity to this region by 2019. After completion of the Merivale project, the transformers at Rideau Heights will need to be upgraded due to end of life condition adding an additional 1MVA of capacity for future growth.

The additional capacity from Borden Farm DS and Merivale MTS will introduce four new feeders to the area. Plans are in place to reconfigure the feeders in the Merivale employment area to improve feeder load distribution once Merivale MTS is energized.

The forecasted 20-year load growth along with planned capacity upgrade projects is shown in Figure 7.11.

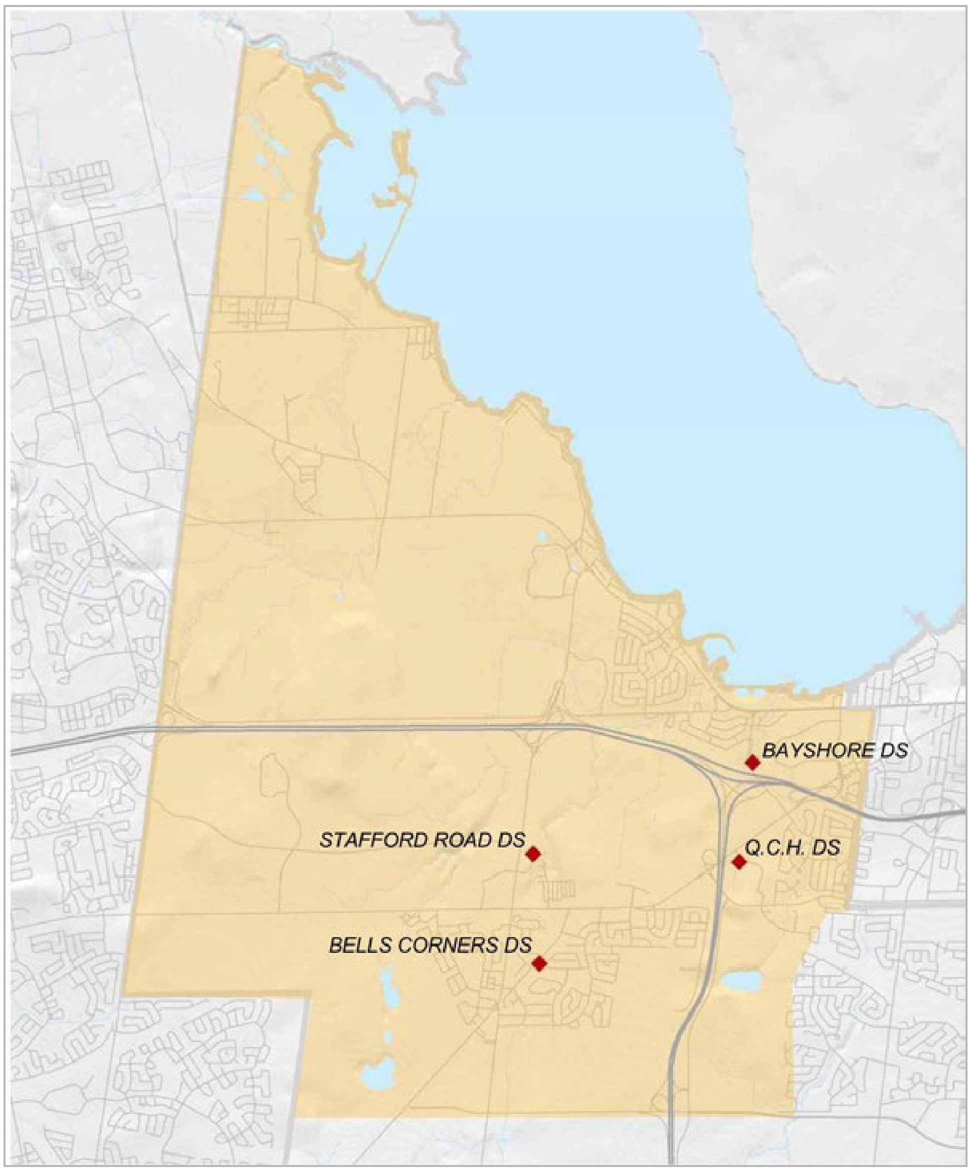
Figure 7.11 – Core Nepean 8kV Load Growth



7.2.2.2. West Nepean 8kV System

The West Nepean 8kV supply region includes the north-west portions of Nepean. This region is supplied by the Bayshore DS, QCH DS, Stafford Road DS, and Bells Corners DS. Figure 7.12 shows the supply region of the West Nepean 8kV System.

Figure 7.12 – West Nepean 8kV Supply Region



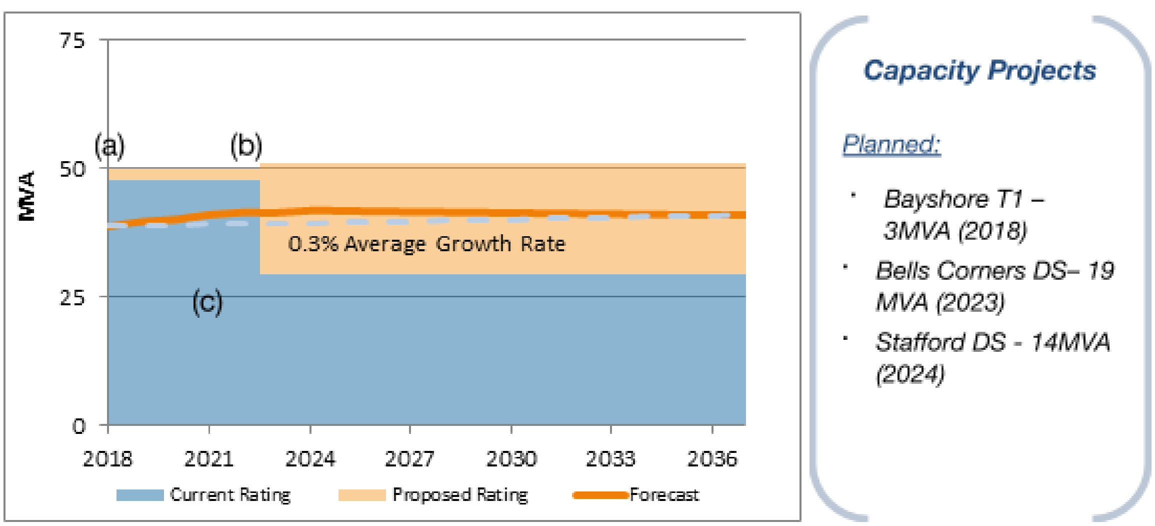
Load in this supply region is expected to remain stable as per historical years since no major projects have been identified or proposed by developers at this time.

Overall, the existing 8kV West Nepean area is operating below the planning capacity limitations; however, Bayshore DS and Stafford DS are operating above their planning capacity rating as shown in Table 7.1 above.

One of the transformers at Bayshore DS was replaced at the end of 2018 increasing the planning capacity rating for this region. The station assets at Bells Corners DS and Stafford DS are approaching end of life and are in need of replacement. The Bells Corners station is planned to be upgraded with three transformers (3x15MVA) facilitating the decommissioning of the nearby station, Stafford DS, by 2024.

The forecasted 20-year load growth, along with planned capacity upgrade projects, is shown in Figure 7.13.

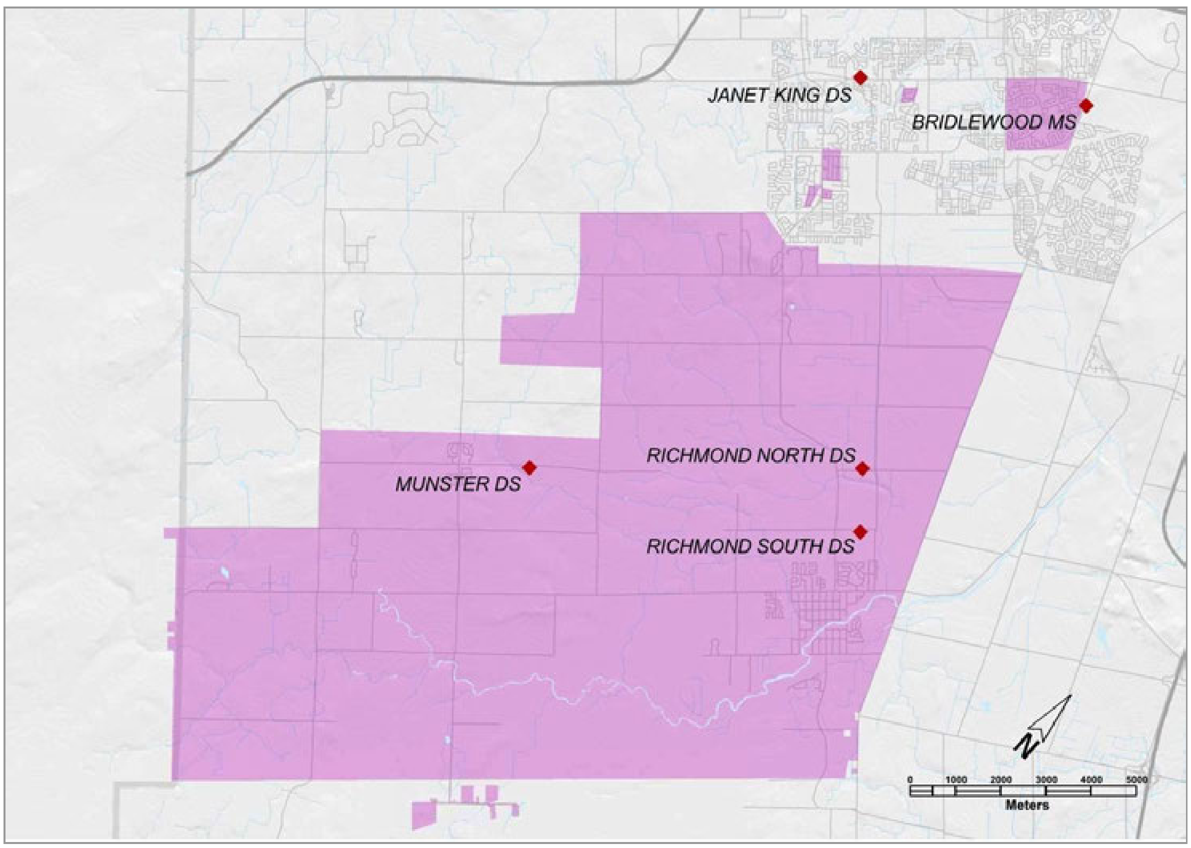
Figure 7.13 – West Nepean 8kV Load Growth



7.2.2.3. West 8kV System

The West 8kV supply region includes the Glen Cairn community, small areas of Stittsville, Richmond Village, Munster and rural Goulbourn. These areas are supplied by Bridlewood DS in Kanata, Janet King DS in Stittsville, Richmond North DS and Richmond South MTS in Richmond Village, and Goulbourn, and Munster DS in Munster. Figure 7.14 shows the supply region of the West 8kV System.

Figure 7.14 – West 8kV Supply Region

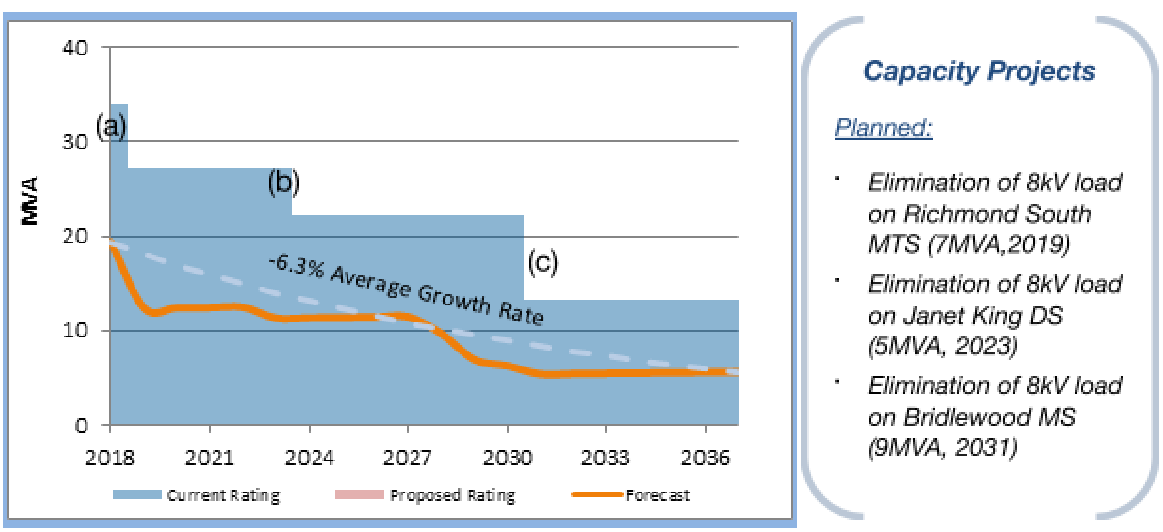


Growth in these areas is limited, due to the rural nature of the supply region. The exception is Richmond Village which required the conversion of Richmond South MTS to 28kV due to planned expansion and growth. The station rebuild is scheduled for completion by late 2019. The main streets of Richmond village are in the process of being converted, with several overhead line upgrades implemented in 2017 to 2019 along main roads. Conversions of minor roads and side streets will continue to be supplied at 8kV, through step-down transformers at the rebuilt Richmond South MTS. New developments will be connected onto the 28kV system. Therefore, the drivers for conversion of the remaining 8kV areas of Richmond Village will be based on asset condition and risks to reliability.

Overall, the existing west 8kV area is spread out over a large geographical area, with few backup feeder options between stations, apart from Richmond North and Richmond South. With the conversion of Richmond South, and the eventual elimination of 8kV load in Stittsville and Glen Cairn, the remaining 8kV region will center on Goulbourn, specifically Munster DS. Contingencies will need to be developed between the two remaining 8kV stations, Munster DS and Richmond North DS. No ties currently exist between these stations, and long-term plans have been put in place to construct ties to facilitate maintenance and outage restoration.

The forecasted 20-year load growth, along with planned capacity upgrade projects, is shown below in Figure 7.15.

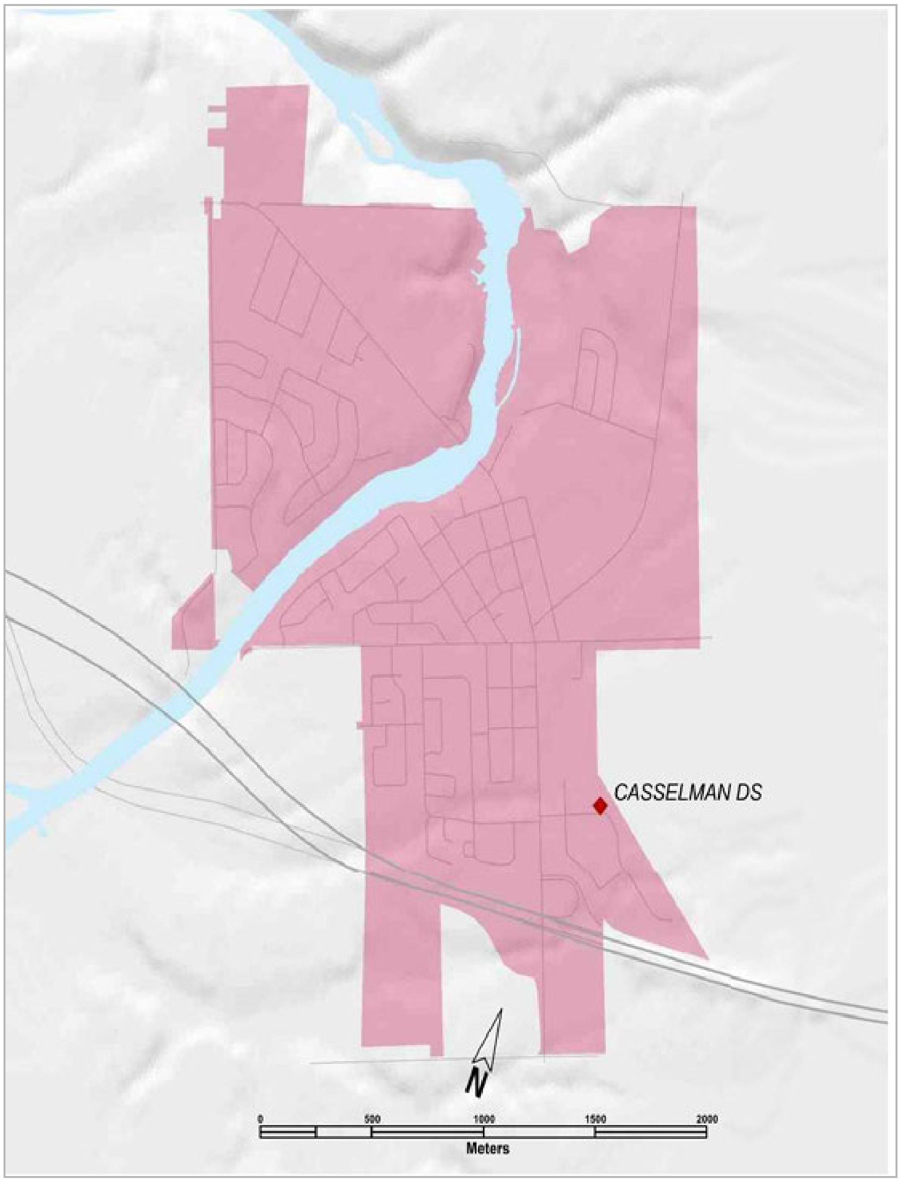
Figure 7.15 – West 8kV Load Growth



7.2.2.4. Casselman 8kV System

The Village of Casselman is supplied from a single Hydro Ottawa station, Casselman DS, and three 8kV feeders. Figure 7.16 shows the Casselman supply area.

Figure 7.16 – Casselman 8kV Supply Region

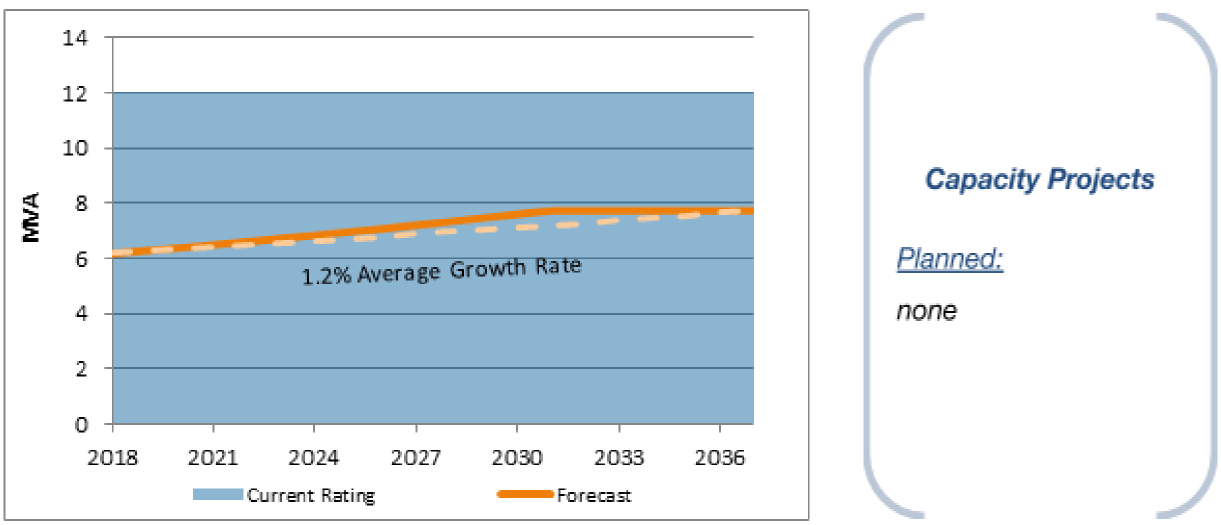


In 2014, a second transformer was installed to provide redundancy for contingency situations and improve reliability to the area. In 2020, a fourth feeder will be added at the station to enable full restoration in an N-1 station bus fault scenario. The additional feeder will improve station reliability.

Growth within the Village of Casselman has been slow and there are no major developments anticipated in the region over the next 20-year forecast period.

The forecasted 20-year load growth is shown in Figure 7.17.

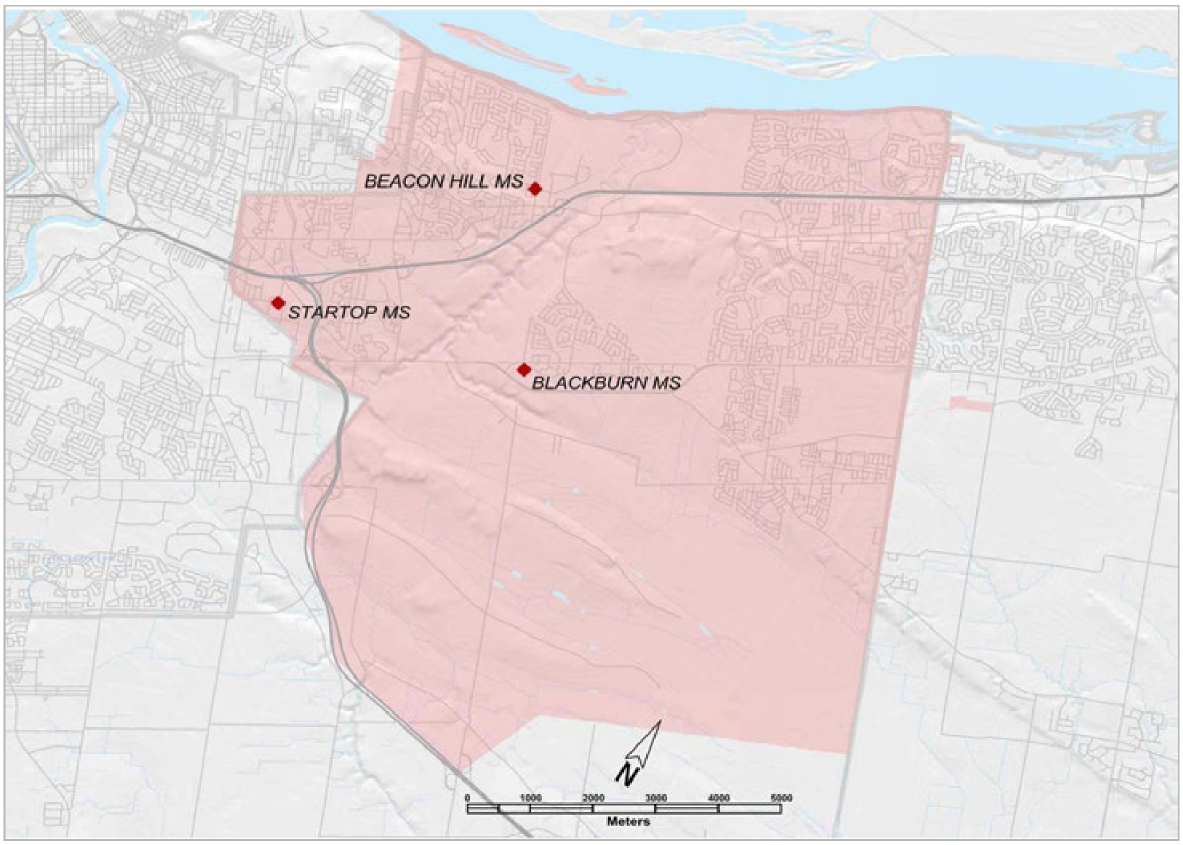
Figure 7.17 – Casselman 8kV Load Growth



7.2.2.5. East 8kV System

The East 8kV supply region is bounded by the old Gloucester and Ottawa municipal boundary and Highway 417 in the south as shown in Figure 7.18. Startop DS, Blackburn DS, and Beaconhill DS supplied this region. These stations are supplied from Hawthorne TS.

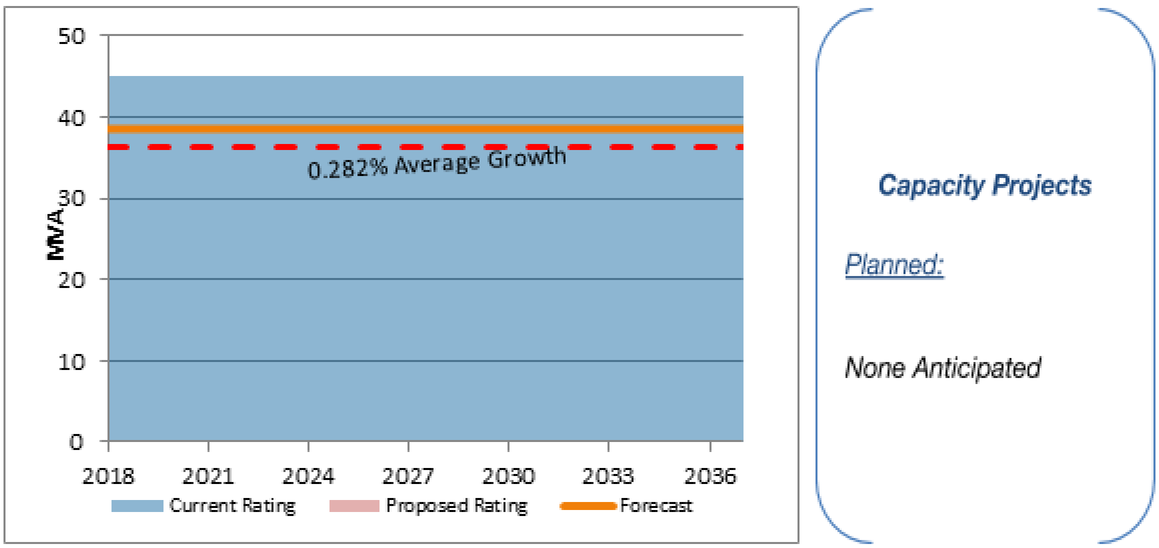
Figure 7.18 – East 8kV Supply Region



The East 8kV area is composed of established developments and services mostly residential and small commercial developments. Over the last 10 years, load on the East 8kV system has remained constant. There is no major growth anticipated on this system since large transit oriented developments will be connecting to the East 28kV system to meet their capacity requirements. One feeder from Startop DS is operating slightly above its planning capacity rating as shown on Table 7.2 above. Since there are available options for transferring load and there is no forecasted growth for this region, no plans have been put in place to lower loading levels at this Startop feeder at this point.

The forecasted 20-year load growth is shown in Figure 7.19.

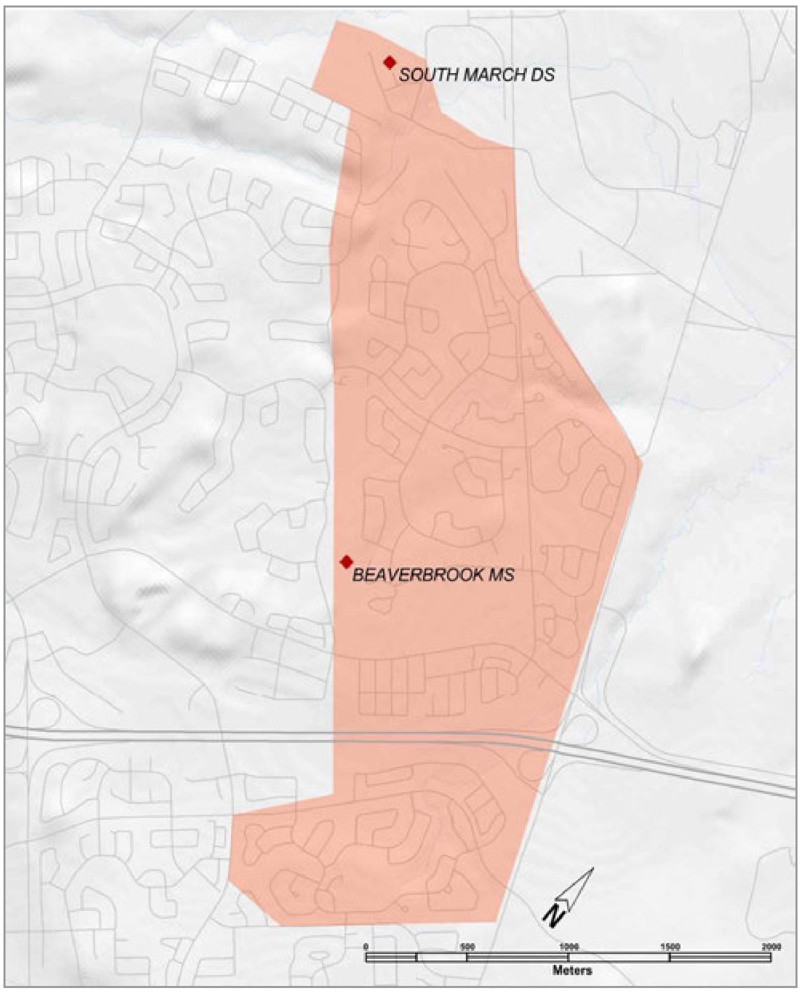
Figure 7.19 – East 8kV Load Forecast



7.2.3. 12 kV System

The West 12kV supply region includes two areas of Kanata, immediately North and South of Highway 417 at Eagleson Road. The communities are supplied by Beaverbrook MS and South March DS, with no distribution capabilities beyond these stations. Figure 7.20 shows the supply region of the West 12kV System.

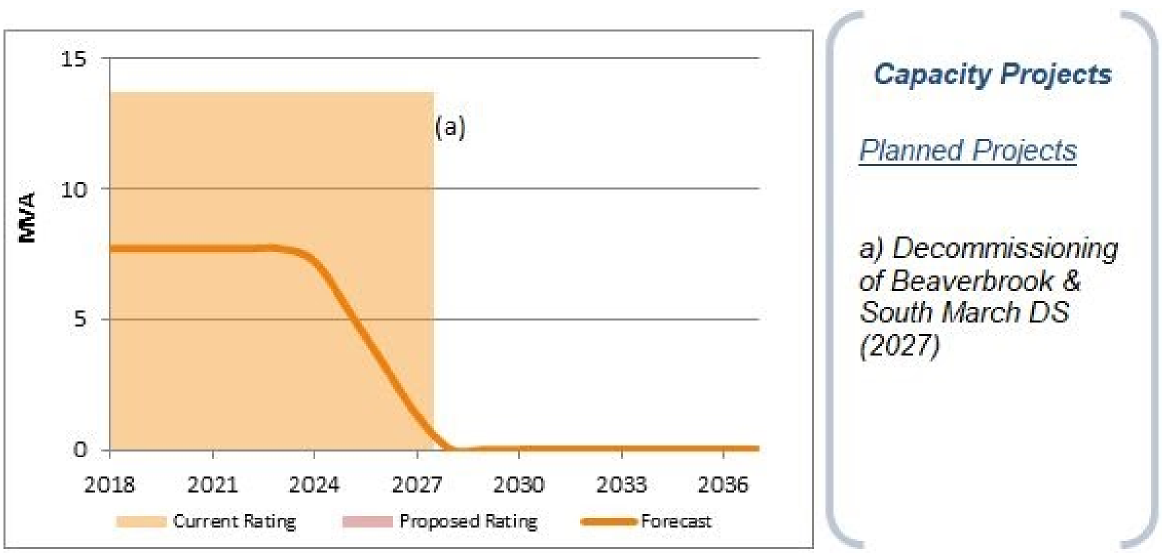
Figure 7.20 – West 12kV Supply



The 12kV supply area is mostly residential with a mixture of small to medium commercial, and has experienced very low to no growth over the past several years. There is no significant load growth forecast for the 12kV system, therefore no additional station capacity is required. The area is planned to be converted to 28kV beginning in 2021. Conversion work will last several years due to large areas of end of life cable that require replacement under the cable renewal program. The decommissioning of Beaverbrook and South March stations is tentatively planned for 2027 and needs to be coordinated with the construction of the New Kanata Station due to existing capacity limitations in the 28kV system. In the short-term, strategic locations will be converted to 28kV but energized at 12kV to improve reliability in the 12kV supply area for the next eight years until the stations are decommissioned.

The forecasted 20-year load growth, along with planned capacity upgrade projects, are shown below in Figure 7.21.

Figure 7.21 – West 12kV Load Forecast

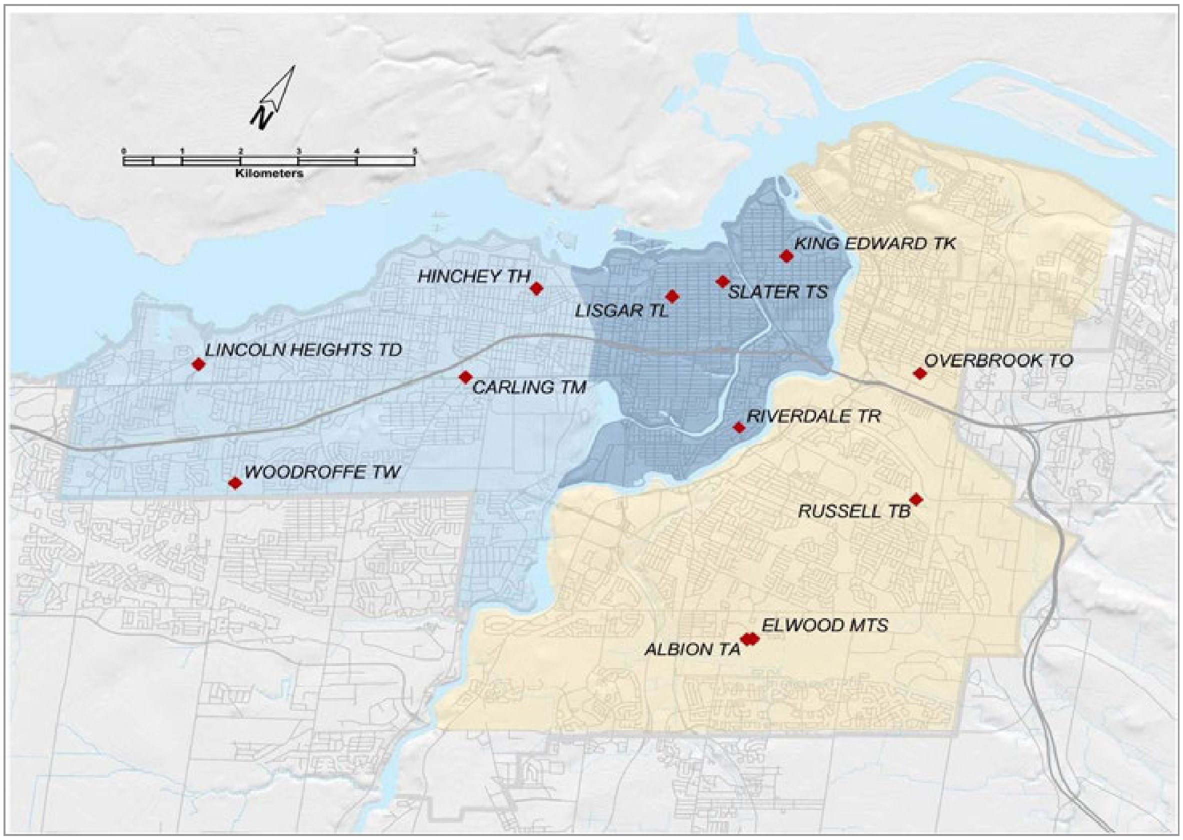


7.2.4. 13kV System

The Hydro Ottawa 13kV supply region is composed of three main areas, as shown in Figure 7.22. These zones correspond to the 4kV system mentioned in section 7.2.1 above. The three areas are as follows:

1. The West 13kV supply region covers from Bayview Yards and west of Preston Street to Bayshore Drive, north of Baseline Road. This region is supplied by Hinchey TS, Carling TS, Woodroffe TS, and Lincoln Heights TS. Hinchey TS also supports the Core 13kV supply region.
2. The Core 13kV area follows the Rideau River to the East and covers to LeBreton Flats in the West. This region is supplied by King Edward TS, Slater TS, Lisgar TS, Hinchey TS, and Riverdale TS. Riverdale TS and King Edward TS also support the East 13kV supply region.
3. The East 13kV supply region includes the eastern portion of the Old City of Ottawa. This region is supplied by the Russell TS, Albion TS, Ellwood MTS, Overbrook TS, Riverdale TS, and King Edward TS.

Figure 7.22 – 13kV Supply



Much of the residential load in these regions is not directly supplied from the 13kV system, but rather from the thirty-five 4kV stations, which are supplied from the 13kV system.

Through the Official Plan, the City of Ottawa is promoting new growth by means of intensification within central Ottawa. This impacts the 13kV system as it covers mostly established areas. Many new developments are trading in low-rise apartments for larger, high density residential buildings.

The majority of the load growth on the 13kV system is from City driven Community Design Plans, Ottawa LRT, Transit Oriented Development, and new large development plans such as Tunney's Pasture, LeBreton Flats, Greystone Village, Wateridge Village, and Zibi.

In the short-term, there is a requirement for capacity upgrades and the construction of station interconnections to transfer load in order to manage the load within the 13kV system. System expansions will also be required due to system demand. As shown in Table 7.2, there are seven 13kV feeders above their planning capacity ratings: TB2JP, ELW11, 2206, 630, 509, TR2FB, and TW18. Feeder capacity upgrades are in place under the Distribution Capacity Upgrades Program to address the most critical feeders. Feeders with minor overloads and minimal forecasted growth will continue to be monitored for future upgrades.

Riverdale TS Switchgear Capacity Upgrade

Riverdale TS transformation capacity exceeds the load forecast at this time; however, the overall station rating is limited due to a lack of unused or unloaded breakers in the secondary lineup. The switchgear is planned to be replaced by 2024 and will include an additional six feeder breakers. The bus's ampacity will also be increased to prevent future limiting factors in case of transformer capacity upgrades.

Slater TS Transformer Upgrade

Slater TS station’s T1 transformer failed in early 2018, and was subsequently replaced by HONI with a larger unit (100MVA) for future forecast growth and contingency requirements for load transfers within the Core 13kV region. The remaining transformers are also approaching end of life, and will be sized to match the capacity of the new T1 unit.

King Edward TS Transformer Upgrade

The two transformers at King Edward TS are currently mismatched in capacity, limiting the overall available capacity. This project would see the replacement of the undersized transformer increasing the available LTR of the station transformers from 80MVA to 136MVA; however, the planning rating will be limited to 114MVA due to the switchgear. The increased capacity will relieve Slater TS and support supply of the load growth resulting from the Ottawa LRT project. HONI is currently undertaking the installation of a new transmission line to relieve a thermal overloading issue which is required to increase the load on King Edward TS. The planned in-service date of the King Edward upgrade project is 2020.

The existing East 13kV system is forecasted to be operating above the N-1 rating of its supplying stations due to load growth in the near-term.

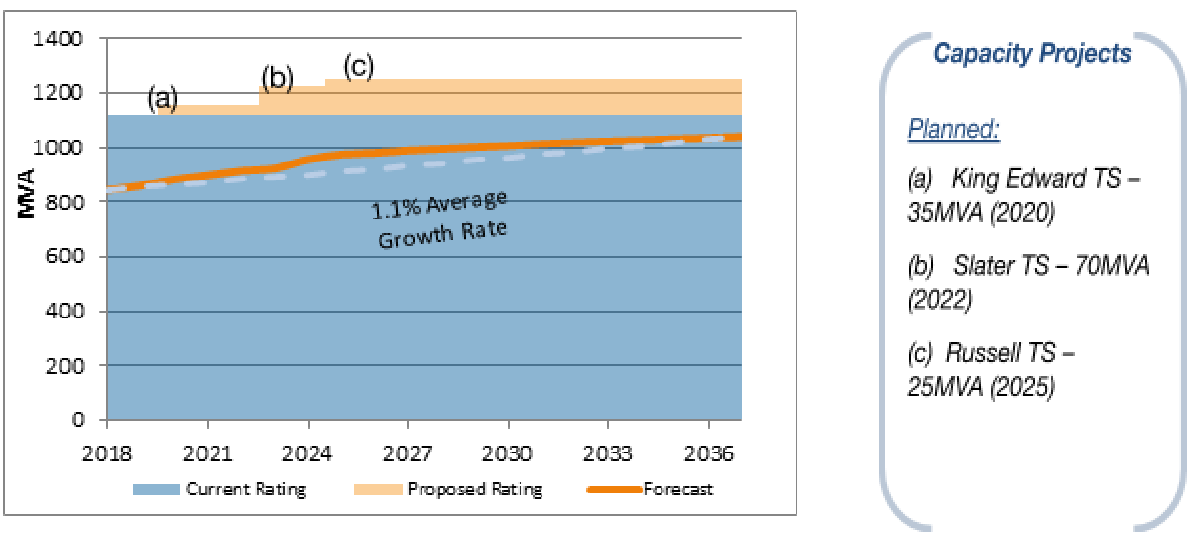
Russell TS Upgrade

The planning capacity at Russell TS is currently 77 MVA. The loading has currently reached the station's capacity planning limit and is forecasted to exceed the planning limit in 2019 with the addition of the Ottawa LRT and transit oriented developments. The forecast is expected to approach 100 MVA in 2025. Additional distribution ties will be created to transfer excess load from Russell TS to neighboring stations with spare transformer capacity such as Ellwood MTS, Albion TS, and Overbrook TS.

Load in all areas will continue to be monitored and forecasted to ensure adequate supply to Ottawa's 13kV system.

The forecasted 20-year load growth, along with planned capacity upgrade projects, is shown below in Figure 7.23.

Figure 7.23 – 13kV Load Forecast



7.2.5. 28kV System

Hydro Ottawa 28kV supply system is comprised of four main areas:

1) South 28kV System
2) South-East 28kV System
3) East 28kV System
4) West 28kV System

7.2.5.1. South 28kV

The South 28kV supply region covers the areas of Nepean south of the Greenbelt. It is supplied by Fallowfield MTS and Longfields DS and two feeders from Limebank MTS. Despite the physical barrier of the river between Nepean and Gloucester, Limebank station plays an essential role in supplying both sides of the river, making it one integrated supply region.

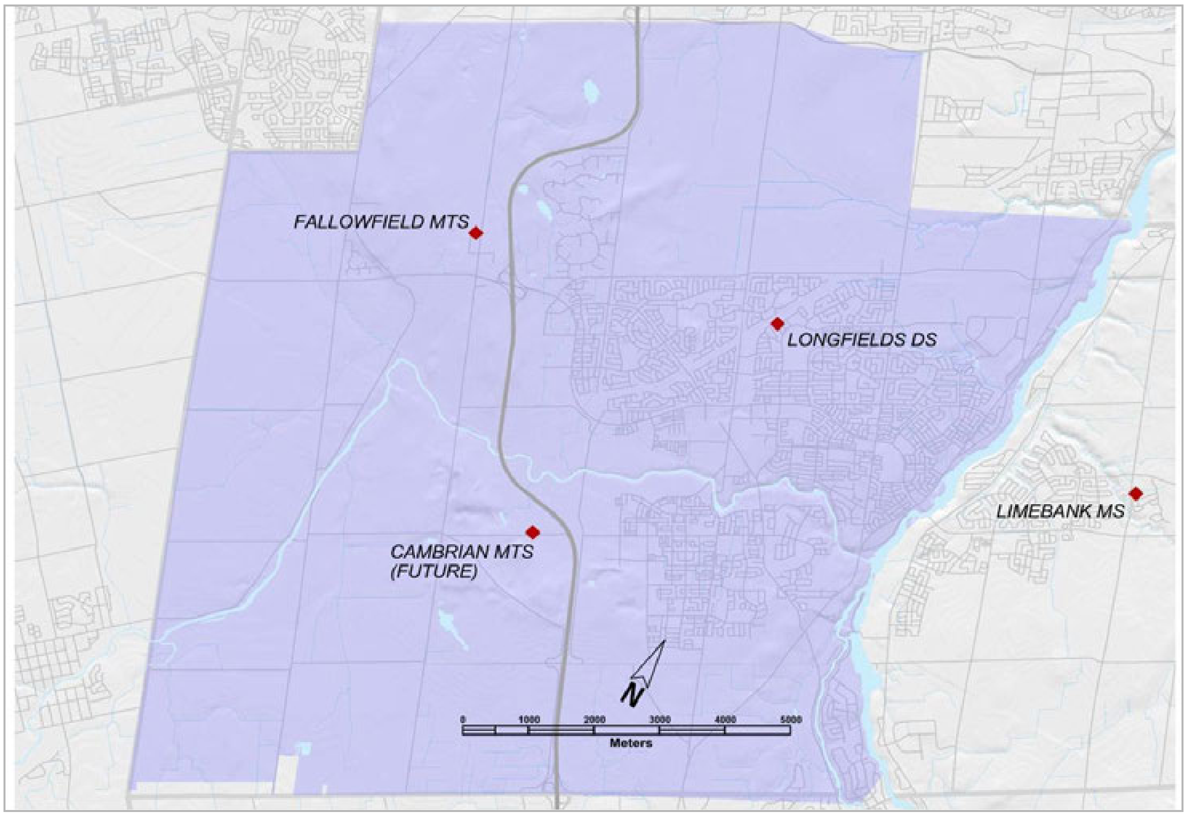
The 2016 IRRP identified the need for an additional station in the South Nepean Region. In May 2016, the IESO provided a letter of recommendation to build a new station to meet the growing electricity demand in the area. The original concept for the station called for a supply from the 230kV transmission system in the area, which would be located within the existing 115kV transmission corridor. In consultation with HONI, it was determined that remaining in the corridor is not feasible due to physical barriers to construction and transmission routing introduced by the Trail Road landfill. Alternative routes and station locations were explored once the limitations of the existing corridor were known, resulting in the proposed site on Cambrian Road, with a 1.5 km transmission extension in a new right-of-way corridor.

This project was approved by the OEB in October 2019. Hydro Ottawa and HONI had submitted a joint Leave to Construct application in May 2019, seeking OEB approval for the station and line scope of work, respectively.[1]

[1] Ontario Energy Board, *Decision and Order*, EB-2019-0077 (October 17, 2019).

Figure 7.24 shows the existing stations in the area as well as the selected location for the new station.

Figure 7.24 – South 28kV Supply Region



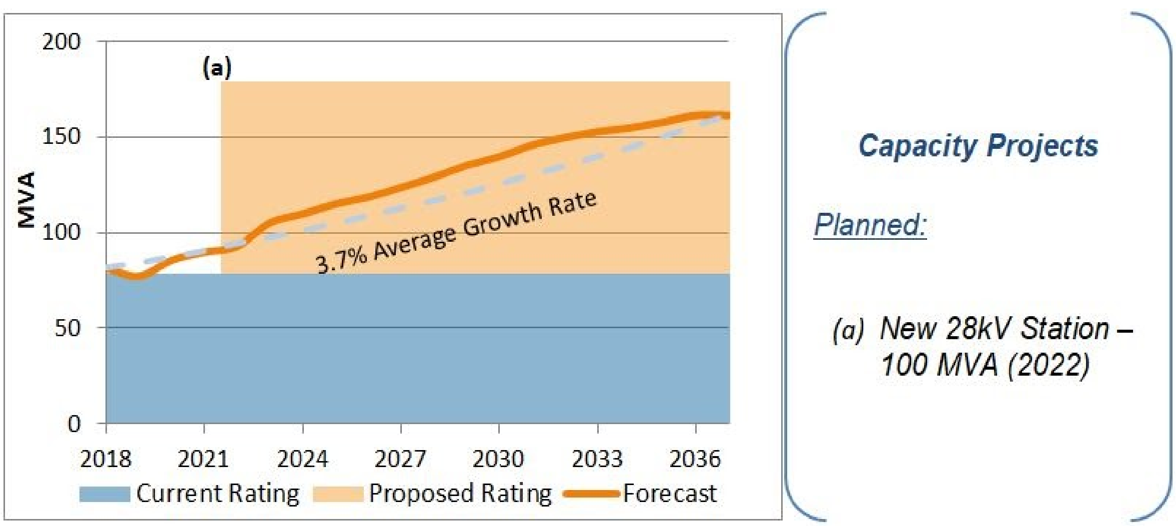
Over the last 10 years, load in the South Nepean region has almost doubled at an average growth rate of 7.6%. Growth in the south supply region is driven by the ongoing expansion of suburban residential developments, the Nepean Town Centre and the Strandherd Business Park. In addition, rural areas south of the Jock River which are currently fed by the 8KV system will be transferred to the 28kV system as 28kV feeders are introduced in the area to supply new suburban developments.

There is a need to expand the system to cover areas seeing growth, as well as strengthen the interconnections to the south of the Jock River. These issues will be addressed by the introduction of a new station that will support the growth in the Fallowfield MTS supply area. Capacity is the main issue affecting restoration and load transfers, as feeders and transformers are at or exceeding planning ratings. As shown in Table 7.1 above, Fallowfield MTS and Longfields DS are currently above their planning capacity ratings. At the feeder level, one feeder from Fallowfield MTS and one feeder from Limebank that supplies the South 28kV region are operating above their planning rating. These issues will also be addressed with the introduction of the new station in this region.

The new station is planned to be built with 2 X 75 MVA (10 day LTR of 100MVA) transformers with a planned energization date of 2022. In addition, investment at the distribution level will be required with the introduction of the new station to bring three of the new feeders across Highway 416 to the east as well as three other feeders west of the station.

The forecasted 20-year load growth, along with planned capacity upgrade projects, is shown in Figure 7.25.

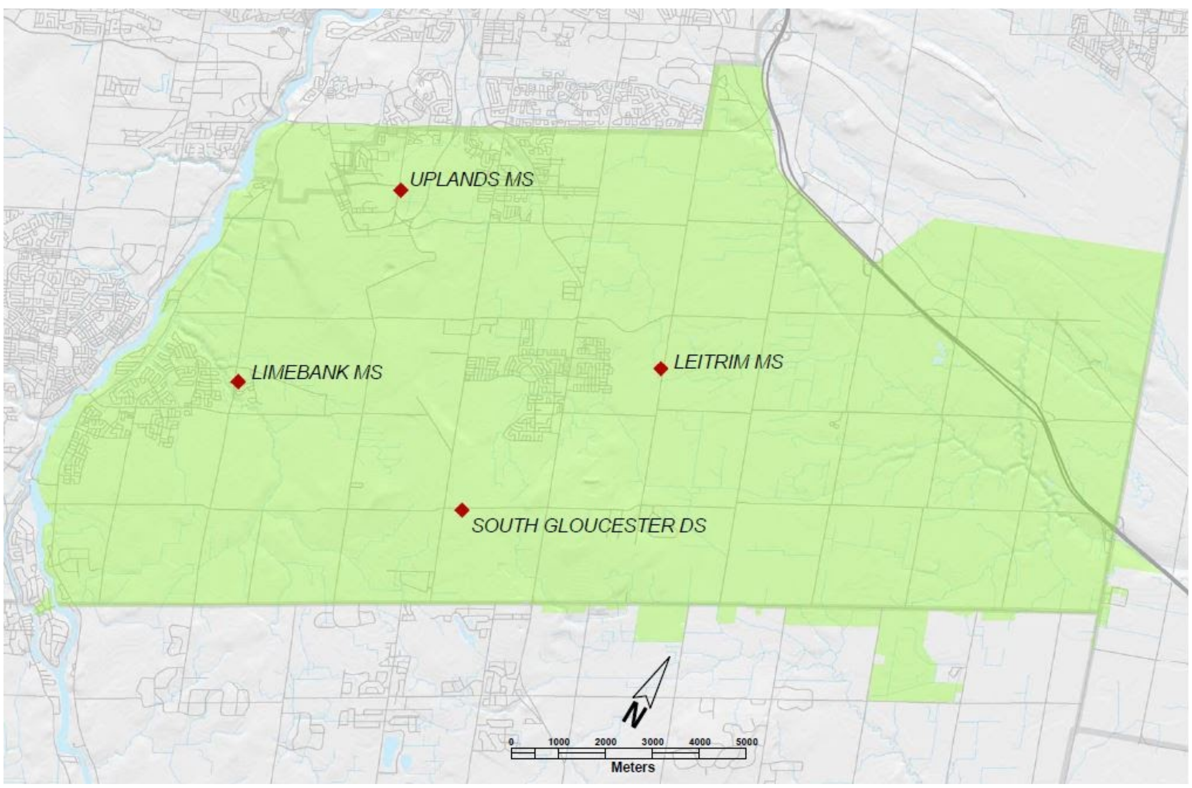
Figure 7.25 – South 28kV Load Forecast



7.2.5.2. South-East 28kV System

The South-East 28kV supply region includes the southern portions of Gloucester. This region is supplied by Limebank MTS, Uplands MTS, and Leitrim DS, as well as a small pocket supplied by an 8kV feeder from the HONI owned South Gloucester station as shown in Figure 7.26. Despite the physical barrier of the river between Nepean and Gloucester, Limebank station plays an essential role in supplying both sides of the river, creating interdependence between the South 28kV and the South East 28kV systems.

Figure 7.26 – South East 28kV Supply Region



Over the past 10 years, demand in the South Gloucester region has been continuously increasing at an average rate of 2.6% per year. Historically, the growth was attributed to the expansion of residential developments in the Riverside South and Leitrim communities.

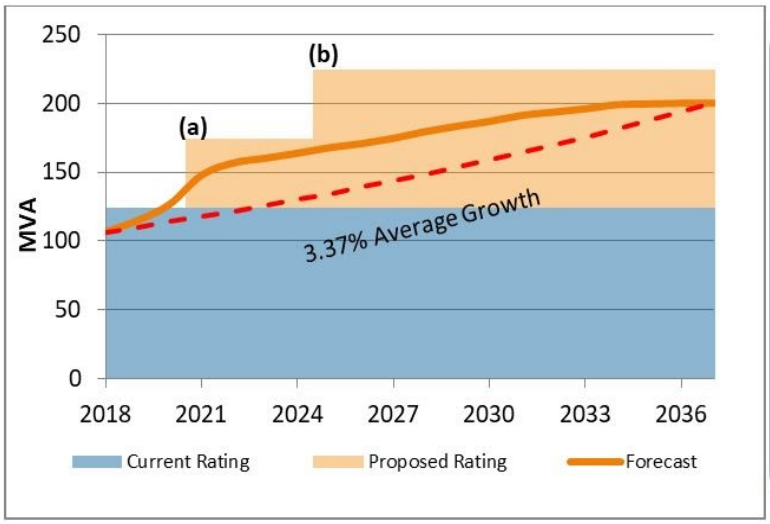
Currently, this region is operating slightly below planning capacity rating; however, Leitrim DS and one feeder from Uplands MTS are operating above its planning capacity ratings. Going forward, the growth rate is expected to increase to an average of 3.4% per year. The increased growth rate is mainly due to the Trillium Line extension of Ottawa LRT, large commercial and light industrial customers. The availability of transit by train is sparking high density residential developments and future business parks in the region. In addition, a new Amazon shipping facility located in the Leitrim supply region will drive future growth in the area due to employment opportunities. Lastly, the South Gloucester region is expected to see an increase in industrial plants in addition to its existing quarries and asphalt plants (i.e. Hawthorne Industrial Park).

Load in the region is forecasted to surpass the region's planning capacity by 2020. Transformation upgrades are currently underway at Uplands MTS and Limebank MTS resulting in a 50 MVA planning limit increase scheduled for 2021. Although, this upgrade may be sufficient to relieve capacity restraints in the western end of the South Gloucester region, the eastern area is currently supplied by a single station, Leitrim DS. Leitrim station is limited by the thermal limitation of the single 44kV supply cable. As such, capacity cannot be increased at the station without adding both redundancy and capacity on the station's supply.

A new station along the 230kV transmission corridor would allow Hydro Ottawa to accommodate the large growth forecasted in the area while maintaining an acceptable level of reliability. Solutions to address the capacity needs in this region are being discussed in the ongoing IRRP. Assessments to date indicate that it is feasible to connect the new station to the existing 230kV transmission line and that non-wire solutions would not be economically feasible to mitigate the capacity needs in this region. Thus, the investment required for building a new station has been included in Hydro Ottawa's capital expenditure plan for 2021-2025 with a planned energization date of 2025.

The forecasted 20-year load growth, along with planned capacity upgrade projects, is shown in Figure 7.27 below.

Figure 7.27 – South East 28kV Load Forecast



Capacity Projects

Planned:

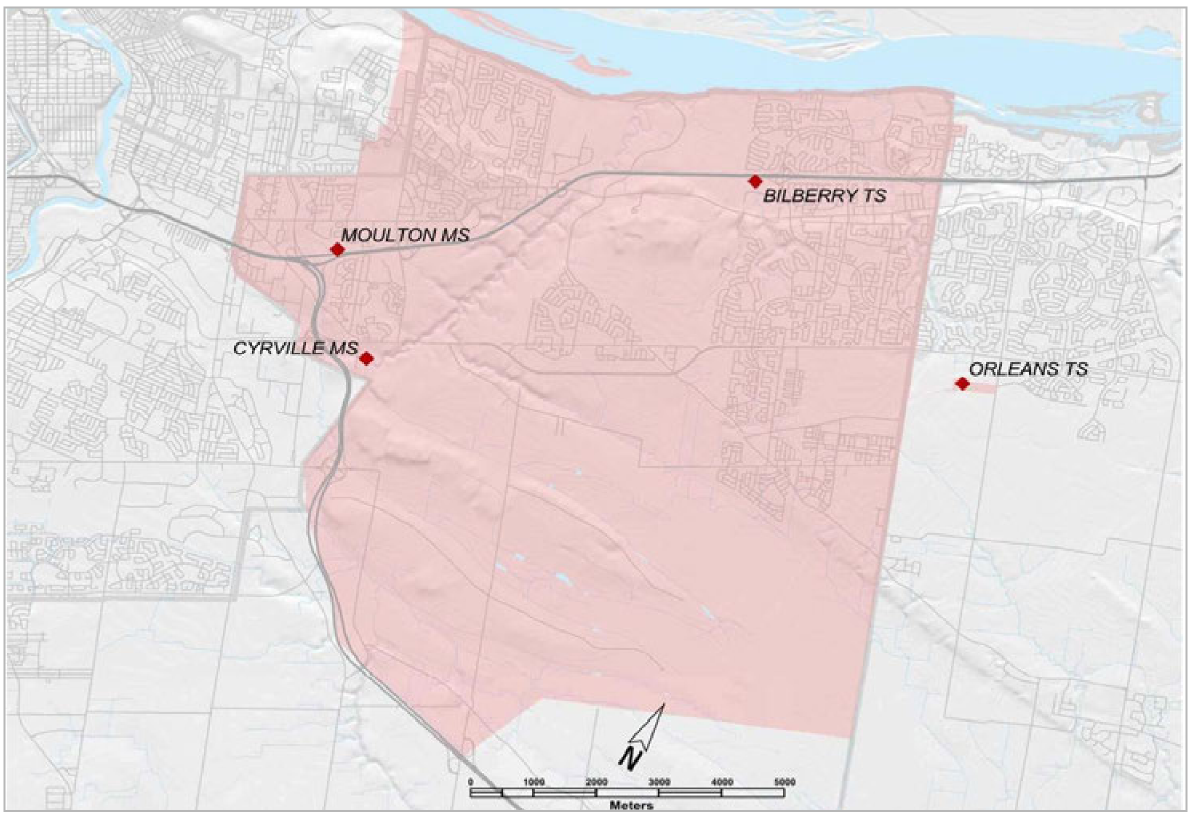
(a) Uplands MS / Limebank MS Transformation Upgrade 50 MVA (2021)

(b) New East Station 50 MVA (2025)

7.2.5.3. East 28kV System

The East 28kV supply is bounded by the old Gloucester and Ottawa municipal boundary and Highway 417 in the south. Supply to the region includes transmission connected 28kV stations Cyrville MTS, Bilberry TS, Orleans TS, and Moulton MTS, as well as 44kV sub transmission supplied 8kV stations Startop DS, Blackburn DS, and Beaconhill DS. Hydro Ottawa owns a single 28kV circuit for HONI's Orleans TS station.

Figure 7.28 – East 28kV Supply Region



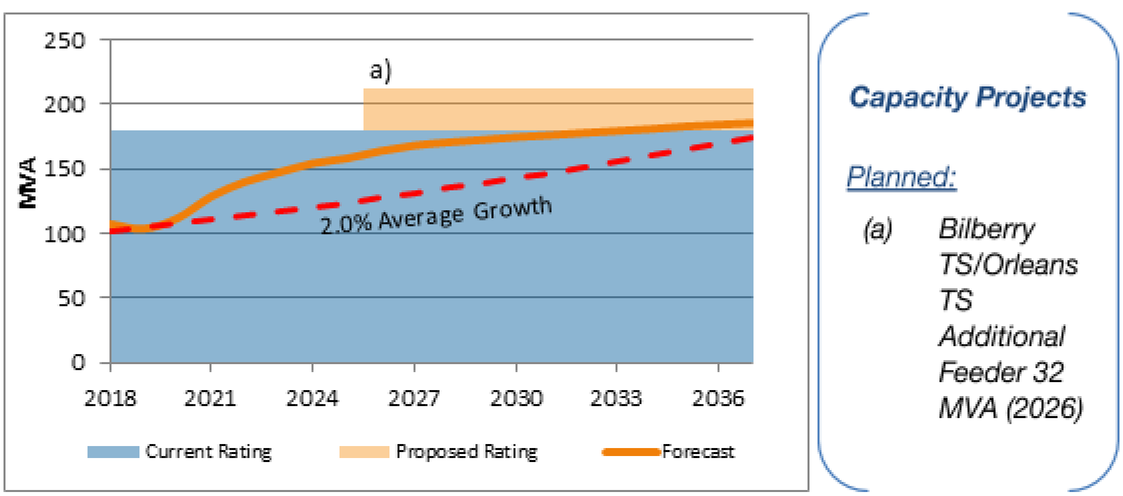
Over the last 10 years, load in the Gloucester and Orleans regions has remained constant. The rate of growth is expected to increase to an average of 2% per year. Growth in this supply region is driven by the ongoing expansion of the East Urban mixed-use community, including the Orleans business park and transit oriented development driven by the introduction of Ottawa

LRT along Highway 174. The existing growth is not expected to exceed the regions planning capacity limit in the region over the forecasted period.

Bilberry TS is a HONI-owned station that supplies Hydro Ottawa's customers and serves as an emergency backup supply to HONI customers currently supplied by Orleans TS. Bilberry TS was built in 1964 and is approaching end-of-life around 2023. Through the ongoing IRRP process, the decommissioning of Bilberry TS, load transfer to Orleans TS, and resulting benefits to the transmission system are being evaluated. Based on completed IRRP assessments for the Bilberry need, it is expected that the working group will recommend the refurbishment of HONI's Bilberry station. Plans for two additional station breakers from Bilberry DS are included under the Distribution Capacity Program for the next rate period. The additional breakers will address growth within the East Urban Community by increasing capacity and addressing reliability concerns on Bilberry feeders by reducing the number of customers per feeder.

The forecasted 20-year load growth along with planned capacity upgrade projects is shown in Figure 7.29.

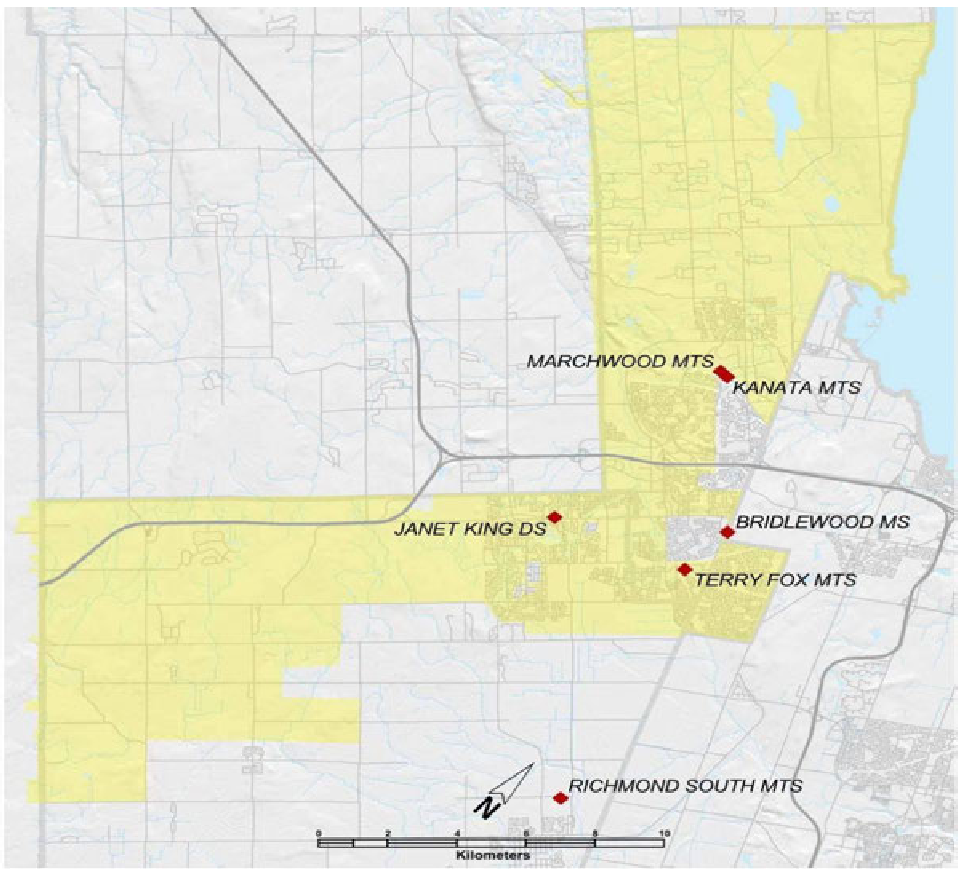
Figure 7.29 – East 28kV Load Forecast



7.2.5.4 West 28kV System

The West 28kV supply region includes the majority of both Kanata North and South, most of the township of Stittsville, and the western region of Goulbourn. These areas are supplied by Kanata MTS and Marchwood MTS in Kanata North (both located at the Station Road site), Bridlewood MTS and Terry Fox MTS in Kanata South, Janet King DS in Stittsville, and the BECKF2 feeder supplied from HONI's Beckwith Station in Goulbourn. When completed, the upgraded Richmond South MTS will also supply the Goulbourn area at 28kV.

Figure 7.30 – West 28kV Supply Region



Currently, this supply region is operating slightly below capacity planning ratings. However, Marchwood MTS and Kanata MTS are operating above their capacity planning rating as well as three feeders from Kanata MTS and one from Marchwood MTS, as shown in Table 7.1 and Table 7.2 above.

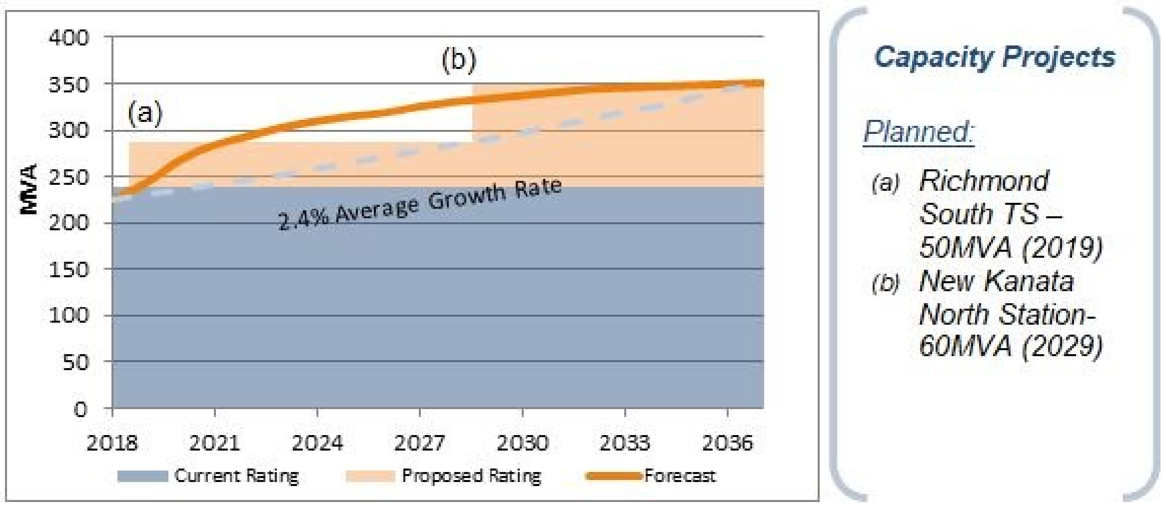
Growth in the West 28kV region is driven by the ongoing expansion of suburban residential developments in the Fernbank and Kanata North areas as well as associated mixed use centres. Additional ties between the primary 28kV area in Kanata and outlying areas, such as Stittsville and Richmond Village, will be required to ensure reliability of supply is maintained. Future medium and long-term planned voltage conversions in Richmond, Glen Cairn, and Beaverbrook will result in large load transfers to the 28kV system. The final result of these conversions will be a consolidation of the Kanata area to 28kV supply, with the 12kV supply area eliminated and 8kV limited to central Goulbourn.

The upcoming voltage conversion of Richmond Village will be supplied by an upgrade of the Richmond South MTS with a 50MVA, 115/28kV transformer, and 2 x 3MVA underground 28kV/8kV step-down transformers. The 8kV system supplied from the step-down transformers allows for conversion of the remaining 8kV system to be planned based on asset condition. The station is planned to be completed in 2019.

Additional capacity is required to supply expected load growth from the Kanata North CDP and offset intensification in the Kanata North high tech area. The solutions to address the capacity needs in Kanata North are being investigated as part of the ongoing IRRP including non-wire solutions, additional transformer capacity and distribution transfers in the area. To date, it has been determined that a new station is required to address the capacity requirements by the end of the study period. The IESO is conducting a parallel network assessment of the 230kV system in western Ottawa to be completed in 2020. Results from that assessment will affect the connection requirements for the new Kanata North station. Thus, short-term solutions have been put in place to address immediate capacity and reliability needs including load transfers to adjacent stations, distribution line extensions, voltage reduction projects in long rural feeders and area-specific CDM demand reduction programs.

The forecasted 20-year load growth, along with planned capacity upgrade projects, are shown in Figure 7.31.

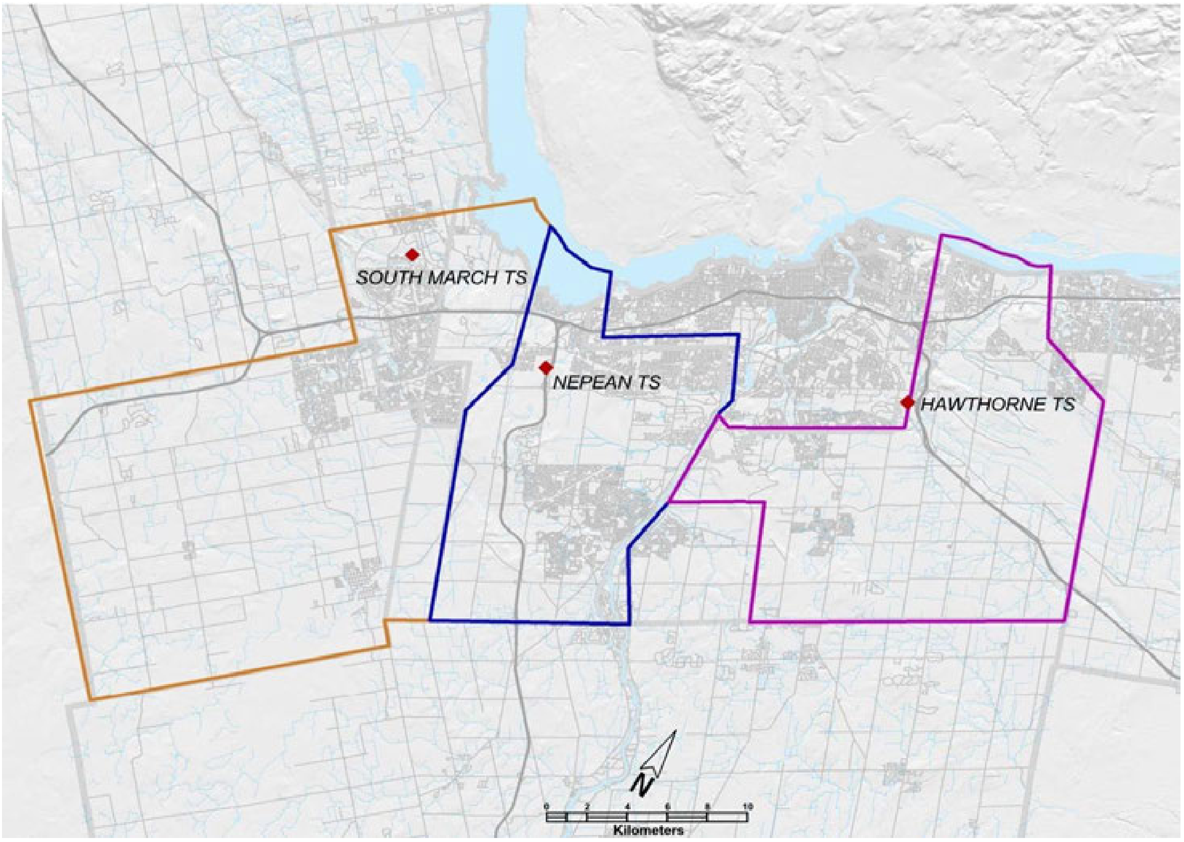
Figure 7.31 – West 28kV Load Growth



7.2.6. 44kV System

The 44kV system spans the entire service area and is supplied from three stations: Hawthorne TS, Nepean TS, and South March TS. This system supplies a number of large commercial and industrial customers as well as 44kV to 28kV and 44kV to 8kV Hydro Ottawa distribution stations. The location of these stations and supply areas are shown in Figure 7.32 below.

Figure 7.32 – 44kV Supply Region



South March TS supplies the west, Nepean TS supplies the south, and Hawthorne TS supplies the east. There are distribution ties between South March TS and Nepean TS feeders, as well as between Nepean TS and Hawthorne TS feeders.

Expansions at Hawthorne TS, in terms of capacity and feeder coverage, will reduce load at Nepean TS, which is at or near planning capacity. A combination of transformer upgrades, from 99MVA to 150MVA (expected in 2019) and a new feeder out of Hawthorne, 48M6, (recently completed and in service) will allow for distribution stations from the Nepean TS system to be transferred to Hawthorne TS.

South March TS demand is forecasted to decrease significantly past 2024. This is due to a combination of projects which eliminate the need for 44kV high-side supply, the planned conversion of the 12kV supply region to 28kV stations supplied by the 115/230kV transmission, reduced load on Richmond North DS due to the upgrade at Richmond South MTS, and the long-term plan to relocate Janet King DS to take advantage of the 230kV corridor in Stittsville.

Based on the large area that these stations cover and limited interconnections between them, they have been studied as separate stations as opposed to as a single region. The 20-year load forecast for each of the stations has been developed (see Figures 7.33 through 7.35 below).

Figure 7.33 – Hawthorne TS Load Growth

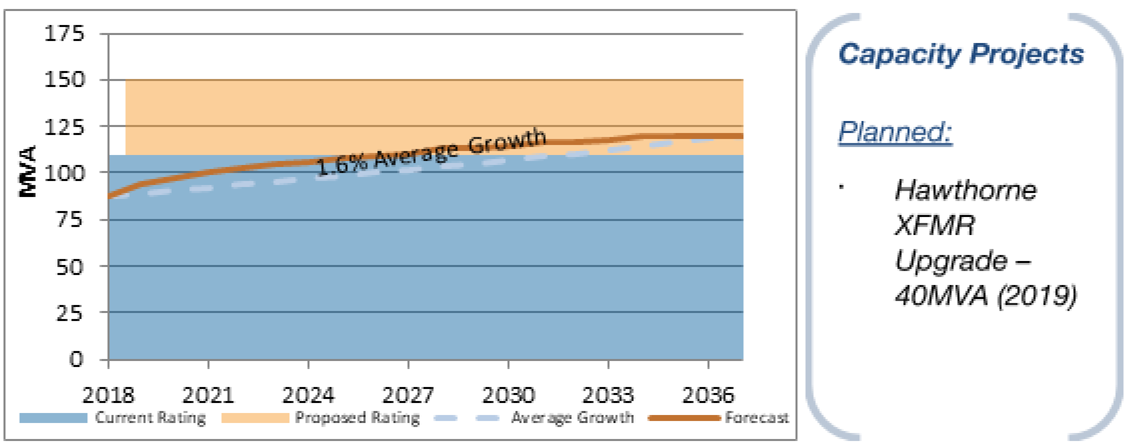
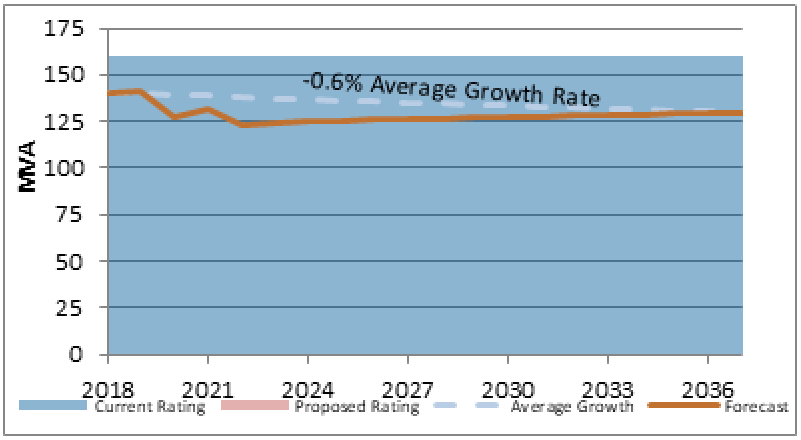


Figure 7.34 – Nepean TS Load Growth

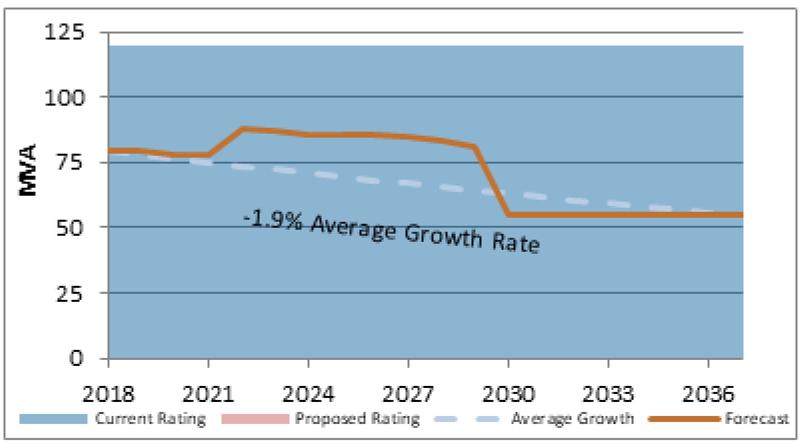


Capacity Projects

Planned:

None anticipated

Figure 7.35 – South March TS Load Growth



Capacity Projects

Planned:

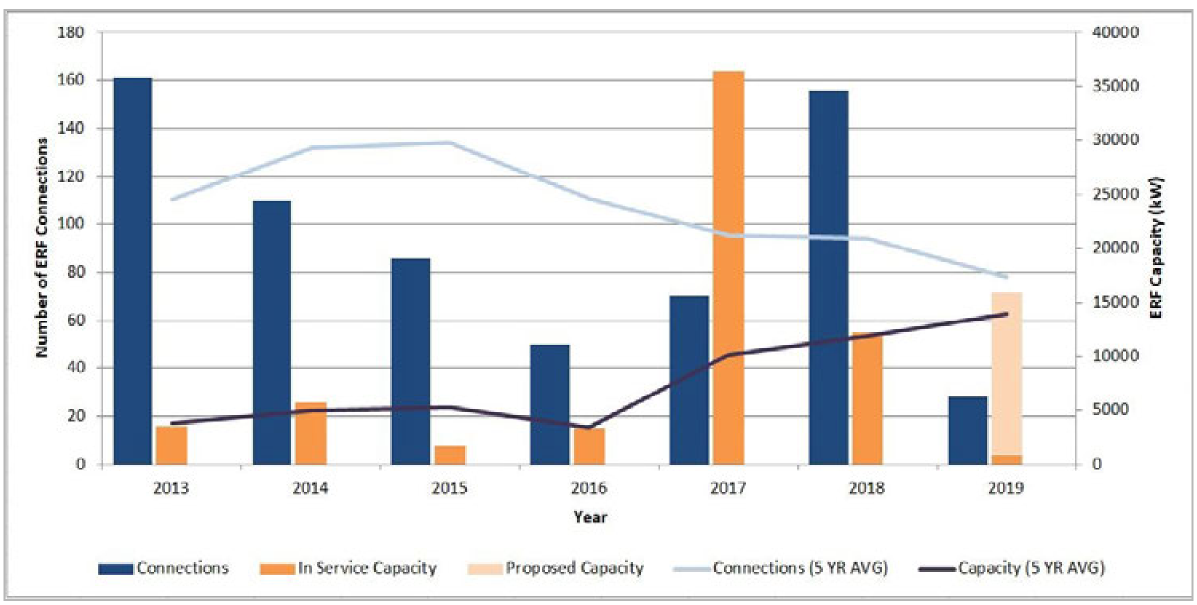
None anticipated

7.3. ABILITY TO CONNECT NEW ENERGY RESOURCE FACILITIES

7.3.1. System Capability Assessment for Energy Resource Facilities

There is a mix of both renewable and non-renewable ERFs (electricity generation or storage facilities) within Hydro Ottawa's service area and there continues to be customer and stakeholder interest in both types. These ERFs have been connected and continue to be connected under various programs, such as IESO-administered programs (FIT, HCI, PSUI-CDM, RESOP, HESOP), as well as Net-Metering and Load Displacement. See Figure 7.36 for the annual number of ERF connections and associated capacity.

Figure 7.36 – Historical ERF Connections by Year



Hydro Ottawa has a significant number of renewable energy generators within its service area, with the majority of existing installations being solar energy FIT or MicroFIT contracts. Interest in solar generation is expected to continue in the form of Net Metering or Load Displacement applications. Additionally, there have been a number of initial inquiries into battery storage technology, although only the 4 MW Ellwood Battery storage project has been formalized to date. In 2017, the connected capacity was the largest over the historical period mainly driven by the 29 MW Chaudiere hydroelectric generation connection. In 2018, the most significant ERF connections were the Ellwood Battery Storage connection (4 MW) and the Algonquin College natural gas generation connection (2 x 2 MW).

Figure 7.37 – Solar Installation at Hydro Ottawa's Bank Street Facility

In addition, there were approximately 140 small generation connections, which were impacted by the ending of the microFIT program. In 2019 and 2020, the most significant connections will be the Hull 1 and Hull 2 (43 MW) hydroelectric generation connections.

The existing renewable and non-renewable ERF connections within Hydro Ottawa's service area are shown in Figure 7.38 below.

Figure 7.38 – ERF Connections

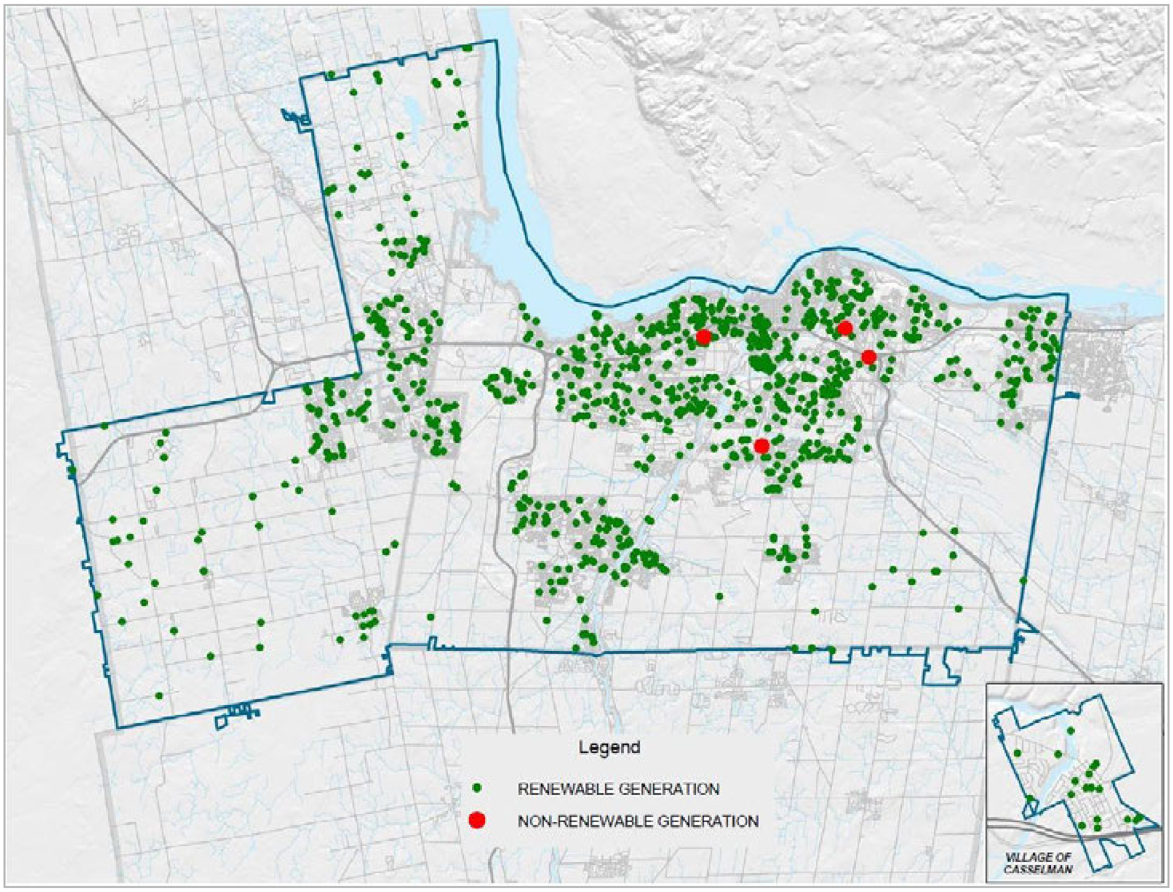


Table 7.8 – 2018 ERF Facility Connections

Program / DSC Category	Large		Medium		Small		Micro		Total	
	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty
Non-Renewable										
Battery-IESO			4,000	1					4,000	1
HOEP										
Standby			999	1					999	1
Load Displacement			21,578	8	500	1			22,075	9
Renewable										
FIT					15,017	107			15,017	107
HCI			18,780	5	465	1			19,245	6
HESOP	29,352	1							29,352	1
Load Displacement					997	6	5.5	1	1003	7
HOEP					28	1			28	1
RES			8,378	2					8,378	2
RESOP			10,000	1					10,000	1
MicroFIT							7,348	880	7,348	880
Net-Meter							183	27	183	27
TOTAL	**29,352**	**1**	**63,735**	**18**	**17,007**	**116**	**7,536**	**908**	**117,630**	**1043**

By the end of 2018, Hydro Ottawa had 1,043 ERF connections of various sizes. The details on the number and total kilowatts of ERFs connected by size and program are provided in Table 7.8, where the generation categories are defined in accordance with section 1.2 of the DSC, as follows:

- **Micro-embedded generation facility**: Facilities with a name-plate rated capacity of 10kW or less
- **Small embedded generation facility**: Facilities with a name-plate rated capacity of 500kW or less in the case of a facility connected to a less than 15kV line or 1 MW or less in the case of a facility connected to a 15kV or greater line
- **Medium embedded generation facility**: Facilities with a name-plate rated capacity above 500kW but less than 10 MW in the case of a facility connected to a less than

15kV line, or above 1 MW but less than 10 MW in the case of a facility connected to a 15kV or greater line

- **Large embedded generation facility**: Facilities with a name-plate rated capacity of more than 10MW

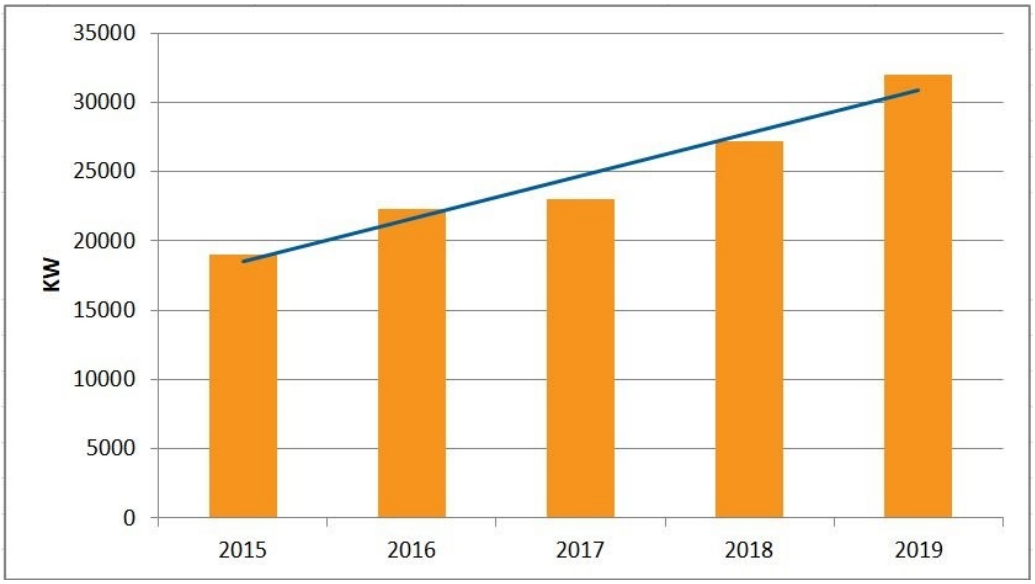
7.3.1.1. Existing Facilities over 10kW

As of the end of 2018, Hydro Ottawa had a total of 135 connected ERFs greater than 10kW, totalling 110 MW peak nameplate capacity. Out of that total, 124 facilities featured renewable ERFs representing 83 MW of renewable generation.

7.3.2. Energy Resource Facilities Forecast

Interest in generation projects within Hydro Ottawa's service area has fluctuated over the historical years driven by external factors. Removing connections larger than 1 MW results in a historical increasing trend in connected capacity for 2016-2019, as shown in Figure 7.39 below. This increasing trend is expected to continue. Thus, an ERF annual growth rate of 11% has been applied to the forecast for the next five years.

Figure 7.39 – ERF Connected Capacity (kW) (Excluding Large Connections)



Among other factors driving the ERF forecast, the City of Ottawa, through its official renewable energy strategy known as “Energy Evolution,” is seeking ways to promote greater deployment of distributed and renewable resources.

With the Government of Ontario’s cancellation of various renewable energy contracts, future generation connections will predominantly take the form of Net Metering and Load Displacement projects of various fuel types.

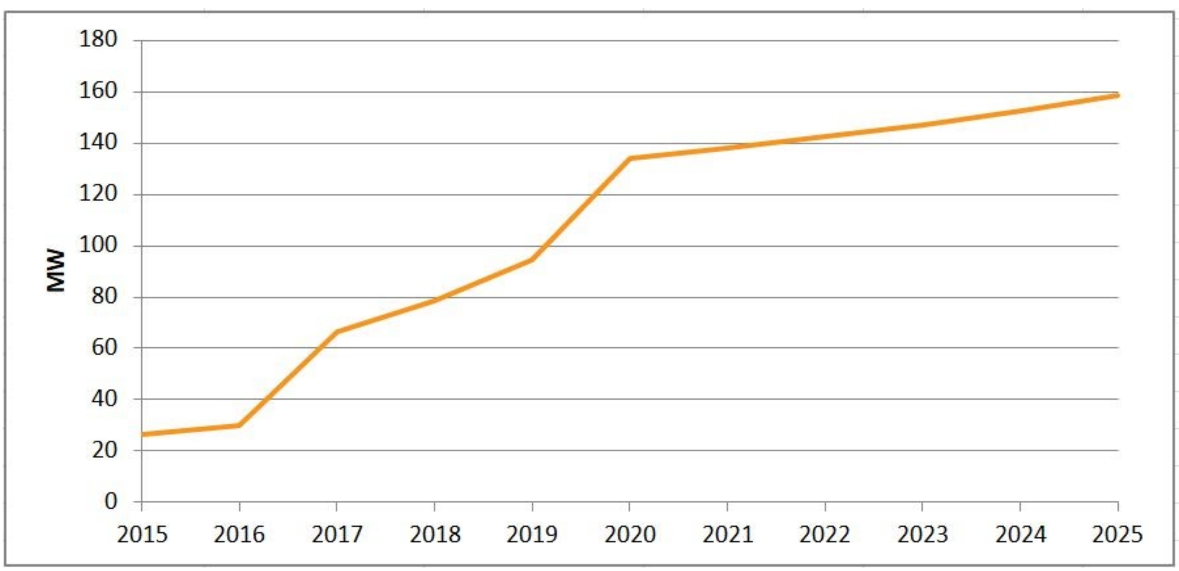
Forecasts for ERF connections are provided in Table 7.9 below and are based on initial consultations and executed Connection Impact Assessments (“CIAs”) received and completed as of February 2019. The initial consultations include projects applicable to either the Net Metering, Load-Displacement, or Energy Storage programs.

Between 2019 and 2025, Hydro Ottawa forecasts that approximately 64 MW of additional ERF capacity will be connected to its distribution system, as shown in Figure 7.40 below, by applying the historical trend identified in Figure 7.38 above, in addition to accounting for known upcoming projects of all sizes.

Table 7.9 – Forecasted ERF Connections

Type	Number of Applications	Total Nameplate Capacity (kW)
Solar PV	21	5,223
Natural Gas	5	6,098
Hydro-Electric	2	42,880
Battery	2	6,110
Biogas	1	5,700
Wind	0	0
Co-Generation	0	0
Diesel	0	0
TOTAL	**31**	**66,011**

Figure 7.40 – Forecasted ERF Capacity



7.3.3. Factors Affecting Ability to Connect New Energy Resource Facilities

The ability of the distribution system to connect distributed ERFs may be limited by the following factors:

1. **Station Loading** – Some station transformers have limited or no capability for reverse power flow. At these stations, the total connected generation cannot exceed either:
    a. 60% of the top transformer rating plus the minimum station loading; or
    b. The minimum station loading when the station transformers do not have reverse flow capability. This limit has been adopted from HONI's evaluation tool for generation connection assessment.

2. **Feeder Thermal Rating** – Exceeding the feeder ampacity rating will result in overheating the conductors and connected equipment thereby reducing their effective life. For distributed ERFs, the available thermal capacity is the full feeder ampacity rating less contingency loading.

3. **Short Circuit Rating** – Connection of distributed ERFs will increase the available current that flows through the system during faults. The total available current during faults cannot exceed the equipment ratings.

4. **Power Quality** – The following power quality concerns arise when connecting distributed generation:
    a. harmonics caused by inverter based generation
    b. phase imbalance caused by single-phase generators
    c. voltage instability caused by generators connected at various points along a feeder, or by induction generators requiring reactive power
    d. flicker caused by generators intermittently turning on and off which can affect the voltage on the circuit, thus impacting the quality of supply to Hydro Ottawa customers

5. **Anti-Islanding** – Distributed ERFs may introduce safety and power quality issues in the event of continued un-sanctioned generation after the loss of distribution supply. The installation of transfer trip functionality and alternate anti-islanding methods may be used to mitigate the potential for the un-sanctioned islanding of a generator. Currently, transfer trip is only required for generation connections equal to or larger than 500kW.

The ERFs connected to both feeders and stations must be managed to prevent adverse impacts to existing Hydro Ottawa load and customers.

7.3.4. System Constraints for Connecting New Energy Resource Facilities

Hydro Ottawa currently owns/co-owns three stations which have restrictions on generation connection of any size. Slater TS and Ellwood MTS are due to short circuit limitations while Lisgar TS is on the restricted list due to reverse power flow concerns. The following sections identify any potential system constraints categorized regionally and by voltage level.

Core 13kV

Currently, there are connection restrictions at Slater TS and Lisgar TS. Slater TS is limited due to the available short circuit levels at the station, whereas Lisgar TS is limited by minimum normal loading on the station bus, thus raising reverse power flow concerns should additional generation be installed.

Hydro Ottawa has had discussions with a few proponents interested in large size district heating and cooling, hydro-generation, or energy storage within this region. With the coming load growth and planned station upgrades, capacity may become available to accommodate these requests on more stations in the future.

East 13kV

There is a connection restriction at Ellwood MTS due to the available short circuit levels at the station potentially exceeding the bus ratings.

West 13kV

A recent HONI transformer and Hydro Ottawa switchgear upgrade at Hinchey TS has provided additional capacity for ERF connections. A large hydro generation facility connecting to Carling TS with 29.35 MW of generation was commissioned early in 2018.

South 28kV

There are currently no station restrictions for the connection of distributed generation at the South 28kV stations.

South-East 28kV

There are currently no station restrictions for the connection of distributed generation at the South-East 28kV stations.

East 8kV & 28kV

There are currently no station restrictions for the connection of distributed generation at the East 28kV and 8kV stations.

West 28kV

There are currently no station restrictions for the connection of distributed generation at the West 28kV stations.

Nepean Core 8kV

There are currently no station restrictions for the connection of distributed generation at the Nepean Core 8kV stations.

West Nepean 8kV

There are currently no station restrictions for the connection of distributed generation at the West Nepean 8kV stations. All these stations are supplied from HONI High Voltage Distribution Stations ("HVDS"), either South March TS or Nepean TS.

West 8kV

There are currently no station restrictions for the connection of distributed generation at the West 8kV stations.

West 12kV

There are currently no station restrictions for the connection of distributed generation at the West 12kV stations.

City Wide 44kV

There are currently no station restrictions for the connection of distributed generation at the 44kV Stations.

7.3.5. Energy Resource Facility Connection Capacity

The available station capacity of the system to connect ERFs, as of September 2019, is shown in Table 7.10 below and illustrates the capacity availability to connect ERFs at each Hydro Ottawa-owned HVDS. If an HVDS has an open bus-tie switch, capacity is provided per bus. Where the bus-tie is normally closed, it is provided by the bus pair.

Overall, where Hydro Ottawa station limitations exist, they are limited by thermal capacity and not short circuit capacity, with the exception of Ellwood MTS and Epworth MTS. When transformers are identified as having reverse flow capability as per manufacturer specification, the limiting factor is the transformer capacity plus minimum station load. Otherwise, the limiting factor is simply the station minimum load.

Table 7.10 – Capacity for Generation at Hydro Ottawa HVDS

Station	Bus	Connected & Committed (kW)	Remaining Generation Capacity		Limiting Factor
			Equivalent Inverter Based Generation (kW)	Equivalent Spinning Generation (kW)	
BRIDLEWOOD MTS	B1	35	3,562	2,125	Thermal Capacity
	Q	209	2,247	1,464	Thermal Capacity
CENTREPOINTE MTS	B1	61	15,097	14,921	Thermal Capacity
	B2	30	8,694	8,337	Thermal Capacity
CYRVILLE MTS	JQ	566	32,800	34,035	Thermal Capacity
ELLWOOD MTS	JQ	4546	1,694	457	Short Circuit
FALLOWFIELD MTS	J	8175	3,910	-	Thermal Capacity
	Q	120	3,021	2,562	Thermal Capacity
KANATA MTS	B1B2	1451	73,630	39,200	Thermal Capacity
LIMEBANK MTS	B1		21,544	21,070	Thermal Capacity
	B2	130	23,952	23,129	Thermal Capacity
	JQ	619	21,359	20,565	Thermal Capacity
MANORDALE MTS	B1	52	8,850	8,358	Thermal Capacity
	B2	532	6,974	6,676	Thermal Capacity
MARCHWOOD MTS	JQ	551	16,026	12,605	Thermal Capacity
MERIVALE MTS	B1		2,348	1,575	Thermal Capacity
	B2		2,269	1,815	Thermal Capacity
MOULTON MTS	B1	145	25,066	22,569	Thermal Capacity
	B2	999	21,791	19,961	Thermal Capacity
NEPEAN EPWORTH MTS	B	39	1,162	288	Short Circuit
	Q	42	10,203	9,730	Thermal Capacity
RICHMOND SOUTH MTS	B	318	1,831	1,356	Thermal Capacity
TERRY FOX MTS	J	822	43,398	43,087	Thermal Capacity
	Q	677	42,873	43,644	Thermal Capacity
UPLANDS MTS	Z	244	39,874	38,336	Thermal Capacity

Typically, more capacity at the stations is available for inverter based generation as opposed to spinning generation for two reasons:

- When reverse flow is the limiting factor, the minimum station load is higher between 10AM to 3PM (the same period the solar generation nameplate capacity will likely be reached and the facility nameplate in capacity calculation is considered); and
- Short circuit contribution of inverter based generators is by rule of thumb 1.2 times the full load current and for spinning generation is considered to be five to 10 times the full load current.

The column label Connected & Committed represents all non-standby ERF (renewable and non-renewable) that is already connected to the grid, committed for connection due to having an IESO contract, or Hydro Ottawa has issued a CIA and tentatively allocated or reserved capacity.

7.3.6. Constraints for Embedded Distributors

Hydro Ottawa does not have any embedded distributors within its service territory. As such, any current or future ERF connections will not have an impact in regards to embedded distributor constraints.

Hydro Ottawa is classified as an embedded distributor to HONI. As a result, there is potential for Hydro Ottawa to be impacted by HONI's generation connections upstream of the respective HONI-owned HVDS stations, as identified in Appendix B.

8. CAPITAL EXPENDITURE PLAN

8.1. CAPITAL INVESTMENTS OVERVIEW

The capital expenditure plan details the system investments made through the asset management and capital expenditure planning processes described in section 5. Investments are detailed by investment category, and are organized around a Capital Program and Budget Program for the Historical Years of 2016-2018, Bridge Years of 2019-2020 and Test Years of 2021-2025.

Hydro Ottawa's Capital Expenditures are broken into four Investment Categories which are summarized in Table 8.1.

Table 8.1 – Capital Investment Categories

Investment Category	Description
System Access	Modifications (including asset relocation) to a distributor's system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.
System Renewal	Replacing and/or refurbishing system assets to extend their original service life and thereby maintain the ability of the distributor's distribution system to provide customers with reliable and safe electricity services.
System Service	Modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity demand and service requirements.
General Plant	Modifications, replacements or additions to a distributor's assets that are not part of its distribution power delivery system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities.

Capital Expenditures for Historical and Bridge Years are outlined in Table 8.2, which shows actual spending for the years 2016-2018 and committed spending for 2019 and 2020, including variance from OEB approved budgets for the 2016-2020 period. The forecast spending levels for the test years of 2021-2025 are outlined in Table 8.3. Hydro Ottawa's capital expenditures over the 10-year period (2016-2025) can be found in Attachment 2-4-3(B): OEB Appendix 2-AB - Capital Expenditure Summary.

Table 8.2 – Capital Expenditure Historical Summary ($'000s)

Investment Category	Historical						Bridge			
	2016		2017		2018		2019		2020	
	Act.	Var.	Act.	Var.	Act.	Var.	Act.	Var.	Act.	Var.
System Access	$37,805	(3%)	$30,908	(12%)	$40,849	16%	$44,775	25%	$53,331	46%
System Renewal	$42,639	12%	$43,816	46%	$54,942	59%	$29,446	(14%)	$32,288	(4%)
System Service	$17,783	(21%)	$24,844	(30%)	$29,801	(5%)	$27,509	(15%)	$32,621	(7%)
General Plant	$20,323	(56%)	$38,300	(20%)	$56,738	210%	$35,239	88%	$42,580	205%
Total Capital Expenditures	**$118,550**	**(18%)**	**$137,867**	**(8%)**	**$182,349**	**53%**	**$136,969**	**13%**	**$160,820**	**35%**
Capital Contributions	$(19,491)	(18%)	$(17,315)	(25%)	$(16,742)	(27%)	$(27,580)	18%	$(34,532)	45%
Net Capital Expenditures	**$99,058**	**(19%)**	**$120,552**	**(4%)**	**$165,607**	**72%**	**$109,388**	**12%**	**$126,288**	**32%**

Overall spending has fluctuated over the last five years of the 2016-2020 period due to variances that typically arise during the planning and execution of large capital programs. Significant increases in 2018, 2019 and 2020 are mainly due to:

- Underspending in the Facilities Renewal Program ("FRP") over the first three years with the majority of spend happening in 2018;

- Delays in some station projects (i.e. Merivale Station, Richmond South Station and New South Station) over the first three years with increased spending in 2018; and
- Increased spending in the Corrective Renewal Program from 2015-2020 due to:
  - An increase in the required interventions identified through the distribution inspection programs; and
  - Significant weather events which occurred in 2018.

Through the course of the 2016-2020 period, Hydro Ottawa has reprioritized projects and adjusted programs pacing as necessary while continuing to meet the objectives outlined in the 2016-2020 DSP. Detailed descriptions of these variances by Capital Program for each Investment Category are provided in sections 8.2 through section 8.5.

Table 8.3 – Capital Expenditure Forecasted Summary ($'000s)

Investment Category / Capital Program	2021	2022	2023	2024	2025
System Access	$56,693	$41,032	$37,434	$34,462	$34,039
System Renewal	$43,296	$44,012	$40,191	$39,436	$40,474
System Service	$31,001	$27,415	$24,337	$25,155	$23,899
General Plant	$32,047	$11,681	$7,556	$17,354	$16,884
Total Capital Expenditures	**$163,037**	**$124,140**	**$109,518**	**$116,407**	**$115,296**
Capital Contributions	$(41,254)	$(25,217)	$(19,943)	$(19,226)	$(19,264)
Net Capital Expenditures	**$121,783**	**$98,923**	**$89,574**	**$97,181**	**$96,032**

Over the 2021-2025 period, overall annual average spending will be slightly lower than the 2016-2020 rate period (excluding the FRP). This spending plan is a continuation of the objectives outlined in the 2016-2020 DSP, which focused on the enhancement of system capacity to keep pace with growth and shifts in loads within the service territory, and the renewal of aged and aging infrastructure that are at greatest risk of failure.

Changes by Investment Category are described below for 2021-2025:

- Spending in System Access programs will see a slight decrease since large projects requiring significant system expansion such as the Chaudière and Hull generation projects as well as Ottawa LRT will be complete before or during the early years of the next rate period. Spending in commercial and residential connection projects are expected to remain at the same as historical level.
- Spending in System Renewal programs will see a slight increase in order to continue replacement of the critical assets as outlined in Section 6 Asset Lifecycle Optimization.
- Spending in System Service programs will remain at the same levels, mainly driven by the construction of new stations in the south and east regions. The new station in the south region is expected to be energized by 2022 and the new station in the east is planned for energization by 2025. In addition, there are associated distribution projects to deliver additional capacity from the new stations to the growth areas. Also, there are follow up enhancements to the SCADA upgrade project included in Hydro Ottawa's 2016-2020 rate application, such as the upgrade to the existing OMS and implementation of DMS functionality.
- Spending in General Plant will return to historical levels with the completion of the FRP.

8.1.1. Historical and Forecasted Expenditure Comparison

Figure 8.1 and Table 8.4 depict the expenditures by Investment Category over the historical period of 2016-2020 and the projected expenditures for the 2021-2025 period.

The 2016-2020 period had an average annual expenditure of $147M and the 2021-2025 period is set to have an average annual expenditure of $126M, a decrease of almost 15%. The reduction in spending is mostly in two spending categories: General Plant, where the FRP will be completed, and in System Access, due to the completion of large generation projects. System Renewal will remain mostly at historical levels, with reductions in some lower risk asset replacement programs used to fund increased expenditures for other higher priority replacement programs such as Cable Renewal. System Service expenditures will remain at historical levels to fund large capacity upgrade projects planned over the forecast period, such as the Cambrian MTS station project. The cost for Cambrian MTS includes HONI CCRAs $50M in General Plant and $27M for station construction and equipment in System Service. (See Attachment 2-4-3(E) for more details on the project).

Figure 8.1 – Expenditure by Investment Category

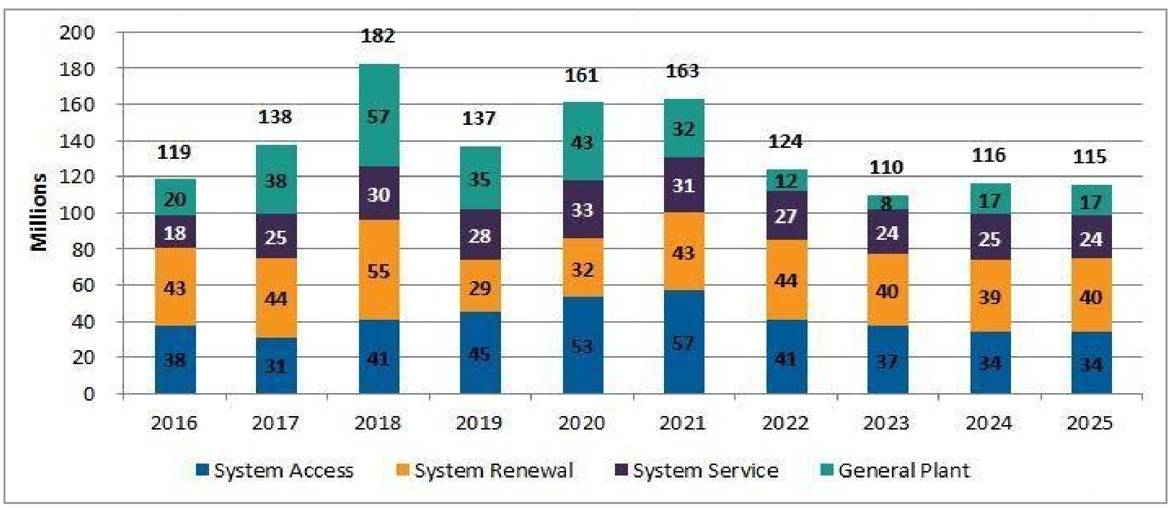


Table 8.4 – Expenditures by Investment Category ($'000s)
Part One – Historical and Bridge Years

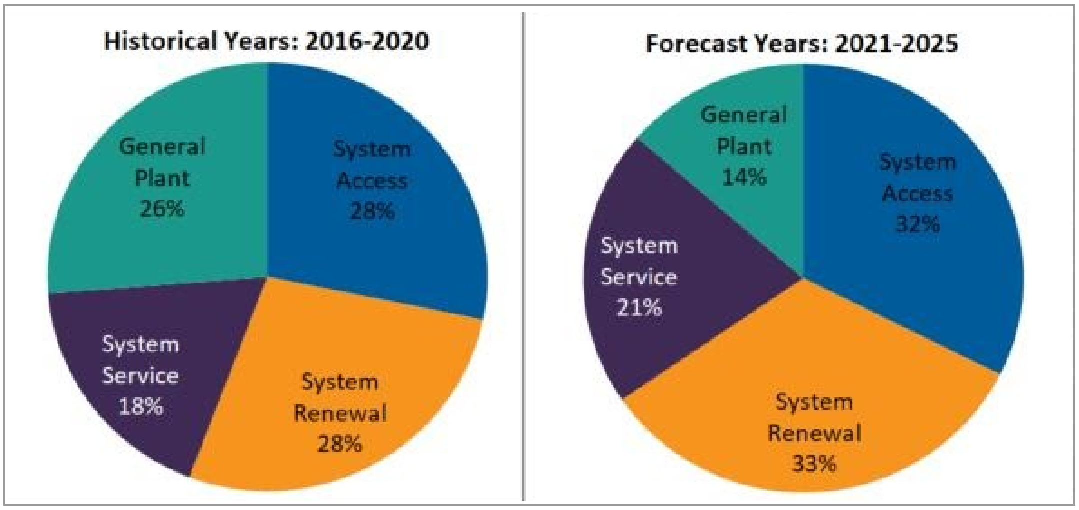
Investment Category	Historical			Bridge		Avg
	2016	2017	2018	2019	2020	
System Access	$37,805	$30,908	$40,849	$44,775	$53,331	$41,533
System Renewal	$42,639	$43,816	$54,942	$29,446	$32,288	$40,626
System Service	$17,783	$24,844	$29,801	$27,509	$32,621	$26,512
General Plant	$20,323	$38,300	$56,738	$35,239	$42,580	$38,636
Total Capital Expenditures	**$118,550**	**$137,867**	**$182,330**	**$136,969**	**$160,820**	**$147,307**
Capital Contributions	$(19,491)	$(17,315)	$(16,742)	$(27,580)	$(34,532)	$(23,132)
Net Capital Expenditures	**$99,058**	**$120,552**	**$165,587**	**$109,388**	**$126,288**	**$124,175**

Part Two – Test Years

Investment Category	Test					Avg
	2021	2022	2023	2024	2025	
System Access	$56,693	$41,032	$37,434	$34,462	$34,039	$40,732
System Renewal	$43,296	$44,012	$40,191	$39,436	$40,474	$41,482
System Service	$31,001	$27,415	$24,337	$25,155	$23,899	$26,361
General Plant	$32,047	$11,681	$7,556	$17,354	$16,884	$17,105
Total Capital Expenditures	**$163,037**	**$124,140**	**$109,518**	**$116,407**	**$115,296**	**$125,680**
Capital Contributions	$(41,254)	$(25,217)	$(19,943)	$(19,226)	$(19,264)	$(24,981)
Net Capital Expenditures	**$121,783**	**$98,923**	**$89,574**	**$97,181**	**$96,032**	**$100,699**

Figure 8.2 shows the average percent contribution of annual expenditures to each of the Investment Categories over the 2016-2020 period compared to the forecast period of 2021-2025. System Renewal and System Access Investment Categories continue to be the top contributors, with significant reductions in General Plant due to the completion of the new facilities project.

Figure 8.2 – Percentage Contribution of Investment Categories to Total Expenditures



8.1.2. Impact on O&M Costs

Impacts to operation and maintenance costs vary by Investment Category, as described below.

System Access

System Access projects can introduce new assets to the system, resulting in an increasing quantity of equipment requiring maintenance, and additional potential failure points within the grid.

System Renewal

System Renewal investments target the replacement of ageing infrastructure. As certain assets age, the required maintenance and associated costs increase. Assets which have deteriorated to the point of failure result in high O&M costs associated with the emergency work required to respond and restore power. When an asset is replaced, maintenance is still required, but typically involves less time and resources resulting in lower O&M expenses in comparison. Through proactive replacement, additional O&M costs can be avoided.

As Hydro Ottawa replaces assets, new technologies are introduced. There are benefits to such improvements, such as reduced crew travel time, but other added costs such as software licencing, increased communication infrastructure and the need for device specific training can increase O&M costs.

System Service

System Service investments represent the costs associated with growing the distribution system, thereby increasing the number of assets to maintain and introducing additional potential failure points within the system.

8.1.3. Drivers by Investment Categories

The drivers by investment category have been described in section 5.2.1 - Project Concept Definition. Table 8.6 shows the average historical and forecast expenditures by driver and Figure 8.3 shows the distribution by driver of the total expenditure over the forecast period.

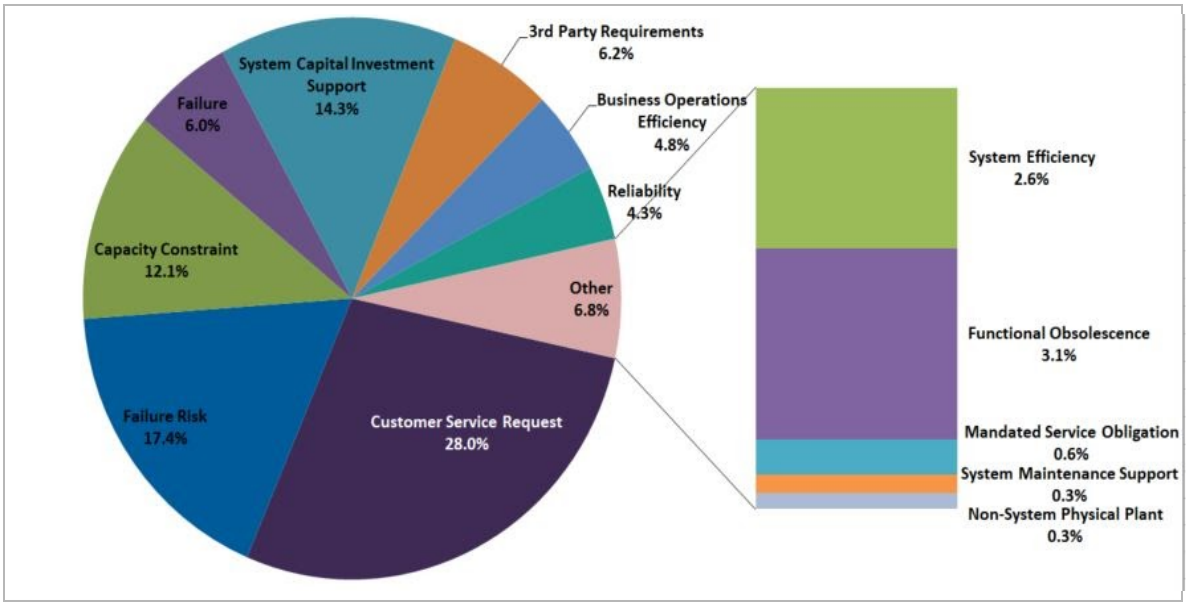
Customer Service Request, Failure Risk, System Capital Investment Support, and Capacity Constraints are the top four drivers in the proposed forecast expenditure for the 2021-2025 rate period. Many programs under the System Access investment category are driven by Customer Service Requests, including expansion of the distribution system, residential connections, commercial connections and generation connections. Assets that are being replaced due to Failure Risk in the System Renewal investment category include the following: station transformers, station switchgear, P&C equipment, batteries, poles, OH switches, cables, civil structures and UG switchgear. Projects driven by System Capital Investment Support include capital contributions to intangible assets purchased from HONI in conjunction with Hydro Ottawa's major station projects such as the new Cambrian MTS and the New East Stations. Projects driven by Capacity Constraints include construction of new stations such as the Cambrian MTS and the New East Station as well as associated distribution work to bring additional capacity to growth pockets.

1 **Table 8.6 – Expenditures by Driver ($'000s)**

Investment Category	Driver	2016-2020 Avg	2016-2020 Total	2021-2025 Avg	2021-2025 Total
SA - System Access	Third Party Requirements	$8,156	$40,781	$7,581	$37,905
	Customer Service Request	$31,839	$159,194	$32,197	$160,987
	Mandated Service Obligation	$1,539	$7,693	$953	$4,767
SR - System Renewal	Failure	$10,051	$50,254	$9,819	$49,095
	Failure Risk	$29,574	$147,869	$28,734	$143,670
	High Performance Risk	$529	$2,644	$0	$0
	Substandard Performance	$90	$450	$0	$0
	Functional Obsolescence	$383	$1,913	$2,929	$14,644
SS - System Service	Capacity Constraint	$14,643	$73,216	$16,342	$81,712
	Reliability	$6,545	$32,725	$5,840	$29,199
	System Efficiency	$5,323	$26,616	$4,179	$20,895
GP - General Plant	Business Operations Efficiency	$8,926	$44,630	$7,535	$37,676
	Non-System Physical Plant	$17,570	$87,849	$413	$2,066
	System Capital Investment Support	$11,575	$57,877	$8,688	$43,438
	System Maintenance Support	$565	$2,824	$469	$2,343
GRAND TOTAL		**$147,307**	**$736,536**	**$125,680**	**$628,398**

2

Figure 8.3 – Contribution to Total Forecast Expenditures by Drivers (2021-2025)



8.1.4. Non-distribution Activities

At the end of 2018, Hydro Ottawa received funding from the IESO to complete a "Local Achievable Potential ("LAP") study" in the Kanata North area (see Attachment 2-4-3(K): Local Achievable Potential Study).

The objective of this study was to evaluate non-wires options potential to offset load growth in the Kanata North area to defer or eliminate the need for new infrastructure. The non-wire options considered in the study include Conservation and Demand Management ("CDM") programs, distributed generation, and energy storage.

The study concluded that the desired peak demand reductions cannot be achievable from CDM programs. The higher achievable potential is reachable with the consideration of utility-scale energy storage. The budgetary cost for implementing this project is estimated at $9.6M and $22.7M to introduce peak reduction ranging from 3.75 MW-7.5 MW.

Short-term solutions have been put in place to address immediate capacity and reliability needs in the Kanata North area, including load transfers to adjacent stations, distribution line extensions, VAR control projects in long rural feeders and area-specific CDM demand reduction programs through IESO funding opportunities.

Hydro Ottawa has submitted two CDM program funding applications to the IESO strategically targeting capacity constrained areas in Kanata North. These programs are the Thermostat Program and the Kanata North Retrofit T&T Program (Top-Up and Targeted Outreach) for a total of $3.25M in funding requirements. The Thermostat Program leverages Enbridge Gas Distribution's existing smart thermostat rebate program and offers more beneficial incentives to Hydro Ottawa customers in the Kanata North region. Potential demand reduction from the Smart Thermostat program is 0.76 MW. The Kanata North Retrofit T&T Program offers top-up incentives at 100% or double the incentive amounts with a targeted outreach strategy. The potential demand impact from the Retrofit Top-up is expected to be 1.8 MW. The total demand reduction in the Kanata North area from these programs is expected to be 2.6 MW. Obtaining funding from IESO for CDM programs minimizes the impact to customer rates and provides short-term capacity relief in the Kanata North area.

Based on the results from the Kanata North LAP study, Hydro Ottawa did not include expenditures for non-distribution activities in the forecast expenditure plan.

8.1.5. System Capability Assessment

Over the 2021-2025 period, Hydro Ottawa will not specifically address stations that have restrictions for the connection of ERFs (including REGs) within the capital expenditure plan. However, as station transformers are identified for replacement through the Asset Management Process (section 5.1) due to either reaching their end of life or capacity constraints, the new units will have-reverse flow capabilities specified to eliminate potential restrictions to the connection of ERFs. Also, the addition of new station transformers in the east and south regions of Hydro Ottawa's service area allows for additional capacity for ERF connections.

8.1.6. System Development Expectations

This section describes how Hydro Ottawa anticipates the system to develop over the next five years in relation to load and customer growth, changing climate patterns, Smart Grid development and the accommodation of forecasted renewable energy generation projects.

8.1.6.1. Load and Customer Growth

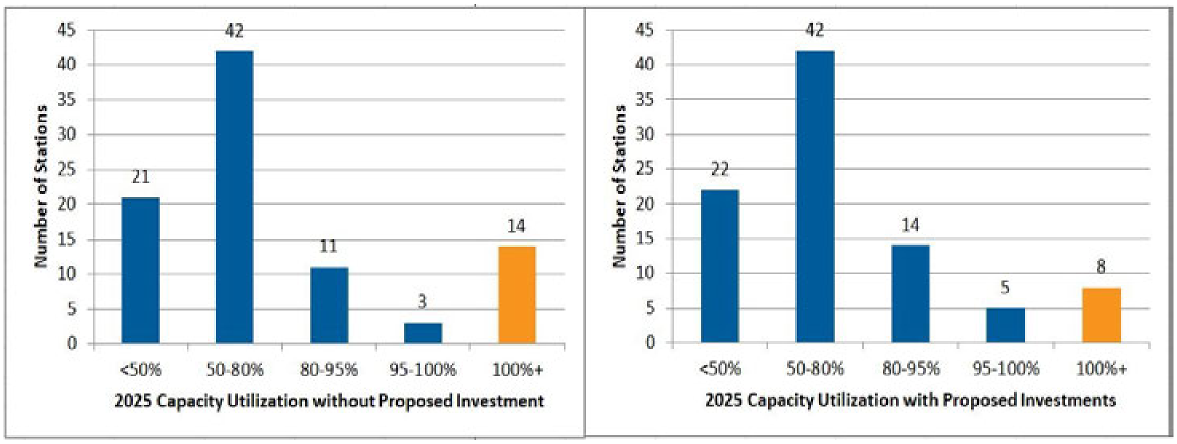
Hydro Ottawa's system capacity is lagging behind load growth. At present, 16% of stations are above their specified planning rating. Over the next five years, Hydro Ottawa is expecting growth to continue as previous rural areas are changed to urban areas and the City's plan for intensification continues.

Overall, the City of Ottawa is seeing continued growth, primarily focused in five regions: the downtown core, Nepean and Riverside South, Leitrim, South Kanata and Stittsville, and Orleans. This growth is being seen through the development of new mixed retail/residential communities as well as intensification of existing communities and the Ottawa LRT developments. Moving forward, significant investment in capacity for the system, at both the station and distribution level, will be required to catch up to and maintain pace with the demand. These capacity upgrade projects are identified through the Capacity Planning process. In addition, there are a number of distribution expansions which will be required to deliver power from the stations to the customer site. Customer-driven distribution expansions go through an economic evaluation to determine customer contribution for the project.

With the proposed Capacity Upgrades projects, the number of stations above the specified planning rating is expected to decrease to 9%, as per Figure 8.4. With the exception of Marchwood station, the other seven stations above their planning rating will be between 100% and 115%. All stations above their planning capacity have feeder contingency plans in place in case of a single transformer failure at any of the seven stations.

Without the proposed Capacity Upgrades projects, the number of stations above the specified planning rating is expected to be at 15% by 2025, as per Figure 8.4 (assuming that on-going projects are completed). Fallowfield station would be above its station rating and five out of the 14 stations would be between 115% and 185% of their planning rating.

Figure 8.4 – Stations above Planning Rating by 2025



There are several upgrades of transmission interties within the City which may be necessary over the next 20 years to maintain adequate and reliable supply from the bulk system. Hydro Ottawa is involved in an IRRP that is evaluating the transmission capacity and infrastructure requirements in the Ottawa region. The final report is expected to be completed in the first quarter of 2020. However, Hydro Ottawa's proposed five-year investment plan incorporates preliminary needs identified for the short term through this study. These are summarized in Table 8.7 below.

1 **Table 8.7 – IRRP Results**

Need	Description	Preliminary Solution
Supply to Kanata	Several stations in the area are operating at or near their planning capacity. Large commercial and residential developments are driving significant growth in electricity demand in the near and medium term.	Limitations on the existing transmission system in the area cannot accommodate expansion of the existing stations. A new station is likely required to provide reliable long term supply in the area. The IESO is currently developing a bulk transmission plan in parallel to the Greater Ottawa IRRP that might impact requirements for connecting the new station. Bulk transmission plan will be finalized in 2020. Hydro Ottawa is planning to implement distribution system upgrades to distribute forecast growth between stations in the area.
Supply to South East Ottawa	Several stations in the area are operating at or near their planning capacity. Demand is expected to increase driven by large residential, mixed and industrial developments.	Hydro Ottawa will proceed with a plan to build a new 230 kV connected supply station in the south east part of the City. The new station is planned for energization in 2025. HONI will evaluate the options for this upgrade in the Regional Infrastructure Plan (RIP).
Supply to East Ottawa	Bilberry Creek TS came into service in 1976 and is approaching end of life; options to decommission or refurbish the station were evaluated including the impact to the bulk system. Large industrial and residential mixed use developments are forecasted to increase demand over the near and medium term.	HONI will refurbish Bilberry Creek TS, including like for like transformer replacement. HONI will expand the station to provide two additional breaker positions to supply Hydro Ottawa customers.
Supply to the Regional 115kV System	Several of the 230/115 kV transformers at Merivale and Hawthorne are operating at or near their capability	HONI will replace the more limiting of the 230/115 kV transformers at Merivale TS in the near term so that the two Merivale transformers have similar capability. Subsequent to the release of the IRRP, the Working Group will undertake an IRRP Addendum Study, this will include an evaluation of potential benefit of non-wires options to manage future demand growth on the 115kV system.

8.1.6.2. Accommodation of Forecasted ERF Projects

Hydro Ottawa is predicting a continued interest in the installation of ERF within the service territory, over the five-year forecast period. Among the factors pointing towards sustained public and consumer interest in this regard are the objectives set forth in the City of Ottawa's "Energy Evolution" strategy in support of increased deployment of renewable resources. Based on the current ability of the system to connect new ERF, there are no constraints at the anticipated connecting stations for the forecasted connections. For more detailed information on accommodation of forecasted renewable energy projects in the next five years, refer to section 7 - System Capacity Assessment.

8.1.6.3. Climate Adaptation

Extreme weather events include, but are not limited to, high wind events, freezing rain, temperature and precipitation extremes, as well as complex events such as tornadoes. Such extreme weather has had an increasing impact on Hydro Ottawa's assets and operations over the past decade. In response to these events, and forecasted changes in weather patterns attributed to climate change, Hydro Ottawa has undertaken a Climate Vulnerability Risk Assessment ("CVRA"), and subsequent development of an adaptation plan as part of its distribution planning activities. Please see Attachment 2-4-3(H): Distribution System Climate Risk and Vulnerability Assessment for further details.

The CVRA was used to evaluate potential impacts and risks to the Hydro Ottawa electrical distribution system and supporting infrastructure as a result of changing climate and extreme weather events. This assessment process followed the Canadian Electricity Association's ("CEA") guide on adaptation to climate change, and Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") Protocol. This assessment methodology conforms to the International Organization for Standardization ("ISO") 31000:2018 Risk Management Standard, to identify relevant climate parameters and infrastructure responses, and assign risk ratings to each response to relevant climate considerations. The process involved the systematic review of historical climate information and the projection of the nature, severity and probability of future climate changes and events. The assessment of climatic changes was used to establish the exposure of infrastructure systems to these climate events. The impact of a particular damaging or disruptive climate event was then quantified and used to calculate the risk for a particular climate-infrastructure interaction. This process was repeated for all applicable infrastructure elements to produce an electrical distribution infrastructure climate risk profile.

The CRVA utilized the following methodology:

1. Identification of climate events (e.g. temperature, precipitation, winds) and their threshold values above which infrastructure performance would be affected and projecting the probability of occurrence of the climate hazards in the future (i.e. 2050s).

2. Assignment of a probability score for each climate event based on climate data. This involved converting the projected probability of occurrence of future climate parameters into the five-point rating scale used in Hydro Ottawa's Asset Management System Risk Procedures.

3. Assignment of a severity rating for the impact of climate events on each element of the distribution system considered in the assessment. Impacts on the infrastructure were assessed for various performance criteria. This part of the assessment was completed through a staff workshop.

4. Calculation of the risk for each infrastructure element was performed.

5. Using Hydro Ottawa's Asset Management System Risk Table, medium, high and very high risks to infrastructure and operations were identified.

The adaptive capacity – the ability of a system to respond which takes into consideration factors like, age, design setting, etc.– of the infrastructure elements were taken into account during the risk assessment stage.

Further information on the forecasted climate parameters used in the CVRA can be found in section 2.4.1. The analyses in this study use projections for the "business-as-usual" Representative Concentration Pathway emissions scenario – RCP8.5 – and for the 2050s (2041-2070).

This study identified a number of risks, which will be considered in the management of Hydro Ottawa's assets moving forward. 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, 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.

Key adaptations which are incorporated into this DSP include planning for climate, increased system resilience, and increased operational capability.

- Planning for climate: in response to a changing climate Hydro Ottawa will formalize the incorporation of climate into its planning systems, to ensure risks and adaptation remain current as climate trends and science evolve. Hydro Ottawa will continue to perform post-event analysis to identify lessons learned. Further, the utility will ensure future climate resilience is considered in all decision making practices, and establish recurring process to evaluate vulnerability risks to ensure long term sustainability of its current investments.
- Increased system resilience: the company will focus on sustaining and introducing practices to mitigate damage during severe wind and ice events. Hydro Ottawa will evaluate and, where feasible, implement augmentations to its vegetation management

practices to mitigate the impact of extreme weather, building on the success of storm hardening, and revised vegetation management practices implemented in 2014/2015. Hydro Ottawa will work with the City of Ottawa and the Village of Casselman to explore feasibility to expand trimming to include heritage trees, and trees in the fall zone outside of the utility's right-of-way if condition assessment indicates vulnerability.

- Renewal of aged, and decayed overhead infrastructure to withstand climatic forces from storm events is key to resilience over the long term for the system. Most notably, Pole Renewal programs support the development of this resilience. Hydro Ottawa will augment the impact of these renewal investments over the 2021-2025 period through the development of new anti-cascade standards and risk based application guides to further mitigate damage in high risk installations when damage does occur.
- Increased operational capability: Hydro Ottawa will continue to invest in appropriate technologies to augment its response to outages when weather events do cause interruption. These include system capacity investments to maintain sufficient operational capacity and redundancy, as well as, automation investments, to enable remote and automatic, isolation and restoration of faulted system components.

8.1.6.4. Electric Vehicles

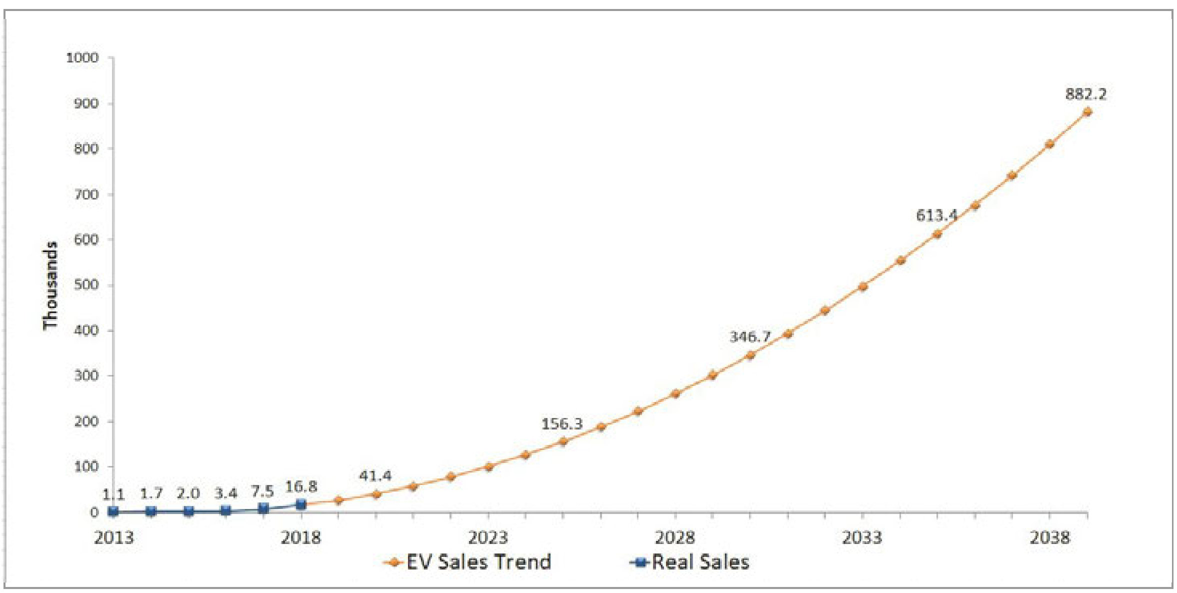
In response to the increasing growth of electric vehicles ("EVs"), Hydro Ottawa seeks to remain vigilant and adaptive to the impact EVs may have on the distribution system. Over the course of five years, EV yearly sales in the Province of Ontario have increased from 1,092 in 2013 to 16,814 in 2018, representing a compound annual growth rate of 11.56%. A breakdown of yearly EV sales can be found in Table 8.8. Using these sales data, a growth projection can be modelled further into the future, as shown in Figure 8.5. Comparing the 2018 trend, modelled sales of 2018 to the real EV sales of the same year yields a percent deviation of 2.57%.

Table 8.8 – Historical Ontario EV Sales[1]

Year	EV Sales
2013	1,092
2014	1,736
2015	2,049
2016	3,400
2017	7,477
2018	16,814

Extrapolating from the sales results in Table 8.8, the compound annual growth rate from 2013 real sales to 2039 projection sales was determined to be 31%. This extrapolated growth is shown in Figure 8.5.

Figure 8.5 – Ontario EV Sales Forecast



[1] Sources: "Electric Vehicle Sales In Canada, 2017," FleetCarma, 08-May-2019. Available: https://www.fleetcarma.com/electric-vehicle-sales-canada-2017/ and "Electric Vehicle Sales in Canada in 2018," Electric Mobility Canada - Mobilité Electrique Canada, Feb-2019. Available: https://emc-mec.ca/new/electric-vehicle-sales-in-canada-in-2018/.

Based on provincial EV per capita rates, it was estimated that Ottawa will have 2,959 EVs, as of 2018. By the end of 2019, this number is projected to rise to 4,832, a 63% increase. By 2039, the number of EVs within Ottawa is forecasted to grow to 511,332. In comparison to the total light vehicles ("LV") population, EVs will make up 66% by 2039 of all LVs in the City of Ottawa if trends continue.

Charging Technologies

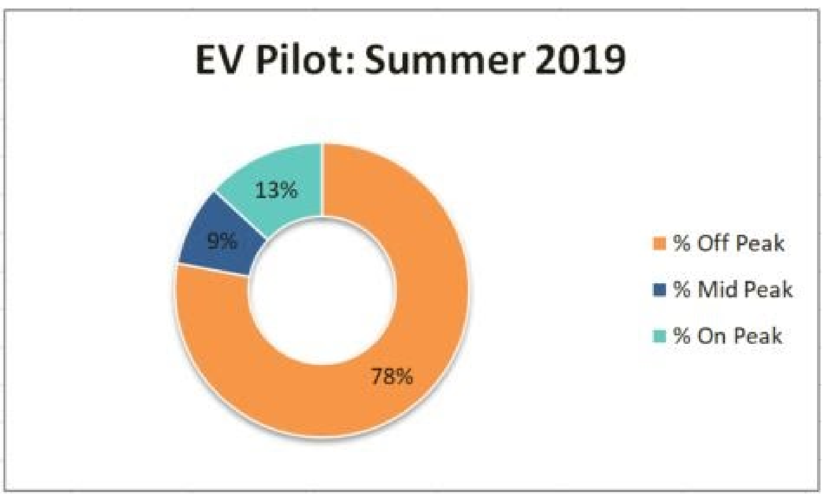
Modern day EV chargers can be categorized into three levels: level 1 (L1), level 2 (L2), and level 3 (L3) chargers. L1 chargers are very basic chargers that draw power in the range of 1.44 kW and 1.92 kW. L2 charger rated power ranges from 3.1 kW to 19.2 kW. L3 chargers range between 50 kW to 150 kW. DC fast chargers are typically what would be found in public installations.

At present, going by market trends, the 7.7 kW L2 charger is the preference for EV onboard chargers. In particular, the Tesla Model 3 has an onboard charger of 7.7 kW. Tesla is currently the major market leader in EVs for North America. Accordingly, this analysis will be focused on their leading market technology.

Hydro Ottawa EV Charger Program

In 2018, Hydro Ottawa began a pilot study gathering EV charging data from select participants to better understand charging patterns. The participants were chosen on a first come/first served volunteer basis with each characterized as using the FLO X5 charging station. As of August 2019, there were 67 charging station installations that Hydro Ottawa has the capability to collect data from across the City of Ottawa. The data collected from each active installation includes the following: total kWh consumption, date of use, time of use (broken down into off-peak, mid-peak, and on-peak), consumption per charge session, and km driven per week. The most valuable of these data points is the time of use (specifically, the on-peak periods). It allows Hydro Ottawa to analyze and understand the behavioural trends of consumers as it relates to charging for each month and season. The summer demand of EVs from the pilot study showed that 13% was on-peak, as shown in Figure 8.6.

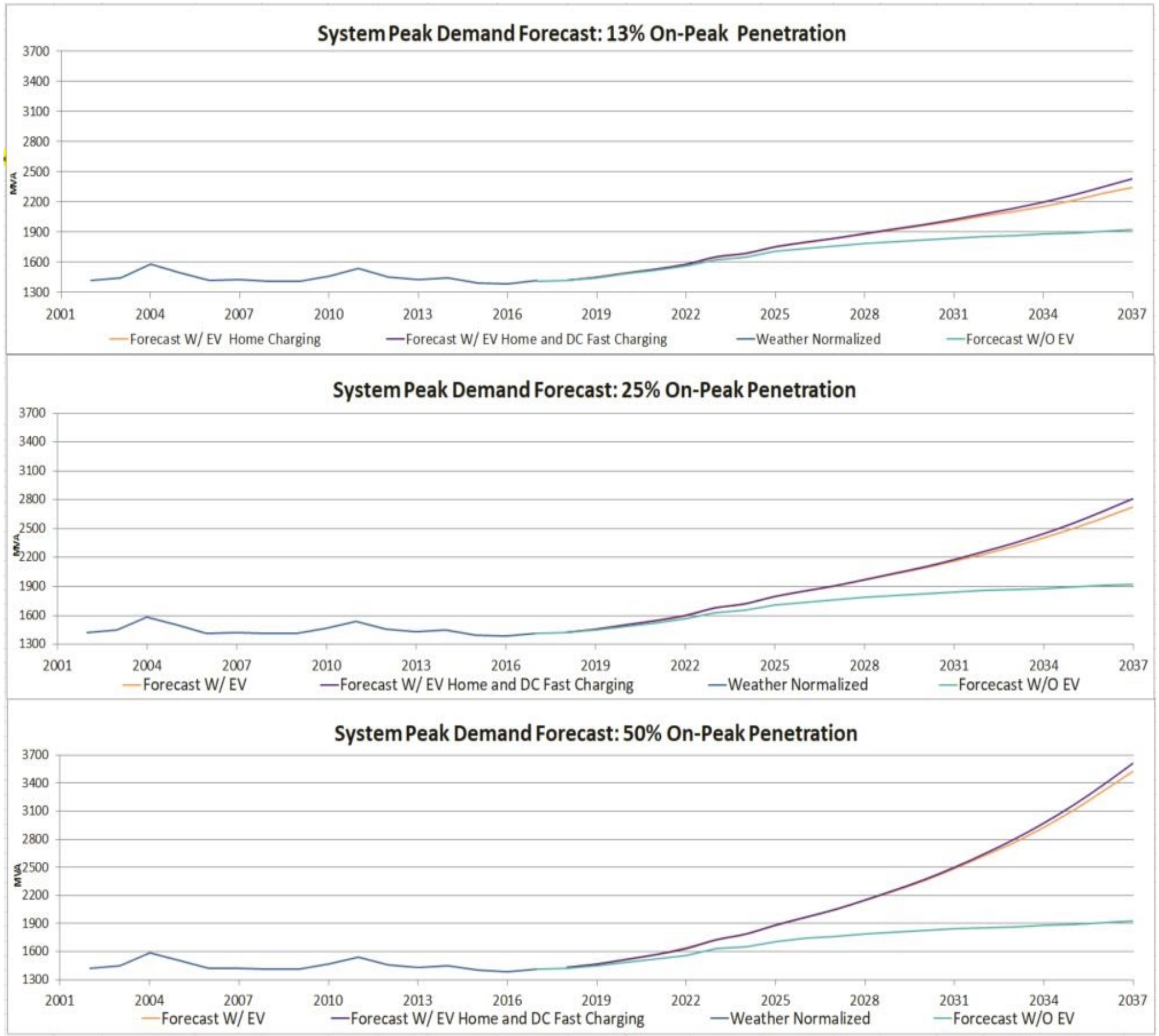
Figure 8.6 – EV Charging Summer Trends from Hydro Ottawa Pilot Program



Hydro Ottawa System EV Impact

Using Hydro Ottawa demand growth data from section 7.3, estimated EV penetration trends, and commonly used home charging technology, Hydro Ottawa adjusted its demand growth forecast to reflect the possible impact of EVs on Hydro Ottawa's distribution system. On-peak penetration levels of 13%, 25% and 50% were analyzed for system peak demand forecasting effect.

Figure 8.7 – Impact of EV Penetration on System Demand Forecast



A peak demand forecast graph comparing the projections with and without EV considerations is shown in Figure 8.7. All three scenarios show very little impact over the short term; however, long term impacts to demand forecasts drastically increase under all three scenarios. There are many factors that may influence the growth of EVs the further into the future a projection is made. In the next five years, the EV population in Ontario – and by extension, Ottawa – is expected to grow significantly. From 2019-2025, the EV population is projected to grow to approximately 43,000 vehicles. Applying the 13%, 25% and 50% charging diversity factors results in an increase in the demand forecasts by up to 212 MW by 2025, as shown in Table 8.9.

Table 8.9 – Demand Forecast by 2025 with EVs

Scenarios	2025		
	13%	25%	50%
Forecast (MVA)	1708	1708	1708
Forecast +EV Home (MVA)	1745	1778	1920
Forecast increase with EVs (MVA)	37	70	212

In addition to home charging, public charging infrastructure will also impact this future electrical demand. A report issued in 2019 by Natural Resources Canada ("NRCan") on DC Fast Charging clusters in the Ottawa region concluded that these new L3 charging stations would increase system peak load demand of the system by 2.7% in 2037.[2] Notably, the impact of DC fast charging stations on utility demand is much smaller than the impact of home charging. This is primarily because approximately 80% of an EV's charging occurs at home due to convenience and lower charging costs. This trend may change in the future as charging stations become more widely available, which will further increase market competition and lower charging costs.

Station Level EV Impact

For station level transformers, current and future investment in capacity increases will further strengthen the system's ability to not only serve future development growth but also to accommodate the impact of new technologies such as EVs. The 37MVA of additional demand expected under the 13% on-peak penetration scenario by 2025 is not expected to significantly shift the station capacity planning utilization factor shown in Figure 8.4 since EVs will be spread across different areas of Hydro Ottawa's service territory.

Distribution Transformer EV Impact

As EV penetration levels continue to rise in the Ottawa area, loading on distribution transformers at the residential level will be impacted. In new residential neighbourhoods, Hydro

[2] L. Wilkens and H. Ribberink, "The Impact of Clusters of DC Fast Chargers on the Electricity Grid in Ottawa," Natural Resource Canada (2019).

Ottawa typically would install 50kW transformers to connect a maximum of 10 customers. Taking into consideration future increases in EV penetration, the standard transformer size has increased to 100kW for a max connection of 12 customers. The changes from the current practice are shown in Table 8.10.

Table 8.10 – Changes in Standard Transformer Sizing

XFMR Size (kVA)	Max # of Homes	
	New Standard	Current Practice
50	5	10
75	8	25
100	12	37
167	20	51

The changes to the distribution transformers sizes in new and upgraded residential loops provide higher capacity for future EV penetration without affecting the life of the transformer.

As more data is collected from Hydro Ottawa's EV Charger pilot study, a more accurate on-peak EV demand profile will be created and applied to the transformer and system-wide impact analysis, thereby increasing the accuracy of the demand profile. In order to manage the impacts from EV growth, Hydro Ottawa will continue to monitor these trends to ensure a reliable power supply is maintained.

Hydro Ottawa will continue to lead and participate in pilot projects to get a better understanding of new technologies and their impact on the distribution system. Projects such as the Great-DR Project – Phase 2 (currently known as MiGen) will enable participants to share power from their renewable energy micro-generation plant with connected neighbours, store power at optimal times, and deliver excess power to the grid. This technology can be an invaluable tool in managing power supply at the demand source especially during peak demand situations where EVs at the neighbourhood level are a main cause. For more information on MiGen, please see the Material Investment Plan for Distribution Enhancements, in the System Service segment of Attachment 2-4-3(E).

8.1.6.5. Impact of Customer Preferences, Technology, and Innovation on Total Capital Cost

As identified in section 1.10.1 and Exhibit 1-2-1: Customer Engagement Overview, Hydro Ottawa utilizes a variety of activities to maintain awareness of its customers' preferences, which were incorporated into the draft 2021-2025 plans presented to its customers in Phase II of the Customer Engagement. Through this engagement, Hydro Ottawa's customers have expressed overall support of the draft plan, with 48% of residential and 47% of small business having identified that "Hydro Ottawa should maintain the forecasted annual increase to deliver a program which delivers on the stated priorities." This survey also identified support for furthering renewal of Hydro Ottawa's infrastructure and system renewal where it will positively impact customer reliability. In contrast, mid-market customers have expressed concern over proposed rate increases, and an openness to decreases in service reliability if it would reduce the forecasted increases in the bill.

Based on this feedback, Hydro Ottawa will continue forward with its proposed balanced investment plan – with a continued focus on efficiencies and a strategy to maximize the impact of investments to match residential customer expectations, without further increasing rate pressures on business customers.

8.1.6.6. Technology Based Opportunities

Over the next five years, Hydro Ottawa will continue implementing grid technologies to improve the reliability and efficiency of the distribution system. Annual automation installations will continue to improve system reliability and operational performance. Continued investment in the communication infrastructure will be essential to support current automation plans while maintaining the flexibility to integrate the technologies of tomorrow.

Hydro Ottawa's Supervisory Control and Data Acquisition ("SCADA") was upgraded in 2018. SCADA supports system reliability by providing system operators with real-time access to system status and control, reducing the time required to identify service disruptions, locate system faults, and operate the system to restore customers. As more distribution assets are connected to the SCADA system, the operator's situational awareness improves, resulting in a more focused and effective restoration effort. As a continuation of the SCADA upgrade project, Hydro Ottawa will be purchasing Distribution Management System ("DMS") functions to complement earlier efforts. The DMS implementation will enable analysis and automation tools as well as integration of other existing tools.

Another follow up to the SCADA project is the integration of the existing Outage Management System ("OMS") to the same platform as the new SCADA/DMS solution, making it a true Advanced Distribution Management System ("ADMS") platform. This includes software and services upgrades as well as new hardware implementation to run the system. This investment will enhance the efficiency and performance of the system operators in the control room by removing separate interfaces and incorporating SCADA, DMS and OMS into a single view.

Hydro Ottawa will be investing in new sensors and remotely operated devices in the distribution system. These additional devices will provide real-time data into the new DMS and OMS platforms as well as provide opportunities to remotely operated devices to improve restoration times.

8.1.6.7. Innovative Processes, Services, Business Models, or Technologies

In 2020, Hydro Ottawa will upgrade Copperleaf C55, an industry-leading and established Asset Investment Planning tool. This planning tool was first implemented in 2014, enabling the development of a strategic framework, investment decision optimization, and performance management. Copperleaf C55 achieves the objectives of value creation through better decision making, improved efficiency in the planning process, and meeting the standards set by the OEB's performance-based Renewed Regulatory Framework. The budget for upgrading C55 has been allocated to remain current with vendor support and take advantage of new functionality. Additionally, new value models will be configured to aid in the decision making process.

8.2. SYSTEM ACCESS INVESTMENTS

System Access expenditures are mandated by provincial legislation. While Hydro Ottawa strives to ensure projects in this Investment Category are completed as efficiently as possible, the company does not control the timing of these projects. While every attempt is made to predict and budget these costs, the actual implementation is not within Hydro Ottawa's control.

Budgeting is based on historical spending, known large projects and changes in legislative requirements. The System Access Investment Category is broken down into eight Capital Programs which are described below:

Table 8.11 – System Access Capital Programs

	Capital Program	Description
SYSTEM ACCESS	Plant Relocation & Upgrade	Relocation or upgrade of Hydro Ottawa owned or Joint-Use overhead or underground equipment
	Residential Subdivision	New residential subdivisions consisting of townhomes, semi-detached, singles, or any combination of thereof
	Commercial Development	New Commercial development serviced via underground or vault equipment
	System Expansion	A demand driven addition to a distribution system in response to a request for additional customer connections that otherwise could not be made
	Embedded Generation	Customer driven embedded generation projects
	Infill Service (Residential & Small Commercial)	Infill service, or service upgrade, either Residential or Small Commercial
	Damage to Plant	Replacement of asset damages resulting in the loss of functional use caused by a third party
	Metering	Revenue Meter installations or retrofits

Spending in the System Access Capital Programs focuses on:

- Relocation of existing plant due to infrastructure projects undertaken by third party agencies (e.g. the City of Ottawa and Village of Casselman, Ministry of Transportation of Ontario, National Capital Commission)
- Costs associated with the connection of new residential and commercial customers
- Expansion of Hydro Ottawa's distribution system to meet a specific customer or developer's needs
- Connection of new generation customers under various provincial programs
- Connection of one-off residential and small commercial infill connection requests that do not fall under the dedicated Residential and Commercial Capital Programs
- Replacement of damaged assets caused by a third party
- New and retrofit meter installations

As of 2021, the Damage to Plant Program will be moved to the System Renewal Investment Category since the primary driver for replacement of assets under this program is asset failure. Although the failure of the asset is caused by a third party, it aligns better with the description of System Renewal in the OEB Chapter 5 Filing Requirements.

The Capital Programs under System Access are broken down by Budget Program, as shown in Table 8.12. The table below includes a description for each Budget Program along with the primary driver. Please refer to section 5.2.1 Project Concept Definition for the definition of the drivers.

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Table 8.12 – System Access Expenditure Categories

Capital Program	Budget Program	Primary Driver	Description
Plant Relocation & Upgrade	Plant Relocation & Upgrade	3rd Party Requirements	• Relocation or upgrade of Hydro Ottawa owned or joint-use overhead or underground equipment; • Equipment to permit for safe limits of approach.
Residential Subdivision	Residential Subdivision	Customer Service Request	• To connect new residential subdivisions consisting of townhomes, semi-detached, single, or any combination of housing units; • Includes alternative bid and Hydro Ottawa built subdivisions; • Trunk, primary & secondary distribution infrastructure all considered within scope.
Commercial Development	New Commercial Development	Customer Service Request	• New developments serviced via padmounted equipment (switchgear and/or transformers) or via a vault.
System Expansion	System Expansion Demand	Customer Service Request	• A demand driven addition to a distribution feeder in response to a request for additional customer; for example a line extension.
	Long Term Load Transfers	Mandated Service Obligation	• OEB mandated elimination of load transfers between Hydro Ottawa and HONI. Mandated load transfers have been completed.
	PSPC – Asset Transfer	Customer Service Request	• Ownership transfer and upgrade of customer-owned equipment at Tunney's Pasture, Central Experimental Farm and Confederation Height.
Embedded Generation	Embedded Generation	Customer Service Request	• Connection of customer driven embedded generation projects; • Includes metering, service connection and protection and control as required.
Infill Service	Infill (Res & Small Com)	Customer Service Request	• Infill service or service upgrade for either residential or small commercial developments, i.e. services that do not require padmounted equipment or vault installations.
	ESA Flash Notice	Mandated Service Obligation	• Corrective actions to eliminate configurations where there is a transformer with a solidly grounded wye secondary with a potential return path via ground from the service to the transformer
Damage to Plant	Damage to Plant	Mandated Service Obligation	• Unplanned replacement of damaged assets caused by a third party; • Target 100% recovery of cost from the third party; however, where tracking information is not available, Hydro Ottawa absorbs the cost or may attempt at recovery from its insurer.
Metering	Suite Metering	Customer Service Request	• Retrofit of suite meters (retrofit of bulk meters) for commercial and multi-residential buildings; • Focus of the program is on residential retrofits in vertically arranged establishments

8.2.1. Historical Expenditures

The following section outlines Hydro Ottawa's System Access Capital Programs and projects from 2016 through 2020 and discusses the variance in spending from the 2016-2020 rate application budgets previously approved by the OEB. Gross historical spending for each program under System Access is shown in Table 8.13.

Table 8.13 – Historical Spending in System Access (Gross) ($'000s)

Investment Category / Capital Program	2016		2017		2018		2019		2020	
	Act.	Var.	Act.	Var.	Act.	Var.	Act. (*)	Var.	Act. (*)	Var.
Plant Relocation	$7,129	(30)%	$5,183	(33)%	$4,737	(40)%	$11,719	45%	$12,012	46%
Residential	$4,350	(37)%	$4,945	(30)%	$6,179	(14)%	$8,090	11%	$4,681	(37)%
Commercial	$11,880	(11)%	$10,990	(16)%	$19,519	55%	$10,793	(16)%	$11,023	(16)%
System Expansion	$8,726	146%	$3,833	62%	$5,984	148%	$8,216	234%	$19,128	662%
Embedded Generation	$678	80%	$291	(24)%	$89	(77)%	$165	(59)%	$338	(17)%
Infill & Upgrade	$3,844	22%	$4,787	49%	$3,046	(7)%	$3,658	9%	$4,087	19%
Damage to Plant	$1,122	(2)%	$851	(27)%	$1,125	(6)%	$1,250	3%	$986	(21)%
Metering	$77	(54)%	$26	(84)%	$169	(3)%	$884	400%	$1,075	496%
Total System Access	**$37,805**	**(3)%**	**$30,908**	**(12)%**	**$40,849**	**16%**	**$44,775**	**25%**	**$53,331**	**46%**
Capital Contribution	$(19,490)	(18)%	$(17,310)	(25)%	$(16,701)	(27)%	$(25,928)	11%	$(32,945)	38%
Net System Access	**$18,316**	**20%**	**$13,597**	**14%**	**$24,147**	**98%**	**$18,847**	**51%**	**$20,387**	**61%**

(*) Note that 2019 Actuals and 2020 Forecast are based on a 2019 Q2 Forecast

Since a large portion of projects under this Investment Category are customer driven, customer contributions are determined through the application of the OEB's prescribed economic evaluation methodology. Historically, customers contributed approximately 50% of the gross expenditure for System Access investments. Table 8.14 shows historical capital contribution by Capital Program. Hydro Ottawa expects this trend to continue based on the OEB's prescribed methodology.

Table 8.14 – System Access Historical Contributions ($'000s)

SA Capital Contributions	2016		2017		2018		2019		2020	
	Act.	Var.	Act.	Var.	Act.	Var.	Act. (*)	Var.	Act. (*)	Var.
Plant Relocation	$(4,039)	(12)%	$(2,731)	(41)%	$(2,781)	(42)%	$(7,099)	46%	$(9,261)	87%
Residential	$(3,676)	(44)%	$(3,112)	(53)%	$(7,398)	9%	$(9,182)	32%	$(3,288)	(54)%
Commercial	$(9,447)	(23)%	$(9,200)	(22)%	$(10,022)	(11)%	$(8,657)	(25)%	$(9,417)	(20)%
System Expansion	$(1,915)	120%	$(2,200)	272%	$(1,362)	126%	$(4,936)	702%	$(10,557)	1582%
Embedded Generation	$(284)	18%	$(223)	(17)%	$(87)	(68)%	$(100)	(64)%	$(186)	(35)%
Infill & Upgrade	$(1,452)	15%	$(1,699)	32%	$(1,701)	29%	$(1,796)	34%	$(1,643)	20%
Damage to Plant	$0		$0		$0		$0		$0	
Metering	$(21)		$(37)		$37		$0		$0	
Contributed Capital	**$(20,835)**	**(19)%**	**$(19,201)**	**(24)%**	**$(23,313)**	**(7)%**	**$(31,770)**	**24%**	**$(34,352)**	**32%**
Plant Relocation	$0		$0		$1,332		$0		$0	
Residential	$1,345	(35)%	$1,891	(10)%	$5,280	146%	$5,707	160%	$1,407	(37)%
Commercial	$0		$0		$0		$135		$0	
Infill & Upgrade	$1		$0		$0		$0		$0	
Contributed Plant	**$1,346**	**(35)%**	**$1,891**	**(10)%**	**$6,612**	**207%**	**$5,842**	**166%**	**$1,407**	**(37)%**
Capital Contributions	**$(19,490)**	**(18)%**	**$(17,310)**	**(25)%**	**$(16,701)**	**(27)%**	**$(25,928)**	**11%**	**$(32,945)**	**38%**

*Note that 2019 Actuals and 2020 Forecast are based on a 2019 Q2 Forecast

Gross historical spending in System Access has increased from 2016 through 2019 with the exception of 2017 due to delays in some majors projects. In 2020, the increase in spending is expected to continue. While some Capital Programs have remained consistent, others have seen considerable growth, causing the overall trend to show a steady increase in gross spending. While attempts are made to budget for both the historical trending and known major projects in System Access, variances from the budget do occur on a regular basis and are typically offset by the other Capital Programs within this category.

Plant Relocation and Upgrade

Hydro Ottawa experienced a lower than expected Plant Relocation and Upgrade spending in during 2016-2018. Spending in 2016 was largely driven by the City of Ottawa's LRT project while a decrease in 2017 spending was due to the Canada 150 celebration. In 2018, spending decreased primarily due to project delays. Spending in 2019 increased in comparison to previous years due to various City road rehabilitation projects such as Elgin Street renewal and Leitrim Road widening, as well as an increase in commercial customers requesting equipment upgrades. This trend is forecasted to continue in 2020 due to known planned projects such as Ottawa's LRT Stage 2, Montreal Road revitalization, and continued work on Elgin Street renewal.

Contributions to Plant Relocation and Upgrade projects are, on average, approximately 60% of total spending under this program. This is primarily due to cost sharing under the *Public Service Works on Highways Act* ("PSWHA") covering road work. Contributions are expected to increase in 2020 due to relocations required for the Ottawa's LRT Stage 2 project which does not fall under PSWHA.

Residential Subdivisions

Historically, residential subdivisions in Hydro Ottawa's service territory have followed a seven to 10 year rolling trend that has been consistent with the provincial and national averages since amalgamation. Hydro Ottawa experienced lower than expected Residential Subdivision spending in 2016 and 2017, but demand has increased through 2018 and 2019. Demand growth has been driven by a shift in development housing trends over this timeline due to intensification policies, where more blocks within a subdivision are being used for high density housing (stacked townhomes) on private streets. In addition, Hydro Ottawa is installing capacity infrastructure to accommodate future vehicle electrification. The forecast spend in 2020 is expected to be in line with 2016 and 2017 spending based on projects closing in 2019 and the known projects for 2020.

Contribution to Residential Subdivision projects are, on average, approximately 40% of total spending under this program. This is primarily due to the cost sharing using the OEB's prescribed economic evaluation methodology and incorporating contributed plant for assets the customers install which will be owned by Hydro Ottawa. Contributions typically fluctuate with respect to spending due to project delays year over year, but are expected to be in line with the average in 2020.

Commercial Developments

New Commercial Development has remained strong in Ottawa in recent years due to developer demand. Hydro Ottawa experienced a slightly lower than expected Commercial Development spending in 2016 and 2017 where the Canada 150 celebration had construction restrictions throughout the City. Spending in 2018 increased due to large projects such as the Museum of Science and Technology Storage Facility project. Spending in 2019 and forecasted for 2020 is in line with 2016 and 2017 trends.

Contributions to Commercial Development projects are on average approximately 80% of total spending. This is primarily due to the cost sharing using the OEB's prescribed economic evaluation methodology. Contributions typically fluctuate with respect to spending due to project delays year over year, but are expected to be in line with the average in 2020.

System Expansion

System Expansion spending fluctuates year-over-year due to customer requests and significant project requirements. Hydro Ottawa works with the relevant City of Ottawa departments and third parties to ensure that the forecasts are in line with their forecasted projects. However, the timing of these projects, and therefore the actual costs, are driven by third parties and not controlled by Hydro Ottawa.

Hydro Ottawa experienced above-forecasted System Expansion spending in the period of 2016-2019 due to various projects. A major project in 2016 and 2017 was the system expansion required for connecting the Domtar-Chaudiere project, a green energy hydro generation facility.

In 2018 and 2019, major contributors to this program are the Hull 1 & 2 projects, which involve connection of additional green energy hydro generation facilities, Ottawa's LRT Stage 2 extension projects, and the Public Services and Procurement Canada ("PSPC") asset transfer. The latter two projects are major drivers in the forecasted expenditures in 2020 making up 77% of total spending under this program.

Contributions to System Expansion projects are on average approximately 43% of total spending. This is primarily due to the cost sharing using the OEB's prescribed economic evaluation methodology for load and generation customers. Contributions have increased in 2019 and are forecasted to increase in 2020 compared to the average due to the contribution for the PSPC asset transfer project.

Embedded Generation

Costs associated with the connection of ERFs decreased over the period from 2016-2018. Spending in 2016 increased due to the connection of the Domtar-Chaudiere project, a green energy hydro generation facility. However, due to the IESO's FIT program ending, generation project spending has been decreasing. Spending in 2019 and 2020 are forecasted to increase due to customers participating in installing net-metering projects and the connection of Hull1 & 2, additional green energy hydro generation facilities.

Contributions to Embedded Generation projects are, on average, approximately 66% of total spending. This is primarily due to the cost sharing using the OEB's prescribed methodology for utilities to enable the connection of renewable generation. Contributions fluctuate based on the generation type and scope of the required connections year over year.

Infill Service (Residential & Small Commercial)

Infill services remain strong due to the City's Official Plan which encourages urban infill developments. Spending for Infill Services has remained consistent year-over-year with a slight decrease in 2018 due to reduction in customer demand. On average, program spending is 18% higher than forecasted budgets for the period of 2016-2020. The timing of Infill Service projects, and therefore actual costs, are driven by third parties and are not controlled by Hydro Ottawa. Spending in 2020 is forecasted to be consistent with recent years.

Contributions to Infill Service projects are, on average, approximately 44% of total spending under this program. This includes cost sharing using the OEB's prescribed methodology for a basic connection credit and Hydro Ottawa's annual free isolation to encourage customer maintenance. Contributions are expected to be in line with the average in 2020.

Damage to Plant

The Damage to Plant program covers costs associated with damage to Hydro Ottawa-owned plant caused by a third party. Hydro Ottawa targets 100% recovery of the costs from the third party; however, where tracking information is not available, Hydro Ottawa absorbs the cost or may attempt at recovery from the insurer. Due to the largely unpredictable and variable nature of the Damage to Plant Capital Program historical trends are used as the basis for budgeting and forecasting. Since 2007, Damage to Plant expenditures have remained relatively consistent year-over-year. The vast majority of damages occur to overhead and underground transformers, and wooden poles. The impact of increasing material and labour costs has offset gains made in reducing volumes and/or severity of incidents. As of 2021, the Damage to Plant Program will be moved to the System Renewal Investment Category.

Metering

Spending under this program has fluctuated over the years and focuses on customer requested installations of new and retrofits suite metering. This program experienced a significant increase in spend in 2019 from customer requests, majority from multi-residential high rises, to retrofit to Hydro Ottawa individual unit metering from a bulk meter. This trend is expected to continue in 2020 while customers look to provide tenants with more control of their electrical usage and cost.

8.2.2. Forecasted Expenditure

Forecasted annual spending takes into consideration a number of variables:

- Historic spending levels – trending of each category
- Known large future developments
- City plans and projects
- Economic indicators

The capital planning process has minimal impact on System Access capital expenditures since they are customer and third party driven, and thus, typically considered to be mandatory.

System Access projects may in some cases require a System Renewal or Service project to be delayed due to physical restrictions in the work area or system operability restrictions. In these circumstances, the risk to the system is evaluated and an optimal solution is determined with regards to work timing and prioritization.

Table 8.15 – System Access Forecast Expenditures by Capital Program ($'000s)

Investment Category / Capital Program	Forecast				
	2021	2022	2023	2024	2025
Plant Relocation	$10,135	$8,418	$8,474	$5,451	$5,427
Residential	$4,893	$4,999	$5,006	$5,010	$4,980
Commercial	$16,078	$13,465	$11,639	$11,806	$11,914
System Expansion	$20,116	$8,685	$6,960	$6,768	$6,289
Embedded Generation	$ 360	$296	$297	$306	$319
Infill & Upgrade	$4,164	$4,221	$4,099	$4,164	$4,151
Metering	$947	$947	$958	$957	$959
Total System Access	**$56,693**	**$41,032**	**$37,434**	**$34,462**	**$34,039**
Capital Contribution	$(38,872)	$(23,153)	$(19,713)	$(18,836)	$(18,784)
Net System Access	**$17,820**	**$17,879**	**$17,720**	**$15,626**	**$15,255**

System Access spending for the period of 2021-2025 is expected to be initially higher due to large known projects described below and then reduce to consistently lower levels. The majority of the increase in spending will be offset due to customer contributions based on the project drivers. The forecasted net spending in the System Access category is expected to remain at consistent levels through 2021-2025 as seen in Table 8.16. Hydro Ottawa expects that the economy in Ottawa will remain steady over the next five years, and work associated with the System Access Category will remain, on average, at the levels seen from 2016 through 2020.

Table 8.16 – System Access Forecast Contributions by Capital Program ($'000s)

Capital Contribution	Forecast				
	2021	2022	2023	2024	2025
Plant Relocation	$(7,919)	$(4,241)	$(4,274)	$(3,270)	$(3,256)
Residential	$(3,423)	$(3,497)	$(3,502)	$(3,505)	$(3,483)
Commercial	$(14,057)	$(11,198)	$(9,893)	$(10,035)	$(10,127)
System Expansion	$(13,075)	$(3,864)	$(1,740)	$(1,692)	$(1,572)
Stations Embedded Generation	$(198)	$(163)	$(163)	$(168)	$(176)
Infill & Upgrade	$(1,666)	(1,688)	$(1,640)	$(1,666)	$(1,660)
Metering	$0	$0	$0	$0	$0
Contributed Capital	**$(40,337)**	**$(24,650)**	**$(21,212)**	**$(20,336)**	**$(20,275)**
Residential	$ 1,465	$1,497	$1,499	$1,500	$ 1,491
Contributed Plant	**$1,465**	**$1,497**	**$1,499**	**$1,500**	**$1,491**
CAPITAL CONTRIBUTION	**$(38,872)**	**$(23,153)**	**$(19,713)**	**$(18,836)**	**$(18,784)**

Plant Relocation and Upgrade

Plant Relocation costs are expected to remain at the elevated costs seen since 2016 as a result of the Ottawa LRT project. This project has resulted in a large increase in relocation costs for Hydro Ottawa. With Stage 1 of the Ottawa LRT completed in 2019, the City of Ottawa will continue directly into Stage 2 of the project. Additionally, there is a continued focus on customers looking to upgrade their aging equipment. Due to the combination of these drivers, Hydro Ottawa expects the spending to remain high from 2021-2023 before decreasing to previous historical averages.

Residential Subdivisions

With the housing starts forecast in line with historicals in Ottawa, Hydro Ottawa is expecting that the customer connection needs in the Residential Subdivision Program in the period of 2021-2025 will remain consistent with the average spend levels from 2016 through 2020. Hydro Ottawa plans to continue installing capacity infrastructure to accommodate future vehicle electrification.

Commercial Developments

Commercial connections in 2021 and 2022 are expected to experience an increase in spending due to the forecasted connection of Ottawa's LRT Stage 2 stations in addition to typical customer demand. Hydro Ottawa is expecting that the customer connection needs in the Commercial Developments Program from 2023-2025 will remain consistent with recent historical averages.

System Expansion

System Expansion is expected to return to historical values once all stages of Ottawa's LRT project are completed. Stage 1 of the Ottawa's LRT project was completed in 2019, with Hydro Ottawa completing its required work for this project in 2018. Stage 2 of the Ottawa's LRT project started in 2018 and will continue to 2023. Hydro Ottawa plans on starting system expansion work in 2020, with an expectation to complete this work by 2021. Additionally, the PSPC Asset Transfer Program of equipment transfer and upgrading is expected to continue through to 2022.

Embedded Generation

The Embedded Generation program is expected to remain at the consistent levels forecasted in 2020, with an increase for net metering connections from 2021 through 2025.

Infill Service (Residential & Small Commercial)

Hydro Ottawa is expecting that the customer connection needs in Infill & Upgrade Capital Programs will remain consistent with the levels from 2021 through 2025.

Damage to Plant

Starting in 2021, the Damage to Plant Capital Program will be moved to System Renewal since work done under this program aligns better with the OEB's definition for the System Renewal category. A damaged asset by a third party is a failed asset that needs to be replaced to be able to continue to provide customers with electricity services. Therefore, the forecast for the Damage to Plant Capital Program will not be part of the 2021-2025 forecasts for System Access.

Metering

With the continued interest from customers requesting to retrofit to Hydro Ottawa unit metering from a bulk meter, Hydro Ottawa is expecting that the Metering Program will remain consistent with spending levels in 2019 and 2020 for the 2021-2025 Test Years.

8.2.3. Material Investments

System Access investments are "modifications (including asset relocation) to a distributor's Distribution System a distributor is obligated to perform to provide a customer (including a generation customer) or group of customers with access to electricity services via the distribution system" as per the Chapter 5 Filing Requirements. Table 8.17 shows historical and forecast average expenditures by Budget Program within System Access.

Table 8.17 – Average System Access Expenditures by Budget Program ($'000s)

Investment Category / Capital Program	2016-2020 Avg	2021-2025 Avg
Plant Relocation	$8,156	$7,581
Residential	$5,649	$4,978
Commercial	$12,841	$12,981
System Expansion	$9,178	9,764
Embedded Generation	$312	$316
Infill & Upgrade	$3,885	$4,160
Metering	$446	$953
TOTAL SYSTEM ACCESS	**$ 40,467**	**$40,732**

8.2.3.1. Plant Relocation

The Hydro Ottawa Plant Relocation Capital projects are undertaken in response to requests to relocate Hydro Ottawa's distribution plant. When such a request is received, Hydro Ottawa will exercise its rights and discharge its obligations in accordance with existing acts, by-laws and Regulations including the *Public Service Works on Highways Act* for public road authorities, formal agreements, easements and law.

8.2.3.2. Residential, Commercial, System Expansion and Infill & Upgrade

Hydro Ottawa's Residential, Commercial, System Expansion, and Infill & Upgrade Capital Programs are driven by the requirements as set out in the DSC, s*ection 6 – Distributors' Responsibilities, 6.1 – Responsibilities to Load Customers, 6.1.1,* which states that "A distributor shall make every reasonable effort to respond promptly to a customer's request for connection. In any event a distributor shall respond to a customer's written request for a customer connection within 15 calendar days. A distributor shall make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the load customer before the offer can be made."

8.2.3.3. Stations Embedded Generation

The Hydro Ottawa Stations Embedded Generation Capital Program is driven by the DSC requirement from s*ection 6.2 – Responsibilities to Generators, 6.2.4* that states "Subject to all applicable laws, a distributor shall make all reasonable efforts in accordance with the provisions of section 6.2 to promptly connect to its distribution system a generation facility which is subject to an application for connection".

8.2.3.4. Metering

The Hydro Ottawa Metering Capital Program is driven by the DSC requirement from s*ection 5.1 – Provision of Meters and Metering Services, 5.1.1* that states "A distributor shall provide, install and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distributor's distribution system…".

8.3. SYSTEM RENEWAL INVESTMENTS

System Renewal investment includes sustainment programs that replace or refurbish assets which are nearing or have reached the end of their useful lives. The System Renewal Investment Category is broken down into four Capital Programs as described in Table 8.18.

Table 8.18 – System Renewal Capital Programs

	Capital Program	Description
SYSTEM RENEWAL	Station Asset Renewal	Sustainment of discreet stations assets based on condition (Health Index) and prioritization.
	Overhead Distribution Assets Renewal	Sustainment of discreet overhead distribution assets based on assessed condition (Health Index) and prioritization.
	Underground Distribution Assets Renewal	Sustainment of discreet underground distribution assets based on assessed condition (Health Index) and prioritization.
	Corrective Renewal	Unplanned replacement of failed assets.

Capital expenditures for System Renewal are sustainment investments that are determined as an output of the Asset Investment Strategy (see section 5 - Asset Management & Capital Expenditure Process Overview). The primary planning activities which impact System Renewal investments are the Asset Management Plans. The Asset Management Plans provide strategic guidance on replacement and investment forecasts, manage priorities, and identify process gaps.

Spending in the System Renewal Capital Programs is focused around the following:

- Replacement of end of life and obsolete station equipment such as power transformers, switchgear and protection devices
- Refurbishment of station building structures and facility systems

- Replacement of end of life Distribution Assets such as poles, distribution transformers, cables and switches
- Replacement of in service failed assets through the Corrective Renewal Program

The Capital Programs under System Renewal are broken down by Budget Program, as shown in Table 8.19. Table 8.19 includes a description for each Budget Program along with the primary driver. Please refer to section 5.2.1 Project Concept Definition for the definition of the drivers.

Table 8.19 – System Renewal Expenditure Categories

	Capital Program	Budget Program	Primary Driver	Description
SYSTEM RENEWAL	Station Assets Renewal	Station Transformer Renewal	Failure Risk	• Station transformer refurbishment (life extension), or replacement as guided by the Asset Management Process.
		Station Switchgear Renewal	Failure Risk	• Stations switchgear and relay refurbishment (life extension), or replacement as guided by the Asset Management Process.
		Station Major Rebuilt	Failure Risk	• Station major rebuilds driven by multiple end-of-life assets.
		Station P&C Renewal	Failure Risk	• Station protection and control devices refurbishment (life extension) or replacement guided by the Asset Management Process.
		Station Battery Renewal	Failure Risk	• Station battery and charger refurbishment (life extension) or replacement guided by the Asset Management Process
		Station Minor Assets Renewal	Failure Risk	• Station minor assets (such as insulators, arrestors, structures, etc.) refurbishment (life extension) or replacement • Repairs, refurbishment or replacement of existing station building or property assets
	OH Distribution Assets Renewal	Pole Renewal	Failure Risk	• Planned replacement or upgrade of Hydro Ottawa owned poles or cross-arms based on condition assessment; • Pole attachments and conductors are considered in scope for replacement along with the poles/cross-arms where they are of the same vintage as the poles

	Capital Program (Cont'd)	Budget Program (Cont'd)	Primary Driver (Cont'd)	Description (Cont'd)
SYSTEM RENEWAL	OH Distribution Assets Renewal	Insulator Replacement	High Performance Risk	• Replacement or upgrade of Hydro Ottawa owned insulators that have been deemed a safety hazard, operationally inadequate and/or may cause pole fires
		OH Transformer Renewal	Failure Risk	• Replacement of overhead distribution transformers due to functional, safety or environmental concern (leaks, PCBs, corrosion, failure risk, etc.), or upgrade, including transformer shop testing and commissioning
		OH Switch/Recloser Renewal	Failure Risk	• Installation of new or the rehabilitation of overhead equipment (i.e. switches, reclosers, cutouts, or arrestors) based on condition or functional requirements (i.e. upgrade to gang operable switches or automated devices)
	UG Distribution Assets Renewal	Elbow & Insert Replacement	Substandard Performance	• Replacement and upgrade of distribution transformer non-vented elbows and/or inserts on the 28 kV system due to safety concerns of flash over during operation below 0°C.
		Vault Renewal	Failure Risk	• Vault rehabilitation due to condition of equipment or removal for consolidation or system betterment; • Includes replacement of Jack-Bus arrangements; • Exclusive of work considered under Plant Relocation & Upgrade
		Civil Renewal	Failure Risk	• Rehabilitation or rebuild of underground cable chambers, collars, ducts, and equipment pads due to condition or failure risk; • Includes installation of pads and vault space under pads; • Duct extensions considered under Line Extensions
		Cable Renewal	Failure Risk	• Replacement of underground cable based on condition; • All cable types considered, i.e. PILC, XLPE, butyl rubber, etc.; • Can include associated distribution transformer replacements based on condition assessment on a case-by-case basis

	Capital Program (Cont'd)	Budget Program (Cont'd)	Primary Driver (Cont'd)	Description (Cont'd)
	UG Distribution Assets Renewal	UG Switchgear Renewal	Failure Risk	• Replacement, refurbishment or upgrade of Hydro Ottawa owned switchgear based on condition
		Cable Rejuvenation	Failure Risk	• Injection of underground cable based on condition.
		UG Transformer Renewal	Failure Risk	• Replacement of underground distribution transformers due to functional, safety or environmental concern (leaks, PCBs, corrosion, failure risk, etc.), or upgrade, including transformer shop testing and commissioning
	Corrective Renewal	Damage to Plant	Failure	• Replacement of harmed or injured assets, resulting in the loss of functional use of the asset caused by a third party.
		Emergency Renewal	Failure	• Failed equipment typically resulting in an outage but not necessarily.
		Critical Renewal	Failure	• Failed equipment that may still be providing service, but no longer meet their designed requirements for safety, environmental or reliability reasons.

8.3.1. Historical Expenditures

The following section outlines the capital expenditures in the System Renewal category from 2016 through 2020. Projects contained in the System Renewal and System Service categories are determined through Hydro Ottawa's Capital Expenditure Process described in section 5.2 - Variances in this category are tracked and approved through Hydro Ottawa's change order request process. This process documents changes in project plans or costs associated with each individual project. This process allows Hydro Ottawa to track and adjust the progress of the project to ensure that spending is completed as close as possible to the planned budget. Any large variance in the plan can be identified and allow for adjustment of the plan to keep the Asset Management Plan on track.

Historical spending in System Renewal has fluctuated over the five-year period, but overall has seen an increase in the spending trend, as in the other capital categories. Historical spending for 2016-2018 and spending for the bridge years (2019 and 2020), along with the variance from the plan budgets presented in the 2016-2020 rate application, are shown in Table 8.20. All of the Capital Programs under the System Renewal investment category are for the replacement of existing aging infrastructure and assets in poor condition.

Table 8.20 – System Renewal Historical Variances ($'000s)

Investment Category / Capital Program	2016		2017		2018		2019		2020	
	Act.	Var.	Act.	Var.	Act.	Var.	Act.*	Var.	Act.*	Var.
Stations Asset Renewal	$13,346	(20)%	$13,991	16%	$20,478	43%	$8,531	(45)%	$6,970	(52)%
OH Distribution Assets Renewal	$11,801	21%	$11,099	31%	$10,846	11%	$6,487	(27)%	$9,164	(1)%
UG Distribution Assets Renewal	$9,677	14%	$9,421	46%	$9,023	21%	$4,627	(31)%	$7,415	5%
Corrective Renewal	$7,815	160%	$9,304	210%	$14,595	386%	$9,801	227%	$8,739	191%
Total System Renewal	**$42,639**	**12%**	**$43,816**	**46%**	**$54,942**	**59%**	**$29,446**	**(14)%**	**$32,288**	**(4)%**
Capital Contribution	$(2)		$(5)		$(41)		$0		$0	
NET SYSTEM RENEWAL	**$42,637**	**12%**	**$43,811**	**46%**	**$54,901**	**59%**	**$29,446**	**(14)%**	**$32,288**	**(4)%**

(*) Note that 2019 Actuals and 2020 Forecast are based on a 2019 Q2 Forecast

Stations Asset Renewal

The investments in Stations Asset have remained steady from 2016-2017 with a large increase in 2018. While attempts to maintain overall spending on major station projects (Transformer Replacement and Switchgear Replacement) remain consistent year over year, it is not possible to smooth the spending over all years of the Capital Programs. The individual projects are budgeted to maximize the efficiency of the project and can cause the timing of costs required for these multiyear projects to fluctuate.

Distribution Overhead and Underground Asset Renewal

Spending in Distribution Assets has varied from 2016-2018 and is expected to decrease for 2019 and 2020. Spending in the Capital Program continues to focus on Pole and Cable Replacement Projects.

Corrective Renewal

The Corrective Renewal Capital Program previously known as “Plant Failure,” was re-named and re-structured in 2018. Under the old structure, there were two budget programs- Distribution Plant Failure and Stations Plant Failure. Captured within these two Budget Programs was work to replace assets that had functionally failed requiring urgent intervention, as well as those that had fully failed requiring emergency replacement.

Under the new Corrective Renewal Program, there are two Budget Programs - Emergency Asset Renewal and Critical Asset Renewal. Emergency Asset Renewal addresses failed assets that typically, but not necessarily, result in an outage. Critical Asset Renewal addresses assets that still provide service, but no longer meet design requirements in regards to safety, environmental or reliability.

8.3.1.1. Historical Variances

In 2016, spending in the System Renewal Investment Category was 5% over the approved budget. Sustainment (System Renewal and System Service) as defined by Hydro Ottawa was 4% below the approved budget. Individual programs variances are described below:

- The Corrective Renewal program was 160% over the approved budget. Poles, PILC cable and underground transformer failures continued to be major contributors to spending. In 2016, poles showed a significant increase in spending due to an increase in the required interventions identified through the distribution inspection programs.
- The Overhead Distribution Assets Renewal Program showed an increase of 21% over the approved budget. Pole replacement projects in Centretown East and West had some minor adjustments to scope due to issues found in the field. The Hawthorne 48M2

overhead pole line was identified for replacement through inspection results in late 2015 following the acquisition of the overhead line from HONI. The project was added to the budget early in the year.

- The Underground Distribution Assets Renewal Program was 14% above the approved budget primarily due to overspending in Cable Renewal.
- The Station Assets Program was 20% below the approved budget mainly due to delays in the construction of the Merivale Rebuilt project as HONI demanded changes in the new station design. The items identified in the HONI feasibility study failed to capture HONI's concern and a large change in scope was required after final review of the design drawings.

In 2017, spending in the System Renewal Investment Category was 46% over the approved budget. Sustainment (System Renewal and System Service) as defined by Hydro Ottawa was 4% above the approved budget. Individual programs variances are described below.

- The Corrective Renewal program was 210% over the approved budget. Poles, PILC cable and underground transformer failures continued to be major contributors to spending in this program. In 2017, poles and underground transformers showed high levels of spending due to increased attention to distribution inspection programs which identified a number of very poor poles and transformers.
- The Underground Asset Renewal Program was 46% above approved budget. Results from cable testing identified new areas where cables were in poor condition increasing budget requirements under the Cable Renewal Program. Through inspections, a switchgear was identified with major arcing and in need of replacement, and two adjacent switchgears were deemed as end of life and with no replacement parts. Therefore, scope was expanded to replace all three switchgear increasing spending under the Underground Switchgear Renewal Program.
- The Overhead Asset Renewal Program was 31% above approved budget mainly due to increases in the Pole Renewal Program. An overhead section on Hawthorne Road was identified as end of life and in poor condition during the installation of fiber in the area

that was part of the Telecommunication Masterplan project. Replacement was therefore accelerated to be able to install fiber on these poles. Composite poles were installed since this area was prone to woodpecker damage. In addition, there were two pole replacement projects which had an increase in scope after initial field inspections to include replacement of additional poor condition poles and secondary work.

In 2018, spending in the System Renewal Investment Category was 59% over the approved budget. Sustainment (System Renewal and System Service) as defined by Hydro Ottawa was 28% above the approved budget. Requirements for additional funds for the programs listed below were required to complete the project or meet required timelines. Unfortunately, they were determined late in the year not allowing enough time to react by adjusting other programs and projects leading to the overspend. Budgets for 2019 and 2020 have been adjusted to ensure alignment with OEB approved budget level for the 2016-2020 rate period. Individual programs variances are described below.

- The Corrective Renewal Program was 386% above the approved budget. Poles, PILC cable and underground transformer failures continued to be major contributors to spending in this program. In 2018, there were three major weather events that affected the Ottawa area heavily impacting the spending in emergency replacement of overhead assets. These events are described in section 4.3.2 Major Events.
- The Station Assets Renewal Program was 43% above approved budget mainly due to shift in spending from delays in the Merivale station project and increased spending required for Overbrook station project due to site issues.

In 2019, spending in the System Renewal Investment Category is forecasted to be 14% below the approved budget. Sustainment (System Renewal and System Service) as defined by Hydro Ottawa is forecasted to be 14% below the approved budget. Individual programs variances are described below.

- Due to overspending in 2018 in the Corrective Renewal Program, the 2019 sustainment budget was reduced by $9.5M from approved levels.
- The System Renewal Investment Category was reduced by $4.7M primarily due to reductions in Station Asset Renewal, OH Asset Renewal, and UG Asset Renewal.
- Corrective Renewal is expected to continue spending trends experienced in 2016-2017 due to increased attention to distribution inspection programs, which continue to identify a number of very poor poles and transformers.

In 2020, spending in the System Renewal Investment Category is forecasted to be 4% below the approved budget. Sustainment (System Renewal and System Service) as defined by Hydro Ottawa is forecasted to be 6% below the approved budget. Individual programs variances are described below.

- An additional reduction of $4.1M to the 2020 sustainment budget is required due to overspending in 2018 including a $1.5M reduction from System Renewal.

8.3.2. Forecasted Expenditures

Annual spending for System Renewal is expected to on average $41.5M over the 2021-2025 period, which is a slight increase from the $40.6M annual spending during the 2016-2020 period, as seen in Table 8.21. The main driving factor for fluctuations in spending over 2020-2025 is due to timing of the major station projects. A continued focus will be seen through to 2025 and beyond on replacements of the critical assets as outlined in Section 6 Asset Lifecycle Optimization.

- **Station Assets Renewal** will decrease from spending levels seen in 2016-2020 due to moderate slowing of station asset replacements mitigated by increased monitoring of station transformers' condition. On average, this program will see a 25% reduction from the 2016-2020 rate period. A switchgear Renewal project is planned for Overbrook TO and Major Station Renewal projects are planned at Bells Corners DS, Rideau Heights DS, Fisher DS, Dagmar DS, and Shillington DS.

- **Overhead Distribution Asset Renewal** will focus on the replacement of poles with a 14% decrease from previous years mainly due to elimination/reduction of other OH equipment programs such as Insulator Renewal, OH Switch Renewal and OH Transformer Renewal.
- **Underground Distribution Asset Renewal** will see a 37% increase from previous rate submission mainly due to increased spending in Cable Renewal and Civil Renewal programs in order to maintain overall distribution system reliability
- **Corrective Renewal** will be kept at the same spending levels seen from 2017-2020.
- **Metering Renewal** is a new program introduced in the 2021-2025 rate period for replacement of various types of metering equipment that have reached end of life.

Table 8.21 – System Renewal Forecast Expenditures by Capital Program ($'000s)

Investment Category / Capital Program	Forecast				
	2021	2022	2023	2024	2025
Stations Asset Renewal	$9,938	$12,071	8,444	$7,437	$9,316
OH Distribution Assets Renewal	$7,999	$8,795	$8,795	$8,841	$8,044
UG Distribution Assets Renewal	$11,082	$10,780	$11,164	$11,079	$11,077
Corrective Renewal	$9,822	$9,805	$9,838	$9,812	$9,817
Metering Renewal	$4,455	$2,561	$1,950	$2,266	$2,219
TOTAL SYSTEM RENEWAL	**$43,296**	**$44,012**	**$40,191**	**$39,436**	**$40,474**

8.3.3. Material Investments

System Renewal investments "involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services" as per section 5.1.2 of the OEB's Chapter 5 Filing Requirements.

The full Budget Program expenditures over the forecast period is shown in Table 8.22. Details for Hydro Ottawa's System Renewal Budget Programs from 2021 through 2025 that meet the materiality threshold of $750K are included in Attachment 2-4-3(E): Material Investments.

1 **Table 8.22 – System Renewal Forecast Expenditure by Program ($'000s)**

Capital Program	Budget Program[3]	Forecast				
		2021	2022	2023	2024	2025
Stations Asset Renewal	Station Transformer Renewal	$2,365	$0	$0	$0	$0
	Station Switchgear Renewal	$1,572	$2,242	$1,669	$1,199	$32
	Station Battery Renewal	$84	$84	$84	$84	$84
	Station P&C Renewal	$576	$618	$0	$0	$0
	Station Minor Asset Renewal	$616	$785	$499	$709	$499
	Station Major Rebuilt	$4,725	$8,342	$6,192	$5,444	$8,700
OH Distribution Assets Renewal	Pole Renewal	$7,999	$8,044	$8,044	$8,044	$8,044
	OH Switch/Recloser Renewal	$0	$751	$751	$797	$0
UG Distribution Assets Renewal	Vault Renewal	$496	$496	$496	$496	$496
	Civil Renewal	$1,010	$1,010	$1,010	1,010	$1,010
	Cable Replacement	$8,972	$8,453	$9,053	$8,969	$8,967
	UG Switchgear Renewal	$605	$605	$605	$605	$605
	UG Transformer Renewal	$0	$216	$0	$0	$0
Corrective Renewal	Emergency Renewal	$4,482	$4,482	$4,482	$4,482	$4,482
	Critical Renewal	$4,297	$4,297	$4,297	$4,297	$4,297
	Damage to Plant[4]	$1,043	$1,026	$1,059	$1,033	$1,038
Metering Renewal	Metering Upgrades	$4,455	$2,561	$1,950	$2,266	$2,219
TOTAL SYSTEM RENEWAL		**$43,296**	**$44,012**	**$40,191**	**$ 39,436**	**$ 40,474**

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[3] For further details on System Renewal Budget Programs, please see Attachment 2-4-3(E): Material Investments.
[4] Hydro Ottawa's Damage to Plant Capital Program covers costs associated with damage to Hydro Ottawa owned plant which is caused by a third party. Hydro Ottawa targets 100% recovery of the costs from the third party; however, when Hydro Ottawa is unable to identify the responsible party, Hydro Ottawa absorbs the cost or may attempt at recovery from the insurer.

8.4. SYSTEM SERVICE INVESTMENTS

System Service investments are “modifications to a distributor’s distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future electricity service requirements” as per Section 5.1.2 of the OEB’s Chapter 5 Filing Requirements. The five capital programs under System Service are described in Table 8.23 below.

Table 8.23 – System Service Capital Programs

	Capital Program	Description
SYSTEM SERVICE	Capacity Upgrades	For relieving system capacity constraints resulted from load growth.
	Distribution Enhancements	A modification to the distribution system for purposes of improving system operating characteristics.
	Station Enhancements	A modification to a station for purposes of improving system operating characteristics.
	Grid Technologies	For improving and upgrading the operation of the system through new technologies and enhanced communications
	Metering	Upgrading customer meters for the ability to remotely disconnect and reconnect.

Spending in the System Service Investment Category focuses on the following:

- Stations Capacity Upgrades, which covers the building of new or rebuilding of stations for the addition of transformation capacity or supply
- Enhancements, which includes a range of system betterment project such as Line Extensions and System Voltage Conversions projects

- Grid Technologies Program, which includes upgrades to the SCADA and communication systems

Capital Programs under System Service are broken down by Budget Program, as shown in Table 8.24. It includes a description of each Budget Program along with the primary driver. Please refer to section 5.2.1 Project Concept Definition for the definition of the drivers.

Table 8.24 – System Service Expenditure Categories

	Capital Program	Budget Program	Primary Driver	Description
SYSTEM SERVICE	Capacity Upgrades	Stations Capacity Upgrades	Capacity Constraint	• New stations or increased station transformation capacity through transformer upgrades or additions at existing stations as identified through the System Capacity Assessment.
		Distribution Capacity Upgrades	Capacity Constraint	• New distribution capacity projects identified through the System Capacity Assessment including conductor upgrades, and line extensions (Not deemed "System Expansion").
	Distribution Enhancement	Distribution System Reliability	Reliability	• Specific enhancements to particular areas identified as having poor system reliability; typically more complex projects, including line extensions and addition of remote operable switches.
		System Voltage Conversion	Capacity Constraint	• Distribution voltage conversion to increase capacity in areas seeing significant growth; • Typically coincides with the retirement of existing stations or distribution assets due to condition or failure risk
		Distribution Enhancements	System Efficiency	• Modifications to the existing distribution system made to improve system operating characteristics or operability (e.g. circuit reconfiguration) • Installation of automated equipment for the purposes of improving operability
	Grid Technologies	SCADA Upgrades	System Efficiency	• Upgrades to the Supervisory Control and Data Acquisition (SCADA) system; both hardware and software upgrades are considered.
		RTU Upgrades	System Efficiency	• Upgrading and addition of Remote Terminal Units (RTUs) in the distribution network to improve SCADA functionality
		Communication Infrastructure	System Efficiency	• Installation of automated equipment for the purposes of communication.
	Station Enhancements	Stations Enhancements	System Efficiency	• Modifications to an existing station that is made to improve system operating characteristics.
		Station Reliability	Reliability	• Specific enhancements to particular areas identified as having poor system reliability, typically more complex projects
	Metering	Remote Disconnected Smart Meter	System Efficiency	• Upgrading customer meters to enable remote disconnects and reconnects

8.4.1. Historical Expenditures

The following section and Table 8.25 outlines capital spending in the System Service Investment Category from 2016 through 2020. Projects contained in the System Renewal and System Service categories are determined through Hydro Ottawa's capital expenditure planning process. Variances in this category are tracked and approved though Hydro Ottawa's change order request process. This process documents changes in project plans or costs associated with each individual project. This process allows Hydro Ottawa to track and adjust the progress of the sustainment project to ensure that spending is completed as close as possible to the planned budget. Any large variance in the plan can be identified and allow for adjustment of the plan to keep the asset management plan on track.

Table 8.25 – System Service Historical Spending

Investment Category / Capital Program	2016		2017		2018		2019		2020	
	Act.	Var.	Act.	Var.	Act.	Var.	Act.*	Var.	Act.*	Var.
Capacity Upgrades	$3,186	(44)%	$6,050	(60)%	$14,423	38%	$13,870	(4)%	$22,127	42%
Stations Enhancements	$219	61%	$1	(99)%	$14	(96)%	$20	(92)%	$21	(93)%
Distribution Enhancements	$12,715	6%	$11,805	(4)%	$6,108	(57)%	$7,920	(38)%	$7,420	(45)%
Grid Technology	$1,306	(70)%	$6,098	(5)%	$8,243	69%	$4,685	46%	$2,021	(53)%
Metering	357	(14)%	$890	(42)%	$1,013	(36)%	$1,013	(38)%	$1,031	(38)%
Total System Service	**$17,783**	**(21)%**	**$24,844**	**(30)%**	**$29,801**	**(5)%**	**$27,509**	**(15)%**	**$32,621**	**(7)%**
Capital Contribution	$0		$0		$0		$0		$(1,177)	
Net System Service	**$17,783**	**(21)%**	**$24,844**	**(30)%**	**$29,801**	**(5)%**	**$27,509**	**(15)%**	**$31,443**	**(11)%**

(*) Note that 2019 Actuals and 2020 Forecast are based on a 2019 Q2 Forecast

Historical spending in the System Service category has fluctuated within each Capital Program over the past five years, but overall has shown a steady upward trend. The largest contributors to System Service costs were Capacity Upgrades and Distribution Enhancements Capital Programs. These programs are designed to build out the distribution system to efficiently serve the customer at the best possible value.

Capacity Upgrades

The spending in Stations Capacity has fluctuated over the past five years, mainly due to timing in construction of major station projects. While attempts were made to keep overall spending on major station projects (Stations Capacity, Transformer Replacement and Switchgear Replacement) consistent year-over-year, it was not possible to levelize spending over all years of the Budget Programs. However, individual projects are budgeted in a manner that maximizes the efficiency of the project, but nonetheless can cause the timing of costs for these multiyear projects to fluctuate.

Distribution Enhancements

Spending in Distribution Enhancements has fluctuated since 2016, but overall has shown a decreasing trend. The largest spending in 2016 was in the Voltage Conversion Budget Program, which focused on the Woodroffe TS, South Nepean and Richmond areas. Line Extensions projects designed to deliver more capacity to areas have been moved to the Capacity Upgrades Capital Program. The majority of these projects are tied to the timing of the completion of Station New Capacity projects.

Capital Contributions are expected in 2020 for the Great DR Project - Phase 2 (currently known as MiGen) due to funding from NRCan.

Grid Technologies

The first year of Hydro Ottawa's Telecom Plan implementation and the SCADA upgrade projects was 2015. There have been some delays in these projects which shifted the original completion date from 2019 to 2020.

Metering

A new program was initiated in 2016 to upgrade meters to enable remote disconnection and reconnection of customers. This project eliminates the requirement to send a meter technician to the premise to disconnect or reconnect the meter when required. This also eliminates the need to install power limiters based on timer functionality for non-payment during the winter months along with the associated expense of travelling to the premise.

8.4.1.1. Historical Variances

In 2016, System Service spending was 21% below the original budget due to the following:

- The Capacity Upgrades program was 44% below budget due mainly to changes in project scope and delays in review of SIA/CIA by the IESO. The regulatory delay for TransCanada's Energy East pipeline and subsequent load deferral from the planned pumping station West of Richmond resulted in significant changes to the Richmond South Rebuild scope. The station project scope was reduced to a single transformer and half-switchgear line-up, with the infrastructure available for a second transformer in the future.
- The Grid Technology program was 70% below budget due to delays in fibre design and deployment in the Telecommunication Master Plan project.

In 2017, System Service spending was 30% below the approved budget due to the following:

- The Capacity Upgrades program was 60% below mainly due to the delays for the Richmond South as explained in previous year.
- The Metering program was 42% below budget since actual costs for installation were significantly less than what was estimated.

In 2018, System Service spending was 5% below the approved budget due to the following:

- The Capacity Upgrades program was 38% above budget due to major spending for Richmond South Station Project. This spending was originally forecasted for 2016 and 2017.

- The Grid Technology program was 69% above budget as a result of 2016-2017 under budget spending. In 2018, work was issued to an external contractor and execution accelerated in order to complete previous years scope.
- Distribution Enhancements program was 57% below budget due to underspent in Line Extensions and Voltage Conversion projects.

Spending in 2019 and 2020 for System Service is expected to be 15% and 7% below budget, respectively, as a result of the overall decrease in the sustainment (System Renewal and System Service) budget to accommodate for overspending in 2018. Major reductions occurred in the Distribution Enhancements Program.

8.4.2. Forecasted Expenditures

Annual spending for System Service is expected to average $26.3M over the 2021-2025 period which is an increase from the $22M average annual spending during the 2016-2020. Spending in the System Service category is expected to be high in 2021-2022 with a slight decrease over the last three years mainly due to timing of the major station projects. The requirement for the Stations Capacity and Distribution Enhancement Capital Programs has been defined in section 7 System Capacity Assessment.

Hydro Ottawa will continue to build and enhance stations while developing distribution feeders and ties similar to the 2016-2020 rate period as described in the following and summarized in Table 8.26:

- **Capacity Upgrades Program** will increase spending mainly due to the final years of the building of Cambrian MTS in the South Nepean region, as well as the construction of a new station in the east Leitrim region along with additional transmission upgrades to improve reliability and increase transmission capacity. Another contributor to the increased spending is the extension of associated new feeders to connect the new capacity with the customers and load

- **Distribution Enhancement Program** will slightly decrease spending from previous years. Spending will be focused on targeted distribution reliability improvements, the MiGen project and the Smart Grid Fund Initiatives program
- **Station Enhancement Program** includes spending required for enhancing of cyber security at stations as well as installation of new monitoring equipment at station transformers
- **Grid Technology Program** will maintain similar spending levels as in the previous rate period to upgrade Hydro Ottawa's OMS and enhance the new SCADA system by adding functionality to the Distribution Management System, along with the Field Area Network upgrade project
- **Metering Program** will continue to include the replacement of meters with remote connect/disconnect ability, but at a reduced investment level from the previous rate period

Table 8.26 – System Service Forecast Expenditures by Capital Program ($'000s)

Investment Category / Capital Program	Forecast				
	2021	2022	2023	2024	2025
Capacity Upgrades	$19,791	$9,717	$14,577	$17,799	$13,964
Stations Enhancements	$905	$459	$459	$459	$459
Distribution Enhancements	$6,957	$12,732	$5,981	$4,597	$4,796
Grid Technology	$2,847	$4,006	$2,819	$1,799	$4,179
Metering	$501	$501	$501	$501	$501
Total System Service	**$31,001**	**$27,415**	**$24,337**	**25,155**	**$23,899**
Capital Contribution	$(2,022)	$(1,723)	$0	$0	$0
Net System Service	**$28,980**	**$25,691**	**$24,337**	**$25,155**	**$23,899**

8.4.3. Material Investments

The full Budget Program planned expenditure over the forecast period is shown in Table 8.27. The full justifications of the projects/programs above the $750K materiality threshold can be found in Attachment 2-4-3(E): Material Investments.

Table 8.27 – System Service Forecast Expenditure by Budget Program ($'000s)

Capital Program	Budget Program	Forecast				
		2021	2022	2023	2024	2025
Capacity Upgrades	Stations Capacity Upgrades	$16,931	$6,112	$10,327	$12,786	$8,950
	Distribution Capacity Upgrades	$2,860	$3,605	$4,250	$5,013	$5,013
Stations Enhancements	Stations Enhancements	$905	$459	$459	$459	$459
Distribution Enhancements	Distribution System Reliability	$1,002	$5,683	$1,620	$2,006	$3,007
	System Voltage Conversion	$0	$3,034	$2,099	$731	$0
	Distribution Enhancements	$5,955	$4,016	$2,262	$1,860	$1,788
Grid Technology	SCADA Upgrades	$803	$2,708	$1,521	$501	$1,891
	RTU Upgrades	$253	$253	$253	$253	$253
	Communications Infrastructure	$1,790	$1,044	$1,044	$1,044	$2,035
Metering	Remote Disconnected Smart Meter	$501	$501	$501	$501	$501
System Service		**$31,001**	**$27,415**	**$24,337**	**$25,155**	**$23,899**

8.4.3.1. Stations Capacity Upgrades

The expenditures under the Station Capacity Upgrades Budget Program are identified and prioritized through the Capital Expenditure Process (section 5.2, and more specifically, through the System Capacity Assessment process). The 20-year outlook for capacity requirements is detailed in section 7.2 Ability to Connect New Load. Details on projects under the Station Capacity Upgrade Budget Program can be found in Attachment 2-4-3(E): Material Investments.

8.4.3.2. Distribution Capacity Upgrades

The expenditures under the Distribution Capacity Upgrades Budget Program are identified and prioritized through the Capital Expenditure Process (section 5.2, and more specifically through the System Capability Assessment section 7). Ability to Connect New Load. Details on the Distribution Capacity Upgrade Budget Program can be found in Attachment 2-4-3(E): Material Investments.

8.4.3.3. Station Enhancements

The expenditures under Station Enhancement Budget Program are aimed at increasing visibility into the distribution system and improving reliability and operability through increasing remote operability and reporting/alarms. This program includes station investments driven by the Cybersecurity program, to ensure Hydro Ottawa is able to identify, protect and detect cyber threats on these critical systems. Details on the projects under the Station Enhancement Budget Programs can be found in Attachment 2-4-3(E): Material Investments.

8.4.3.4. Distribution System Reliability

The expenditures under the Distribution System Reliability Budget Program are identified and prioritized through the Capital Expenditure Process (section 5.2) and include projects identified through evaluation of the Worst Feeders (section 4.3.3). Details on the Distribution System Reliability Budget Program can be found in Attachment 2-4- (E): Material Investments.

8.4.3.5. Voltage Conversion

Details on the Voltage Conversion Budget Program can be found in Attachment 2-4-3(E): Material Investments.

8.4.3.6. Distribution Enhancements

Distribution Enhancement projects are targeted at making improvements to the existing distribution system in terms of reliability and/or operability and are typically targeted towards areas or equipment that are deemed problematic. Details on the Distribution Enhancement Budget Program can be found in Attachment 2-4-3(E): Material Investments.

8.4.3.7. SCADA Upgrades

The SCADA Upgrades Budget Program covers expenditures related to upgrading and/or renewing SCADA equipment that has reached end of life or has become obsolete. Details on the projects under the SCADA Upgrades Budget Program can be found in Attachment 2-4-3(E): Material Investments.

8.4.3.8. RTU Upgrades

The SCADA RTU Budget Program covers expenditures related to upgrading and/or renewing SCADA remote terminal units that have reached end of life or have become obsolete. Details on the projects under the RTU Upgrades Budget Program can be found in Attachment 2-4-3(E): Material Investments.

8.4.3.9. Communication Infrastructure

The Communication Infrastructure Budget Program covers expenditures related to the installation of equipment for the purposes of communication. Details on the projects under the Communication Infrastructure Budget Program can be found in Attachment 2-4-3(E): Material Investments.

8.4.3.10. Remote Disconnect Metering

Details on the Remote Disconnect Metering Budget Program can be found in Attachment 2-4-3(E): Material Investments.

8.5. GENERAL PLANT INVESTMENTS

General Plant investments are “modifications, replacements or additions to a distributor’s assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock, electronic devices and software used to support day to day business and operations activities and capital contributions to other utilities” as per Section 5.1.2 of OEB’s Chapter 5 Filing Requirements. Projects and programs in this category are driven by the requirements for capital to support day-to-day business and operations activities. There are nine capital programs under General Plant which are described in Table 8.28 below.

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Table 8.28 – General Plant Capital Programs

	Capital Program	Program Description
GENERAL PLANT	HONI Payments	Capital contributions to intangible assets purchased from HONI in conjunction with Hydro Ottawa's major station projects. Generally referred to as Connection and Cost Recovery Agreements (CCRAs).
	Buildings - Facilities	The program addresses the necessary building improvements for the administrative buildings, the operation centres including warehouse, storage and fleet space to ensure employees have a safe and efficient environment to operate within.
	Customer Service	The program includes the Customer Care and Billing system, Customer Service strategy, and Website Enhancements. The program objective is to add value to the customers and ensure accurate billing.
	ERP System	The Enterprise Resource Planning (ERP) system is a vital technology solution to achieve business outcomes. Hydro Ottawa utilizes J.D. Edwards (JDE) with an integration to WorkDay as its financial system. It is used to manage budgets, procure to pay, inventory, payroll, job costing, and all general ledger functions.
	Fleet Replacement	Acquisition of vehicles to replace end of life vehicles. Program objective is to provide safe, reliable and efficient vehicles to meet the operational requirements.
	IT New Initiatives	The program focuses on initiatives to optimize business operations including a Document Management System, an Enterprise Architecture Program, and a Data Management System.
	IT Life Cycle & Enhancements	The program addresses the renewal and maintenance of the IT infrastructure including device replacements, network security, data loss prevention program, network switches upgrade, network file storage, and software licenses.
	Operation Initiatives	The program objective is to strengthen the Geospatial Resource Management (GRM) system, enhance reliability services, and increase productivity and organizational effectiveness.
	Tools Replacement	Tools are needed to carry out the distribution maintenance and capital program efficiently and effectively, this program covers replacement of aged tool equipment.

General Plant includes three major funding requirements:

1) The largest part of the General Plant investments is to replace assets that have reached end of life, including vehicles, tools, information technology equipment and software, and facilities. The investments are essential to meet the day-to-day operational needs and to provide employees with the tools and vehicles necessary to perform their work safely and efficiently;

2) Capital contributions to HONI for associated expansion work under CCRAs; and

3) New technology initiatives which have been identified in the 2021-2025 rate period. The key focus is to add value to customers and to increase operational efficiencies.

The Capital Programs under General Plant are broken down by Budget Program, as shown in Table 8.29. It includes the associated primary driver for each Budget Program. Please refer to section 5.2.1 - Project Concept Definition for the driver definitions.

Table 8.29 – General Plant Expenditure Categories

	Capital Program	Budget Program	Primary Driver
GENERAL PLANT	HONI Payments	HONI Payments	System Capital Investment Support
	Facilities Management	Facilities Management	Non-System Physical Plant
	Fleet Replacement	Fleet Replacement	System Capital Investment Support
	Tools Replacement	Tools Replacement	System Maintenance Support
	IT Life Cycle & On-Going Enhancements	IT Life Cycle & On-Going Enhancements	Business Operation Efficiency
	IT New Initiatives	IT New Initiatives	Business Operation Efficiency
	ERP System	ERP System	Business Operation Efficiency
	Customer Service	Customer Service	Business Operation Efficiency
	Operation Initiatives	Operation Initiatives	Business Operation Efficiency

8.5.1. Historical Expenditures

The following section, as well as Tables 8.30 and 8.31, outline Hydro Ottawa's General Plant Programs from 2016 through 2020 and discuss the spending variances over this five-year period. Expenditures and variances are tracked regularly by Hydro Ottawa's management team and are adjusted to align with any changes in corporate priorities.

1 **Table 8.30 – General Plant Historical Expenditure ($'000s)**

Investment Category / Capital Program	2016		2017		2018		2019		2020	
	Act.	Var.	Act.	Var.	Act.	Var.	Act.*	Var.	Act.*	Var.
HONI Payments	$4,647	2%	$5,647	13%	$3,143	(37)%	$6,757	35%	$30,070	501%
Buildings - Facilities	$3,904	(85)%	$18,207	(48)%	$46,658	620%	$18,627	5659%	$453	87%
Customer Service	$1,296	(65)%	$2,275	(4)%	$38	(97)%	$4,528	(32%)	$5,099	348%
ERP System	$3,721	(26)%	$7,309	1966%	$104	(70)%	$159	(55)%	$679	(36)%
Fleet Replacement	$2,619	80%	$1,584	31%	$1,195	(18)%	$583	(61)%	$1,632	(13)%
IT New Initiatives	$1,658	(22)%	$651	(44)%	$2,839	182%	$2,057	69%	1,115	(7)%
IT Life Cycle & Ongoing Enhancement	$1,152	(19)%	$858	(51)%	$2,059	8%	$800	(64)%	$1,458	(20)%
%Operations Initiatives	$937	(13)%	$1,327	194%	$199	(51)%	$688	(23)%	$1,624	52%
Tools Replacement	$390	(24)%	$442	(15)%	$503	(5)%	$1,039	93%	$450	(18)%
TOTAL GENERAL PLANT	**$20,323**	**(56)%**	**$38,300**	**(20)%**	**$56,738**	**210%**	**$35,239**	**88%**	**$42,580**	**205%**
Capital Contribution and Other	**$0**		**$0**		**$0**		**$(1,652)**		**$(410)**	
NET GENERAL PLANT	**$20,323**	**(56)%**	**$38,300**	**(20)%**	**$56,738**	**210%**	**$33,586**	**80%**	**$42,170**	**202%**

2 (*) Note that 2019 Actuals and 2020 Forecast are based on a Q2 2019 Forecast

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Table 8.31 – General Plant Historical Contributions ($'000s)

Capital Contribution	Actual				
	2016	2017	2018	2019*	2020*
IT Life Cycle & Ongoing Enhancement	$0	$0	$0	$(1,330)	$(410)
Operations Initiatives	$0	$0	$0	$(323)	$0
Contributed Capital and Other	**$0**	**$0**	**$0**	**$(1,652)**	**$(410)**

*Note that 2019 Actuals and 2020 Forecast are based on Q2 2019 Forecast

Historical spending in the General Plant investments, excluding the Facilities Renewal Program and CCRAs, were kept at an average of $12M per year and spending was relatively consistent over the past five years. The details of these variances are outlined below.

HONI Payments

The HONI Payments Program is expected to be 105% above the total budget for 2016-2020 mainly due to $34.2M in transmission payments to HONI for the Cambrian MTS project. The total cost for the transmission upgrades required for connecting the new station is $50.2M; the remaining $16.0M will be paid in 2021. Other projects that contributed to spending under this program were:

- Richmond South ($60.9K)
- Hawthorne new 44M6 feeder ($1.8M)
- A6R Upgrade ($7.0M)
- Woodroffe TS CCRA ($1.9M)
- King Edward TS CCRA($100K)
- Merivale MTS Rebuilt ($2.3M)
- Slater T1 Emergency Replacement ($0.2M)
- Limebank T4 ($56.6K)
- Ellwood TS True up payment ($1.2M)
- Hawthorne 115kV True up payment ($2.2M)

Buildings - Facilities

Spending in this category was kept at a minimum level in 2016 and 2017 due to the anticipated move to the new facilities in 2019. In 2018, spending increased due to a renovation project at the Bank Street location. Bank Street was renovated to align with the Training & Development Plan (Exhibit 4-1-5: Workforce Staffing and Compensation), with the renovations completed in 2019. In 2019, the increase in spending is also partially due to Hydro Ottawa's behind-the-meter Solar arrays at the new facilities. This investment is expected to reduce Hydro Ottawa's environmental footprint and electricity costs for the next 30 years. Initiatives such as these demonstrate Hydro Ottawa's leadership with respect to reducing its environmental footprint. Moreover, the company was recognized as one of Canada's Greenest Employers for the seventh time.

Facilities Renewal Program ("FRP")

This project is a once in a generation investment to consolidate operations and administrative staff from the aging facilities carried since amalgamation into new facilities. For details, please see Attachment 2-1-1(A): New Administrative Office and Operations Facilities.

Customer Service

The essence of Hydro Ottawa's strategy is to put the customer at the centre of everything the company does. In the past five years, $13M was spent on capital investments to add value and improve the customer experience. The spending was slightly below the budget of $15M. Of this $13M, $8M was spent on an upgrade of the Customer Care and Billing system to meet regulatory and business requirements. The upgrade started in 2019 (later than the budget expectation). It is anticipated to be completed in 2020.

Enterprise Resource Planning ("ERP") System

Spending in 2016 and 2017 was largely for the implementation of a new ERP system with streamlined and automated Human Resources, Finance, Accounting, and Supply Chain processes. Back office operation improved significantly. Decision making improved due to increased self-service capabilities. The implementation was a huge success and Hydro Ottawa won the award for the Most Innovative Use of HR Technology at the Canadian HR Awards. This award recognizes Hydro Ottawa's use of the latest HR-specific technology to greatest effect. Due to an expanded project scope, some spending on the ERP system was delayed from 2016 to 2017.

Fleet Replacement

The increase in 2016 spending was due to a significant increase in US exchange rates and steel price increase subsequent to the budget preparation in late 2014. With Hydro Ottawa's strong commitment to budget control, 2019 spending was reduced significantly to allow five-year spending to materially achieve the approved budget of $7.5M. Also, as part of the company's central focus on innovation, productivity and cost control, there were two new models of mini bucket trucks purchased, making construction in narrow areas possible. These mini machines make digging and setting utility poles, restoring power, undertaking construction of distribution systems and maintaining power lines both safe and more efficient.

Figure 8.8 – Mini Bucket Truck in Use

IT New Initiatives

This program focuses on initiatives to optimize business operations. Spending in 2016 and 2017 was largely for the implementation of the Enterprise Communication Platform. The customer contact platform was expanded to allow multi-channel communication (voice, test, email, chat, etc.). Voice and data infrastructure was also upgraded before moving into the new facilities in 2019, which saved approximately $1M to $2M to install a traditional phone system in the facilities, and ongoing OM&A savings as well. The aging Interactive Voice Response ("IVR") was replaced by the new IVR, which improved reliability and call volume capability. In 2018 and 2019, the largest investment was the IT infrastructure for the Data Center in the new buildings. The project was designed to increase reliability and to minimize disruption to the business from the move. A Hot Aisle Containment Unit was purchased to increase data center cooling and energy efficiency which avoids the need for expensive raised floor construction. Overall spending was delayed slightly to align with the building move-in date.

IT Life Cycle & Ongoing Enhancements

The IT Life Cycle & Ongoing Enhancements Capital Program was largely to replace computer and network equipment. Spending was significantly below budget due to investments that were re-evaluated none of the end of life assets were being replaced automatically. Instead, they were reassessed with the consideration of innovation, productivity, and cost control to meet future technology needs. Certain funding was therefore reprioritized to fund the IT New Initiatives described in the previous paragraph.

Operations Initiatives

Spending in this program was mainly to finish the implementation of Mobile Workforce Management ("MWM"), the ongoing enhancement for Geographical Information System ("GIS"), OMS, and GPS. Spending exceeded the five-year budget, in part, due to the delay in completing the full implementation of the MWM system. The system went live in December 2015 with the new residential service connections contractor; however, some technical difficulties throughout implementation delayed full adoption by other groups including metering, collections, forestry until early 2016.[5] Additional increases in 2020 were due to the addition of Field Service Management and the Mobile Application Programs referenced in Attachment 2-4-3(E): Material Investments. These investments are aimed at increasing field service efficiency.

Tools Replacement

Spending for the Tools Replacement Capital Program was consistent over the past five years, with the exception of 2019 due to the new buildings and the old warehouse tools no longer being usable. The new warehouse tools allow for maximum capacity and efficiency.

8.5.2. Forecasted Expenditures

General Plant expenditure (excluding HONI Payments) are expected to average $12M annually over the 2021-2025 period (Table 8.32). This is an increase from the $11M annual spending during the 2016-2020 period (excluding the Facilities Renewal Program and HONI Payments).

[5] For more information on MWM implementation, please see Attachment 1-1-10(A): 2016 Annual Summary: Achieving Ontario Energy Board Renewed Regulatory Framework Performance Outcomes.

Table 8.32 – General Plant Forecast Expenditure ($'000s)

Investment Category / Capital Program	Plan					Average
	2021	2022	2023	2024	2025	
HONI Payments	$16,918	$210	$200	$5,130	$4,200	$5,332
Buildings - Facilities	$428	$428	$403	$403	$403	$413
Customer Service	$2,539	$1,616	$846	$826	$1,188	$1,403
ERP System	$756	$896	$1,245	$6,554	$5,588	$3,008
Fleet Replacement	$6,345	$4,526	$2,220	$1,681	$2,008	$3,356
IT New Initiatives	$924	$549	$609	$333	$887	$660
IT Life Cycle & Ongoing Enhancement	$1,981	$1,411	$1,250	$1,035	$1,664	$1,468
Operations Initiatives	$1,681	$1,572	$321	$928	$477	$996
Tools Replacement	$474	$474	$462	$465	$469	$469
TOTAL GENERAL PLANT	**$32,047**	**$11,681**	**$7,556**	**$17,354**	**$16,884**	**$17,105**
Capital Contribution and Other	$(360)	$(340)	$(230)	$(390)	$(480)	$(360)
NET GENERAL PLANT	**$31,687**	**$11,341**	**$7,326**	**$16,964**	**$16,404**	**$16,745**

Over the 2021-2025 rate period, Hydro Ottawa's General Plant investments will address the following needs under each Capital Program, which will continue to add value to Hydro Ottawa customers and to increase operational efficiencies:

- **HONI Payments** will increase significantly, especially in 2021, due to $16M forecasted for the S7M line upgrade associated with the Cambrian MTS project.
- **Buildings - Facilities** will encompass minimal investments in capital work relating to substations.
- **Customer Service** is mainly annual enhancements forecasted to meet the regulatory requirements and business needs of systems and services.In 2021, there will be an upgrade of the Meter Data System.
- **ERP Solution** spending is required to leverage next generation technology to provide a more cost-effective, flexible, and agile solution. The project will start in 2023 and be completed by 2025.

- **Fleet** spending will be higher than historical spending due to the need to replace aging fleet. The program objective is to maintain safe and reliable operation, as well as cost effective investments i.e. to avoid large repair costs or inefficiency caused by the aged vehicles.
- **IT New and Life Cycle** spending will continue to focus on innovation, productivity, and cost control. This is designed to move Hydro Ottawa from Good to Great and aid in achieving greatest efficiencies through automation, accurate information, and faster response time. Cybersecurity is strengthened to ensure customer data and Hydro Ottawa's distribution system are protected.
- **Operation** Initiatives continue to enhance Hydro Ottawa's GIS and OMS system annually. In addition, in 2021 and 2022, the Field Service Management and the new AMI Management will be implemented. This will benefit operations and increase efficiencies.
- **Tools** spending will be in line with historical spending.

8.5.3. Material Investments

The full justifications of the General Plant Programs above the materiality threshold can be found in Attachment 2-4-3(E): Material Investments.

8.5.3.1. HONI Payments

The forecast for HONI Payments is expected to fluctuate over the 2021-2025 rate term. In 2021, there will be a final $16M payment to HONI for the transmission cost associated with the supply to the new Cambrian MTS.

New agreements are expected to be signed for a number of transmission connected stations and jointly owned stations through 2025. Below is a list of projects that have been identified to start in the 2021-2025 rate period that will have new agreements with HONI issued. Forecasted capital contributions by Hydro Ottawa have been estimated, this forecast will only be confirmed once HONI completes the evaluation of projects and a contract is signed.

- Limebank MTS T4 CCRA ($800K)
- Overbrook TS CCRA ($400K)
- Riverdale TS CCRA ($2.4M)
- New East Station CCRA ($6.1M)
- Additional breakers at Bilberry CCRA (TBD)
- Uplands MTS CCRA ($83K)

Hydro Ottawa has a number of agreements signed with HONI. As a result, the company has obligations under these agreements to complete true-up reviews on five-year increments. These reviews may require that payments be made for any shortfall of revenue generated by HONI as a result of the forecasted load from Hydro Ottawa not materializing. While Hydro Ottawa attempts to maintain the loading committed to in the CCRA agreements, shortfalls do occur. Table 8.33 outlines the existing CCRA contracts that have true-up reviews over the 2021-2025 period.

Table 8.33 – CCRA True-ups Schedule

Project Name	2021	2022	2023	2024	2025
A6R Upgrade				X	
Hawthorne Transformer Upgrade				X	
Overbrook Transformer Upgrade		X			
Limebank MTS T3				X	
Orleans TS Feeder				X	
Terry Fox MTS			X		

8.5.3.2. Buildings-Facilities

The Buildings-Facilities Program anticipates minimal investments in capital work relating to substations.

8.5.3.3. Customer Service

The Customer Service Capital Program is mainly forecasted for annual enhancement to meet regulatory requirements and business needs. No major upgrades are required over the next five years, except for a Meter Data System upgrade in 2021. Details on projects under the Customer Service Budget Program can be found in Attachment 2-4-3(E): Material Investments .

8.5.3.4. ERP Solution

Details on projects under the ERP Solution Program can be found in Attachment 2-4-3(E): Material Investments.

8.5.3.5. Fleet

Details on projects under the Fleet Replacement Program can be found in Attachment 2-4-3(F): Fleet Replacement Program.

8.5.3.6 IT New and Life Cycle

Details on projects under the IT New and Life Cycle Programs can be found in Attachment 2-4-3 (E): Material Investments.

8.5.3.7. Operation Initiatives

Details on projects under the Operations Initiatives can be found in Attachment 2-4-3(E): Material Investments.

8.5.3.8. Tools

Tools spending will be consistent with historical levels.

1

GLOSSARY to the DSP

CAIDI	Customer Average Interruption Duration Index
CCRA	Connection & Cost Recovery Agreement
CDP	Community Design Plan
CEATI	Centre for Energy Advancement through Technological Innovation
Chapter 5	Ontario Energy Board's Filing Requirements for Electricity Distribution Rate Applications-2018 Edition for 2019 Rate Applications-, Chapter 5, Consolidated Distribution System Plan, July 12th, 2018
CIA	Connection Impact Assessment
CSA	Canadian Standard Association
DC	Direct Current
DER	Distributed Energy Resources
DGA	Dissolved Gas Analysis
DS	Distribution Station
DSC	Distribution System Code
DSP	Distribution System Plan
ECA	Electrical Contractors Association
ESA	Electrical Safety Authority
ERF	Energy Resource Facility
FEMI	Feeders Experiencing Multiple Interruptions
FIT	Feed-In-Tariff
GEA	Green Energy Act
GIS	Geographic Information System
GTAP	Grid Transformation Action Plan
HCI	Hydroelectric Contract Initiative
HESOP	Hydroelectric Standard Offer Program
HONI	HONI Networks Inc.
Hydro Ottawa	Hydro Ottawa Limited
HVDS	High Voltage Distribution Station
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
IR	Infrared
IRRP	Integrated Regional Resource Planning
ITIC	Information Technology Industry Council
KPI	Key Performance Indicator
LDC	Local Distribution Company
LoS	Loss of Supply
LRT	Light Rail Transit
LTR	Limited Time Rating
O&M	Operation & Maintenance
OEB	Ontario Energy Board
OM&A	Operation, Maintenance & Administration
OMS	Outage Management System
ORTAC	Ontario Resource and Transmission Assessment Criteria

PILC	Paper Insulated Lead Cable
PMBOK	Project Management Body of Knowledge
PSUI-CDM	Process and Systems Upgrade initiative - Conservation Demand Management
REG	Renewable Energy Generation
RESOP	Renewable Energy Standard Offer Program
RIP	Regional Infrastructure Planning
RTU	Remote Terminal Units
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SARFI	System Average Root Mean Square (RMS) Variation Frequency Index
SCADA	Supervisory Control And Data Acquisition
SF6	Sulfur Hexafluoride
the City	City of Ottawa
TIM	Testing, Inspection & Maintenance
TOD	Transit Oriented Developments
TS	Transmission Station
UCC	Utility Coordinating Committee
XFMR	Transformer
XLPE	Cross-Linked Polyethylene

1 **Definitions**

10 day Limited Time Rating (LTR)	The maximum loading level that can be applied to a station power transformer over a 10 day period resulting in a 0.1% loss in transformer life
Asset Owner	Shall be the Chief Electricity Distribution Officer or competent delegate. The Asset Owner is responsible for supporting the Asset Management System and providing top level visibility, as well as making high-level strategic decisions and approvals such as approving asset management objectives.
Asset Manager	Shall be the Director, Distribution Engineering and Asset Management supported by the Director, Distribution Operations or a competent delegate. The Asset Manager is responsible for the operation and continual improvement of the Asset Management System, making strategic decisions such as determining the balance of asset cost, risk and performance to meet the asset management objectives.
Asset Management Council	For asset management, the Asset Management Council (AMC) determines: ● the stakeholders that are relevant to the asset management system; ● the requirements and expectations of these stakeholders with respect to asset management; ● the criteria for asset management decision making; and ● the stakeholder requirements for recording financial and non-financial information relevant to asset management.
Budget Program	A grouping of similar projects that address the same assets and primary drivers.
Capital Program	A grouping of Budget Programs that have a similar asset type which are grouped on a meaningful basis for management reporting and are associated with the OEB Investment Categories.
Cold Load Pick Up	The operation of restoring power to equipment that has been without power for a period of time and thus will require additional current for the equipment restart
Corrective Maintenance	Activities aimed at fixing discovered issues of an asset
Distribution Assets	All infrastructure and equipment owned by Hydro Ottawa outside of the station used to distribute power to customers
Distribution Station (DS)	A sub-transmission (44kV or 13.2kV) connected station that steps down voltage to a distribution level (<44kV)
High Voltage Distribution Station (HVDS)	A transmission (≥50kV) connected station that steps down voltage to a distribution or sub-transmission level (<50kV)
Key Performance Indicator (KPI)	A measure of continuous improvement in asset management planning, capital investment planning and in customer oriented performance
Maintenance Program	A set of planned activities which improve the condition of Hydro Ottawa's assets
Measures	A quantifiable unit used to identify KPIs
Overhead	All infrastructure and equipment used to distribute power to customers that is supported above ground level by a series of poles
Predictive Maintenance	Activities that are used to determine the condition of an asset in order to predict when maintenance or replacement should be performed

Preventative Maintenance	Activities that are regularly performed on equipment to lessen the likelihood of it failing
Program	An activity plan that includes multiple subprojects
Project	A specific plan carried out to address a need
Station Assets	All infrastructure and equipment owned by Hydro Ottawa inside the station yard used to convert transmission voltages to distribution voltages
Transmission Station (TS)	A transmission (≥50kV) connected station that steps down voltage to a lower transmission voltage (≥50kV)
Underground	All infrastructure and equipment used to distribute power to customers that is located beneath ground level

1 ## Appendix A: Chapter 5 Filing Requirements to DSP Cross-reference

OEB Chapter 5 Filing Requirements Section		Hydro Ottawa DSP Section	
5.2	**Distribution System Plans**		
5.2	Cross Reference Table from DSP to Chapter 5 Requirements		Appendix A
5.2.1	**Distribution System Plan overview**	**1.0**	**Distribution System Plan Background**
		1.1	Introduction
		1.2	Overview of the document
5.2.1 a)	Key Elements of the DSP	1.3	Key Elements of the DSP
5.2.1 b)	Customers' preferences and expectations	1.6	Overview of Customer's Preferences and Expectations
5.2.1 c)	Sources of Cost Savings	1.7	Sources of Cost Savings and Planning Coordination
5.2.1 d)	DSP Period	1.4	DSP Period
5.2.1 e)	Vintage of Information	1.5	Vintage of Information
5.2.1 f)	Asset Management Process Updates	1.8	Changes in the DSP
5.2.1 g)	Aspects Contingent on Ongoing Activities or Future Events	1.9	Aspects Contingent on Ongoing Activities or Future Events
5.2.1 h)	Projects addressing the goals of the LTEP	1.11	Grid Modernization
5.2.2	Coordinated planning with third parties	1.1	Coordination with Third Parties
5.2.2 a)	Consultations	1.10.1	Customer Consultations
5.2.2 b)	Deliverables	1.1	Coordination with Third Parties
5.2.2 c)	Relevant material documents		Appendix E: Integrated Regional Planning -Load Forecast
5.2.2 d)	IESO Letter of Comment – HOL's REG Investments Plan	1.10.4	Energy Resource Facility Generation Investment Coordination
5.2.3	**Performance measurement for continuous improvement**	**4.0**	**Performance Measurement for Continuous Improvement**
5.2.3 a)	Distribution System Planning Process Performance Indicators	4.1	Distribution System Planning Process Key Performance Indicators
5.2.3 b)	Unit cost metrics for capital expenditures and O&M	4.2	Unit Cost Metrics
5.2.3 c)	Performance Summary	4.3	Historical Reliability Performance Analysis

5.2.3 d)	Effect of Performance Indicators on the DSP	4.4	Historical Performance Impact on DSP
5.2.4	Realized efficiencies due to smart meters	4.5	Realized Efficiencies Due to Smart Meters
5.3	Asset Management Process	5.1	Asset Management Process
5.3.1	Asset management process overview	5.1	Asset Management Process
5.3.1 a)	**Asset Management Objectives**	**3.0**	**Asset Management Strategy & Objectives**
5.3.1 b)	Asset Management Process Components	5.1	Asset Management Process
5.3.2	**Overview of assets managed**	**2.0**	**Overview of the Distribution System**
5.3.2 a)	Features of the Distribution Service Area	2.1	Features of the Distribution Service Area
		2.3	Area Consideration
		2.4	Current and Future Climate
5.3.2 b)	System Configuration	2.2	System Configuration
5.3.2 c)	Asset Demographics and Condition	6.1	Asset Demographics and Condition
5.3.2 d)	Capacity of the Existing System Assets	7.1	Capacity of the Existing Assets
		7.2	Ability to Connect New Load
5.3.3	Asset lifecycle optimization policies and practices	6.2	Asset Lifecycle Optimization Policies & Practices
5.3.3 a)	Asset Replacement and Refurbishment	6.2.1	Asset Replacement and Refurbishment Policies
5.3.3 b)	Asset Life Cycle Risk Management	6.3	Asset Lifecycle Risk Management
5.3.4	System Capability assessment for renewable energy generation	7.3.1	System Capability Assessment for Energy Resource Facilities
5.3.4 a)	Connected Renewable generators over 10kW	7.3.1.1	Existing Facilities over 10kW
5.3.4 b)	Renewable generation Forecast	7.3.2	Energy Resource Facilities Forecast
5.3.4 c)	Capacity of the System to Connect REG	7.3.5	Energy Resource Facility Connection Capacity
5.3.4 d)	System Constraints	7.3.4	System Constraints for Connecting New Energy Resource Facilities
5.3.4 e)	Constraints for an Embedded distributor	7.3.6	Constraints for Embedded Distributors
5.4	**Capital Expenditure Plan**	**8.0**	**Capital Expenditure Plan**
5.4 a)	Customer Engagement Activities	5.4	Customer Engagement Activities
5.4 b)	System Development Expectations	8.1.6	System Development Expectations

5.4.1	Capital expenditure planning process overview	5.2	Capital Expenditure Process
5.4.1 a)	Analytics tools and Risk Management Methods	5.2.2	Project Evaluation
5.4.1 b)	Prioritization Process, Tools and Methods	5.2.4	Project Optimization
5.4.1 c)	Prioritization of REG Investments		
5.4.1 d)	Non-Distribution System Alternatives	5.3	Non-distribution System Activities
5.4.1 e)	Strategy for Grid Modernization	5.5	Implementation of Cost Effective Modernization of the Distribution System
5.4.1 f)	Rate-Funded Activities to Defer Distribution Infrastructure	8.1.4	Non-distribution Activities
5.4.2	Capital expenditure summary	8.1	Overall Capital Investments
5.4.2	System Access	8.2	System Access
5.4.2	System Renewal	8.3	System Renewal
5.4.2	System Service	8.4	System Service Investments
5.4.2	General Plant	8.5	General Plant
5.4.3	Justifying capital expenditures	8.1.1	Historical and Forecasted Expenditure Comparison
		8.1.2	Impact O&M Cost
		8.1.3	Drivers by Investment Categories
5.4.3.1	Overall plan	8.1	Overall Capital Investments
5.4.3.2	Material investments	Att. 2-4-3(E)	Material Investments

Appendix B: Hydro Ottawa Station Table

The following Hydro Ottawa and HONI owned stations in the table below are used to supply Hydro Ottawa's customers. The stations are herein referenced by the nomenclature (Hydro Ottawa Station Name) used by Hydro Ottawa.

Hydro Ottawa Station Name	Designation	Owner	Primary/Secondary Voltage (kV)
Albion TA	HVDS	HONI-Hydro Ottawa	230/13.2
Albion UA	DS	Hydro Ottawa	13.2/4.16
Augusta UD	DS	Hydro Ottawa	13.2/4.16
Bantree AL	DS	Hydro Ottawa	13.2/4.16
Barrhaven DS	DS	Hydro Ottawa	44/8.32
Bayshore DS	DS	Hydro Ottawa	44/8.32
Bayswater UJ	DS	Hydro Ottawa	13.2/4.16
Beaconhill MS	DS	Hydro Ottawa	44/8.32
Beaverbrook	DS	Hydro Ottawa	44/12.43
Beckwith DS	DS	HONI	44/27.6
Beechwood UB	DS	Hydro Ottawa	13.2/4.16
Bells Corner DS	DS	Hydro Ottawa	44/8.32
Bilberry TS	HVDS	HONI-Hydro Ottawa	115/27.6
Blackburn MS	DS	Hydro Ottawa	44/8.32
Borden Farm DS	DS	Hydro Ottawa	44/8.32
Bridlewood MS 27kV	HVDS DS	Hydro Ottawa	115/27.6 44/27.6
Bridlewood MS 8kV	HVDS DS	Hydro Ottawa	115/8.32 44/8.32
Bronson SB	DS	Hydro Ottawa	13.2/4.16
Brookfield AF	DS	Hydro Ottawa	13.2/4.16
Cahill AN	DS	Hydro Ottawa	13.2/4.16
Cambridge AM	DS	Hydro Ottawa	13.2/4.16
Carling SM	DS	Hydro Ottawa	13.2/4.16
Carling TM	HVDS	HONI-Hydro Ottawa	115/13.2
Casselman MS	DS	Hydro Ottawa	44/8.32
Centrepointe DS	HVDS	Hydro Ottawa	115/8.32
Church AA	DS	Hydro Ottawa	13.2/4.16

Clifton UL	DS	Hydro Ottawa	13.2/4.16
Clyde UC	DS	Hydro Ottawa	13.2/4.16
Cyrville MTS	HVDS	Hydro Ottawa	115/27.6
Dagmar AC	DS	Hydro Ottawa	13.2/4.16
Eastview UT	DS	Hydro Ottawa	13.2/4.16
Edwin UV	DS	Hydro Ottawa	13.2/4.16
Ellwood MTS	HVDS	Hydro Ottawa	230/13.2
Epworth DS	HVDS	Hydro Ottawa	115/8.32
Fallowfield MS	HVDS	Hydro Ottawa	115/27.6
Fisher AK	DS	Hydro Ottawa	13.2/4.16
Florence UF	DS	Hydro Ottawa	13.2/4.16
Gladstone UX	DS	Hydro Ottawa	13.2/4.16
Hawthorne TS	HVDS	HONI	230/44
Henderson UN	DS	Hydro Ottawa	13.2/4.16
Hillcrest AH	DS	Hydro Ottawa	13.2/4.16
Hinchey TH	HVDS	HONI-Hydro Ottawa	115/13.2
Holland SH	DS	Hydro Ottawa	13.2/4.16
Janet King DS 28kV	DS	Hydro Ottawa	44/27.6
Janet King DS 8kV	DS	Hydro Ottawa	44/8.32
Jockvale DS	DS	Hydro Ottawa	44/8.32
Kanata MTS	HVDS	Hydro Ottawa	230/27.6
King Edward SK	DS	Hydro Ottawa	13.2/4.16
King Edward TK	HVDS	HONI-Hydro Ottawa	115/13.2
Langs AP	DS	Hydro Ottawa	13.2/4.16
Leitrim MS	DS	Hydro Ottawa	44/27.6
Limebank MS	HVDS	Hydro Ottawa	115/27.6
Lincoln Heights TD	HVDS	HONI-Hydro Ottawa	115/13.2
Lisgar TL	HVDS	HONI-Hydro Ottawa	115/13.2
Longfields DS	DS	Hydro Ottawa	44/27.6
Manordale DS	HVDS	Hydro Ottawa	115/8.32
Marchwood MS	HVDS	Hydro Ottawa	115/27.6
McCarthy AQ	DS	Hydro Ottawa	13.2/4.16
Merivale MTS	HVDS	Hydro Ottawa	115/8.32
Moulton MS	HVDS	Hydro Ottawa	115/27.6
Munster DS	DS	Hydro Ottawa	44/8.32
Nepean AB	DS	Hydro Ottawa	13.2/4.16
Nepean TS	HVDS	HONI	230/44

Orleans TS	HVDS	HONI	230/27.6 115/27.6
Overbrook SO	DS	Hydro Ottawa	13.2/4.16
Overbrook TO	HVDS	HONI-Hydro Ottawa	115/13.2
Parkwood Hills DS	DS	Hydro Ottawa	44/8.32
Playfair AJ	DS	Hydro Ottawa	13.2/4.16
Q.C.H. DS	DS	Hydro Ottawa	44/8.32
Queens UQ	DS	Hydro Ottawa	13.2/4.16
Richmond North DS	DS	Hydro Ottawa	44/8.32
Richmond South DS	HVDS	Hydro Ottawa	115/8.32
Rideau Heights DS	DS	Hydro Ottawa	44/8.32
Riverdale SR	DS	Hydro Ottawa	13.2/4.16
Riverdale TR	HVDS	HONI-Hydro Ottawa	115/13.2
Russell TB	HVDS	HONI-Hydro Ottawa	115/13.2
Shillington AD	DS	Hydro Ottawa	13.2/4.16
Slater SA	DS	Hydro Ottawa	13.2/4.16
Slater TS	HVDS	HONI-Hydro Ottawa	115/13.2
South Gloucester DS	HVDS	HONI	115/8.32
South March TS	HVDS	HONI	230/44
South March DS	DS	Hydro Ottawa	44/12.43
Stafford Road DS	DS	Hydro Ottawa	44/8.32
Startop MS	DS	Hydro Ottawa	44/8.32
Terry Fox MTS	HVDS	Hydro Ottawa	230/27.6
Uplands MS	HVDS	Hydro Ottawa	115/27.6
Urbandale AE	DS	Hydro Ottawa	13.2/4.16
Vaughan UG	DS	Hydro Ottawa	13.2/4.16
Walkley UZ	DS	Hydro Ottawa	13.2/4.16
Woodroffe DS	DS	Hydro Ottawa	44/8.32
Woodroffe TW	HVDS	HONI-Hydro Ottawa	115/13.2

Appendix C: Capital Budget Restructure

	OLD		NEW	
	Capital Program	**Budget Program**	**Capital Program**	**Budget Program**
SYSTEM ACCESS	Plant Relocation	Plant Relocation & Upgrade	Plant Relocation	Plant Relocation & Upgrade
	Residential	Residential Subdivision	Residential	Residential Subdivision
	Commercial	Commercial Development	Commercial	Commercial Development
	System Expansion	System Expansion	System Expansion	System Expansion
				Long Term Load Transfers
				PWGSC – Asset Transfer
	Embedded Generation	Embedded Generation	Embedded Generation	Embedded Generation
	Infill & Upgrade	Infill Service (Res & Small Com)	Infill & Upgrade	Infill Service (Res & Small Com)
				ESA Flash Notice
	Damage to Plant	Damage to Plant	Metering Upgrades	Metering - Reverification
				Suite Metering
SYSTEM RENEWAL	Station Assets	Stations Transformer Replacement	Station Assets Renewal	Station Transformer Renewal
		Stations Switchgear Replacement		Station Switchgear Renewal
		Stations Plant Failure		**Station Battery Renewal**
	Stations Refurbishment	Stations Enhancements		**Station P&C Renewal[1]**
				Station Ground Grid Renewal[1]
				Station Minor Assets Renewal[1]
				Station Major Rebuild[1]

	Distribution Assets	Pole Replacement	OH Distribution Assets Renewal	Pole Renewal
		Insulator Replacement		Insulator Replacement
		Elbow & Insert Replacement		OH Transformer Renewal
		Distribution Transformer Replacement		OH Switch/Recloser Renewal
		Vault Rehab or Removal	UG Distribution Assets Renewal	Elbow & Insert Replacement
		Civil Rehabilitation		Vault Renewal
		Cable Replacement		Civil Renewal
		Switchgear New & Rehab		Cable Renewal
		O/H Equipment New & Rehab		UG Switchgear Renewal
				Cable Rejuvenation[1]
				UG Transformer Renewal 1
		Distribution Plant Failure	Corrective Renewal	**Damage to Plant**[2]
				Emergency Renewal[1]
				Critical Renewal[1]
	Distribution Enhancement	System Voltage Conversion		
	Metering	Remote Disconnected Smrt Meter		
SYSTEM	Stations Capacity	Stations New Capacity	Capacity Upgrades	Stations Capacity Upgrades
	Distribution Enhancement	Line Extensions		Distribution Capacity Upgrades
		System Reliability	Distribution Enhancement	**Distribution System Reliability**[1]
		Distribution Enhancements		**System Voltage Conversion**[2]
	Automation	Distribution Automation		**Distribution**

SERVICE				**Enhancements**[2]
		Substation Automation	Grid Technologies	SCADA Upgrades
		SCADA Upgrades		RTU Upgrades
		RTU Additions		Communication Infrastructure
			Stations Enhancements	**Stations Enhancements**[2]
				Station Reliability[1]
			Metering	**Remote Disconnected Smrt Meter**[2]
GENERAL PLANT	HONI Payments	HONI Payments	HONI Payments	HONI Payments
	Facilities Management	Facilities Management	Facilities Management	Facilities Management
	Fleet Replacement	Fleet Replacement	Fleet Replacement	Fleet Replacement
	Tools Replacement	Tools Replacement	Tools Replacement	Tools Replacement
	IT Life Cycle & On-Going Enhancements	IT Life Cycle & On-Going Enhancements	IT Life Cycle & On-Going Enhancements	IT Life Cycle & On-Going Enhancements
	IT New Initiatives	IT New Initiatives	IT New Initiatives	IT New Initiatives
	ERP System	ERP System	ERP System	ERP System
	Customer Service	Customer Service	Customer Service	Customer Service
	Operation Initiatives	Operation Initiatives	Operation Initiatives	Operation Initiatives
	Facilities Renewal Program (FRP)	FacilitiesRenewal Program(FRP)		

Table Notes:

1 - New Programs

2 - Programs relocated

Appendix D: Integrated Regional Planning-Load Forecast

Pocket	Station	10-Day LTR (MVA)	10-Day LTR (MW) @0.9	2017 Net Coincident Demand	Starting Point of Forecast (Gross, Median Weather)	Net Demand Forecast with Extreme Weather Conditions																			
						2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	25	22.5	9.8	11.2	14.6	14.5	14.4	15.4	15.3	16.3	16.2	16.7	19.1	20.9	21.5	21.3	21.2	21.0	20.9	20.8	20.8	20.8	20.9	21.0
	Marchwood MTS	33	29.7	39.2	44.8	59.5	65.0	67.0	68.5	69.8	70.5	71.0	71.3	71.5	70.8	70.2	69.5	68.9	68.5	68.1	67.9	67.9	67.9	67.9	67.9
	Fallowfield DS	25	22.5	39.5	47.1	48.7	43.0	49.9	53.1	23.3	26.6	27.1	28.0	28.2	29.1	29.3	31.1	31.4	32.5	32.3	33.1	33.2	33.2	33.2	33.3
	Manotick DS	8.6	7.74	5.6	6.5	6.9	7.7	8.6	9.4	10.3	11.1	11.9	11.8	11.8	11.5	11.6	11.3	11.5	11.3	11.3	11.2	11.3	11.3	11.4	11.3
	Richmond DS	75	67.5	4.5	5.1	7.4	12.6	14.3	18.6	22.7	25.9	27.6	27.3	28.8	28.5	28.3	28.0	27.7	27.5	27.3	27.3	27.2	27.1	27.1	27.2
	Manordale MTS	10	9	8.5	9.7	10.2	10.0	10.0	10.1	10.1	10.1	10.1	10.1	10.2	10.2	10.3	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.3
	Limebank MTS	66	59.4	46.8	53.5	55.8	62.0	74.6	77.5	85.1	78.3	81.4	77.0	79.9	84.5	88.8	93.2	97.5	101.8	105.3	108.4	110.8	113.3	115.9	118.5
	Marionville DS	15	13.5	10.3	11.8	12.6	12.6	12.8	13.0	13.1	13.2	13.2	13.3	13.2	13.1	13.0	13.0	12.9	12.9	12.9	12.9	13.0	13.0	13.1	13.1
	Uplands MTS	33	29.7	19.8	22.6	24.5	27.6	29.8	31.3	38.0	43.1	48.1	57.4	57.3	57.2	57.5	57.8	57.8	57.8	57.9	58.1	58.5	58.8	59.3	59.3
	South Gloucester DS	7.5	6.75	3.8	4.3	4.6	4.6	4.7	4.8	4.8	4.8	4.8	4.8	4.9	4.8	4.8	4.8	4.8	4.7	4.7	4.7	4.7	4.7	4.8	4.8
	Greely DS	30	27	16.0	18.2	19.3	19.5	19.8	20.1	20.5	20.7	20.9	21.0	21.0	20.9	21.0	21.0	20.9	20.9	20.9	21.1	21.3	21.4	21.8	22.0
	Russell DS	7.5	6.75	3.4	3.9	4.1	4.2	4.3	4.3	4.4	4.4	4.3	4.5	4.4	4.4	4.3	4.3	4.3	4.3	4.3	4.3	4.2	4.3	4.3	4.3
	Centerpoint MTS	14	12.6	13.8	15.8	16.6	16.8	16.7	16.7	16.7	16.7	16.6	16.4	16.3	16.1	16.1	15.9	15.7	15.6	15.5	15.5	15.5	15.5	15.5	15.5
	Merivale TS	25	22.5	14.4	16.5	17.4	17.1	19.9	20.0	20.0	20.2	20.6	20.9	20.8	21.1	21.2	21.0	20.7	20.5	20.3	20.4	20.3	21.1	21.1	21.1
	National Aeronautical CTS	1.2	1.08	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	Kanata MTS	54.2	48.78	51.6	59.0	64.8	67.1	68.8	72.5	72.5	72.2	71.7	71.3	70.6	70.9	70.7	70.0	69.4	69.0	68.8	68.7	68.6	68.6	68.6	68.7
	South March TS	122.3	110.07	78.0	89.2	93.9	94.4	95.2	95.8	106.2	106.0	105.0	104.6	103.9	102.6	100.3	98.2	96.8	96.5	96.4	96.8	97.1	97.4	98.1	98.6
	Nepean TS	160.6	144.54	131.9	150.8	157.9	157.2	142.5	146.7	138.4	137.9	138.0	137.1	135.9	134.5	133.2	132.1	131.0	130.2	129.5	129.5	129.4	129.5	129.6	129.7
	Terry Fox MTS	90	81	49.7	56.8	63.4	68.4	69.9	71.9	73.8	75.4	76.8	78.1	79.3	80.4	81.5	82.6	83.6	84.7	85.9	85.7	85.7	85.6	85.6	85.7
	South Nepean TS	TBD	TBD	0.0	0.0	0.0	0.0	0.0	0.0	39.2	43.2	47.0	49.7	53.2	56.4	58.7	61.1	63.9	66.3	67.7	69.4	72.1	75.2	75.3	75.3
Outer Ottawa West*	Almonte	TBD	TBD	0.0	N/A	47.9	47.9	50.1	46.1	47.0	47.6	48.0	48.0	47.9	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8
Merivale Pocket TOTAL				**547**	**627**	**683**	**705**	**724**	**750**	**785**	**797**	**813**	**822**	**831**	**838**	**843**	**847**	**851**	**857**	**861**	**866**	**872**	**880**	**884**	**888**
Downtown	Nepean Epworth TS	14	12.6	10.5	11.7	12.1	12.0	11.9	11.9	11.8	11.9	11.8	11.7	11.5	11.4	11.3	11.2	11.0	11.1	11.0	10.9	10.9	10.9	10.9	10.9
	Carling TS	106	95.4	78.9	88.1	94.4	95.4	97.0	98.1	98.7	98.5	102.9	102.6	101.7	100.8	100.3	99.8	99.2	98.5	97.9	97.7	97.5	97.6	97.6	97.6
	Albion TS	79.8	71.82	38.1	42.5	45.6	45.9	45.6	47.9	47.8	47.7	47.5	56.2	55.7	55.1	54.7	54.2	53.7	53.4	53.0	52.8	52.8	52.8	52.8	52.9
	Woodroffe TS	101	90.9	26.7	29.8	33.1	32.7	33.2	34.1	34.7	35.1	51.6	51.1	50.6	50.1	49.6	49.2	48.7	48.4	48.1	48.0	47.8	47.9	47.9	47.9
	Hinchey TS	96	86.4	42.4	47.3	49.9	51.6	56.0	41.0	43.2	44.9	47.4	49.9	50.8	51.8	52.8	53.7	54.7	55.4	56.9	57.7	58.9	60.0	61.2	62.4
	Slater TS	215	193.5	102.1	114.0	128.1	128.0	126.8	126.6	126.7	126.5	125.7	124.6	123.3	121.8	120.3	119.3	118.1	118.0	117.0	116.8	116.7	116.6	116.6	116.7
	Lisgar TS	83	74.7	55.6	62.1	72.5	71.8	72.1	64.8	71.5	71.7	72.7	72.5	72.4	74.8	74.5	74.3	74.0	74.9	74.7	75.0	75.5	75.9	76.5	77.0
	King Edward TS	91.5	82.35	75.8	84.6	93.6	92.8	94.0	94.8	95.6	96.0	96.0	96.2	95.9	95.6	95.3	95.1	95.0	94.3	93.6	93.4	93.3	93.3	93.3	93.4
	Russell TS	77.8	70.02	68.8	76.8	81.1	83.0	86.9	86.8	87.1	87.0	86.8	86.0	85.1	84.1	83.2	82.5	81.6	81.0	80.5	80.8	80.7	80.7	80.8	80.8
	Overbrook TS	105.6	95.04	57.8	64.5	69.0	73.2	76.4	78.7	80.4	82.6	84.4	85.9	86.0	86.2	86.3	86.8	86.7	87.4	87.7	88.8	89.4	90.6	91.5	92.6
	Riverdale TS	117.6	105.84	70.8	79.1	87.6	86.5	87.3	89.3	91.1	92.1	92.2	92.4	92.2	92.0	91.8	91.7	91.6	92.8	92.8	93.2	94.0	94.5	95.2	95.9
	Albion TS	99.4	89.46	52.2	58.3	60.0	59.6	59.3	59.6	59.7	59.6	59.4	59.1	58.8	58.3	57.9	57.5	57.1	56.9	56.8	56.9	56.9	57.1	57.3	57.4
	Ellwood TS	50	45	34.4	38.4	39.4	40.0	40.4	41.6	42.4	42.9	42.7	42.4	42.0	41.7	41.2	40.9	40.6	40.3	40.0	40.0	39.9	39.9	40.0	40.5
Downtown TOTAL				**714**	**797**	**866**	**873**	**887**	**875**	**891**	**896**	**921**	**931**	**926**	**924**	**919**	**916**	**912**	**912**	**910**	**912**	**914**	**918**	**922**	**926**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	94.9	85.41	35.3	40.6	42.7	42.4	42.7	49.1	52.8	52.7	52.3	51.9	51.5	51.0	50.5	50.0	49.6	49.3	49.3	49.3	49.3	49.3	49.3	49.4
	Orleans TS	130.3	117.27	88.2	101.5	106.0	107.6	110.0	112.0	114.6	117.0	118.4	119.7	121.8	123.2	123.2	123.2	123.0	122.7	122.4	122.9	123.5	124.1	124.5	124.9
	Cyrville MTS	50	45	20.9	24.0	24.8	25.1	28.1	33.6	36.8	39.8	43.9	45.0	46.4	47.2	47.8	48.4	48.8	49.5	50.1	50.9	51.7	52.9	54.0	55.0
	Moulton MTS	33	29.7	23.6	27.2	28.3	28.1	29.8	31.7	33.6	35.3	35.1	34.8	34.5	34.2	33.9	33.5	33.3	33.0	32.8	32.7	32.7	32.7	32.7	32.7
	Wilhaven DS	20	18	3.3	3.9	3.4	3.4	3.5	3.6	3.6	3.5	3.6	3.7	3.6	3.6	3.5	3.6	3.5	3.5	3.8	3.9	3.9	4.0	4.1	4.1
	Navan DS	15	13.5	3.6	4.2	3.6	3.7	3.7	3.8	3.8	3.9	3.9	3.8	4.0	3.9	3.9	3.9	3.9	3.8	4.2	4.2	4.2	4.3	4.5	4.7
	Cumberland DS	7.5	6.75	4.7	5.4	5.6	5.6	5.7	5.8	5.9	5.9	6.0	5.9	6.1	6.1	6.4	6.3	6.4	6.4	6.5	6.6	6.7	6.7	6.8	6.8
	Hawthorne TS	152	136.8	88.6	102.0	126.0	124.4	123.5	125.7	132.5	135.8	135.9	136.9	137.6	139.9	142.6	143.9	148.3	149.4	150.3	152.4	155.2	157.5	160.0	161.4
	National Research TS	28	25.2	5.7	6.5	9.3	9.2	9.1	9.1	9.1	9.1	9.0	9.0	9.1	9.1	9.2	9.1	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Outer Ottawa East*	Clarence DS	3.7	3.33	2.4	2.8	2.9	2.9	2.9	3.0	3.0	3.1	3.1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.1
	Rockland DS	14.3	12.87	6.9	8.0	8.3	8.2	8.3	8.3	8.4	8.5	8.5	8.5	8.5	8.4	8.4	8.4	8.4	8.3	8.3	8.3	8.4	8.4	8.4	8.5
	Rockland East DS	8.6	7.74	10.3	11.9	12.5	12.6	12.8	12.9	13.1	13.2	13.2	13.1	13.1	13.0	13.0	13.0	12.9	12.9	12.9	12.9	12.9	13.0	13.1	13.1
	Wendover TS	15	TBD	10.1	11.7	12.0	8.0	8.1	9.7	9.9	10.2	10.2	10.1	10.2	10.3	10.3	10.3	10.3	9.9	10.2	10.3	10.4	10.6	10.7	14.8
	Hawkesbury MTS	TBD	TBD	9.5	10.9	11.8	11.8	11.9	11.9	12.0	12.0	12.0	12.1	12.1	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Hawthorne Pocket TOTAL				**274**	**315**	**350**	**349**	**356**	**374**	**393**	**403**	**408**	**411**	**415**	**418**	**421**	**422**	**426**	**427**	**429**	**432**	**436**	**441**	**445**	**448**
Ottawa Area Sub-region TOTAL				**1535**	**1740**	**1899**	**1927**	**1967**	**2000**	**2068**	**2097**	**2142**	**2163**	**2171**	**2180**	**2183**	**2185**	**2189**	**2196**	**2200**	**2211**	**2223**	**2238**	**2251**	**2262**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals.

Pocket	Station	10-Day LTR (MVA)	10-Day LTR (MW) @0.9	2017 Net Coincident Demand	Starting Point of Forecast (Gross, Median Weather)	Net Demand Forecast with Extreme Weather Conditions																			
						2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	25	22.5	9.8	11.2	14.6	14.5	14.4	15.5	15.4	16.4	16.3	16.9	19.4	21.4	22.2	22.0	22.0	21.9	21.8	21.8	21.8	21.8	21.9	21.9
	Marchwood MTS	33	29.7	39.2	44.8	59.5	65.0	67.0	68.8	70.1	70.8	71.5	72.2	72.8	72.5	72.4	72.0	71.8	71.5	71.3	71.1	71.1	71.1	71.2	71.2
	Fallowfield DS	25	22.5	39.5	47.1	48.7	43.0	49.9	53.3	23.4	26.8	27.3	28.3	28.7	29.8	30.2	32.2	32.6	33.9	33.8	34.7	34.7	34.8	34.8	34.8
	Manotick DS	8.6	7.74	5.6	6.5	6.9	7.7	8.6	9.5	10.4	11.2	12.1	12.1	12.1	12.0	12.2	12.1	12.4	12.2	12.3	12.3	12.4	12.4	12.5	12.4
	Richmond DS	75	67.5	4.5	5.1	7.4	12.6	14.3	18.6	22.8	26.0	27.8	27.7	29.5	29.4	29.5	29.3	29.2	29.1	29.0	29.0	28.9	28.9	28.9	28.9
	Manordale MTS	10	9	8.5	9.7	10.2	10.0	10.0	10.1	10.1	10.1	10.2	10.2	10.3	10.4	10.5	10.5	10.5	10.6	10.6	10.6	10.6	10.6	10.7	10.7
	Limebank MTS	66	59.4	46.8	53.5	55.8	62.0	74.6	77.8	85.5	78.6	82.0	77.9	81.3	86.5	91.6	96.5	101.5	106.2	110.1	113.4	116.0	118.7	121.4	124.1
	Marionville DS	15	13.5	10.3	11.8	12.6	12.6	12.8	13.1	13.2	13.3	13.4	13.6	13.7	13.8	13.9	13.9	14.0	14.1	14.1	14.2	14.3	14.4	14.5	14.5
	Uplands MTS	33	29.7	19.8	22.6	24.5	27.6	29.8	31.5	38.2	43.3	48.5	58.1	58.4	58.8	59.5	60.2	60.4	60.6	60.9	61.2	61.6	62.0	62.5	62.5
	South Gloucester DS	7.5	6.75	3.8	4.3	4.6	4.6	4.7	4.8	4.8	4.8	4.9	4.9	5.0	4.9	4.9	5.0	5.0	5.0	4.9	4.9	5.0	5.0	5.0	5.0
	Greely DS	30	27	16.0	18.2	19.3	19.5	19.8	20.2	20.6	20.8	21.1	21.3	21.5	21.6	21.9	22.1	22.2	22.3	22.4	22.5	22.8	23.0	23.4	23.6
	Russell DS	7.5	6.75	3.4	3.9	4.1	4.2	4.3	4.3	4.4	4.4	4.4	4.6	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.5	4.5	4.6	4.6	4.6
	Centerpoint MTS	14	12.6	13.8	15.8	16.6	16.8	16.7	16.8	16.8	16.8	16.7	16.6	16.6	16.5	16.6	16.5	16.4	16.3	16.3	16.2	16.3	16.3	16.3	16.3
	Merivale TS	25	22.5	14.4	16.5	17.4	17.1	19.9	20.2	20.2	20.3	20.9	21.4	21.5	22.1	22.6	22.6	22.5	22.5	22.4	22.5	22.5	23.4	23.4	23.4
	National Aeronautical CTS	1.2	1.08	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	Kanata MTS	54.2	48.78	51.6	59.0	64.8	67.1	68.8	72.8	72.8	72.5	72.3	72.2	71.9	72.7	73.1	72.7	72.5	72.2	72.3	72.2	72.2	72.2	72.2	72.3
	South March TS	122.3	110.07	78.0	89.2	93.9	94.4	95.2	96.3	106.8	106.6	106.1	106.3	106.6	106.3	105.0	103.5	102.8	103.0	103.4	103.8	104.3	104.8	105.5	106.1
	Nepean TS	160.6	144.54	131.9	150.8	157.9	157.2	142.5	147.4	139.0	138.6	139.3	139.0	138.8	138.5	138.4	137.9	137.6	137.2	136.9	137.1	137.1	137.3	137.4	137.5
	Terry Fox MTS	90	81	49.7	56.8	63.4	68.4	69.9	72.2	74.1	75.7	77.4	79.0	80.7	82.3	84.1	85.6	87.1	88.5	90.0	89.8	89.8	89.8	89.8	89.9
	South Nepean TS	TBD	TBD	0.0	0.0	0.0	0.0	0.0	0.0	39.4	43.4	47.5	50.4	54.4	58.0	61.0	63.8	67.1	69.8	71.6	73.4	76.3	79.8	79.8	79.8
Outer Ottawa West*	Almonte	TBD	TBD	0.0	N/A	47.9	47.9	50.1	46.1	47.0	47.6	48.0	48.0	47.9	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8
Merivale Pocket TOTAL				**547**	**627**	**683**	**705**	**724**	**754**	**788**	**801**	**820**	**833**	**848**	**863**	**875**	**884**	**893**	**902**	**909**	**916**	**923**	**931**	**936**	**940**
Downtown	Nepean Epworth TS	14	12.6	10.5	11.7	12.1	12.0	11.9	11.9	11.9	11.9	11.9	11.9	11.8	11.8	11.8	11.7	11.7	11.7	11.7	11.7	11.7	11.6	11.6	11.7
	Carling TS	106	95.4	78.9	88.1	94.4	95.4	97.0	98.6	99.2	98.9	103.8	104.0	103.8	103.8	104.1	104.2	104.1	103.8	103.5	103.3	103.3	103.4	103.4	103.5
	Lincoln Hights TS	79.8	71.82	38.1	42.5	45.6	45.9	45.6	48.1	48.0	47.9	47.9	56.9	56.8	56.6	56.6	56.4	56.1	56.0	55.8	55.6	55.6	55.7	55.7	55.7
	Woodroffe TS	101	90.9	26.7	29.8	33.1	32.7	33.2	34.2	34.9	35.2	52.0	51.8	51.6	51.6	51.4	51.3	51.0	50.9	50.7	50.6	50.5	50.6	50.6	50.6
	Hinchey TS	96	86.4	42.4	47.3	49.9	51.6	56.0	41.3	43.5	45.2	48.1	50.9	52.4	54.0	55.7	57.1	58.6	59.7	61.5	62.5	63.8	65.0	66.3	67.7
	Slater TS	215	193.5	102.1	114.0	128.1	128.0	126.8	127.4	127.6	127.3	127.2	126.9	126.8	126.7	126.6	126.4	126.2	126.9	126.5	126.4	126.4	126.6	126.6	126.6
	Lisgar TS	83	74.7	55.6	62.1	72.5	71.8	72.1	65.2	71.9	72.2	73.4	73.7	74.2	77.4	77.9	78.2	78.4	79.7	79.9	80.2	80.8	81.3	81.9	82.5
	King Edward TS	91.5	82.35	75.8	84.6	93.6	92.8	94.0	95.3	96.1	96.5	97.0	97.6	98.1	98.7	99.3	99.7	100.2	99.9	99.5	99.4	99.3	99.5	99.5	99.5
	Russell TS	77.8	70.02	68.8	76.8	81.1	83.0	86.9	87.3	87.6	87.6	87.7	87.5	87.3	87.2	87.2	87.0	86.7	86.5	86.3	86.7	86.8	86.8	86.9	87.0
	Overbrook TS	105.6	95.04	57.8	64.5	69.0	73.2	76.4	79.1	80.7	83.0	85.1	87.0	87.8	88.8	89.6	90.6	91.1	92.1	92.7	94.0	94.7	96.0	96.9	98.2
	Riverdale TS	117.6	105.84	70.8	79.1	87.6	86.5	87.3	89.8	91.6	92.5	93.0	93.7	94.2	94.7	95.3	95.7	96.2	97.8	98.1	98.6	99.5	100.2	100.9	101.7
	Albion TS	99.4	89.46	52.2	58.3	60.0	59.6	59.3	59.8	60.0	59.9	59.9	59.8	59.9	60.0	60.0	59.9	59.8	59.8	59.9	60.0	60.1	60.4	60.5	60.6
	Ellwood TS	50	45	34.4	38.4	39.4	40.0	40.4	41.8	42.6	43.1	43.0	43.0	42.8	42.8	42.7	42.6	42.5	42.3	42.1	42.1	42.1	42.1	42.2	42.8
Downtown TOTAL				**714**	**797**	**866**	**873**	**887**	**880**	**895**	**901**	**930**	**945**	**948**	**954**	**958**	**961**	**963**	**967**	**968**	**971**	**975**	**979**	**983**	**988**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	94.9	85.41	35.3	40.6	42.7	42.4	42.7	49.3	53.0	52.9	52.7	52.6	52.6	52.4	52.4	52.1	52.0	51.9	51.9	52.0	52.0	52.1	52.1	52.2
	Orleans TS	130.3	117.27	88.2	101.5	106.0	107.6	110.0	112.8	115.5	117.9	120.0	122.3	125.9	129.0	130.9	132.0	133.0	133.7	134.2	135.0	135.9	136.9	137.3	137.8
	Cyrville MTS	50	45	20.9	24.0	24.8	25.1	28.1	33.8	37.0	39.9	44.3	45.5	47.2	48.3	49.3	50.1	50.9	51.7	52.5	53.4	54.2	55.5	56.7	57.7
	Moulton MTS	33	29.7	23.6	27.2	28.3	28.1	29.8	31.8	33.7	35.5	35.4	35.3	35.2	35.2	35.1	34.9	34.8	34.7	34.5	34.5	34.5	34.5	34.5	34.5
	Wilhaven DS	20	18	3.3	3.9	3.4	3.4	3.5	3.6	3.6	3.6	3.7	3.8	3.7	3.7	3.7	3.8	3.8	3.8	4.1	4.2	4.2	4.3	4.4	4.4
	Navan DS	15	13.5	3.6	4.2	3.6	3.7	3.7	3.8	3.8	3.9	3.9	3.9	4.1	4.1	4.1	4.1	4.1	4.1	4.5	4.5	4.5	4.6	4.8	5.0
	Cumberland DS	7.5	6.75	4.7	5.4	5.6	5.6	5.7	5.8	5.9	5.9	6.0	6.0	6.2	6.2	6.5	6.5	6.6	6.6	6.7	6.8	6.9	6.9	7.0	7.0
	Hawthorne TS	152	136.8	88.6	102.0	126.0	124.4	123.5	126.4	133.3	136.6	137.3	139.1	140.9	144.7	148.9	151.2	156.8	158.5	160.2	162.6	165.8	168.3	171.0	172.5
	National Research TS	28	25.2	5.7	6.5	9.3	9.2	9.1	9.1	9.1	9.1	9.1	9.1	9.2	9.3	9.4	9.4	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Outer Ottawa East*	Clarence DS	3.7	3.33	2.4	2.8	2.9	2.9	2.9	3.0	3.0	3.1	3.1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.1
	Rockland DS	14.3	12.87	6.9	8.0	8.3	8.2	8.3	8.3	8.4	8.5	8.5	8.5	8.5	8.4	8.4	8.4	8.4	8.3	8.3	8.3	8.4	8.4	8.4	8.5
	Rockland East DS	8.6	7.74	10.3	11.9	12.5	12.6	12.8	12.9	13.1	13.2	13.2	13.1	13.1	13.0	13.0	13.0	12.9	12.9	12.9	12.9	12.9	13.0	13.1	13.1
	Wendover TS	15	TBD	10.1	11.7	12.0	8.0	8.1	9.7	9.9	10.2	10.2	10.1	10.2	10.3	10.3	10.3	10.3	9.9	10.2	10.3	10.4	10.6	10.7	14.8
	Hawkesbury MTS	TBD	TBD	9.5	10.9	11.8	11.8	11.9	11.9	12.0	12.0	12.0	12.1	12.1	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Hawthorne Pocket TOTAL				**274**	**315**	**350**	**349**	**356**	**376**	**395**	**405**	**412**	**418**	**425**	**433**	**440**	**444**	**452**	**455**	**458**	**462**	**468**	**473**	**477**	**481**
Ottawa Area Sub-region TOTAL				**1535**	**1740**	**1899**	**1927**	**1967**	**2010**	**2079**	**2107**	**2163**	**2195**	**2221**	**2250**	**2273**	**2289**	**2307**	**2324**	**2336**	**2349**	**2365**	**2383**	**2397**	**2409**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals.

Pocket	Station	10-Day LTR (MVA)	10-Day LTR (MW) @0.9	2017 Net Coincident Demand UPDATED	Starting Point of Forecast (Gross, Median Weather)	Net Demand Forecast with Median Weather Conditions																			
						2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	25	22.5	9.8	11.2	13.5	13.4	13.3	14.2	14.1	15.0	14.9	15.4	17.6	19.2	19.8	19.6	19.5	19.4	19.2	19.2	19.2	19.1	19.3	19.3
	Marchwood MTS	33	29.7	39.2	44.8	54.8	59.9	61.7	63.1	64.3	64.9	65.4	65.7	65.9	65.2	64.7	64.0	63.5	63.1	62.8	62.5	62.5	62.5	62.5	62.6
	Fallowfield DS	25	22.5	39.5	47.1	44.9	39.6	46.0	48.9	21.5	24.5	24.9	25.8	26.0	26.8	27.0	28.6	28.9	29.9	29.8	30.5	30.6	30.6	30.6	30.6
	Manotick DS	8.6	7.74	5.6	6.5	6.4	7.1	7.9	8.7	9.5	10.2	11.0	10.9	10.8	10.6	10.6	10.4	10.6	10.4	10.4	10.4	10.4	10.4	10.5	10.4
	Richmond DS	75	67.5	4.5	5.1	6.8	11.6	13.1	17.1	20.9	23.9	25.4	25.2	26.6	26.3	26.1	25.8	25.5	25.3	25.1	25.1	25.1	25.0	25.0	25.0
	Manordale MTS	10	9	8.5	9.7	9.4	9.2	9.2	9.3	9.3	9.3	9.3	9.3	9.4	9.4	9.5	9.4	9.4	9.5	9.5	9.5	9.5	9.5	9.5	9.5
	Limebank MTS	66	59.4	`	53.5	51.4	57.1	68.7	71.4	78.4	72.2	74.9	70.9	73.6	77.8	81.8	85.9	89.8	93.8	97.0	99.8	102.1	104.4	106.7	109.2
	Marionville DS	15	13.5	10.3	11.8	11.6	11.7	11.8	12.0	12.0	12.2	12.2	12.3	12.2	12.1	12.0	12.0	11.9	11.9	11.8	11.9	11.9	12.0	12.1	12.1
	Uplands MTS	33	29.7	19.8	22.6	22.6	25.4	27.5	28.9	35.0	39.7	44.3	52.9	52.8	52.7	53.0	53.3	53.3	53.2	53.3	53.5	53.9	54.2	54.6	54.6
	South Gloucester DS	7.5	6.75	3.8	4.3	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.4	4.5	4.4	4.4	4.4	4.4	4.3	4.3	4.3	4.4	4.4	4.4	4.4
	Greely DS	30	27	16.0	18.2	17.8	17.9	18.3	18.5	18.9	19.1	19.2	19.3	19.3	19.3	19.3	19.4	19.3	19.3	19.3	19.4	19.6	19.8	20.1	20.3
	Russell DS	7.5	6.75	3.4	3.9	3.8	3.9	3.9	3.9	4.0	4.0	4.0	4.1	4.1	4.0	4.0	4.0	4.0	4.0	3.9	3.9	3.9	4.0	4.0	4.0
	Centerpoint MTS	14	12.6	13.8	15.8	15.3	15.5	15.4	15.4	15.4	15.4	15.3	15.1	15.0	14.8	14.8	14.6	14.5	14.4	14.3	14.2	14.3	14.3	14.3	14.3
	Merivale TS	25	22.5	14.4	16.5	16.0	15.7	18.3	18.4	18.4	18.6	19.0	19.2	19.1	19.4	19.6	19.3	19.1	18.9	18.7	18.8	18.7	19.4	19.4	19.4
	National Aeronautical CTS	1.2	1.08	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	Kanata MTS	54.2	48.78	51.6	59.0	59.7	61.8	63.4	66.8	66.8	66.5	66.0	65.7	65.0	65.3	65.1	64.5	63.9	63.5	63.4	63.2	63.2	63.2	63.2	63.3
	South March TS	122.3	110.07	78.0	89.2	86.5	86.9	87.7	88.2	97.8	97.6	96.7	96.3	95.8	94.5	92.4	90.4	89.1	88.9	88.8	89.1	89.4	89.8	90.4	90.9
	Nepean TS	160.6	144.54	131.9	150.8	145.4	144.8	131.2	135.1	127.5	127.1	127.1	126.3	125.2	123.9	122.7	121.7	120.7	119.9	119.3	119.3	119.2	119.3	119.4	119.4
	Terry Fox MTS	90	81	49.7	56.8	58.4	63.0	64.4	66.2	68.0	69.5	70.8	72.0	73.1	74.0	75.1	76.1	77.1	78.1	79.2	79.0	78.9	78.9	78.9	79.0
	South Nepean TS	#REF!	#REF!	0.0	0.0	0.0	0.0	0.0	0.0	36.1	39.8	43.3	45.8	49.0	51.9	54.1	56.3	58.8	61.0	62.4	63.9	66.4	69.3	69.3	69.4
	Temp					80.5	85.1	87.5	87.5	125.8	131.2	136.2	139.9	144.2	148.0	151.2	154.4	157.9	161.1	163.6	164.9	167.3	170.2	170.2	170.3
Outer Ottawa West*	Almonte	TBD	TBD	0.0	N/A	44.1	44.1	46.1	42.5	43.3	43.8	44.2	44.2	44.1	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Merivale Pocket TOTAL					**627**	**629**	**649**	**667**	**691**	**723**	**734**	**749**	**757**	**765**	**772**	**776**	**780**	**784**	**789**	**793**	**798**	**804**	**810**	**815**	**818**
Downtown	Nepean Epworth TS	14	12.6	10.5	11.7	11.3	11.2	11.1	11.1	11.0	11.1	11.0	10.9	10.8	10.7	10.5	10.4	10.3	10.3	10.2	10.2	10.2	10.2	10.2	10.2
	Carling TS	106	95.4	78.9	88.1	88.1	89.1	90.5	91.6	92.1	91.9	96.0	95.8	94.9	94.1	93.6	93.2	92.6	91.9	91.4	91.2	91.0	91.1	91.1	91.1
	Lincoln Hights TS	79.8	71.82	38.1	42.5	42.6	42.8	42.5	44.7	44.6	44.5	44.3	52.4	52.0	51.5	51.0	50.6	50.1	49.8	49.5	49.3	49.3	49.3	49.3	49.3
	Woodroffe TS	101	90.9	26.7	29.8	30.9	30.6	31.0	31.8	32.4	32.7	48.1	47.7	47.2	46.8	46.3	45.9	45.5	45.2	44.9	44.8	44.7	44.7	44.7	44.7
	Hinchey TS	96	86.4	42.4	47.3	46.6	48.2	52.3	38.3	40.3	41.9	44.3	46.6	47.4	48.4	49.3	50.2	51.1	51.8	53.1	53.9	55.0	56.0	57.1	58.3
	Slater TS	215	193.5	102.1	114.0	119.6	119.5	118.3	118.2	118.3	118.1	117.3	116.3	115.1	113.7	112.3	111.3	110.2	110.2	109.2	109.0	108.9	108.8	108.9	108.9
	Lisgar TS	83	74.7	55.6	62.1	67.7	67.0	67.3	60.5	66.7	67.0	67.8	67.7	67.5	69.8	69.5	69.4	69.1	69.9	69.8	70.0	70.4	70.8	71.4	71.8
	King Edward TS	91.5	82.35	75.8	84.6	87.3	86.6	87.8	88.4	89.2	89.6	89.6	89.8	89.5	89.3	89.0	88.8	88.7	88.0	87.4	87.2	87.1	87.1	87.1	87.1
	Russell TS	77.8	70.02	68.8	76.8	75.7	77.5	81.1	81.0	81.3	81.2	81.0	80.3	79.4	78.5	77.7	77.0	76.2	75.6	75.1	75.4	75.4	75.3	75.4	75.4
	Overbrook TS	105.6	95.04	57.8	64.5	64.4	68.3	71.3	73.5	75.0	77.1	78.8	80.2	80.2	80.5	80.5	81.0	81.0	81.6	81.9	82.9	83.5	84.6	85.4	86.5
	Riverdale TS	117.6	105.84	70.8	79.1	81.7	80.7	81.5	83.4	85.1	85.9	86.0	86.2	86.1	85.9	85.7	85.6	85.5	86.6	86.6	87.0	87.7	88.2	88.9	89.5
	Albion TS	99.4	89.46	52.2	58.3	56.0	55.6	55.4	55.6	55.7	55.6	55.4	55.1	54.8	54.4	54.1	53.7	53.3	53.1	53.0	53.1	53.1	53.3	53.5	53.5
	Ellwood TS	50	45	34.4	38.4	36.8	37.4	37.7	38.8	39.6	40.1	39.8	39.6	39.2	38.9	38.5	38.2	37.9	37.6	37.3	37.3	37.2	37.3	37.4	37.8
Downtown TOTAL					**797**	**809**	**814**	**828**	**817**	**831**	**837**	**859**	**869**	**864**	**862**	**858**	**855**	**851**	**852**	**849**	**851**	**853**	**857**	**860**	**864**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	94.9	85.41	35.3	40.6	39.4	39.2	39.5	45.4	48.8	48.7	48.3	48.0	47.6	47.1	46.7	46.3	45.9	45.6	45.6	45.6	45.6	45.6	45.6	45.7
	Orleans TS	130.3	117.27	88.2	101.5	98.0	99.5	101.7	103.5	106.0	108.2	109.4	110.7	112.6	113.9	114.0	113.9	113.7	113.5	113.2	113.6	114.2	114.7	115.1	115.5
	Cyrville MTS	50	45	20.9	24.0	22.9	23.2	26.0	31.1	34.1	36.8	40.6	41.6	42.9	43.6	44.2	44.7	45.1	45.8	46.3	47.1	47.8	48.9	49.9	50.8
	Moulton MTS	33	29.7	23.6	27.2	26.2	26.0	27.5	29.3	31.0	32.6	32.5	32.2	31.9	31.6	31.3	31.0	30.8	30.5	30.3	30.2	30.2	30.2	30.2	30.2
	Wilhaven DS	20	18	3.3	3.9	3.2	3.1	3.2	3.3	3.3	3.3	3.3	3.4	3.4	3.3	3.3	3.3	3.3	3.2	3.5	3.6	3.6	3.7	3.8	3.8
	Navan DS	15	13.5	3.6	4.2	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.5	3.7	3.6	3.6	3.6	3.6	3.5	3.9	3.9	3.9	4.0	4.2	4.4
	Cumberland DS	7.5	6.75	4.7	5.4	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5	5.6	5.7	5.9	5.9	5.9	5.9	6.0	6.1	6.2	6.2	6.3	6.3
	Hawthorne TS	152	136.8	88.6	102.0	116.5	115.1	114.2	116.2	122.5	125.6	125.6	126.6	127.2	129.4	131.8	133.0	137.2	138.1	139.0	141.0	143.5	145.6	148.0	149.2
	National Research TS	28	25.2	5.7	6.5	8.6	8.5	8.4	8.4	8.4	8.4	8.4	8.3	8.4	8.4	8.5	8.4	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Outer Ottawa East*	Clarence DS	3.7	3.33	2.4	2.8	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
	Rockland DS	14.3	12.87	6.9	8.0	7.6	7.6	7.6	7.7	7.8	7.9	7.9	7.8	7.8	7.8	7.8	7.8	7.7	7.7	7.7	7.7	7.7	7.8	7.8	7.8
	Rockland East DS	8.6	7.74	10.3	11.9	11.6	11.7	11.8	11.9	12.1	12.2	12.2	12.1	12.1	12.1	12.0	12.0	11.9	11.9	11.9	11.9	12.0	12.0	12.1	12.1
	Wendover TS	15	TBD	10.1	11.7	11.1	7.4	7.4	9.0	9.1	9.4	9.4	9.4	9.4	9.5	9.5	9.5	9.5	9.2	9.5	9.5	9.6	9.8	9.9	13.7
	Hawkesbury MTS	TBD	TBD	9.5	10.9	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.2	11.2	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Hawthorne Pocket TOTAL					**315**	**323**	**323**	**329**	**346**	**363**	**373**	**377**	**380**	**383**	**387**	**389**	**390**	**394**	**395**	**396**	**400**	**404**	**407**	**412**	**414**
Ottawa Area Sub-region TOTAL					**1740**	**1761**	**1787**	**1824**	**1854**	**1917**	**1944**	**1986**	**2006**	**2013**	**2021**	**2024**	**2026**	**2029**	**2036**	**2039**	**2049**	**2061**	**2074**	**2086**	**2097**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals.

Pocket	Station	10-Day LTR (MVA)	10-Day LTR (MW) @0.9	2017 Net Coincident Demand UPDATED	Starting Point of Forecast (Gross, Median Weather)	Net Demand Forecast with Median Weather Conditions																			
						2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	25	22.5	9.8	11.2	13.5	13.4	13.3	14.2	14.2	15.1	15.0	15.5	17.9	19.7	20.4	20.3	20.3	20.2	20.1	20.1	20.1	20.0	20.2	20.2
	Marchwood MTS	33	29.7	39.2	44.8	54.8	59.9	61.7	63.3	64.5	65.2	65.9	66.5	67.0	66.8	66.7	66.4	66.1	65.9	65.7	65.5	65.5	65.5	65.5	65.6
	Fallowfield DS	25	22.5	39.5	47.1	44.9	39.6	46.0	49.1	21.6	24.6	25.1	26.1	26.5	27.4	27.8	29.6	30.1	31.2	31.1	31.9	32.0	32.1	32.1	32.1
	Manotick DS	8.6	7.74	5.6	6.5	6.4	7.1	7.9	8.7	9.6	10.3	11.2	11.1	11.2	11.1	11.3	11.2	11.4	11.3	11.3	11.3	11.4	11.4	11.5	11.4
	Richmond DS	75	67.5	4.5	5.1	6.8	11.6	13.1	17.2	21.0	24.0	25.6	25.5	27.2	27.1	27.1	27.0	26.9	26.8	26.7	26.7	26.7	26.6	26.6	26.7
	Manordale MTS	10	9	8.5	9.7	9.4	9.2	9.2	9.3	9.3	9.3	9.4	9.4	9.5	9.6	9.7	9.7	9.7	9.8	9.8	9.8	9.8	9.8	9.8	9.8
	Limebank MTS	66	59.4	`	53.5	51.4	57.1	68.7	71.7	78.7	72.4	75.5	71.7	74.9	79.7	84.4	88.9	93.5	97.9	101.5	104.5	106.9	109.3	111.8	114.3
	Marionville DS	15	13.5	10.3	11.8	11.6	11.7	11.8	12.0	12.1	12.3	12.4	12.5	12.6	12.7	12.8	12.8	12.9	12.9	13.0	13.1	13.2	13.2	13.3	13.3
	Uplands MTS	33	29.7	19.8	22.6	22.6	25.4	27.5	29.0	35.2	39.9	44.7	53.5	53.8	54.1	54.8	55.4	55.7	55.8	56.1	56.4	56.8	57.2	57.6	57.6
	South Gloucester DS	7.5	6.75	3.8	4.3	4.2	4.3	4.3	4.5	4.4	4.4	4.5	4.5	4.6	4.6	4.5	4.6	4.6	4.6	4.6	4.5	4.6	4.6	4.6	4.6
	Greely DS	30	27	16.0	18.2	17.8	17.9	18.3	18.6	19.0	19.2	19.4	19.6	19.8	19.9	20.2	20.4	20.4	20.5	20.6	20.8	21.0	21.2	21.5	21.7
	Russell DS	7.5	6.75	3.4	3.9	3.8	3.9	3.9	4.0	4.1	4.0	4.0	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.3	4.3	4.3
	Centerpoint MTS	14	12.6	13.8	15.8	15.3	15.5	15.4	15.5	15.4	15.5	15.4	15.3	15.3	15.2	15.3	15.2	15.1	15.1	15.0	15.0	15.0	15.0	15.0	15.0
	Merivale TS	25	22.5	14.4	16.5	16.0	15.7	18.3	18.6	18.6	18.7	19.3	19.7	19.8	20.4	20.8	20.8	20.7	20.7	20.6	20.7	20.7	21.5	21.5	21.5
	National Aeronautical CTS	1.2	1.08	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	Kanata MTS	54.2	48.78	51.6	59.0	59.7	61.8	63.4	67.1	67.0	66.8	66.6	66.5	66.3	67.0	67.3	67.0	66.8	66.6	66.6	66.5	66.5	66.5	66.5	66.6
	South March TS	122.3	110.07	78.0	89.2	86.5	86.9	87.7	88.7	98.4	98.2	97.8	97.9	98.2	97.9	96.7	95.4	94.7	94.9	95.2	95.7	96.1	96.6	97.2	97.7
	Nepean TS	160.6	144.54	131.9	150.8	145.4	144.8	131.2	135.8	128.1	127.7	128.3	128.1	127.8	127.6	127.5	127.1	126.8	126.4	126.2	126.3	126.3	126.5	126.5	126.6
	Terry Fox MTS	90	81	49.7	56.8	58.4	63.0	64.4	66.5	68.2	69.7	71.3	72.8	74.4	75.8	77.4	78.8	80.2	81.5	82.9	82.7	82.7	82.7	82.7	82.8
	South Nepean TS	#REF!	#REF!	0.0	0.0	0.0	0.0	0.0	0.0	36.3	40.0	43.7	46.4	50.1	53.5	56.2	58.7	61.8	64.3	65.9	67.6	70.3	73.5	73.5	73.5
	Temp					80.5	85.1	87.5	87.8	126.2	131.7	137.1	141.3	146.5	151.3	155.6	159.6	164.0	167.8	170.8	172.3	175.0	178.2	178.2	178.3
Outer Ottawa West*	Almonte	TBD	TBD	0.0	N/A	44.1	44.1	46.1	42.5	43.3	43.8	44.2	44.2	44.1	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Merivale Pocket TOTAL					**627**	**629**	**649**	**667**	**694**	**726**	**738**	**755**	**767**	**781**	**795**	**806**	**814**	**822**	**831**	**838**	**844**	**850**	**858**	**862**	**866**
Downtown	Nepean Epworth TS	14	12.6	10.5	11.7	11.3	11.2	11.1	11.1	11.1	11.2	11.1	11.1	11.0	11.0	11.0	10.9	10.9	11.0	10.9	10.9	10.9	10.9	10.9	10.9
	Carling TS	106	95.4	78.9	88.1	88.1	89.1	90.5	92.0	92.6	92.3	96.9	97.1	96.9	96.9	97.1	97.2	97.2	96.9	96.6	96.4	96.4	96.5	96.5	96.6
	Lincoln Hights TS	79.8	71.82	38.1	42.5	42.6	42.8	42.5	44.9	44.8	44.7	44.7	53.1	53.0	52.9	52.8	52.7	52.4	52.3	52.1	51.9	51.9	52.0	52.0	52.0
	Woodroffe TS	101	90.9	26.7	29.8	30.9	30.6	31.0	32.0	32.5	32.9	48.5	48.3	48.2	48.1	48.0	47.9	47.6	47.5	47.4	47.2	47.2	47.2	47.2	47.3
	Hinchey TS	96	86.4	42.4	47.3	46.6	48.2	52.3	38.6	40.6	42.2	44.9	47.5	48.9	50.4	52.0	53.3	54.7	55.7	57.4	58.3	59.5	60.7	61.9	63.2
	Slater TS	215	193.5	102.1	114.0	119.6	119.5	118.3	118.9	119.1	118.8	118.7	118.5	118.4	118.2	118.2	118.0	117.8	118.4	118.0	118.0	118.0	118.1	118.1	118.2
	Lisgar TS	83	74.7	55.6	62.1	67.7	67.0	67.3	60.9	67.1	67.3	68.5	68.8	69.2	72.3	72.7	73.0	73.2	74.4	74.5	74.9	75.4	75.9	76.5	77.0
	King Edward TS	91.5	82.35	75.8	84.6	87.3	86.6	87.8	88.9	89.7	90.0	90.5	91.1	91.6	92.1	92.7	93.1	93.5	93.2	92.9	92.8	92.7	92.8	92.9	92.9
	Russell TS	77.8	70.02	68.8	76.8	75.7	77.5	81.1	81.5	81.7	81.7	81.9	81.6	81.5	81.4	81.4	81.2	81.0	80.8	80.6	80.9	81.0	81.1	81.1	81.2
	Overbrook TS	105.6	95.04	57.8	64.5	64.4	68.3	71.3	73.8	75.4	77.4	79.5	81.2	81.9	82.8	83.6	84.5	85.0	85.9	86.5	87.7	88.4	89.6	90.5	91.6
	Riverdale TS	117.6	105.84	70.8	79.1	81.7	80.7	81.5	83.8	85.5	86.4	86.8	87.4	87.9	88.4	89.0	89.3	89.8	91.2	91.6	92.1	92.9	93.5	94.2	94.9
	Albion TS	99.4	89.46	52.2	58.3	56.0	55.6	55.4	55.8	56.0	55.9	55.9	55.8	55.9	56.0	56.0	55.9	55.9	55.8	55.9	56.0	56.1	56.3	56.5	56.5
	Ellwood TS	50	45	34.4	38.4	36.8	37.4	37.7	39.0	39.7	40.2	40.2	40.1	40.0	39.9	39.8	39.7	39.7	39.5	39.3	39.3	39.3	39.3	39.4	39.9
Downtown TOTAL					**797**	**809**	**814**	**828**	**821**	**836**	**841**	**868**	**882**	**885**	**891**	**894**	**897**	**899**	**903**	**904**	**906**	**910**	**914**	**918**	**922**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	94.9	85.41	35.3	40.6	39.4	39.2	39.5	45.6	49.0	48.9	48.8	48.6	48.6	48.5	48.4	48.2	48.1	48.0	48.0	48.1	48.1	48.2	48.2	48.2
	Orleans TS	130.3	117.27	88.2	101.5	98.0	99.5	101.7	104.3	106.8	109.0	111.0	113.1	116.5	119.3	121.0	122.1	123.0	123.6	124.1	124.8	125.7	126.6	127.0	127.4
	Cyrville MTS	50	45	20.9	24.0	22.9	23.2	26.0	31.2	34.2	36.9	40.9	42.1	43.7	44.7	45.6	46.4	47.0	47.8	48.5	49.3	50.2	51.3	52.4	53.3
	Moulton MTS	33	29.7	23.6	27.2	26.2	26.0	27.5	29.4	31.2	32.8	32.8	32.6	32.5	32.5	32.4	32.3	32.2	32.1	31.9	31.9	31.9	31.9	31.9	31.9
	Wilhaven DS	20	18	3.3	3.9	3.2	3.1	3.2	3.3	3.3	3.3	3.4	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.8	3.9	3.9	3.9	4.1	4.1
	Navan DS	15	13.5	3.6	4.2	3.3	3.4	3.4	3.6	3.5	3.6	3.6	3.6	3.8	3.8	3.8	3.8	3.8	3.8	4.2	4.2	4.2	4.3	4.5	4.6
	Cumberland DS	7.5	6.75	4.7	5.4	5.2	5.2	5.3	5.4	5.5	5.5	5.5	5.5	5.7	5.8	6.0	6.0	6.1	6.1	6.2	6.3	6.4	6.4	6.5	6.5
	Hawthorne TS	152	136.8	88.6	102.0	116.5	115.1	114.2	116.9	123.2	126.3	126.9	128.6	130.3	133.8	137.7	139.8	145.0	146.6	148.1	150.4	153.3	155.7	158.2	159.5
	National Research TS	28	25.2	5.7	6.5	8.6	8.5	8.4	8.4	8.4	8.4	8.4	8.4	8.5	8.6	8.7	8.7	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Outer Ottawa East*	Clarence DS	3.7	3.33	2.4	2.8	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
	Rockland DS	14.3	12.87	6.9	8.0	7.6	7.6	7.6	7.7	7.8	7.9	7.9	7.8	7.8	7.8	7.8	7.8	7.7	7.7	7.7	7.7	7.7	7.8	7.8	7.8
	Rockland East DS	8.6	7.74	10.3	11.9	11.6	11.7	11.8	11.9	12.1	12.2	12.2	12.1	12.1	12.1	12.0	12.0	11.9	11.9	11.9	11.9	12.0	12.0	12.1	12.1
	Wendover TS	15	TBD	10.1	11.7	11.1	7.4	7.4	9.0	9.1	9.4	9.4	9.4	9.4	9.5	9.5	9.5	9.5	9.2	9.5	9.5	9.6	9.8	9.9	13.7
	Hawkesbury MTS	TBD	TBD	9.5	10.9	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.2	11.2	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Hawthorne Pocket TOTAL					**315**	**323**	**323**	**329**	**348**	**365**	**375**	**381**	**386**	**393**	**400**	**407**	**411**	**418**	**420**	**424**	**428**	**432**	**437**	**441**	**444**
Ottawa Area Sub-region TOTAL					**1740**	**1761**	**1787**	**1824**	**1864**	**1927**	**1954**	**2005**	**2035**	**2059**	**2086**	**2107**	**2122**	**2139**	**2154**	**2165**	**2178**	**2192**	**2209**	**2222**	**2233**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals.

Sub-Region	Station	Effective Capacity																				
		2017	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Marchwood MTS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Fallowfield DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Manotick DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Richmond DS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
	Manordale MTS	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
	Limebank MTS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Marionville DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Uplands MTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	South Gloucester DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Greely DS	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.0
	Russell DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Centerpoint MTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Merivale TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	National Aeronautical CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Kanata MTS	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	South March TS	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.5	0.4	0.4	0.4	0.1	0.1	0.1
	Nepean TS	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.4	0.1	0.1	0.1	0.0	0.0	0.0
	Terry Fox MTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	South Nepean TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outer Ottawa West*	Almonte	10.4	10.8	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	8.0	8.0	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Merivale Pocket TOTAL		**2.0**	**2.3**	**2.3**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**1.6**	**1.0**	**1.0**	**1.0**	**0.4**	**0.4**	**0.1**
Downtown	Nepean Epworth TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Carling TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Lincoln Hights TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Woodroffe TS	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
	Hinchey TS	0.0	0.0	0.0	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7
	Slater TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Lisgar TS	0.0	0.0	0.0	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
	King Edward TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Russell TS	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.1	0.1	0.1	0.0	0.0	0.0
	Overbrook TS	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0
	Riverdale TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Albion TS	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1
	Ellwood TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
Downtown TOTAL		**1.4**	**1.5**	**1.6**	**25.8**	**25.8**	**25.8**	**25.8**	**25.8**	**25.8**	**25.8**	**25.8**	**25.8**	**25.8**	**25.8**	**25.3**	**24.6**	**24.6**	**24.6**	**24.4**	**24.4**	**24.3**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0
	Orleans TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Cyrville MTS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
	Moulton MTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Wilhaven DS	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Navan DS	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.4	0.4	0.4	0.4	0.2	0.0	0.0
	Cumberland DS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
	Hawthorne TS	3.6	3.7	3.7	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	0.8	0.6	0.5	0.5	0.5	0.4	0.2	0.2	0.0
	National Research TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outer Ottawa East*	Clarence DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Rockland DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Rockland East DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Wendover TS	0.2	0.2	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	4.1	3.8	3.8	3.8	3.7	3.7	0.0
	Hawkesbury MTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hawthorne Pocket TOTAL		**5.4**	**5.5**	**5.5**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**2.6**	**2.4**	**1.4**	**1.0**	**1.0**	**0.9**	**0.4**	**0.2**	**0.0**
Ottawa Area Sub-region TOTAL		**8.8**	**9.3**	**9.3**	**33.7**	**33.7**	**33.7**	**33.7**	**33.7**	**33.7**	**33.7**	**33.7**	**33.7**	**30.7**	**30.6**	**28.3**	**26.7**	**26.7**	**26.6**	**25.1**	**25.0**	**24.4**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals.

Sub-Region	Station	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	0.3	0.4	0.5	0.5	0.6	0.7	0.8	0.9	1.2	1.6	1.8	2.0	2.1	2.3	2.4	2.4	2.5	2.5	2.5	2.5
	Marchwood MTS	1.9	2.4	2.8	2.8	3.0	3.2	3.6	4.2	4.8	5.4	6.0	6.6	7.1	7.5	7.9	8.2	8.2	8.2	8.2	8.2
	Fallowfield DS	1.9	2.1	2.4	2.5	1.6	1.8	1.9	2.0	2.3	2.5	2.8	3.2	3.4	3.7	3.8	4.1	4.0	4.0	4.0	4.0
	Manotick DS	0.2	0.4	0.5	0.5	0.6	0.7	0.8	0.9	1.1	1.2	1.4	1.5	1.5	1.6	1.7	1.7	1.8	1.8	1.8	1.8
	Richmond DS	0.2	0.4	0.6	0.7	0.9	1.2	1.4	1.7	2.1	2.4	2.5	2.8	3.1	3.3	3.5	3.6	3.6	3.7	3.7	3.7
	Manordale MTS	0.3	0.4	0.5	0.6	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Limebank MTS	2.0	2.5	3.2	3.2	3.5	3.6	4.3	4.6	5.3	6.3	7.5	8.7	9.9	11.1	12.2	12.8	13.2	13.6	13.9	14.1
	Marionville DS	0.5	0.6	0.8	0.8	0.9	0.9	1.0	1.0	1.2	1.4	1.6	1.7	1.9	2.0	2.2	2.1	2.2	2.2	2.2	2.2
	Uplands MTS	0.9	1.2	1.4	1.4	1.7	2.0	2.4	3.3	3.9	4.4	5.0	5.6	6.1	6.6	7.0	7.2	7.3	7.4	7.5	7.4
	South Gloucester DS	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
	Greely DS	0.8	1.0	1.1	1.2	1.1	1.2	1.4	1.5	1.7	1.9	2.2	2.3	2.5	2.7	2.9	3.0	3.0	3.0	3.1	3.1
	Russell DS	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
	Centerpoint MTS	0.6	0.7	0.8	0.8	0.8	0.8	0.9	1.1	1.2	1.4	1.4	1.6	1.7	1.8	1.9	2.0	1.9	1.9	1.9	1.9
	Merivale TS	0.6	0.8	1.2	1.2	1.2	1.3	1.5	1.6	1.9	2.3	2.6	2.8	3.1	3.3	3.5	3.4	3.5	3.7	3.7	3.7
	National Aeronautical CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Kanata MTS	2.3	2.8	3.3	3.3	3.3	3.6	4.1	4.4	5.1	5.7	6.3	7.0	7.5	7.9	8.4	8.5	8.5	8.5	8.5	8.5
	South March TS	3.7	4.7	5.5	5.6	5.9	6.2	6.8	7.6	8.7	9.8	10.6	11.3	12.2	12.9	13.6	13.9	14.1	14.1	14.2	14.2
	Nepean TS	5.9	7.2	7.8	7.9	7.5	7.9	8.7	9.5	10.7	12.0	13.1	14.2	15.1	15.9	16.8	17.0	17.1	17.0	17.0	16.9
	Terry Fox MTS	2.3	2.8	3.2	3.2	3.3	3.6	4.1	4.7	5.3	6.2	7.0	7.8	8.6	9.4	10.1	10.3	10.3	10.4	10.3	10.3
	South Nepean TS	0.0	0.0	0.0	0.0	1.4	1.7	2.2	2.7	3.5	4.3	5.1	5.9	6.9	7.7	8.3	8.8	9.3	9.9	9.9	9.8
Outer Ottawa West*	Almonte	0.5	1.0	1.5	1.5	1.5	1.6	1.7	1.8	1.6	1.4	1.2	1.3	1.3	1.4	1.5	1.5	1.5	1.5	1.4	1.4
Merivale Pocket TOTAL		**25.4**	**32.1**	**37.8**	**38.4**	**39.9**	**42.8**	**48.6**	**54.7**	**62.6**	**71.3**	**79.2**	**87.5**	**95.5**	**102.5**	**109.0**	**111.9**	**113.6**	**115.1**	**115.4**	**115.2**
Downtown	Nepean Epworth TS	0.4	0.5	0.6	0.6	0.7	0.6	0.7	0.8	0.9	1.0	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5
	Carling TS	3.6	4.4	5.1	5.0	5.1	5.3	6.2	6.8	7.7	8.7	9.6	10.5	11.3	12.0	12.6	12.8	13.0	12.9	12.9	12.9
	Lincoln Hights TS	1.7	2.1	2.3	2.4	2.4	2.5	2.8	3.6	4.0	4.6	5.0	5.4	5.9	6.2	6.6	6.8	6.8	6.8	6.8	6.7
	Woodroffe TS	1.2	1.4	1.7	1.7	1.7	1.9	2.8	3.2	3.7	4.1	4.6	4.9	5.4	5.7	6.0	6.2	6.3	6.2	6.2	6.2
	Hinchey TS	1.9	2.4	2.9	3.0	3.2	3.4	3.9	4.5	5.3	6.1	6.9	7.7	8.5	9.1	9.9	10.3	10.5	10.7	10.9	11.0
	Slater TS	5.0	6.5	7.7	7.8	7.7	7.9	8.7	9.7	10.9	12.3	13.7	14.7	15.8	16.8	17.8	18.0	18.1	18.2	18.1	18.1
	Lisgar TS	2.6	3.3	3.8	3.8	4.1	4.3	4.8	5.4	6.2	7.3	8.1	8.9	9.7	10.4	11.0	11.2	11.4	11.5	11.6	11.6
	King Edward TS	3.5	4.4	5.1	5.1	5.1	5.4	6.0	6.7	7.6	8.6	9.6	10.5	11.3	12.0	12.6	12.8	12.9	12.9	12.9	12.9
	Russell TS	3.2	4.1	5.0	5.0	5.0	5.2	5.7	6.4	7.2	8.1	9.0	9.7	10.5	11.1	11.7	11.8	11.9	11.9	11.9	11.9
	Overbrook TS	2.6	3.2	3.8	3.9	3.9	4.3	4.9	5.6	6.4	7.4	8.2	9.1	9.9	10.6	11.3	11.6	11.8	12.0	12.1	12.2
	Riverdale TS	3.3	4.0	4.6	4.6	4.6	5.0	5.6	6.2	7.0	7.9	8.8	9.6	10.5	11.3	12.0	12.3	12.4	12.6	12.6	12.7
	Albion TS	2.4	2.7	3.1	3.1	3.0	3.2	3.7	4.0	4.5	5.0	5.5	6.1	6.5	6.9	7.3	7.4	7.4	7.4	7.4	7.4
	Ellwood TS	1.5	1.8	2.1	2.1	2.1	2.2	2.6	2.8	3.2	3.5	3.9	4.2	4.5	4.8	5.1	5.1	5.2	5.1	5.1	5.2
Downtown TOTAL		**32.9**	**40.9**	**47.8**	**48.2**	**48.6**	**51.3**	**58.2**	**65.7**	**74.8**	**84.8**	**94.1**	**102.6**	**111.3**	**118.2**	**125.1**	**127.7**	**129.1**	**129.9**	**130.2**	**130.2**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	1.8	2.1	2.4	2.4	2.6	2.7	3.1	3.4	3.8	4.3	4.7	5.2	5.6	5.9	6.2	6.3	6.3	6.3	6.3	6.3
	Orleans TS	4.4	5.9	7.2	7.6	7.5	7.7	8.7	9.8	11.6	13.4	15.0	16.3	17.8	18.9	20.1	20.5	20.8	21.1	21.1	21.1
	Cyrville MTS	1.0	1.2	1.4	1.6	1.7	1.9	2.3	2.7	3.1	3.6	4.2	4.6	5.1	5.5	5.9	6.1	6.4	6.5	6.6	6.7
	Moulton MTS	1.0	1.2	1.4	1.5	1.5	1.7	1.9	2.2	2.5	2.7	3.1	3.4	3.6	3.8	4.0	4.2	4.1	4.2	4.2	4.2
	Wilhaven DS	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
	Navan DS	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	Cumberland DS	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Hawthorne TS	4.5	5.7	6.6	6.8	7.0	7.5	8.5	9.6	11.1	12.8	14.5	16.1	17.7	19.0	20.3	21.0	21.6	22.0	22.3	22.4
	National Research TS	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Outer Ottawa East*	Clarence DS	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
	Rockland DS	0.2	0.3	0.4	0.5	0.5	0.5	0.6	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.5
	Rockland East DS	0.2	0.4	0.5	0.5	0.5	0.6	0.7	0.8	0.9	1.1	1.2	1.4	1.5	1.6	1.7	1.7	1.8	1.8	1.8	1.8
	Wendover TS	0.2	0.4	0.5	0.6	0.6	0.7	0.8	0.9	1.1	1.2	1.4	1.6	1.7	1.8	2.0	2.0	2.1	2.1	2.1	2.1
	Hawkesbury MTS	0.1	0.2	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.3
Hawthorne Pocket TOTAL		**14.2**	**18.5**	**22.2**	**23.1**	**23.6**	**25.2**	**28.4**	**32.1**	**36.9**	**42.1**	**47.0**	**51.7**	**56.3**	**60.1**	**63.9**	**65.8**	**67.1**	**68.1**	**68.6**	**68.6**
Ottawa Area Sub-region TOTAL		**72.6**	**91.5**	**107.7**	**109.7**	**112.2**	**119.3**	**135.3**	**152.6**	**174.3**	**198.2**	**220.3**	**241.8**	**263.1**	**280.8**	**297.9**	**305.5**	**309.8**	**313.1**	**314.2**	**314.0**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals.

Sub-Region	Station	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	0.3	0.4	0.5	0.5	0.5	0.6	0.7	0.8	0.9	1.1	1.2	1.3	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.6
	Marchwood MTS	1.9	2.4	2.8	2.5	2.7	2.9	3.1	3.5	3.6	3.8	3.9	4.3	4.5	4.7	5.0	5.2	5.2	5.2	5.2	5.1
	Fallowfield DS	1.9	2.1	2.4	2.3	1.5	1.7	1.7	1.7	1.8	1.9	2.0	2.2	2.2	2.4	2.5	2.7	2.6	2.5	2.5	2.5
	Manotick DS	0.2	0.4	0.5	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8
	Richmond DS	0.2	0.4	0.6	0.6	0.8	1.0	1.2	1.3	1.4	1.5	1.5	1.6	1.7	1.8	1.9	2.0	2.0	2.1	2.1	2.0
	Manordale MTS	0.3	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.3	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Limebank MTS	2.0	2.5	3.2	2.9	3.2	3.3	3.7	3.8	4.1	4.5	5.0	5.6	6.3	7.1	7.8	8.2	8.5	8.7	8.8	8.9
	Marionville DS	0.5	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	1.0	1.0	0.9	0.9	1.0	1.0	1.0
	Uplands MTS	0.9	1.2	1.4	1.3	1.5	1.8	2.1	2.7	2.9	2.9	3.1	3.5	3.6	3.9	4.2	4.4	4.4	4.5	4.5	4.5
	South Gloucester DS	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
	Greely DS	0.8	1.0	1.1	1.1	1.0	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6	1.6	1.6	1.6	1.6	1.6
	Russell DS	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Centerpoint MTS	0.6	0.7	0.8	0.7	0.8	0.7	0.8	0.9	0.9	1.0	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
	Merivale TS	0.6	0.8	1.2	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.6
	National Aeronautical CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Kanata MTS	2.3	2.8	3.3	3.0	3.1	3.3	3.5	3.6	3.9	4.0	4.1	4.5	4.7	4.9	5.2	5.3	5.3	5.2	5.2	5.2
	South March TS	3.7	4.7	5.5	5.1	5.3	5.6	5.7	6.0	6.2	6.3	6.2	6.4	6.7	6.9	7.2	7.4	7.4	7.3	7.3	7.3
	Nepean TS	5.9	7.2	7.8	7.2	6.9	7.2	7.5	7.8	8.0	8.3	8.4	8.8	9.1	9.4	9.9	10.0	10.0	9.8	9.8	9.7
	Terry Fox MTS	2.3	2.8	3.2	2.9	3.0	3.3	3.5	3.8	4.1	4.4	4.6	5.0	5.4	5.9	6.4	6.5	6.6	6.5	6.5	6.5
	South Nepean TS	0.0	0.0	0.0	0.0	1.2	1.5	1.8	2.1	2.4	2.7	3.0	3.5	3.9	4.4	4.8	5.1	5.4	5.7	5.7	5.7
Outer Ottawa West*	Almonte	0.5	1.0	1.5	1.4	1.4	1.4	1.4	1.4	1.0	0.6	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Merivale Pocket TOTAL		**25.4**	**32.1**	**37.8**	**35.0**	**36.3**	**39.2**	**41.6**	**44.1**	**46.0**	**47.9**	**49.0**	**52.6**	**55.7**	**59.4**	**63.1**	**65.0**	**65.7**	**66.0**	**66.2**	**65.8**
Downtown	Nepean Epworth TS	0.4	0.5	0.6	0.6	0.6	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8
	Carling TS	3.6	4.4	5.1	4.6	4.6	4.9	5.3	5.5	5.7	5.9	6.1	6.5	6.7	7.0	7.4	7.6	7.6	7.5	7.5	7.4
	Lincoln Hights TS	1.7	2.1	2.3	2.2	2.2	2.3	2.4	3.0	3.0	3.2	3.2	3.4	3.7	3.8	4.0	4.1	4.1	4.1	4.1	4.0
	Woodroffe TS	1.2	1.4	1.7	1.5	1.5	1.7	2.4	2.6	2.7	2.8	2.9	3.0	3.2	3.4	3.5	3.7	3.8	3.7	3.7	3.7
	Hinchey TS	1.9	2.4	2.9	2.8	2.9	3.1	3.3	3.6	3.9	4.0	4.2	4.5	4.9	5.1	5.5	5.8	5.9	6.0	6.1	6.1
	Slater TS	5.0	6.5	7.7	7.1	6.9	7.2	7.3	7.5	7.6	7.8	7.8	8.0	8.2	8.6	9.0	9.0	9.0	8.9	8.9	8.8
	Lisgar TS	2.6	3.3	3.8	3.5	3.7	3.9	4.1	4.3	4.5	4.9	5.0	5.3	5.6	5.9	6.2	6.4	6.4	6.4	6.5	6.5
	King Edward TS	3.5	4.4	5.1	4.7	4.6	4.9	5.2	5.4	5.6	5.8	5.9	6.2	6.5	6.8	7.1	7.2	7.3	7.2	7.1	7.1
	Russell TS	3.2	4.1	5.0	4.6	4.5	4.8	4.8	5.0	5.2	5.2	5.3	5.5	5.7	5.9	6.2	6.3	6.2	6.2	6.2	6.1
	Overbrook TS	2.6	3.2	3.8	3.5	3.6	3.9	4.2	4.5	4.7	5.0	5.1	5.5	5.8	6.2	6.6	6.8	6.9	7.0	7.0	7.1
	Riverdale TS	3.3	4.0	4.6	4.2	4.2	4.5	4.8	5.0	5.2	5.4	5.5	5.9	6.2	6.7	7.0	7.2	7.2	7.3	7.3	7.3
	Albion TS	2.4	2.7	3.1	2.8	2.8	3.0	3.2	3.3	3.4	3.5	3.5	3.8	4.0	4.2	4.4	4.5	4.5	4.4	4.4	4.4
	Ellwood TS	1.5	1.8	2.1	1.9	2.0	2.1	2.2	2.3	2.4	2.4	2.6	2.7	2.7	2.9	3.1	3.1	3.2	3.1	3.1	3.1
Downtown TOTAL		**32.9**	**40.9**	**47.8**	**43.9**	**44.2**	**46.8**	**49.6**	**52.6**	**54.6**	**56.6**	**57.8**	**61.0**	**64.1**	**67.2**	**70.9**	**72.5**	**72.9**	**72.5**	**72.6**	**72.3**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	1.8	2.1	2.4	2.2	2.4	2.5	2.7	2.8	2.9	3.0	3.0	3.3	3.4	3.5	3.7	3.8	3.8	3.8	3.7	3.7
	Orleans TS	4.4	5.9	7.2	6.8	6.7	6.9	7.1	7.4	7.8	8.0	7.9	8.2	8.4	8.7	9.1	9.3	9.3	9.3	9.3	9.3
	Cyrville MTS	1.0	1.2	1.4	1.4	1.5	1.8	2.0	2.2	2.3	2.5	2.7	2.9	3.2	3.4	3.7	3.9	4.0	4.0	4.1	4.2
	Moulton MTS	1.0	1.2	1.4	1.3	1.4	1.6	1.6	1.8	1.9	1.9	1.9	2.1	2.2	2.3	2.4	2.5	2.5	2.5	2.5	2.5
	Wilhaven DS	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Navan DS	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
	Cumberland DS	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hawthorne TS	4.5	5.7	6.6	6.1	6.3	6.8	7.1	7.6	8.0	8.4	8.7	9.3	9.9	10.5	11.1	11.6	11.9	12.0	12.1	12.1
	National Research TS	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outer Ottawa East*	Clarence DS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Rockland DS	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
	Rockland East DS	0.2	0.4	0.5	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0
	Wendover TS	0.2	0.4	0.5	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1
	Hawkesbury MTS	0.1	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hawthorne Pocket TOTAL		**14.2**	**18.5**	**22.2**	**20.9**	**21.3**	**22.8**	**23.9**	**25.2**	**26.0**	**26.8**	**27.1**	**28.7**	**30.1**	**31.6**	**33.4**	**34.6**	**35.0**	**35.1**	**35.3**	**35.2**
Ottawa Area Sub-region TOTAL		**72.6**	**91.5**	**107.7**	**99.7**	**101.8**	**108.8**	**115.1**	**121.9**	**126.7**	**131.3**	**133.9**	**142.3**	**149.9**	**158.2**	**167.3**	**172.1**	**173.6**	**173.6**	**174.1**	**173.4**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals.

Pocket	Station	10-Day LTR (MVA)	10-Day LTR (MW)	2017 Net Coincident Demand UPDATED	Starting Point of Forecast (Gross, Median Weather)	Gross Demand Forecast with Median Weather Conditions																			
						2018	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	25	22.5	9.8	11.2	14.0	14.0	14.0	14.9	14.9	15.9	15.9	16.5	19.0	21.0	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
	Marchwood MTS	33	29.7	39.2	44.8	56.8	62.4	64.6	66.0	67.3	68.2	69.1	70.0	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7
	Fallowfield DS	25	22.5	39.5	47.1	46.8	41.7	48.4	51.4	23.1	26.3	26.8	27.8	28.3	29.3	29.8	31.8	32.3	33.6	33.6	34.6	34.6	34.6	34.6	34.6
	Manotick DS	8.6	7.7	5.6	6.5	6.6	7.5	8.4	9.2	10.1	10.9	11.8	11.8	11.9	11.8	12.0	11.9	12.1	12.0	12.1	12.1	12.2	12.2	12.3	12.2
	Richmond DS	75	67.5	4.5	5.1	7.1	12.1	13.8	17.9	21.9	25.1	26.9	26.9	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7
	Manordale MTS	10	9.0	8.5	9.7	9.7	9.7	9.8	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
	Limebank MTS	66	59.4	46.8	53.5	53.5	59.7	72.0	74.7	82.0	75.8	79.3	75.5	79.0	84.2	89.4	94.6	99.8	105.0	109.2	112.7	115.3	118.0	120.6	123.3
	Marionville DS	15	13.5	10.3	11.8	12.1	12.3	12.6	12.8	12.9	13.1	13.2	13.3	13.4	13.5	13.6	13.7	13.8	13.9	14.0	14.0	14.1	14.2	14.3	14.3
	Uplands MTS	33	29.7	19.8	22.6	23.5	26.7	28.9	30.4	36.7	41.8	46.8	56.2	56.7	57.1	58.0	58.9	59.4	59.8	60.3	60.7	61.2	61.6	62.1	62.1
	South Gloucester DS	7.5	6.8	3.8	4.3	4.4	4.5	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0
	Greely DS	30	27.0	16.0	18.2	18.7	19.2	19.7	20.0	20.3	20.6	20.9	21.1	21.3	21.5	21.8	22.0	22.1	22.3	22.5	22.7	22.9	23.1	23.3	23.5
	Russell DS	7.5	6.8	3.4	3.9	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6
	Centerpoint MTS	14	12.6	13.8	15.8	15.9	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
	Merivale TS	25	22.5	14.4	16.5	16.6	16.6	19.5	19.7	19.7	19.9	20.5	20.9	21.1	21.7	22.2	22.2	22.2	22.2	22.2	22.2	22.2	23.1	23.1	23.1
	National Aeronautical CTS	1.2	1.1	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	Kanata MTS	54.2	48.8	51.6	59.0	62.3	64.9	67.0	70.4	70.4	70.4	70.4	70.4	70.4	71.3	71.7	71.7	71.7	71.7	71.7	71.7	71.7	71.7	71.7	71.7
	South March TS	122.3	110.1	78.0	89.2	90.7	92.2	93.8	94.5	104.4	104.5	104.1	104.6	105.1	104.9	103.6	102.4	102.0	102.5	102.9	103.4	103.9	104.3	104.7	105.2
	Nepean TS	160.6	144.5	131.9	150.8	151.9	152.6	139.6	143.6	135.5	135.5	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4
	Terry Fox MTS	90	81.0	49.7	56.8	60.7	65.8	67.6	69.4	71.2	73.0	74.8	76.6	78.4	80.2	82.0	83.8	85.6	87.4	89.2	89.2	89.2	89.2	89.2	89.2
	South Nepean TS	#REF!	#REF!	0.0	0.0	0.0	0.0	0.0	0.0	37.5	41.5	45.5	48.5	52.5	56.2	59.2	62.2	65.7	68.7	70.7	72.7	75.7	79.2	79.2	79.2
Outer Ottawa West*	Almonte	TBD	90.0	0.0	N/A	44.1	44.1	46.1	42.5	43.3	43.8	44.2	44.2	44.1	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Merivale Pocket TOTAL				**547**	**627**	**656**	**683**	**705**	**730**	**764**	**778**	**798**	**812**	**829**	**844**	**857**	**869**	**880**	**893**	**902**	**910**	**917**	**925**	**929**	**932**
Downtown	Nepean Epworth TS	14	12.6	10.5	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
	Carling TS	106	95.4	78.9	88.1	91.8	93.6	95.7	96.7	97.3	97.3	102.3	102.7	102.7	102.9	103.3	103.8	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
	Lincoln Hights TS	79.8	71.8	38.1	42.5	44.3	44.9	44.9	47.1	47.1	47.1	47.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1
	Woodroffe TS	101	90.9	26.7	29.8	32.1	32.1	32.8	33.6	34.2	34.7	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Hinchey TS	96	86.4	42.4	47.3	48.5	50.6	55.2	58.1	60.2	62.0	64.9	67.8	69.5	71.2	72.9	74.6	76.3	77.6	79.7	80.9	82.2	83.4	84.7	86.0
	Slater TS	215	193.5	102.1	114.0	124.6	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0
	Lisgar TS	83	74.7	55.6	62.1	70.3	70.3	71.1	71.8	78.2	78.7	80.1	80.6	81.2	84.6	85.1	85.7	86.2	87.7	88.2	88.7	89.3	89.8	90.4	90.9
	King Edward TS	91.5	82.4	75.8	84.6	90.9	91.0	92.9	93.6	94.3	95.0	95.7	96.5	97.2	97.9	98.6	99.3	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
	Russell TS	77.8	70.0	68.8	76.8	79.5	82.2	86.7	86.7	86.9	87.1	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3
	Overbrook TS	105.6	95.0	57.8	64.5	67.2	71.8	75.4	77.6	79.2	81.6	83.9	86.0	86.9	88.1	89.0	90.3	91.1	92.4	93.2	94.5	95.3	96.6	97.5	98.7
	Riverdale TS	117.6	105.8	70.8	79.1	85.0	84.7	86.1	88.0	89.7	90.9	91.6	92.4	93.1	93.8	94.5	95.2	96.0	97.9	98.6	99.3	100.1	100.8	101.5	102.2
	Albion TS	99.4	89.5	52.2	58.3	58.6	58.7	58.8	59.0	59.1	59.2	59.4	59.5	59.7	59.8	59.9	60.1	60.2	60.3	60.5	60.6	60.7	60.9	61.0	61.0
	Ellwood TS	50	45.0	34.4	38.4	38.4	39.3	39.9	41.0	41.8	42.4	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	43.0
Downtown TOTAL				**714**	**797**	**843**	**857**	**877**	**891**	**906**	**914**	**944**	**960**	**965**	**973**	**978**	**984**	**988**	**996**	**1000**	**1004**	**1007**	**1011**	**1015**	**1019**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	94.9	85.4	35.3	40.6	41.6	41.7	42.3	48.2	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	52.0
	Orleans TS	130.3	117.3	88.2	101.5	102.4	105.4	109.0	111.1	113.5	115.9	118.1	120.6	124.3	127.3	128.9	130.2	131.5	132.4	133.3	134.1	135.0	135.8	136.3	136.6
	Cyrville MTS	50	45.0	20.9	24.0	24.0	24.5	27.5	32.7	35.8	38.8	43.0	44.4	46.1	47.3	48.4	49.4	50.3	51.3	52.2	53.2	54.2	55.4	56.5	57.5
	Moulton MTS	33	29.7	23.6	27.2	27.2	27.2	29.0	30.8	32.6	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4
	Wilhaven DS	20	18.0	3.3	3.9	3.9	3.9	4.0	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.3	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4
	Navan DS	15	13.5	3.6	4.2	4.2	4.3	4.4	4.5	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.9	4.9	4.9	5.0	5.0	5.0
	Cumberland DS	7.5	6.8	4.7	5.4	5.4	5.5	5.6	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.5
	Hawthorne TS	152	136.8	88.6	102.0	124.7	124.4	124.5	126.8	133.4	136.9	137.9	140.0	142.1	146.0	150.1	152.9	155.6	157.7	159.8	162.4	165.6	168.0	170.4	171.8
	National Research TS	28	25.2	5.7	6.5	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Outer Ottawa East*	Clarence DS	3.7	3.3	2.4	2.8	2.8	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3
	Rockland DS	14.3	12.9	6.9	8.0	8.1	8.2	8.4	8.5	8.6	8.7	8.7	8.8	8.8	8.9	8.9	9.0	9.0	9.1	9.1	9.2	9.2	9.3	9.3	9.4
	Rockland East DS	8.6	7.7	10.3	11.9	12.1	12.3	12.6	12.7	12.8	13.0	13.1	13.1	13.2	13.3	13.4	13.5	13.5	13.6	13.7	13.7	13.8	13.9	13.9	14.0
	Wendover TS	15	13.5	10.1	11.7	11.9	12.1	12.4	14.0	14.1	14.4	14.5	14.6	14.7	14.8	14.9	15.1	15.1	15.2	15.3	15.4	15.5	15.6	15.7	15.8
	Hawkesbury MTS	TBD	#VALUE!	9.5	10.9	10.9	10.9	11.0	11.0	11.1	11.1	11.1	11.2	11.2	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Hawthorne Pocket TOTAL				**274**	**315**	**342**	**346**	**355**	**373**	**390**	**401**	**409**	**415**	**422**	**431**	**438**	**443**	**448**	**452**	**456**	**460**	**465**	**470**	**474**	**477**
Ottawa Area Sub-region TOTAL				**1535**	**1740**	**1841**	**1885**	**1937**	**1994**	**2059**	**2093**	**2150**	**2187**	**2216**	**2248**	**2272**	**2295**	**2317**	**2340**	**2358**	**2374**	**2389**	**2406**	**2418**	**2428**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals. As well, these stations may or may not reflect DG and CDM impacts.

Sub-Region	Station	10-Day LTR (MVA)	10-Day LTR (MW)	2017 Net Coincident Demand UPDATED	Starting Point of Forecast (Gross, Median Weather)	Gross Demand Forecast with Median Weather Conditions																			
						2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	25	22.5	9.8	11.2	14.0	14.0	14.0	14.9	14.9	15.9	15.9	16.5	19.0	21.0	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
	Marchwood MTS	33	29.7	39.2	44.8	56.8	62.4	64.6	66.0	67.3	68.2	69.1	70.0	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7
	Fallowfield DS	25	22.5	39.5	47.1	46.8	41.7	48.4	51.4	23.1	26.3	26.8	27.8	28.3	29.3	29.8	31.8	32.3	33.6	33.6	34.6	34.6	34.6	34.6	34.6
	Manotick DS	8.6	7.7	5.6	6.5																				
	Richmond DS	75	67.5	4.5	5.1	7.1	12.1	13.8	17.9	21.9	25.1	26.9	26.9	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7
	Manordale MTS	10	9.0	8.5	9.7	9.7	9.7	9.8	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
	Limebank MTS	66	59.4	46.8	53.5	53.5	59.7	72.0	74.7	82.0	75.8	79.3	75.5	79.0	84.2	89.4	94.6	99.8	105.0	109.2	112.7	115.3	118.0	120.6	123.3
	Marionville DS	15	13.5	10.3	11.8																				
	Uplands MTS	33	29.7	19.8	22.6	23.5	26.7	28.9	30.4	36.7	41.8	46.8	56.2	56.7	57.1	58.0	58.9	59.4	59.8	60.3	60.7	61.2	61.6	62.1	62.1
	South Gloucester DS	7.5	6.8	3.8	4.3																				
	Greely DS	30	27.0	16.0	18.2																				
	Russell DS	7.5	6.8	3.4	3.9																				
	Centerpoint MTS	14	12.6	13.8	15.8	15.9	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
	Merivale TS	25	22.5	14.4	16.5	16.6	16.6	19.5	19.7	19.7	19.9	20.5	20.9	21.1	21.7	22.2	22.2	22.2	22.2	22.2	22.2	22.2	23.1	23.1	23.1
	National Aeronautical CTS	1.2	1.1	0.4	0.5																				
	Kanata MTS	54.2	48.8	51.6	59.0	62.3	64.9	67.0	70.4	70.4	70.4	70.4	70.4	70.4	71.3	71.7	71.7	71.7	71.7	71.7	71.7	71.7	71.7	71.7	71.7
	South March TS	122.3	110.1	78.0	89.2	28.1	28.1	28.1	28.1	37.1	36.2	35.3	35.3	35.3	34.4	32.6	30.8	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9
	Nepean TS	160.6	144.5	131.9	150.8	151.9	152.6	139.6	143.6	135.5	135.5	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4
	Terry Fox MTS	90	81.0	49.7	56.8	60.7	65.8	67.6	69.4	71.2	73.0	74.8	76.6	78.4	80.2	82.0	83.8	85.6	87.4	89.2	89.2	89.2	89.2	89.2	89.2
	South Nepean TS	#REF!	#REF!	0.0	0.0	0.0	0.0	0.0	0.0	37.5	41.5	45.5	48.5	52.5	56.2	59.2	62.2	65.7	68.7	70.7	72.7	75.7	79.2	79.2	79.2
Outer Ottawa West*	Almonte	TBD	90.0	0.0	N/A	44.1	44.1	46.1	42.5	43.3	43.8	44.2	44.2	44.1	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Merivale Pocket TOTAL				**547**	**627**	**547**	**570**	**590**	**613**	**643**	**656**	**674**	**687**	**703**	**717**	**729**	**740**	**750**	**762**	**771**	**777**	**784**	**791**	**794**	**797**
Downtown	Nepean Epworth TS	14	12.6	10.5	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
	Carling TS	106	95.4	78.9	88.1	91.8	93.6	95.7	96.7	97.3	97.3	102.3	102.7	102.7	102.9	103.3	103.8	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0
	Lincoln Hights TS	79.8	71.8	38.1	42.5	44.3	44.9	44.9	47.1	47.1	47.1	47.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1
	Woodroffe TS	101	90.9	26.7	29.8	32.1	32.1	32.8	33.6	34.2	34.7	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
	Hinchey TS	96	86.4	42.4	47.3	48.5	50.6	55.2	58.1	60.2	62.0	64.9	67.8	69.5	71.2	72.9	74.6	76.3	77.6	79.7	80.9	82.2	83.4	84.7	86.0
	Slater TS	215	193.5	102.1	114.0	124.6	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	126.0	127.0	127.0	127.0	127.0	127.0	127.0	127.0
	Lisgar TS	83	74.7	55.6	62.1	70.3	70.3	71.1	71.8	78.2	78.7	80.1	80.6	81.2	84.6	85.1	85.7	86.2	87.7	88.2	88.7	89.3	89.8	90.4	90.9
	King Edward TS	91.5	82.4	75.8	84.6	90.9	91.0	92.9	93.6	94.3	95.0	95.7	96.5	97.2	97.9	98.6	99.3	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
	Russell TS	77.8	70.0	68.8	76.8	79.5	82.2	86.7	86.7	86.9	87.1	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3	87.3
	Overbrook TS	105.6	95.0	57.8	64.5	67.2	71.8	75.4	77.6	79.2	81.6	83.9	86.0	86.9	88.1	89.0	90.3	91.1	92.4	93.2	94.5	95.3	96.6	97.5	98.7
	Riverdale TS	117.6	105.8	70.8	79.1	85.0	84.7	86.1	88.0	89.7	90.9	91.6	92.4	93.1	93.8	94.5	95.2	96.0	97.9	98.6	99.3	100.1	100.8	101.5	102.2
	Albion TS	99.4	89.5	52.2	58.3	58.6	58.7	58.8	59.0	59.1	59.2	59.4	59.5	59.7	59.8	59.9	60.1	60.2	60.3	60.5	60.6	60.7	60.9	61.0	61.0
	Ellwood TS	50	45.0	34.4	38.4	38.4	39.3	39.9	41.0	41.8	42.4	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	42.5	43.0
Downtown TOTAL				**714**	**797**	**843**	**857**	**877**	**891**	**906**	**914**	**944**	**960**	**965**	**973**	**978**	**984**	**988**	**996**	**1000**	**1004**	**1007**	**1011**	**1015**	**1019**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	94.9	85.4	35.3	40.6	40.6	40.7	41.2	47.2	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8
	Orleans TS	130.3	117.3	88.2	101.5	8.2	9.2	10.6	11.9	13.1	14.4	16.1	18.0	21.1	23.5	24.5	25.2	26.0	26.4	26.8	27.2	27.6	28.0	28.0	28.0
	Cyrville MTS	50	45.0	20.9	24.0	24.0	24.5	27.5	32.7	35.8	38.8	43.0	44.4	46.1	47.3	48.4	49.4	50.3	51.3	52.2	53.2	54.2	55.4	56.5	57.5
	Moulton MTS	33	29.7	23.6	27.2	27.2	27.2	29.0	30.8	32.6	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4
	Wilhaven DS	20	18.0	3.3	3.9																				
	Navan DS	15	13.5	3.6	4.2																				
	Cumberland DS	7.5	6.8	4.7	5.4																				
	Hawthorne TS	152	136.8	88.6	102.0	103.0	102.3	101.9	104.0	110.3	113.6	114.4	116.4	118.4	122.1	126.1	128.7	131.3	133.3	135.3	137.8	140.9	143.2	145.5	146.8
	National Research TS	28	25.2	5.7	6.5																				
Outer Ottawa East*	Clarence DS	3.7	3.3	2.4	2.8																				
	Rockland DS	14.3	12.9	6.9	8.0																				
	Rockland East DS	8.6	7.7	10.3	11.9																				
	Wendover TS	15	13.5	10.1	11.7																				
	Hawkesbury MTS	TBD	#VALUE!	9.5	10.9																				
Hawthorne Pocket TOTAL				**274**	**315**	**203**	**204**	**210**	**227**	**243**	**252**	**259**	**264**	**271**	**278**	**284**	**288**	**293**	**296**	**299**	**303**	**308**	**312**	**315**	**317**
Ottawa Area Sub-region TOTAL				**1535**	**1740**	**1593**	**1631**	**1677**	**1730**	**1792**	**1821**	**1876**	**1911**	**1938**	**1968**	**1991**	**2012**	**2031**	**2054**	**2070**	**2084**	**2099**	**2114**	**2124**	**2133**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals. As well, these stations may or may not reflect DG and CDM impacts.

Sub-Region	Station	10-Day LTR (MVA)	10-Day LTR (MW)	2017 Net Coincident Demand UPDATED	Starting Point of Forecast (Gross, Median Weather)	Gross Demand Forecast with Median Weather Conditions																			
						2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
West Side of Ottawa (Merivale Pocket)	Bridlewood MTS	25	22.5	9.8	11.2																				
	Marchwood MTS	33	29.7	39.2	44.8																				
	Fallowfield DS	25	22.5	39.5	47.1																				
	Manotick DS	8.6	7.7	5.6	6.5	6.6	7.5	8.4	9.2	10.1	10.9	11.8	11.8	11.9	11.8	12.0	11.9	12.1	12.0	12.1	12.1	12.2	12.2	12.3	12.2
	Richmond DS	75	67.5	4.5	5.1																				
	Manordale MTS	10	9.0	8.5	9.7																				
	Limebank MTS	66	59.4	46.8	53.5																				
	Marionville DS	15	13.5	10.3	11.8	12.1	12.3	12.6	12.8	12.9	13.1	13.2	13.3	13.4	13.5	13.6	13.7	13.8	13.9	14.0	14.0	14.1	14.2	14.3	14.3
	Uplands MTS	33	29.7	19.8	22.6																				
	South Gloucester DS	7.5	6.8	3.8	4.3	4.4	4.5	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0
	Greely DS	30	27.0	16.0	18.2	18.7	19.2	19.7	20.0	20.3	20.6	20.9	21.1	21.3	21.5	21.8	22.0	22.1	22.3	22.5	22.7	22.9	23.1	23.3	23.5
	Russell DS	7.5	6.8	3.4	3.9	4.0	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.6
	Centerpoint MTS	14	12.6	13.8	15.8																				
	Merivale TS	25	22.5	14.4	16.5																				
	National Aeronautical CTS	1.2	1.1	0.4	0.5																				
	Kanata MTS	54.2	48.8	51.6	59.0																				
	South March TS	122.3	110.1	78.0	89.2	62.6	64.1	65.7	66.4	67.3	68.3	68.8	69.3	69.8	70.5	71.0	71.6	72.1	72.6	73.0	73.5	74.0	74.4	74.8	75.3
	Nepean TS	160.6	144.5	131.9	150.8																				
	Terry Fox MTS	90	81.0	49.7	56.8																				
	South Nepean TS	#REF!	#REF!	0.0	0.0																				
Outer Ottawa West*	Almonte	TBD	90.0	0.0	N/A	44.1	44.1	46.1	42.5	43.3	43.8	44.2	44.2	44.1	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Merivale Pocket TOTAL				**547**	**627**	**108**	**112**	**115**	**117**	**120**	**122**	**124**	**125**	**126**	**127**	**128**	**129**	**130**	**130**	**131**	**132**	**133**	**134**	**134**	**135**
Downtown	Nepean Epworth TS	14	12.6	10.5	11.7																				
	Carling TS	106	95.4	78.9	88.1																				
	Lincoln Hights TS	79.8	71.8	38.1	42.5																				
	Woodroffe TS	101	90.9	26.7	29.8																				
	Hinchey TS	96	86.4	42.4	47.3																				
	Slater TS	215	193.5	102.1	114.0																				
	Lisgar TS	83	74.7	55.6	62.1																				
	King Edward TS	91.5	82.4	75.8	84.6																				
	Russell TS	77.8	70.0	68.8	76.8																				
	Overbrook TS	105.6	95.0	57.8	64.5																				
	Riverdale TS	117.6	105.8	70.8	79.1																				
	Albion TS	99.4	89.5	52.2	58.3																				
	Ellwood TS	50	45.0	34.4	38.4																				
Downtown TOTAL				**714**	**797**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
East Side of Ottawa (Hawthorne Pocket)	Bilberry Creek TS	94.9	85.4	35.3	40.6	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
	Orleans TS	130.3	117.3	88.2	101.5	94.2	96.2	98.4	99.3	100.3	101.5	102.0	102.6	103.1	103.8	104.4	105.0	105.5	106.0	106.5	106.9	107.4	107.8	108.2	108.6
	Cyrville MTS	50	45.0	20.9	24.0																				
	Moulton MTS	33	29.7	23.6	27.2																				
	Wilhaven DS	20	18.0	3.3	3.9	3.9	3.9	4.0	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.3	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.4
	Navan DS	15	13.5	3.6	4.2	4.2	4.3	4.4	4.5	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.9	4.9	4.9	5.0	5.0	5.0
	Cumberland DS	7.5	6.8	4.7	5.4	5.4	5.5	5.6	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.5
	Hawthorne TS	152	136.8	88.6	102.0	21.7	22.1	22.6	22.8	23.1	23.3	23.5	23.6	23.7	23.9	24.0	24.2	24.3	24.4	24.5	24.6	24.7	24.8	24.9	25.0
	National Research TS	28	25.2	5.7	6.5																				
Outer Ottawa East*	Clarence DS	3.7	3.3	2.4	2.8																				
	Rockland DS	14.3	12.9	6.9	8.0																				
	Rockland East DS	8.6	7.7	10.3	11.9																				
	Wendover TS	15	13.5	10.1	11.7																				
	Hawkesbury MTS	TBD	#VALUE!	9.5	10.9																				
Hawthorne Pocket TOTAL				**274**	**315**	**130**	**133**	**136**	**137**	**139**	**140**	**141**	**142**	**143**	**144**	**145**	**146**	**146**	**147**	**148**	**148**	**149**	**150**	**150**	**151**
Ottawa Area Sub-region TOTAL				**1535**	**1740**	**239**	**245**	**251**	**255**	**259**	**262**	**265**	**267**	**268**	**270**	**272**	**274**	**276**	**277**	**279**	**280**	**282**	**283**	**284**	**286**

*Outer Ottawa Sub-Region stations are included for reference only and are excluded from the totals. As well, these stations may or may not reflect DG and CDM impacts.

1. Definition of Median and Extreme Weather Conditions

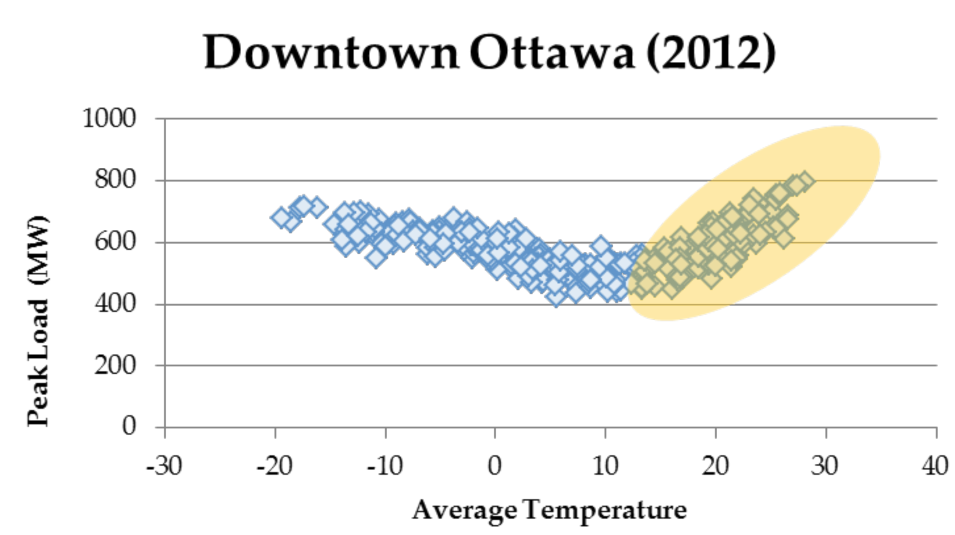
Median Weather tempeaeture is defined as daily peak temperature of 33.3 °C, or daily average temperature of 27.2 °C (median temperature of the past 30 years weather data)
Extreme Weather temperature is defined as daily peak temperature of 36.9 °C, or daily average temperature of 29.2 °C (Max temperature in the past 30 years weather data)

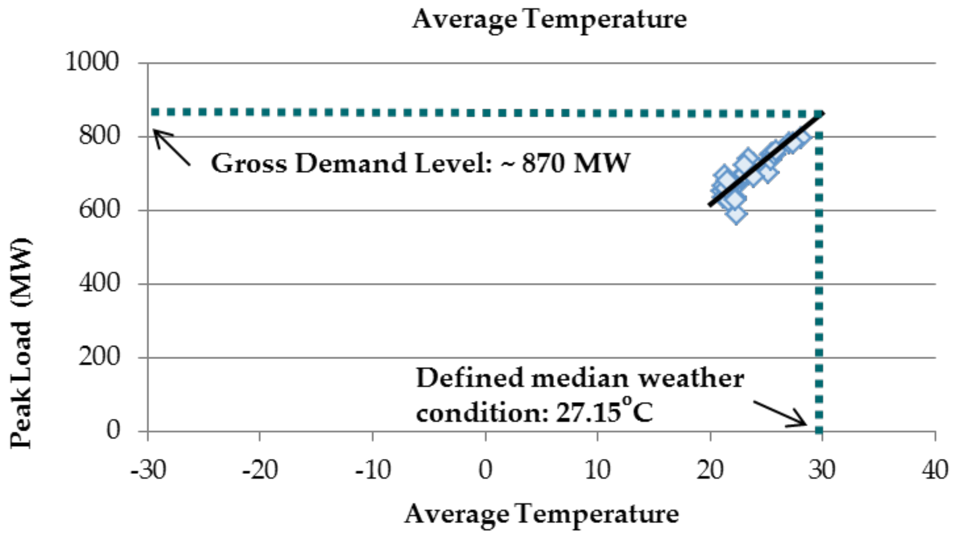
2. Pocket Level Demand and Temperature Correlation

Demand / Temp. Correlation Factor	Hawthorne Pocket	Merivale Pocket	Downtown
2012	0.82	0.88	0.86
2013	0.87	0.87	0.95
2014	0.57	0.56	0.66
2015	0.90	0.88	0.88
2016	0.75	0.80	0.85
2017	0.77	0.80	0.85

Note: Correlation factors are established excluding data points for holidays and weekends

Example of Downtown area demand and temperature corelation (2012)





3. Forecast Median Weather to Extreme Weather Adjustment Factor

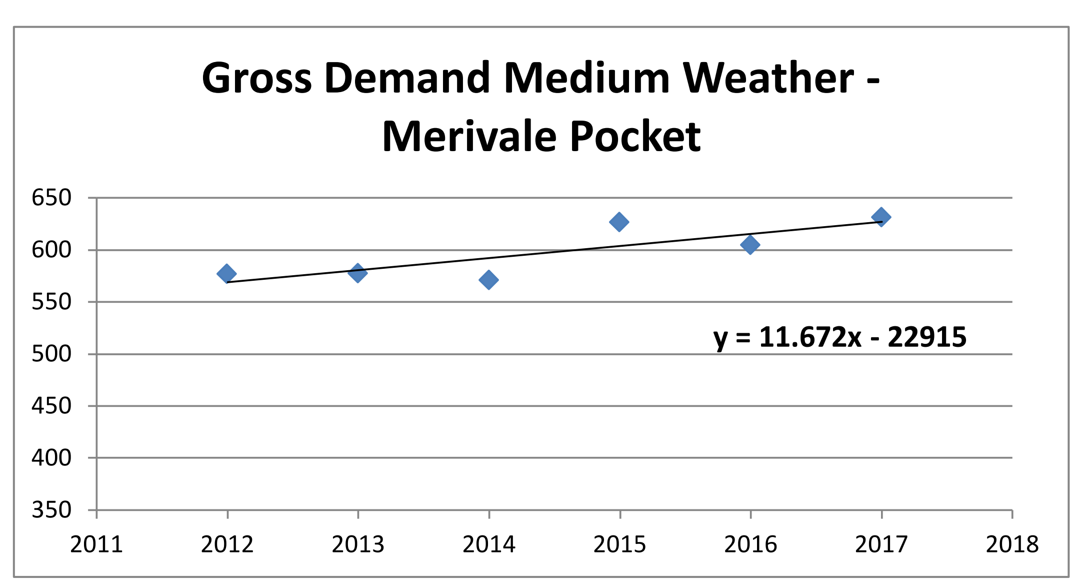
Median to Extreme Weather Adjustment Factor

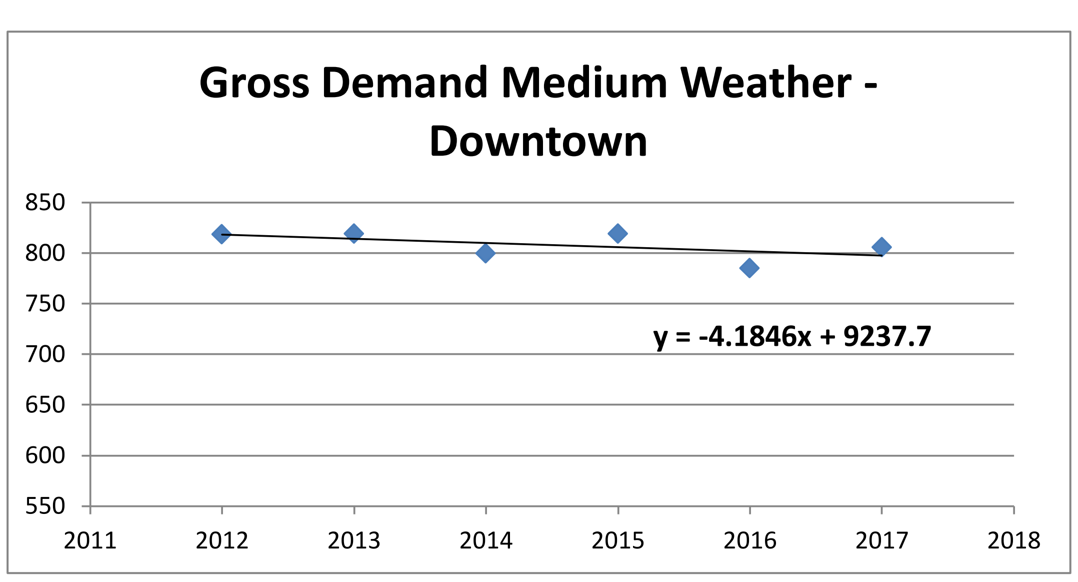
Sub-Pocket	Historical						Forecast
	2012	2013	2014	2015	2016	2017	2018 - 2037
Merivale Pocket	1.10	1.09	1.07	1.11	1.07	1.09	1.09
Downtown	1.07	1.09	1.06	1.08	1.05	1.07	1.07
Hawthorne Pocket	1.08	1.09	1.07	1.10	1.06	1.10	1.08

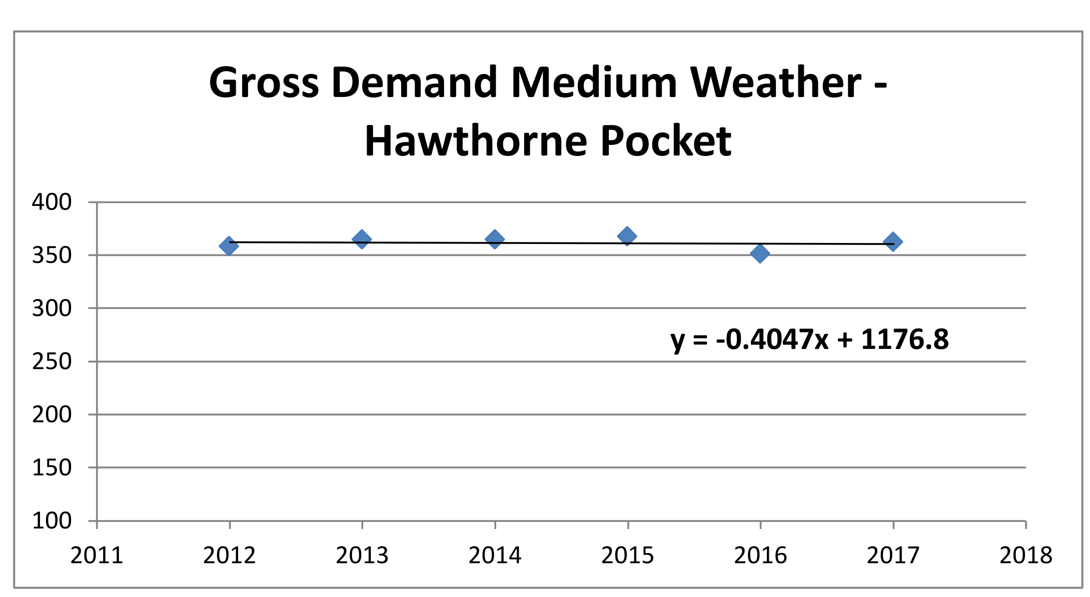
4. Establish the Starting Point of Forecast

Base Year: **2017**

Year	Gross Demand under Median Weather		
	Merivale Pocket	Downtown	Hawthorne Pocket
2012	576.8	818.3	358.1
2013	577.5	819.1	364.5
2014	570.7	799.6	364.7
2015	626.6	819.2	367.6
2016	604.6	784.9	351.3
2017	631.1	805.6	362.7
STARTING POINT	**627.4**	**797.4**	**360.5**







	Starting Point		20 year net median		20 year net extreme		20 year gross median	
	2015	2019	2015	2019	2015	2019	2015	2019
Merivale Area		627	-	818	707	888	782	932
Downtown		797	-	864	1187	926	1314	1019
Hawthorne Area		315	-	414	267	448	296	477
Ottawa Area Sub-region		1740	0	2096.8733	2161	2262	2392	2428

Version	Changes
1.0 - 2.0	Coordination with Ottawa IRRP working group to finalize demand forecast
2.1	Demand updates to South Nepean, Kanata, South March, and Terry Fox due to revised Terry Fox station rating (from 100 MVA to 90 MVA)
2.1.1	Updated CDM (as per Demand update and minor CDM changes at other stations) – by Humphrey Updated DG (added in all Almonte DG and removed all Hawkesbury DG) – by Ben
2.2	New low CDM as per cancelled programs and policies
2.3	Additional Manotick Load by HONI Dx
2.3.1	Updated CDM for Manotick Load
2.4	Updated Orleans TS (one feeder was missing from load forecast), Bilberry Creek TS, Cyrville MTS, and Moulton MTS loads from HOL Updated CDM to reflect load changes Updated effective capacity factor of DGs (Hydro and Biomass) as per HOL input Update Greely LTR from 20 MVA to 30 MVA as per HONI Dx update
2.5	Update Limebank, Uplands, and Hawthorne Loads Update CDM as per load changes Update DG at 115kV downtown stations Added Tab for base CDM and low CDM

Appendix E: Ottawa Regional Planning Status Letter

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Ajay.Garg@HydroOne.com

December 11th, 2019
Ben Hazlett,
Hydro Ottawa Limited
2711 Hunt Club Road, P.O Box 8700
Ottawa ON
K1G 3S4

Dear Mr. Ben Hazlett
Subject: Regional Planning Status Letter 2019

As per your request, this Planning Status letter is provided to meet one of your requirements of cost of service application to the Ontario Energy Board (OEB).

The province of Ontario is divided into 21 Regions for the purpose of Regional Planning (RP), and these regions have been split into three (3) groups for the purposes of prioritizing and managing the RP process. A map of Ontario showing the 21 Regions and the list of LDCs in each of the Region are attached as Appendix A and B respectively. An overview of the RP process is available on Hydro One's RP homepage, which includes current status of each region in the RP process and all corresponding reports.

Hydro Ottawa Limited (HOL) is a LDC supplying electricity to customers in the Greater Ottawa region. The RP status of the Greater Ottawa region is summarized below:

1. Greater Ottawa Region

The first Regional Planning cycle for Greater Ottawa Region was completed in December 2015 and the current cycle of regional planning is in the Integrated Regional Resource Plan (IRRP) phase and RIP will be undertaken by Hydro One after the expected completion of IRRP in Q1 2020.

The previous regional planning cycle identified the following needs:

- **Merivale TS T22 – LTR exceeded:** The need is to increase the 230/115kV transformation capacity for the region. This will be further reviewed as part of the Regional Planning process. Cost allocation will be dependent on the proposed solution and will be consistent with the TSC.
- **Ottawa Centre 115kV Area – Station Capacity:** The following stations are a part of the Ottawa Centre 115kV area capacity increase:
  - **Russell TS & Riverdale TS:** Hydro Ottawa had plans to increase feeder ties between these two stations and other near-by stations to increase load transfer capability. These upgrades have been completed.
  - **King Edward TS – Station Capacity:** Existing transformer T3 is approaching end-of-Life and needs replacement. Consistent with the TSC, HOL will be responsible for incremental cost to upgrade the size of the transformer unit from 75MVA to 100MVA with expected in-service in 2021.

- **South West Area – Station and Transmission Capacity:** There was significant load growth anticipated in the southwest region of Ottawa. The following transmission and station upgrades are required to meet the growing demand:
  - **South Nepean MTS (Cambrian MTS):** HOL plans to construct a new municipal transformer station, to meet the growing demand in the south west region of Ottawa. The station is planned to be in-serviced by November 2021.
  - **South Nepean Transmission Reinforcement:** To supply the new station, South Nepean MTS, Hydro Ottawa has requested Hydro One to connect the station to 230kV circuit E34M and 115kV circuit S7M. HOL is expected to be required to pay a capital contribution of approximately $48.0M. The project is planned to be in-serviced by November 2021.
- **Bilberry Creek TS:** This need is discussed later in this section under the current Regional Planning cycle.

The Needs Assessment (NA) of the current cycle was completed in June 2018 with focus on the Outer Ottawa sub-region. The station and transmission supply capacities in the Outer Ottawa sub-region are sufficient for the duration of the study period with no system reliability or restoration issues. The following need have been identified by the study team:

- **Slater TS – EOL T2/T3 Replacement:** The existing transformers T2 and T3 at Slater TS are approaching end-of-life. The existing 45/75MVA transformer units will be replaced with new higher rated 60/80/100MVA units. Hydro One is coordinating with Hydro Ottawa to address this need. Cost allocation to HOL for this investment will be consistent with the Transmission System Code (TSC). The project is expected to be in-serviced by 2022.

The IESO led IRRP for the Ottawa Area sub-region is underway with an expected completion in Q1 2020. The following needs identified by the study team have cost implications to HOL:

- **27.6kV Supply – Station Capacity (Terry Fox MTS, Marchwood MTS, Kanata MTS):** HOL plans to perform load transfers between the three stations. However, the combined capacity of the stations will be exceed the available capacity under peak load conditions in the near term planning horizon. Hydro One will plan with Hydro Ottawa for any potential transmission infrastructure upgrades as part of the RIP phase of Regional Planning process. Cost allocation will be dependent on the proposed solution and will be consistent with the TSC.
- **Leitrim MS – Station Capacity:** There is growing demand in the southeast region of Ottawa. The demand forecast for Hydro Ottawa's Leitrim MS will exceed station capacity in the near term planning horizon. This need will be further assessed in the RIP phase.
- **Orleans TS – Station Capacity:** This need is tied with the Bilberry Creek TS end-of-life need discussed later in this section. Both needs require further assessment in the RIP phase. Cost allocation will be dependent on the proposed solution and will be consistent with the TSC.

End-of-Life Needs:

- **Bilberry Creek TS – EOL T1/T2 Replacement:** The transformers T1 and T2 at the station are approaching end-of-life. There was discussion whether Bilberry Creek TS can be retired and the existing load on the station can be transferred to Orleans TS. The working group recommends the alternative to refurbish the station with like-for-like transformers and addition of two breaker positions to accommodate HOL load. Cost allocation to HOL for this investment will be consistent with the TSC.

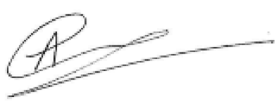
It is expected that there will be some cost implications for Hydro Ottawa to address some of the needs mentioned above.

Reference documents for this region can be found on the Hydro One website at the following link:
https://www.hydroone.com/about/corporate-information/regional-plans/greater-ottawa

The new planning process provides flexibility during the transition period to the new process, and will ensure that both distribution and transmission planning continue to address any short-term needs. Hydro One looks forward to working with Hydro Ottawa Limited in executing the regional planning process.

If you have any further questions, please feel free to contact me.

Sincerely,



Ajay Garg, Manager - Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo- Cambridge-Guelph ("KWCG")		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Energy+ Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc.** • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Alectra Utilities Corporation • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Alectra Utilities Corporation • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Energy+ Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.

6. Metro Toronto	• Alectra Utilities Corporation • Hydro One Networks Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham- Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	• Algoma Power Inc. • Chapleau PUC • Hydro One Networks Inc. • PUC Services Inc
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc.** • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.**
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.

13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • InnPower Corporation • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Alectra Utilities Corporation • Veridian Connections Inc. • Veridian Connections Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham- Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.** • Alectra Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* * Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A → This region is not within Hydro One's territory

19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

**This Local Distribution Company (LDC) has been acquired by Hydro One Networks Inc.

Appendix 2-AA
Capital Programs Table

Projects	2016	2017	2018	2019 Bridge Year	2020 Bridge Year	2021 Test Year	2022 Test Year	2023 Test Year	2024 Test Year	2025 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access										
Plant Relocation	7,129	5,183	4,737	11,719	12,012	10,135	8,418	8,474	5,451	5,427
Residential	4,350	4,945	6,179	8,090	4,681	4,893	4,999	5,006	5,010	4,980
Commercial	11,880	10,990	19,519	10,793	11,023	16,078	13,465	11,639	11,806	11,914
System Expansion	8,726	3,833	5,984	8,216	19,128	20,116	8,685	6,960	6,769	6,289
Stations Embedded Generation	678	291	89	165	338	360	296	297	306	319
Infill & Upgrade	3,844	4,787	3,046	3,658	4,087	4,164	4,221	4,099	4,164	4,151
Damage to Plant	1,122	851	1,126	1,250	986	-	-	-	-	-
Metering	77	26	169	884	1,075	947	947	958	957	959
Sub-Total	37,805	30,908	40,849	44,775	53,331	56,693	41,032	37,434	34,462	34,039
System Renewal										
Stations Asset Renewal	13,346	13,991	20,478	8,531	6,970	9,938	12,071	8,444	7,437	9,316
OH Distribution Assets Renewal	11,801	11,099	10,846	6,487	9,164	7,999	8,795	8,795	8,841	8,044
UG Distribution Assets Renewal	9,677	9,421	9,023	4,627	7,415	11,082	10,780	11,164	11,079	11,077
Corrective Renewal	7,815	9,304	14,595	9,801	8,739	9,822	9,805	9,838	9,812	9,817
Metering Renewal	-	-	-	-	-	4,455	2,561	1,950	2,266	2,219
Sub-Total	42,639	43,816	54,942	29,446	32,288	43,296	44,012	40,191	39,436	40,474
System Service										
Capacity Upgrades	3,186	6,050	14,423	13,870	22,127	19,791	9,717	14,577	17,799	13,964
Stations Enhancements	219	1	14	20	21	905	459	459	459	459
Distribution Enhancements	12,715	11,805	6,108	7,920	7,420	6,957	12,732	5,981	4,597	4,796
Grid Technology	1,306	6,098	8,243	4,685	2,021	2,847	4,006	2,819	1,799	4,179
Metering	357	890	1,013	1,013	1,031	501	501	501	501	501
Sub-Total	17,783	24,844	29,801	27,509	32,621	31,002	27,415	24,337	25,155	23,899
General Plant										
Buildings - Facilities	3,904	18,207	46,658	18,627	453	428	428	403	403	403
Customer Service	1,296	2,275	38	4,528	5,099	2,539	1,616	846	826	1,188
ERP System	3,721	7,309	104	159	679	756	896	1,245	6,554	5,588
Fleet Replacement	2,619	1,584	1,195	583	1,632	6,345	4,526	2,220	1,681	2,008
IT New Initiatives	1,658	651	2,839	2,057	1,115	924	549	609	333	887
IT Life Cycle & Ongoing Enhancer	1,152	858	2,059	800	1,458	1,981	1,411	1,250	1,035	1,664
Operations Initiatives	937	1,327	199	688	1,624	1,681	1,572	321	928	477
Tools Replacement	390	442	503	1,039	450	474	474	462	465	469
Hydro One Payments	4,647	5,647	3,143	6,757	30,070	16,918	210	200	5,130	4,200
Sub-Total	20,323	38,300	56,738	35,239	42,580	32,047	11,681	7,556	17,354	16,884
Miscellaneous										
Total	**118,550**	**137,867**	**182,330**	**136,969**	**160,820**	**163,037**	**124,140**	**109,518**	**116,407**	**115,296**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***										
Total	**118,550**	**137,867**	**182,330**	**136,969**	**160,820**	**163,037**	**124,140**	**109,518**	**116,407**	**115,296**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

2021

CATEGORY	Historical Period (previous plan[1] & actual)															Test Years Forecast Period (planned)				
	2016			2017			2018			2019			2020			2021	2022	2023	2024	2025
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Bridge	Var	Plan	Bridge	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	38,936	37,805	-2.9%	35,156	30,908	-12.1%	35,132	40,849	16.3%	35,835	44,775	24.9%	36,551	53,331	45.9%	56,693	41,032	37,434	34,462	34,039
System Renewal	38,008	42,639	12.2%	30,047	43,816	45.8%	34,580	54,942	58.9%	34,100	29,446	-13.6%	33,769	32,288	-4.4%	43,296	44,012	40,191	39,436	40,474
System Service	22,585	17,783	-21.3%	35,733	24,844	-30.5%	31,430	29,801	-5.2%	32,353	27,509	-15.0%	35,263	32,621	-7.5%	31,001	27,415	24,337	25,155	23,899
General Plant	45,899	20,323	-55.7%	48,138	38,300	-20.4%	18,276	56,738	210.5%	18,695	35,239	88.5%	13,954	42,580	205.1%	32,047	11,681	7,556	17,354	16,884
TOTAL EXPENDITURE	145,428	118,550	-18.5%	149,074	137,868	-7.5%	119,418	182,330	52.7%	120,983	136,969	13.2%	119,537	160,820	34.5%	163,037	124,140	109,518	116,407	115,296
Capital Contributions	- 23,636	- 19,491	-17.5%	- 23,190	- 17,315	-25.3%	- 22,926	- 16,742	-27.0%	- 23,385	- 27,580	17.9%	- 23,853	- 34,532	44.8%	- 41,254	- 25,217	- 19,943	- 19,226	- 19,264
Net Capital Expenditures	121,794	99,058	-18.7%	125,883	120,552	-4.2%	96,491	165,588	71.6%	97,597	109,388	12.1%	95,685	126,288	32.0%	121,783	98,923	89,574	97,181	96,032
System O&M		$ 28,137	--		$ 29,158	--		$ 30,002	--		$ 31,050	--		$ 33,591	--	$ 32,779				

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
See Section 8.1 of Exhibit 2-4-3: Distribution System Plan
Notes on year over year Plan vs. Actual variances for Total Expenditures
See Section 8.1 of Exhibit 2-4-3: Distribution System Plan
Notes on Plan vs. Actual variance trends for individual expenditure categories
See Section 8.1 of Exhibit 2-4-3: Distribution System Plan

Appendix 5-A
Metrics

Metric Category	Metric	Measures[4]	
		1 Year	5 Year Average
Cost	Total Cost per Customer[1]	$803.00	$664.00
	Total Cost per km of Line[2]	$46,678.00	$38,634.00
	Total Cost per MW[3]	$186,762.00	$158,146.00
CAPEX	Total CAPEX per Customer	$544.00	$412.00
	Total CAPEX per km of Line	$31,616.00	$23,970.00
O&M	Total O&M per Customer	$259.00	$252.00
	Total O&M per km of Line	$15,062.00	$14,663.00

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves.

2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor operates to serve its customers.

3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

4 Measures are per 2018 results.

Explanatory Notes on Adverse Deviations (complete only if applicable)

Metric Name:

Metric Name:

Metric Name:

NAVIGANT
A Guidehouse Company

December 30, 2019

Margaret Flores
Supervisor, Asset Planning
Hydro Ottawa Limited
3025 Albion Road North, PO Box 8700
Ottawa, ON K1G 3S4

margaretflores@hydroottawa.com

Re: Independent Assessment of Hydro Ottawa's Distribution System Plan

Dear Ms. Flores:

This letter summarizes Navigant's independent assessment of Hydro Ottawa Limited's (Hydro Ottawa) Distribution System Plan (DSP). Our review and assessment has been structured to address Chapter 5 filing requirements as set forth by the Ontario Energy Board's (OEB).[1] Our review provides responses to the following topics and questions.

1. Is Hydro Ottawa's DSP consistent with the guidelines and objectives set forth in Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications?
2. How well does the DSP addresses the OEB's four performance outcomes, customer focus, operational effectiveness, public policy responsiveness, and financial performance?

Our review assesses Hydro Ottawa's responsiveness and compliance with Sections 5.2, 5.3, and 5.4 of the OEB's Chapter 5 filing requirements for rate regulated electricity distribution utilities in Ontario. The findings and conclusions from our review is based on our detailed analysis and independent assessment of the following three documents that Hydro Ottawa prepared in anticipation of a cost of service application to the OEB in late 2019 or early 2020. Hydro Ottawa incorporated several recommendations following our review of initial drafts of these documents. It is from these revised documents that Navigant based its findings and conclusions.

1. Distribution System Plan (DSP)
2. Strategic Asset Management Plan (SAMP)
3. Attachment E to Hydro Ottawa's DPS – Material Investments

Summary Assessment

From its review of the three documents referenced above, Navigant concludes that Hydro Ottawa has met or exceeded the minimum requirements set forth in Chapter 5. This finding is based on Navigant's compliance review of Chapter 5 DSP filing requirements for the four investment categories that electric distributors must assign to capital investments in its rate application: (1) System Access; (2) System Renewal; (3) System Service; and (4) General Plant.

[1] Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications, July 12, 2018.

Hydro Ottawa's DSP provides the OEB and interested stakeholders with sufficient information to make a determination that the company's investment plan fully complies with the following filing objectives; namely, a distributor must demonstrate that its DSP fully addresses,

- Asset related performance objectives and approach to evaluating its performance relative to those objectives.

  Conclusion: *HOL's DSP describes in detail how each investment optimally meets performance targets and objectives. The DSP lists performance targets over the five-year rate application and how each investment will enable HOL to meet these targets.*

- Approach to lifecycle asset management planning and the management of asset related operational and financial risk

  Conclusion: *HOL's Strategic Asset Management Plan and project evaluation methodology is consistent with leading industry practices. HOL's methodology quantifies the degree to which proposed investments reduces risk and provides value to customers over the life of the asset.*

- Plan for capital-related expenditures over a five-year forecast period and the justification of these expenditures.

  Conclusion: *HOL's DSP documents the company's annual spending plan for each investment category, with supporting analysis that identifies the benefits that each investment provides to customers to justify the proposed investment.*

- Planned investments related to accommodating the connection of renewable energy generation (REG).

  Conclusion: *Where applicable, HOL's DSP describes how specific investments will enable increased REG interconnection, and how these investments mitigate barriers that exist today for renewable generation.*

- Planned investments for the development and implementation of the smart grid to support grid modernization and expenditures as required by legislation. Grid modernization involves investing in innovative solutions that make systems more efficient, reliable and cost effective and more prepared for technological changes, such as electric vehicles and distributed energy resources, and provide more customer choice.

  Conclusion: *HOL's General Plant programs describes in details the company's smart grid, initiatives technologies and specific programs that are underway or proposed during the rate period. The DSP specifically describes ongoing pilots, incentive-based initiatives and innovative strategies to improve reliability, efficiency and customer-oriented measures to enhance the customer experience.*

Navigant's detailed assessment for Sections 5.2 through 5.4, and associated subsections, supporting our conclusion that the DSP fully complies with OEB Chapter 5 requirements follows. The relevant section in OEB's Chapter 5 appears in the parenthetical adjacent to the heading.

Distribution System Plan (Section 5.2)

Hydro Ottawa's DSP is structured to fully address each OEB requirement outlined in Chapter 5. The DSP includes associated spreadsheets, attachments and exhibits to support the methods, plans and projects outlined in the DSP. Among these is Hydro Ottawa's Strategic Asset Management Plan (SAMP), which documents the objectives and processes the company applies in managing its assets and investment decisions, and Attachment E which presents business cases for investments that exceed $750,000.

While the DSP addresses each section of Chapter 5, the DSP does not follow each section sequentially. Hence, the DSP in Attachment – maps each section (and subsection) of Chapter 5 to the correspond section in the DSP where the topic is addressed.

Distribution System Plan overview (Section 5.2.1)

Per Chapter 5 requirements, the DSP provides a high-level overview of the methods, assumptions and data supporting Hydro Ottawa's rate application for investments covering the years 2021 through 2025. Navigant's review of the DSP and supporting documents indicates Hydro meets this requirement via provision of:

- Data highlighting where development activities drive the need for capacity expansion, local infrastructure project such as the light rail transit projects, and aging and deteriorating asset support the capital investments needed to meet reliability, performance and capacity targets;
- The processes the company follows to determine customer preferences and to engage stakeholders in its planning activities These include customer surveys and outreach via community meetings to ensure that proposed investments address customers' preferences and expectations regarding their impacts on their communities and businesses;
- The DSP (and Attachment E for Material Investments) quantify cost savings Hydro Ottawa expects to achieve over the rate application period via effective approaches asset management and capacity planning;
- Specific details on the vintage of major asset classes and end-of-life status as a basis to justify proposed investment drivers used to justify investments, by year, during the five-year rate application interval;
- Documented enhancements to asset management processes, tools and methods since its last DSP filing in the Strategic Asset Management Plan that will be included in the current rate filing;
- Descriptions and details of the approach the company follows to minimize investments needed to meet capacity deficiencies, including effective coordination with the IESO (e.g. via the IRP processes, load transfers, voltage conversions and regional demand management, the latter which resulted in the deferral of a major station; and
- Identification of projects related to cost-effective grid modernization, distributed energy resources, and climate change adaptation and how these projects address the goals of the Long-Term Energy Plan.

Coordinated planning with third parties (Section 5.2.2)

Throughout the DSP, Hydro Ottawa describes the activities, processes and notifications for third parties to ensure they are aware of DSP improvement or construction plans and afforded the opportunity to provide input to plans, and how HOL incorporates third-party feedback into the planning process. In Section 1.10 Hydro Ottawa outlines the activities it has undertaken to coordinate planning on major projects that may affected communities by conducting neighborhood outreach, community meetings, coordination with local officials. Hydro Ottawa provides examples of how third-party feedback has resulted in adjustments or changes to accommodate local concerns or issues.

Hydro Ottawa also coordinates planning activities for capacity supply with the IESO and other regional utilities, including ongoing updates of the regional Integrated Regional Resource Plan that will be issued in 2020. It includes consultation with the IESO and regional utilities for the Regional Infrastructure and Integrated Regional Resource Plans (including the ongoing IRRP), and how these plans are incorporated into Hydro Ottawa's distribution plans. These consultations and actions highlighting where demand response programs may be able to cost-effectively and reliably defer station capacity upgrades.

Performance measurement for continuous improvement (Section 5.2.3)

Section 4.1 of the DSP lists performance targets for reliability, power quality, efficiency (losses), unit costs, safety, capacity overloads, and project completed to support its continuous improvement process. Where targets have not been met, the reasons why and how the company proposes to prospectively meet the target is documented, including how proposed investments will enable the company to meet these targets.

These sections also present historic performance metrics such as SAIDI and SAIFI reliability metrics. Where performance targets have not been met, explanations are provided for the deviation (such as 2018 ice storms) and actions the company will undertake to meet all targets.

Realized efficiencies due to smart meters (Section 5.2.4)

Section 4.5 of the DSP lists the quantity of smart meters HOL has installed since 2006 and the benefits the company and its customers have received. Section 4.5 highlight these benefits, including enhanced billing, improved capacity planning, and data analytics. Accordingly, Hydro Ottawa's smart meter program and benefits it has derived are consistent with Chapter 5 requirements and expectations.

Asset Management Process (Section 5.3)

Hydro Ottawa's asset management processes align with the strategies and objectives outlined in Strategic Asset Management Plan (SAMP). Section 3.0 and Hydro Ottawa's SAMP outlines the foundational principles, policies and responsibilities associated with the company's asset management organization and practices. The SAMP supports the company's strategy to enhance value and customer experience. The DSP documents the methods and criteria HOL uses to implement asset management policies outlined in the SAMP. Section 5 presents Hydro Ottawa's methods for assessing the condition of its station and distribution assets, which is based on a detailed scoring analysis of asset health and associated health indices that reflect likelihood of asset failure. Hydro Ottawa engaged an expert third-party to assess the maturity of its asset condition assessment implementation, which concluded,

> *Overall, the third party found that Hydro Ottawa's ACA framework utilized robust formulations that are in alignment with best practices, and that it was tightly integrated with Hydro Ottawa's broader Asset Management related processes, procedures and outcomes.*

Asset management process overview (Section 5.3.1)

The SAMP outlines how Hydro Ottawa's processes and objectives support the company's strategic plan, which focuses on providing value to its customers. Sections 5 and 8 of the DSP describe the tools and methods the company applied to achieve performance targets at lowest possible cost. It describes the alternatives evaluated and analytical tools used to prioritize investment choices to meet these targets. The DSP also describes how climate change and recent events such as the 2018 ice storms impacted prior spending and proposed equipment replacement programs. Throughout the DSP, Hydro Ottawa describes the role of technology to enhance reliability and customer value such as SCADA and numerous hardware/software upgrades (Section 8 of the DSP and 4 of Attachment E).

Overview of assets managed (Section 5.3.2)

Section 6.1 of the DSP lists in significant detail the quantify and vintage of major asset categories and components for stations, and overhead and underground distribution assets. It includes detailed diagrams and descriptions of specific components, and the significance of these components on equipment performance and reliability. As noted, other sections lists vintages and quantities of major equipment categories, including those exceeding or within ten years of expected end-of-life.

Asset lifecycle optimization policies and practices (Section 5.3.3)

Section 6.2 of the DSP describes the tools and methods the company applies to optimize spending, with proposed investments targeted to meet performance targets and enhance the enhance the customer experience. The methods HOL applied are consistent with leading industry practices and Chapter 5 requirements, as they prioritize investments based on value provided and ability to maximize benefits relative to spending levels. For System Renewal investments, HOL conducted a detailed condition assessment of each asset class and likelihood of failure to determine asset volumes and timing of investments needed to achieve performance goals and manage risk. For System Service, HOL presents alternatives that meet growth in specific areas in manner that maximizes utilization of existing assets at lowest possible cost.

System capability assessment for renewable energy generation (Section 5.3.4)

Section 7.3 of the DSP addresses renewable energy generation or REGs (also referred to as ERFs), with the quantity, capacity rating, location and type summarized in tables and charts for both small (including micro), medium and larger REGs. The DSP lists remaining REG interconnection capacity, by station, for both spinning and inverter-based REGs. Section 7.3 identifies stations that currently are constrained, and actions the company can undertake to mitigate these constraints; mostly reverse power or thermal violations. Notably, there currently are only three stations that are constrained with respect to REG connections.

Capital Expenditure Plan (Section 5.4)

Section 8.0 of the DSP presents the ten-year spending plan for the years 2016 through 2025. The first five years cover the currently approved rate period, with actual spending for 2016 through 2018, and committed (i.e. “bridge”) spending for capital investments for 2019 and 2020. Tables for both historical and future spending are presented, with variances for prior years listed along with capital contributions – explanations for variances from the original spending plan also are provided. Proposed spending for years 2021 through 2025 are included in the company’s five-year rate application for each of the four investment categories, along with capital contributions and net capital spending. It describes the reasons for changes in average spending in each investment category for the rate application period compared to historical levels. As noted in Section 8.0, Ottawa Hydro’s spending plan is designed to achieve the following:

> *This spending plan is a continuation of the objectives outlined in the 2016-2020 DSP, which focused on the enhancement of system capacity to keep pace with growth and shifts in loads within the service territory, and the renewal of aged and aging infrastructure that are at greatest risk of failure.*

Section 8.0 and sections that follow clearly document how the company plans to meet to load and customer growth, climate change adaptation, grid modernization and/or the accommodation of forecasted REG projects via targeted and cost-effective investments, including how customer preferences are incorporated into the asset planning and selection process. Additional details supporting this finding is presented in the following subsections.

Capital expenditure planning process overview (Section 5.4.1)

Section 8.1 of the DSP described the process Hydro Ottawa followed to determine the amount of investments required over the 2021 through 2025 rate application period to meet performance targets and achieve related strategic objectives that focus on enhancing the customer experience. Section 8.1 describes the key drivers underlying investments in each subcategory. This section also describes the methodology Hydro Ottawa applied to determine investment levels for the project and programmatic investments, and how it optimized spending, where applicable, via use of its C55 prioritization tool. Sections 8.2 through 8.5 present in greater detail required investments for the four investment categories, including the impact capital programs are expected to have on O&M expenses.

Section 8.2 describes Hydro Ottawa's processes to determine required investments for System Service, including load forecast for each area within its service territory, and how it will address capacity deficiencies. The company also describes the role climate change has on its investment plans and how electric vehicle additions are likely to impact growth forecasts. Section 8.3 presents processes for System Renewal, required investments are determined via outputs of Hydro Ottawa's Asset Investment Strategy described in further detail in Section 5. Key focus areas for renewal investments are highlighted such as replacement of end of life or obsolete distribution assets and refurbishment of station equipment. Section 8.2 and 8.5 address System Access and General Plant, respectively. Navigant's assessment of the latter two section indicates Hydro Ottawa meets OEB minimum requirements, including the role of technology to enhance efficiency and reduce costs.

Rate-Funded Activities to Defer Distribution Infrastructure (Section 5.4.1.1)

As noted, coordination with the IESO and other entities on the Regional Resource and Integrated Resources Plans has led to the deferral of a major station investment. Hydro Ottawa's asset management strategy and processes has also resulted in deferral of infrastructure investment that could be justified on the basis of age (i.e. exceeds expected end of life), but remains in service due to proactive maintenance or asset condition assessments supporting continued operation of older, but reliable equipment. Further, Hydro Ottawa is applying technology to performance real-time monitoring of major equipment such as station transformers, which provide critical operational data to control room operators to detect abnormal conditions before failure. Hydro Ottawa has also initiated the next phase of its GRid Edge Active Transactional Demand Response, Version 2 (TGDR2), which is designed "to optimize existing distribution, transmission and centralized generation infrastructure by managing supply-demand locally," with demonstration programs at select customer sites.

Capital expenditure summary (Section 5.4.1)

Section 8.1 of the DSP outlines details five-year historical expenditures and proposed spending over the five-year rate application. Historical spending is presented for the years 2016 through 2020, inclusive, with committed spending for years 2019 and 2020 included as bridge years under the currently approved five-year rate period. Tables documenting actual versus budgeted spending are presented, along with a detailed explanation and justification of variances. Where applicable, O&M expense savings are documented, mostly for System Renewal project where reduced maintenance is expected.

Capital expenditure planning process overview (Section 5.4.2)

Various sections throughout the DSP outline HOL's tools, methods and processes for prioritizing and selecting investments included in the 2021 through 2025 rate application. System Renewal investments align with HOL's asset management strategy and objectives documented in the SAMP, which balancing risk based on ACA's for each equipment category versus benefits achieved by better performing and more efficient asset replacements. For example, a thorough assessment of high cost, at risk station transformers is based on potential failure based on ACA results and the number of customers and duration affected. Station capacity investments are made based on several considerations, such as local growth, mandated projects (e.g. light rail transit projects), IESO joint planning, Hydro One system upgrades, and standardization opportunities (i.e. voltage conversions). General Plant requirements incorporate opportunities where technology – in particular, software and system enhancements – contribute to process efficiency and enhanced customer experience. Further, Hydro Ottawa in its planning identifies opportunities to enable increased REG connections by mitigating constraints such as reverse power limits.

Justifying capital expenditures (Section 5.4.3)

Sections 8.1 through 8.5 of Hydro Ottawa's DSP provide details on the methods and rationale the company used to justify proposed spending for projects in each of the four investment categories. The analytic methods applied to evaluate asset condition or capacity deficiencies are described in sufficient detail for the OEB and stakeholders to assess need and proposed spending levels. Key drivers such as asset condition, criticality, customer experience and mandated spending is documented, with additional details on how proposed spending will enable HOL to meet performance goals and targets. Additional detail in the form of in-depth business cases are presented in Attachment E for projects exceeding $750,000.

Overall plan (Section 5.3.2.1)

Sections 8.1 through 8.5 of the DSP outlines Hydro Ottawa's proposed spending plan for each of the four investment categories and associated subcategories. It includes tables that display spending trends and shifts in spending – the reasons for shifts in average spending is documented in Section – as well as several other sections of the DSP. As highlighted earlier, average spending for the five-year rate application will be lower than the prior five years, despite mandated spending for infrastructure projects, development-related load growth, and aging and deteriorating assets.

Material investments (Section 5.3.2.2)

Attachment E of Hydro Ottawa's DSP includes a comprehensive analysis to justify major projects and programs within each of the 4 investment categories; that is, those with investments cost of $750,000 or greater within the five-year rate application interval. For each project or program, Hydro Ottawa evaluated three or more alternatives, including a "do nothing" option, where applicable. Each project is consistently evaluated under several criteria outlined in Chapter 5, including cost effectiveness, customer benefits, risk reduction, reliability, efficiency and impact on operation and maintenance expense. Attachment E builds upon methods and assumptions outlined in the DSP, but with additional details and justification for each investment.

* * * * *

We thank you the opportunity to work with Hydro Ottawa and would be pleased to answer any questions you might have with respect to our independent review of its Distribution System Plan.

Sincerely,

Eugene Shlatz

Eugene J Shlatz

Director

eshlatz@naviant.com


Attachment 2-4-3 (E): Material Investments
2021-2025 Hydro Ottawa Rate Application

SYSTEM RENEWAL

1.1. STATION ASSET RENEWAL

1.1.1. STATION TRANSFORMER RENEWAL PROGRAM

1.1.1.1. Program Summary

Hydro Ottawa's station transformer renewal program is a program used to replace end-of-life station-class power transformers in a planned fashion. Station transformers are critical assets operating within Hydro Ottawa's distribution system. They provide voltage transformation from a higher line voltage to a lower voltage to distribute power throughout the city. Each station transformer is involved in the supply of several thousand customers.

This program includes the planned renewal of station transformers and supporting structures. The renewal program is planned to manage the long term performance of the assets, and it is prioritized based on asset condition assessment. Where multiple systems have reached end-of-service life, transformer renewal is undertaken as part of a full station renewal, under the Station Major Rebuild program.

In the 2021-2025 rate period, Hydro Ottawa plans to initiate projects to renew ten station transformers with eight new ones. Two of these as part of the station transformer renewal program, and six transformers as part of the station major rebuild program. Hydro Ottawa also adds new station transformers through the Station Capacity Upgrades program under System Service.

1.1.1.2. Program Description

1.1.1.2.1. Assets in Scope

Hydro Ottawa owns and operates 167 station transformers equipped with the following primary, high-side voltages: 97 at 13.2 kV, 41 at 44 kV, 23 at 115 kV and 6 at 230 kV. These voltages are stepped down to serve distribution lines at 27.6 kV, 13.2 kV, 12.8 kV, 8.32 kV, and 4.16 kV.

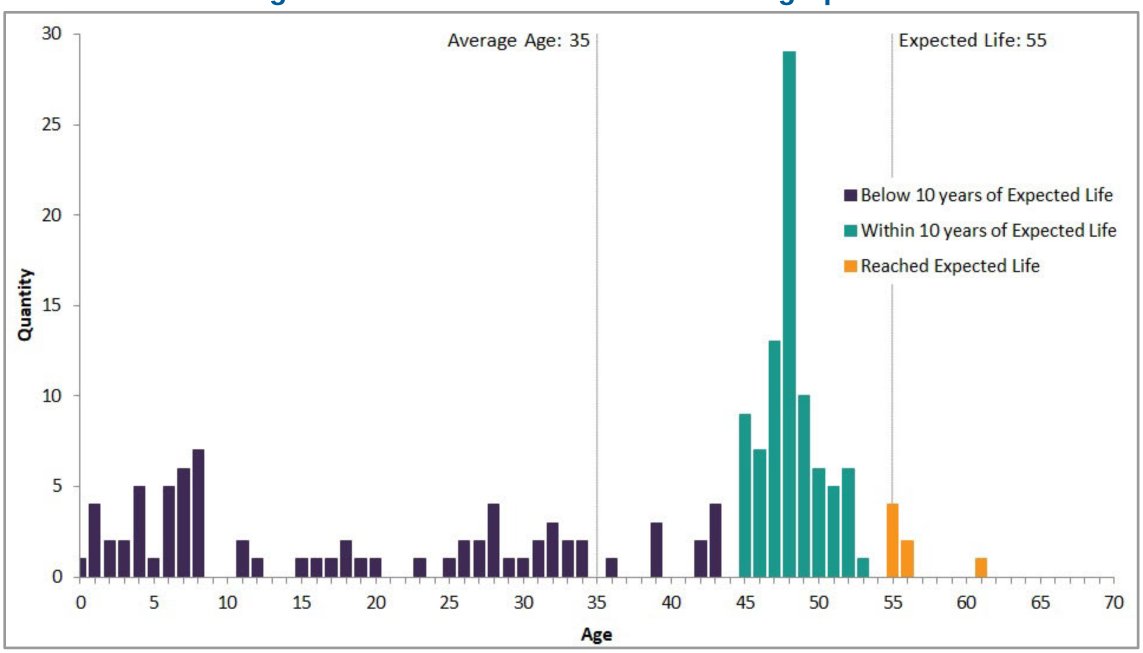
In addition to replacing the station transformer itself, these projects include renewal of the supporting infrastructure and may require the addition or upgrade of oil containment, ground grid, cable, and protection & control ("P&C") systems.

Where multiple station systems are renewed under a single project, the transformer replacement will be undertaken as part of the Station Major Rebuild project. Further details on full station rebuild projects can be found in this document as well as in the *92012234 - Station Major Rebuild* business case document.

1.1.1.2.2. Asset Life Cycle and Condition

The age demographics of Hydro Ottawa's station transformers are shown in Figure 1.1. There are a large number of transformers between 45 and 52 years of age; the majority of these transformers have primary voltages of 13.2 kV or 44 kV. There are currently 7 transformers operating beyond their expected service life of 55 years; this will increase to 62 transformers by the end of 2025 if no transformers are replaced under this program.

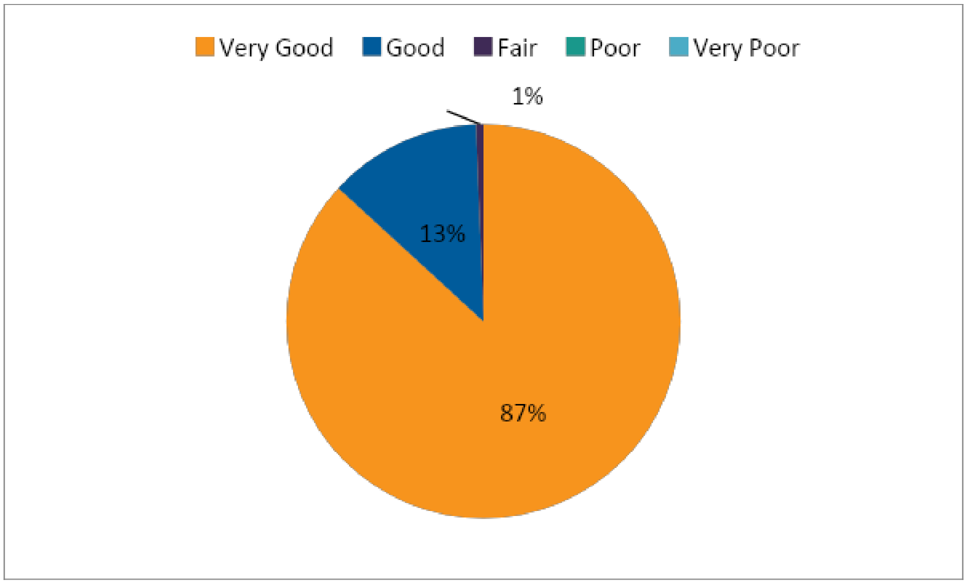
Figure 1.1 - Station Transformer Demographics



The transformer health index is based on degradation factors that are obtained from Hydro Ottawa's testing and inspection programs. The details of the health index formulations can be found in Hydro Ottawa's Health Index Formulation standard-GEG0001.

Figure 1.2 below shows Hydro Ottawa's transformer demographics in terms of condition, based

Figure 1.2 - Station Transformer Health Demographics



1.1.1.2.3. Consequence of Failure

Station transformer failures can have significant financial, reliability, safety and environmental consequences.

Station transformers have a high reliability impact as they supply a relatively large number of customers. Hydro Ottawa's stations are planned and designed to withstand the loss of a single element or contingency, including the loss of a transformer due to failure. As a result, service can typically be restored quickly for a single transformer failure. However, with long lead times and high project complexity, emergency station transformer replacements are lengthy projects. While replacement is being undertaken, the system is left in a state of increased reliability risk, as the ability to restore service following the failure of an element may not be possible, or may require overloading of the remaining unit(s) in service. Both these risks typically result in costly temporary measures until permanent replacement of the failed unit is completed.

Catastrophic transformer failures have the potential to damage other surrounding equipment. Although rare, such catastrophic failures pose a threat to employee safety as well. Failure of the transformer tank can also lead to the release of insulating oil. Depending on the construction of the station and presence of oil containment facilities, this may pose a risk of release to the environment.

Hydro Ottawa has and continues to augment techniques to mitigate these risks through the introduction of various improvements to the design and technology used in the past. Physical infrastructure such as blast walls and oil containment pits reduce the consequences of failure of station transformers. Protection equipment such as protective relays, circuit switchers, and high voltage breakers isolate faulted transformers quickly, thereby limiting damage and mitigating the potential for catastrophic failure. Additionally, Hydro Ottawa employs online monitoring technologies such as live temperature and dissolved gas monitoring to allow system operators to detect potential problems via early indicators and initiate intervention prior to transformer failure.

1.1.1.2.4. Main and Secondary Drivers

The drivers are represented in Table 1.1 below.

Table 1.1 – Main and Secondary Drivers

	Driver	Explanation
Primary	Failure Risk	7 transformer units have exceeded end-of-life criteria that will grow to 62 by the end of rate filing period 2025 if no transformers are replaced under this program. This increasing failure risk due to the number of units surpassing their expected service life will exceed the level which can be addressed if proactive replacements are not maintained.
Secondary	Reliability, Safety	Station transformers have a direct impact on system reliability, as all customers connected will experience a power outage in the event of a failure. An increasing number of power transformer failures will have an impact on SAIFI and SAIDI. The transformer renewal program also offers the opportunity to address issues that would otherwise be impractical to correct. For example, electrical capacity upgrades, physical infrastructure upgrades such as blast walls and oil containment pits, and protection system upgrades can all be implemented in the scope of a transformer renewal project.

1.1.1.2.5. Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the station transformer replacement program, improvements are expected in the KPI metrics shown in Table 1.2 due to high-risk transformers being renewed before failing.

Table 1.2 - Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	Customer Engagement	Maintain Customer Satisfaction
		System Reliability	Maintain SAIFI and SAIDI
Cost Efficiency & Effectiveness	Resource Efficiency	Cost Efficiency	Reduce Cost due to emergency replacement
		Labour Utilization	Reduce Labor Allocation to Outage Restoration
Asset Performance	Asset Value	Defective Equipment Contribution to SAIFI	Maintain Defective Equipment SAIFI
	Health, Safety & Environment	Oil Spilled	Maintain current levels

The station transformer renewal program will enable Hydro Ottawa to reduce transformer failures by replacing high-risk transformers before they fail. This will manage transformer failure risk to an acceptable level, and maintain low failure rates to meet customer expectations for reliability.

1.1.1.3. Program Justification

1.1.1.3.1. Alternatives Evaluation

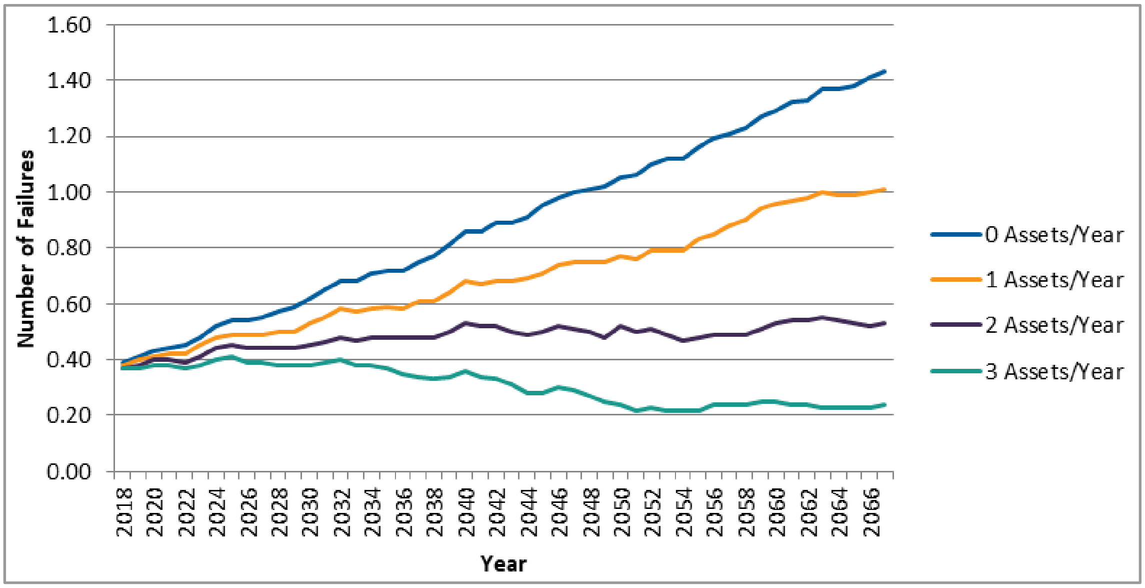
Alternatives Considered

In order to address the drivers and achieve the performance objectives of the program, Hydro Ottawa conducted an analysis to optimize the number of units renewed as part of transformer renewal projects, with the goal of minimizing the number of transformer failures. The alternatives considered in the optimization of the transformer renewal program included:

- Only replacing transformers in a reactive manner, after they have failed
- Replacing one transformer per year
- Replacing two transformers per year
- Replacing three transformers per year

A summary of this analysis is shown in Figure 1.3 below. As there have been two transformer failures in the past five years, the current failure rate per year is 0.4.

Figure 1.3 - Station Transformer Failure Rate per Planned Replacement Level



This analysis was performed with the following assumptions:

- The oldest transformers are prioritized for renewal.
- A failed transformer is replaced in the same year, with no impact on the planned renewal program.

Alternatives Evaluation

Hydro Ottawa evaluates all renewal alternatives with consideration of the following risk criteria:

Failure/Reliability

The increased potential of failure posed by these ageing assets will impact Hydro Ottawa's ability to deliver reliable power. The selected alternative shall maintain or improve the reliability performance of the system.

Safety

Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must mitigate any present risks to Hydro Ottawa's employees and the public safety.

Resources

Unplanned replacements are usually carried out by Hydro Ottawa's own crews, whereas planned replacements can be performed by both internal and external resources. The preferred alternative will lead to more planned renewal projects, where appropriate staffing resources can be allocated, rather than unplanned renewal projects that would take resources away from other work.

Financial

Financial costs and benefits shall include all direct and indirect impacts on the utility's performance and rates.

Preferred Alternative

The preferred alternative is the targeted replacement of an average of two transformers per year from 2021 to 2025. Below is a description of the preferred alternative with respect to the criteria mentioned above.

Failure / Reliability

Failure forecasts indicate that the replacement of two units per year will maintain the transformer failure rate near its current level of 0.4 over the next five years. An increase in replacement rate will be required beyond 2025 to maintain and improve asset performance as more assets move past their expected life.

As is visible in the forecasts shown in Figure 1.3, replacing an average of 3 units annually would have a greater impact to reduce risk in the longer term. However, any additional risk posed by the deferral of these replacements is planned to be mitigated through the planned transformer maintenance program, annual oil sampling, annual station infrared inspection program, as well as through monthly visual inspections.

Safety

The proposed station transformer replacement policy will manage the risk to the safety of Hydro Ottawa employees and the public by reducing the number of transformers that are likely to fail based on age.

Through Hydro Ottawa's inspection and maintenance programs, safety risks will be identified and prioritized for remediation should they arise.

Resources

The preferred alternative will optimize staffing resources by scheduling and planning future work. Planned station transformer renewal requires lower labour resources, through coordination of effort. Furthermore, corrective renewal negatively impacts the ability to complete planned work due to redirection of resources.

Financial

The costs associated with replacing transformers in an emergency situation are higher than planned replacements, as temporary measures are required to restore contingencies until the transformer is replaced.

1.1.1.3.2. Program Timing & Expenditure

Table 1.3 below provides information on the expenditures and station transformer units replaced that were completed in the historical period as part of the transformer renewal program.

Table 1.3 - Expenditure History and Forecast of Transformer Renewal Projects

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Program Cost ($'000,000s)	$3.70	$1.51	$2.75	$0.25	$0.97	$2.36	$0	$0	$0	$0
Transformer Replacement Units	2	0	1	0	0	2	0	0	0	0

Station transformers are also renewed as part of full station rebuilds. Table 1.4 below provides information on the expenditures and station transformer units replaced that were completed in the historical period as part of the station major rebuild program.

Table 1.4 – Expenditure History and Forecast of Station Rebuild Projects

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Program Cost ($'000,000s)	$3.95	$5.24	$8.75	$2.79	$4.18	$4.72	$8.34	$6.19	$5.44	$8.70
Transformer Replacement Units	0	1	2	2	0	0	0	3	2	1

Historically, station transformers have also been renewed as part of switchgear renewal projects. Table 1.5 below provides information on the expenditures and station transformer units replaced that were completed in the historical period as part of the switchgear renewal program.

Table 1.5 – Expenditure History and Forecast of Switchgear Renewal Projects

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Program Cost ($'000,000s)	$5.02	$6.58	$8.79	$4.54	$0.40	$1.57	$2.24	$1.67	$1.20	$0.03
Transformer Replacement Units	0	0	0	3	0	0	0	0	0	0

The execution of station transformer renewal projects can vary depending on the physical and electrical characteristics of the station. Some projects require to be staged such that the new transformer is constructed while keeping the existing transformer in-service. Once constructed, the connections are transferred to the new transformer with minimal interruption to the customers.

1.1.1.3.3. Benefits

Key benefits that will be achieved by implementing the station transformer replacement program are summarized in Table 1.6 below.

Table 1.6 – Program benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	With renewal of the supporting infrastructure as part of the transformer replacement. Provides efficiencies over the life of the renewed asset, new protection, monitoring and control – result in lower risk operation over the life of the new transformer, and increased efficiency of operation through remote monitoring and operation capabilities.
Customer	Improved reliability due to decreased transformer failures. Improved reliability and safety due to upgraded protection and control systems.
Safety	Proactive replacement mitigates risk of catastrophic failure events. Through both renewal of assets, and upgraded protection and control systems allow for better internal fault detection, which rapidly will isolate the transformer under fault conditions.
Cyber-Security, Privacy	(Not applicable)
Coordination, Interoperability	For station transformer replacement projects that involve transmission connection requirements, Hydro Ottawa coordinates with Hydro One to complete the transmission connection.
Economic Development	Hydro Ottawa hires third party contractors to complete certain projects when the projects cannot be completed with its own internal resources.
Environment	Hydro Ottawa reduces the risk of oil release to the environment through the installation of oil containment unit underneath each transformer.

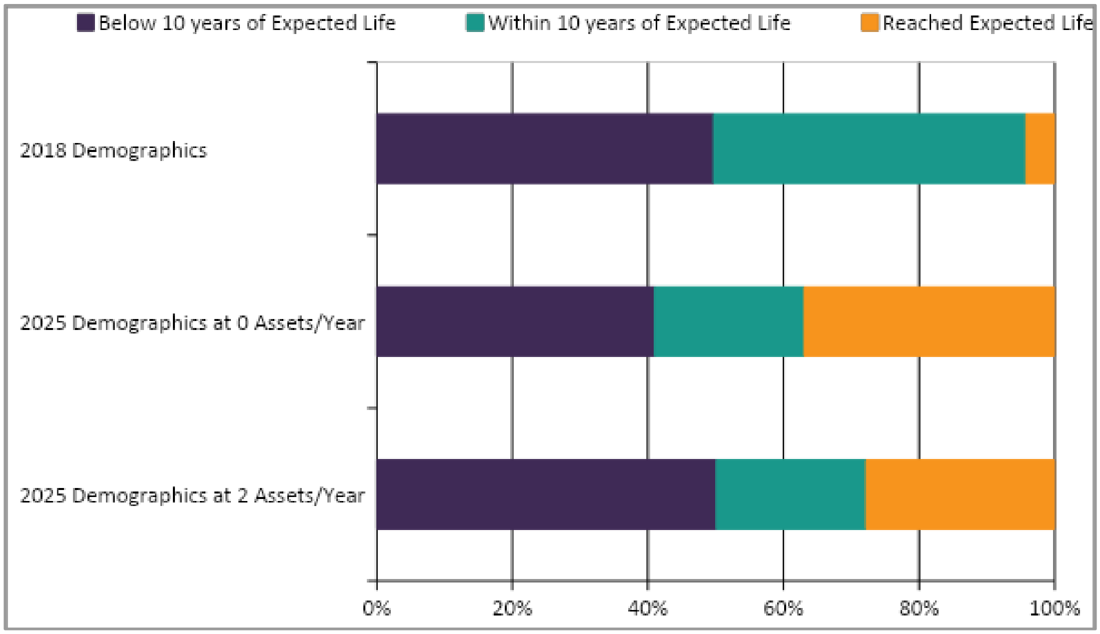
1.1.1.4. Prioritization

1.1.1.4.1. Consequences of Deferral

If the station transformer renewal program is deferred to the next planning period or adequate replacement levels are not achieved, this asset group will pose additional safety, reliability, resource, and financial risks as a result of the increased potential for in-service failures. As shown in Figure 1.3, Hydro Ottawa is expected to experience significantly higher failure rates within the next five years without this program in place.

In the long term, deferral of station transformer replacements will also create a backlog of assets in poor condition that will require more capital investment in the future in order to bring the overall condition of the entire asset class to an acceptable level. Figure 1.4 below shows how Hydro Ottawa's station transformer demographics compare at the end of the 2021 to 2025 rate period with and without the execution of this program.

Figure 1.4 – Hydro Ottawa Station Transformer Alternatives Comparison



1.1.1.4.2. Priority

Station transformer renewal is prioritized on the individual asset failure probability assessed through asset condition, and consequence of failure. With higher reliability impact for older stations with no oil containment, these projects are of significant priority.

1.1.1.5. Execution

1.1.1.5.1. Implementation Plan

Station transformer replacement projects typically span over two to three years. The projects start with the design, followed by equipment procurement, installation, and commissioning. Hydro Ottawa is planning for the following transformer replacements to be completed from 2021 to 2025 as part of the transformer renewal program:

- Bayswater Transformer Renewal (2021)

Hydro Ottawa is planning for the following transformer renewals as part of the station major rebuild program from 2021 to 2025:

- Bell's Corners Rebuild (2019 to 2023)
- Fisher Rebuild (2021 to 2024)
- Rideau Heights (2022 to 2024)
- Dagmar Rebuild (2023 to 2026)
- Shillington (2024 to 2028)

1.1.1.5.2. Risks to Completion and Risk Mitigation Strategies

Table 1.7 below describes the various risks of performing station major rebuild projects, as well as their mitigation strategies.

Table 1.7 - Program Risks and Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: • Project planning to minimize outages to customers and that coordinate with other planned work in the area; • Coordinating with the transmitter (for transmission connected transformers) • Adherence to schedules; • Timely procurement of equipment	Hydro Ottawa has dedicated project managers who oversee the project to ensure that risk is managed accordingly. It is Hydro Ottawa's practice to schedule and coordinate all work (planned and emergency) through our System Office to ensure effective use of resourcing and ensure continued system operability and safety in areas where crews are working.

1.1.1.5.3. Timing Factors

Transformer projects are typically planned to include any civil construction outside of the winter months to avoid weather-related issues. Procurement, and manufacturing timing of the transformers, significantly informs the project schedule.

1.1.1.5.4. Cost Factors

Cost factors that affect replacement projects are listed below:

- Delays in the project schedule, often driven by coordination with other parties such as Hydro One and IESO
- Compatibility with existing equipment
- Material prices (copper, steel), impact transformer costs

1.1.1.5.5. Other Factors

(Not applicable for this program)

1.1.1.6 Renewable Energy Generation

With transformer renewal, Hydro Ottawa's standard is to install an on-load tap changer and protection and control (P&C) on new transformers which allow for reverse power flow. This upgrade increases the capacity for renewable generation which can be connected to the transformer, relative to some legacy transformers that cannot accommodate reverse power flow. Therefore, a transformer renewal performed as part of a transformer renewal project may allow for more new renewable generation to be connected to Hydro Ottawa's system.

1.1.1.7. Leave-To-Construct

(Not applicable for this program)

1.1.1.8. Program Details and Justification

Table 1.8 - Station Transformer Renewal Overview

Project Name:	Station Transformer Renewal
Capital Cost:	$2.36M
O&M:	$0
Start Date:	2021
In-Service Date:	2021
Investment Category:	Renewal
Main Driver:	Failure Risk
Secondary Driver(s):	Reliability
Customer/Load Attachment:	System Wide
Project Scope	
The scope of this program is to replace the existing transformers at Bayswater station with two 7.5MVA units, as well as install oil containment to mitigate the environmental risks posed by oil leaks.	
Priority	
Station transformer renewal is prioritized on the individual asset failure probability assessed through asset condition, and consequence of failure. With high reliability impact for older stations with no oil containment, these projects are of significant priority.	
Work Plan	
The transformer renewal program will be executed in 2021, with a cost of $2.36M.	
Customer Impact	
Customers will experience improved reliability due to decreased transformer failures and availability of redundant systems, as well as improved reliability and safety due to upgraded protection and control systems. The customer benefits from a program that prioritizes station transformers renewal based on condition, ensuring the reliability and cost effectiveness of the distribution system.	

1.1.2. STATION SWITCHGEAR RENEWAL PROGRAM

1.1.2.1. Program Summary

Hydro Ottawa's station switchgears are employed at substations to provide protection to electrical distribution equipment by quickly isolating faults to limit damage to equipment, as well as to provide switching control options to safely isolate equipment during planned and unplanned maintenance and capital activities. The major pieces of equipment renewed within this program include switchgear enclosures, bus work, breakers, and protection and control (P&C) equipment. The program also renews breakers located outside of switchgear enclosures, such as outdoor reclosers, isolation switches, high-voltage gas circuit breakers, and circuit switchers.

The cost of station switchgear replacement cost can vary considerably by location and the impact of failures may have drastically different reliability, operational, safety and environmental consequences. Switchgear renewal programs may also require additional upgrades to the stations systems, communications, and the DC supply system (charger and battery bank). It may also lead to the construction of new switchgear and P&C buildings. The program targets the planned replacement of switchgear based on their age and health indices to maintain safety and system reliability in the most cost effective manner.

The renewal program is planned to maximize the long term performance of the assets, and it is prioritized based on asset condition assessment. Where multiple station systems and equipment have reached their end of service life, switchgear renewal is undertaken as part of a full station renewal, under the 92012234 – Station Major Rebuild program.

During the 2021-2025 rate period, Hydro Ottawa's plans to initiate projects to replace 68 breakers at five different stations. This involves replacing 26 breakers for one project under the switchgear renewal program, and the replacement of 42 breakers in four projects under the station major rebuild program.

1.1.2.2. Program Description

1.1.2.2.1. Assets in Scope

Hydro Ottawa's station switchgear asset class consists of breakers, switches, bus and bus insulation, support structures, P&C systems, arrestors, control wiring, ventilation, and fuses. Hydro Ottawa's current standard is to install arc-resistant switchgear for all of its new switchgear installations.

If the switchgear serves Hydro Ottawa's 4 kV distribution system, a voltage conversion project may be considered as an alternative to like-for-like replacement.

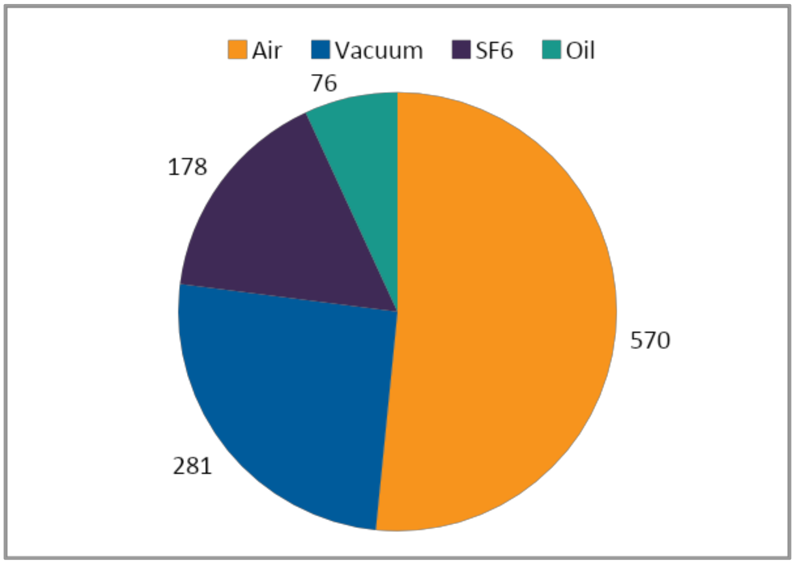
Though multiple projects are planned, the scope of Hydro Ottawa's switchgear renewal program for 2021-2025 is limited to a project to replace one switchgear lineup containing 26 breakers. Projects to renew four other switchgear renewal lineups (containing 42 breakers) are being planned as part of the Station Major Rebuild program to allow for more efficient spending by renewing the entire station, rather than splitting the work into several renewal projects. The station switchgear targeted for replacement from 2021 to 2025 are identified in the specific projects listed in Section 1.2.5.1.

1.1.2.2.2. Asset Life Cycle and Condition

Historically, switchgear replacements have been prioritized based on the age and health index of the individual breakers. Switchgear prioritized and selected for renewal in the 2021 to 2025 period have been assessed using a similar approach.

Hydro Ottawa owns 1,105 station breakers in 85 stations throughout the service territory. There are four main types of breakers used in the system, categorized by their interrupting medium; air, vacuum, oil, and gas (SF6). Breaker demographics are shown in Figure 1.5 below.

Figure 1.5 - Hydro Ottawa's Station Breaker Count by Sub-class



Based on industry-provided probabilities of failure, the expected life of each breaker type is shown in Table 1.9 below.

Table 1.9 – Expected Life of Hydro Ottawa Breaker Types

Breaker Type	Expected Life
Air	42
Oil	55
Vacuum	46
Gas (SF6)	51

As shown in Figure 1.6, Figure 1.7, Figure 1.8, and Figure 1.9 below, 560 of Hydro Ottawa's station breakers are operating at or past their expected operating life. By 2025, the number of station breakers that will be at or past their expected life will increase to 561 if no planned replacements are made. Hydro Ottawa will continue performing preventative maintenance and ongoing inspection to maintain aging breakers beyond their expected lives.

Figure 1.6 - Station Air Breaker Age Demographics

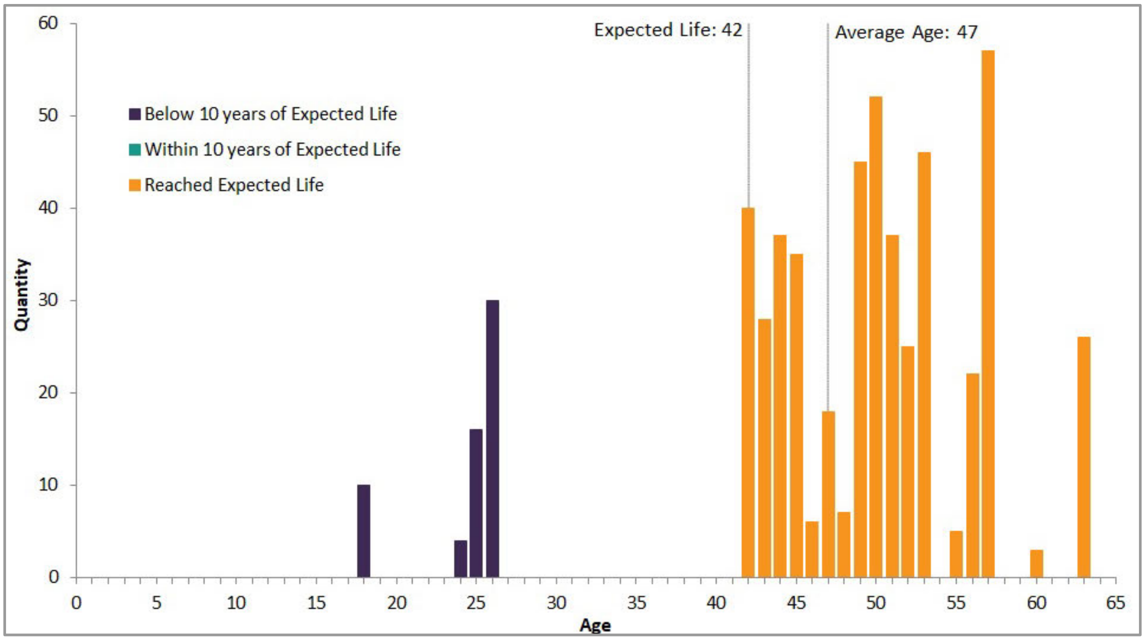


Figure 1.7 – Station Oil Breaker Age Demographics

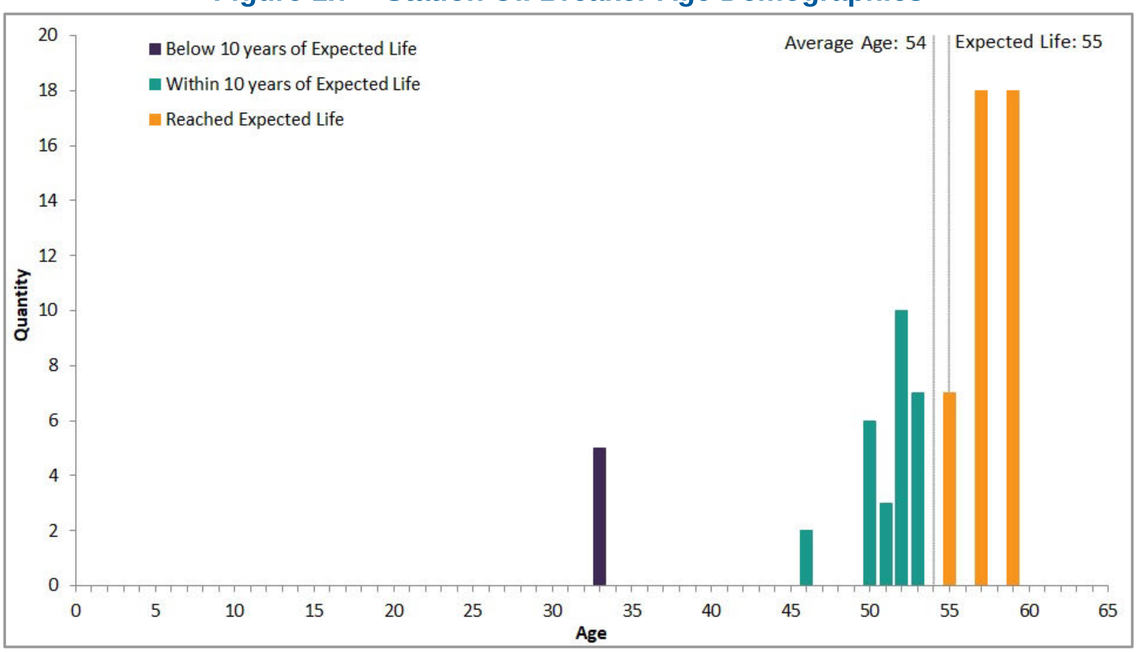


Figure 1.8 – Station SF6 Breaker Age Demographics

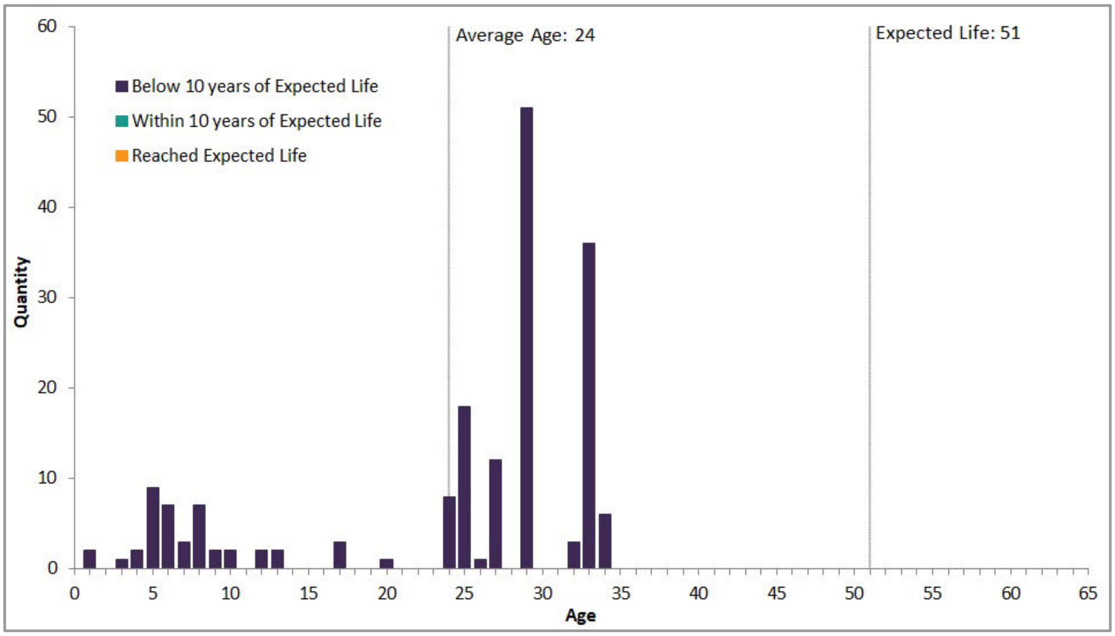
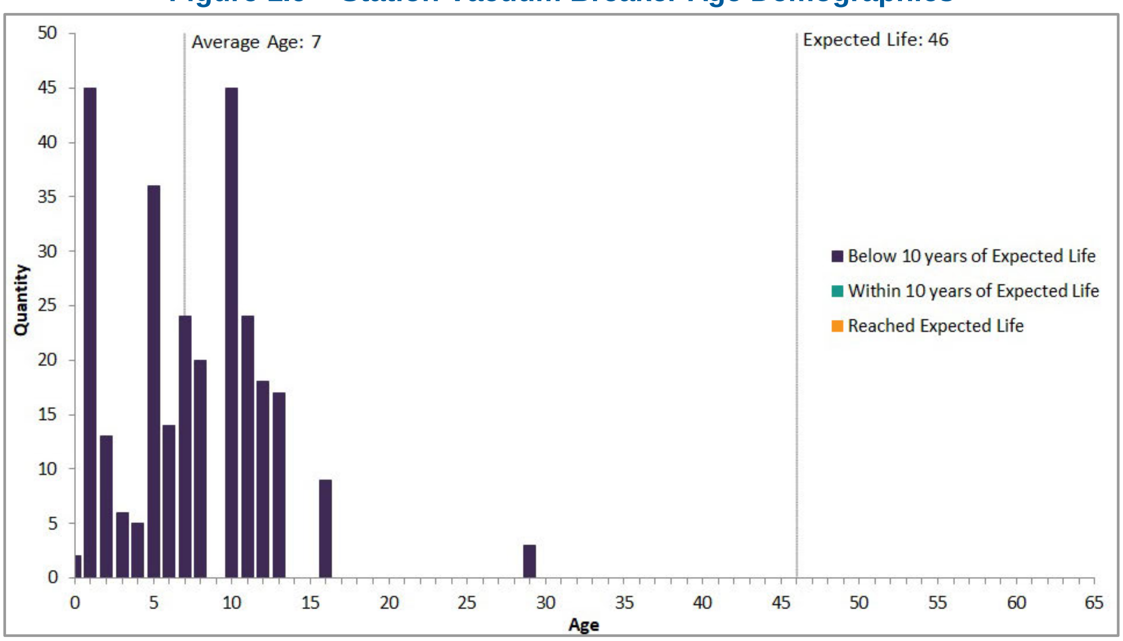


Figure 1.9 – Station Vacuum Breaker Age Demographics



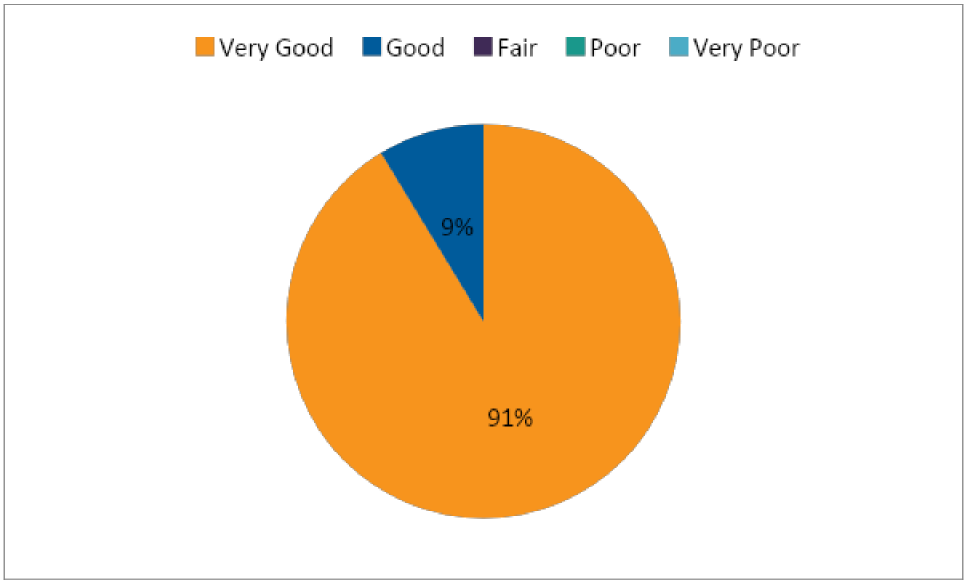
Hydro Ottawa's health condition assessment considers the many components contained within station switchgear assemblies. A qualitative assessment of the equipment condition based on subject matter experience and test results is performed on the switches, breakers, insulation, and supporting structures. Then, the health index is calculated using this information and the age of the equipment.

The health of a breaker can be broken down into three main components: thermal, dielectric, and mechanical stresses.

- Thermal stresses occur due to internal heating or local overheating stemming from short-time overload. Thermal stresses can be measured using micro ohm measurements and through infrared scanning.
- Dielectric stresses occur due to system overvoltages, transient impulse conditions, dielectric ageing, or arcing caused by breaking load current. They can be measured through hi-potential test readings and depending on the type of interrupting medium, through dielectric breakdown (oil), vacuum integrity (vacuum), and gas pressure (SF6) tests.
- Mechanical stresses can occur between operating mechanisms (springs, coils, hydraulic), racking mechanisms, or any other moving part of the breaker. Their integrity is verified by injecting a test current and operating the breaker, and by visual inspection.

Hydro Ottawa currently tracks the health index through results from field-acquired test and inspection data. The breaker health index is based on degradation factors that are obtained from Hydro Ottawa’s testing and inspection programs. Figure 1.10 below illustrates Hydro Ottawa’s breaker health index demographics. The details of the health index formulations, including a list of degradation factors and health index formulas, can be found in Hydro Ottawa’s Asset Health Index Guideline, GEG0001.

Figure 1.10 - Hydro Ottawa's Breaker Health Index Demographics



1.1.2.2.3. Consequences of Failure

On average, there have been 1.6 station switchgear failures experienced annually over the last five years. If no switchgear renewal projects are executed, this trend is expected to increase due to the number of assets past their end-of-life. Therefore, a replacement plan is required to minimize the number of failures. Hydro Ottawa also has a proactive breaker maintenance program used to help mitigate risk, and identify any breakers that may be in poor condition so they can be planned for renewal before they fail.

Breaker failures typically occur due to issues with the insulation, poor contact resistance or a misaligned racking mechanism. They can also occur due to external factors such as moisture ingress or animal contact. In-service failures have a great impact on reliability, but due to the redundancy of Hydro Ottawa's distribution system, will most likely not result in the system operating in major contingency conditions.

In general, switchgear failures will result in power loss to all customers connected to the feeder served by the device. Accordingly, outages caused by a failed component of the switchgear affect a significant number of customers. Figure 1.11 below shows the historical SAIFI metric for station switchgear. Through switching and station work, customers can be restored, however, the typical delivery time for a new breaker is roughly 6 months.

Figure 1.11 – Station Switchgear Historical SAIFI Metric

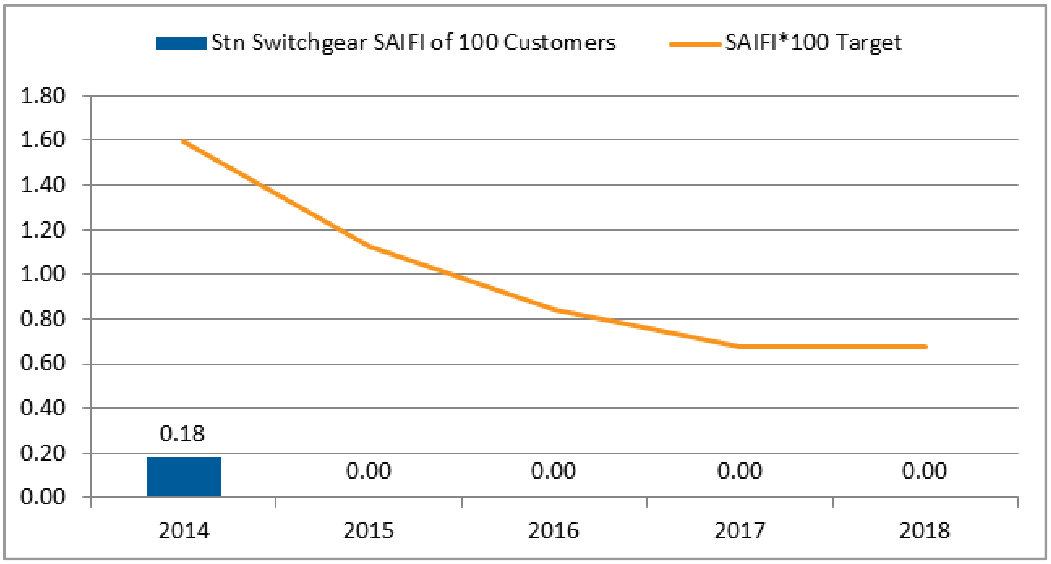


Figure 1.12 below shows the consequence of a failure of a switchgear.

Figure 1.12 - Examples of Failure Consequences

Failure of switchgear that contains oil as an interrupting medium can have a considerable impact on the safety of Hydro Ottawa’s employees and the public. A failure of this type of switchgear can result in burning oil and gas clouds. Older switchgear were not designed to withstand internal arc faults. High energy arcing faults inside the switchgear can lead to explosions (see Figure 1.12), fire, and other catastrophic events that could result in extensive damage to buildings and properties nearby and could cause severe injury to personnel. Furthermore, it can cause oil spills that contaminate the surrounding environment. Even switchgear that contain breakers with other interrupting mediums than oil pose a great risk to the safety of Hydro Ottawa's staff and the public if a failure were to occur. Although a failure wouldn't involve the expulsion of gas clouds and burning oil, it may still cause metal shards and other components to blow off and cause injuries.

1.1.2.2.4. Main and Secondary Drivers

Drivers for the station switchgear replacement program are summarized and described in Table 1.10 below.

Table 1.10 – Main and Secondary Drivers

	Driver	Explanation
Primary	Asset Performance	50.7% of the switchgear in Hydro Ottawa`s system are at or past their useful life. This will grow to 50.8% by 2025 if the switchgear renewal program is not executed. This projection accounts for future breaker failures, which will have been replaced by 2025.
Secondary	System Reliability	Station switchgear have a direct impact on system reliability, as all customers connected will experience a power outage in the event of a switchgear failure. The number of customers that are affected and the duration can be substantial.
	Environment	Station switchgear failures can lead to oil leaks. Hydro Ottawa mitigates this risk through the use of appropriate enclosure and oil containment. However, it is still possible for explosions to cause an oil leak.
	Safety	Station switchgear failure can potentially lead to injury or even death of Hydro Ottawa's employees and the public. Hydro Ottawa's standard is to incorporate arc resistant switchgears to replace station switchgears without arc flash protection. This furthers the safety to employees and the public.

1.1.2.2.5. Performance Targets and Objectives

The station switchgear renewal program seeks to reduce Hydro Ottawa's switchgear and breaker failures over the next 50 years by replacing high-risk switchgear before they fail. Hydro

Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the station switchgear replacement program, improved results are expected in the “Defective Equipment SAIFI” metric.

1.1.2.3. Program Justification

1.1.2.3.1. Alternatives Evaluation

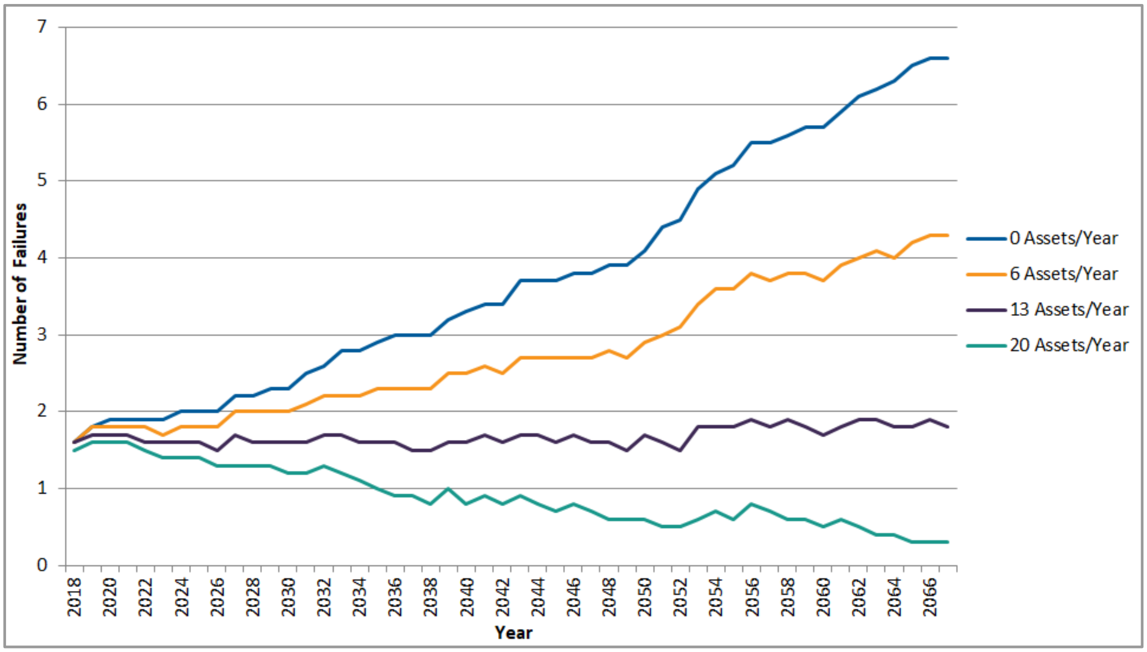
Alternatives Considered

In order to address the drivers and achieve the program’s performance objectives, Hydro Ottawa conducted an analysis to optimize the replacement rate of breakers, with the goal of minimizing the number of breaker failures over the next 50 years. Below is a breakdown of the scenarios that were considered to optimize the spending on switchgear renewal programs.

- Only replacing breakers in a reactive manner, after they have failed
- Replacing six breakers per year (requiring approximately $1.5M in annual spend)
- Replacing 13 breakers per year (requiring approximately $3.25M in annual spend)
- Replacing 20 breakers per year (requiring approximately $5M in annual spend)

The outcome of this analysis is shown in Figure 1.13 below.

Figure 1.13 - Station Breaker Failure Rate per Planned Replacement Level



This analysis was performed with the following assumptions:

- The oldest breakers are prioritized for renewal, regardless of whether or not they've reached their expected operating life.
- A failed breaker is replaced in the same year, with no impact on the planned renewal program.

Alternatives Evaluation

Hydro Ottawa's evaluates all alternatives with consideration of the following criteria:

Failure/Reliability

The increased potential of failure posed by these ageing assets will impact Hydro Ottawa's ability to deliver reliable power. The selected alternative shall maintain or improve the reliability performance of the system.

Safety

Hydro Ottawa's puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must mitigate any present risks to Hydro Ottawa's employees and the public safety.

Resources

Unplanned replacements are usually carried out by Hydro Ottawa's own crews, whereas planned replacements can be performed by both internal and external resources. The preferred alternative shall lead to more planned renewal projects where appropriate staffing resources can be allocated, rather than unplanned renewal projects that would take resources away from other work.

Financial

Financial costs and benefits shall include all direct and indirect impacts on the utility's performance and rates.

Preferred Alternative

The preferred alternative is to replace an average of 13 breakers per year from 2021 to 2025. The combination of renewal projects from the switchgear renewal program and the station major rebuild program is expected to meet this renewal requirement. The 68 proposed breakers for renewal equate to an average replacement level of 13.6 breakers per year over the 2021-2025 rate period.

Failure / Reliability

Failure forecasts indicate that the replacement of 13 units per year will maintain the switchgear failure rate near its current level of 1.6 breakers over the next five years. An increase in replacement rate will be required beyond 2025 in order to maintain and improve asset performance as more assets reach the end of their expected lives.

As shown in Figure 1.13, replacing an average of 20 breakers per year annually would have a greater impact to reduce risk in the longer term. However, any additional risk posed by the deferral of these replacements is planned to be mitigated through the switchgear and breaker maintenance program, annual infrared inspection program, as well as through monthly visual inspections.

Safety

The proposed station switchgear replacement policy will manage the risk to safety of Hydro Ottawa employees and the public by reducing the number of breakers that are likely to fail based on age.

Through Hydro Ottawa's inspection and maintenance, safety risks will be identified and prioritized for remediation should they arise.

Resources

The preferred alternative will optimize staffing resources by scheduling and planning future work. Planned station switchgear renewals require less labour resources, through coordination of effort. Furthermore, corrective renewal negatively impacts the ability to complete planned work due to redirection of resources.

Financial

The costs associated with replacing switchgear in an emergency situation are higher than planned replacements, as temporary measures will need to be put into place to restore contingencies until the switchgear is replaced.

1.1.2.3.2. Program Timing & Expenditure

Table 1.11 below provides information on the replacement expenditures in the historical and future rate period. It also shows the number of projects that have or are expected to be completed during the respective year. Due to the level of planning required, equipment delivery times and the complexity of the work, switchgear projects can extend over more than one year. Costs vary year to year based on the size of the switchgear and the number of projects being executed. The project scopes can also vary from retrofitting a few breakers, to completely rebuilding the entire switchgear, complete with upgraded P&C and DC systems. A switchgear replacement in Table 1.11, Table 1.12 and Table 1.13 refers to a project to replace breakers, reclosers, switches, and P&C at a specific station.

Table 1.11 - Expenditure History and Forecast of Switchgear Renewal Projects

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Program Cost ($'000,000s)	$5.02	$6.58	$8.79	$4.54	$0.40	$1.57	$2.24	$1.67	$1.20	$0.03
Switchgear Replacement Units	0	0	1	2	0	0	0	0	1	0

Station switchgear are also renewed as part of full station rebuilds. Table 1.12 below provides historical and planned expenditures and the number of station switchgear units replacements that were completed in the historical period as part of the station major rebuild program. Note that two switchgear projects not shown in Table 1.12 will be initiated in the 2021-2025 period, but will not be completed until after 2025.

Table 1.12 - Expenditure History and Forecast of Station Rebuild Projects

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Program Cost ($'000,000s)	$3.95	$5.24	$8.75	$2.79	$4.18	$4.72	$8.34	$6.19	$5.44	$8.70
Switchgear Replacement Units	0	1	0	1	0	0	0	1	1	0

Historically, station switchgear has also been renewed as part of the station transformer renewal program. Table 1.13 below provides information on the expenditures and station switchgear units replaced that were completed in the historical period as part of the transformer renewal program.

Table 1.13 – Expenditure History and Forecast of Transformer Renewal Projects

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Program Cost ($'000,000s)	$3.70	$1.51	$2.75	$0.25	$0.97	$2.36	$0	$0	$0	$0
Switchgear Replacement Units	1	0	0	0	0	0	0	0	0	0

Station switchgear replacement projects are usually staged such that the new switchgear is constructed while keeping the existing switchgear in-service. Once constructed, the feeders are transferred to the new switchgear with minimal interruption to the customers.

1.1.2.3.3. Benefits

Key benefits that will be achieved by implementing the station switchgear replacement program are summarized in Table 1.14 below.

Table 1.14 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	New switchgear has the added benefit of replacing manually operated switches with remote-controlled switches that allows for operation from Hydro Ottawa's system operation control room and eliminates the need for a crew to manually operate them. This saves both time and money. The proactive replacement of units prior to failure results in labour cost savings compared to unplanned replacement of a failed unit.
Customer	Improved reliability due to decreased switchgear failures and availability of redundant systems. Improved reliability and safety due to upgraded protection and control systems.
Safety	Switchgear replacements reduce the risk to employee safety by implementing new standards for arc-resistant switchgear. Proactive replacements mitigate the risk of catastrophic failures due to improved protection and control systems to allow for quicker fault detection and isolation.
Cyber-Security, Privacy	(Not applicable)
Coordination, Interoperability	(Not applicable)
Economic Development	Hydro Ottawa's engages contractors to construct and install station switchgear, thereby creating job opportunities. Internal resources are used for the commissioning and acceptance testing of the equipment.
Environment	Proactive replacement of end-of-life station switchgears mitigates the risk of oil spills or SF6 leaks in the event of a switchgear failure.

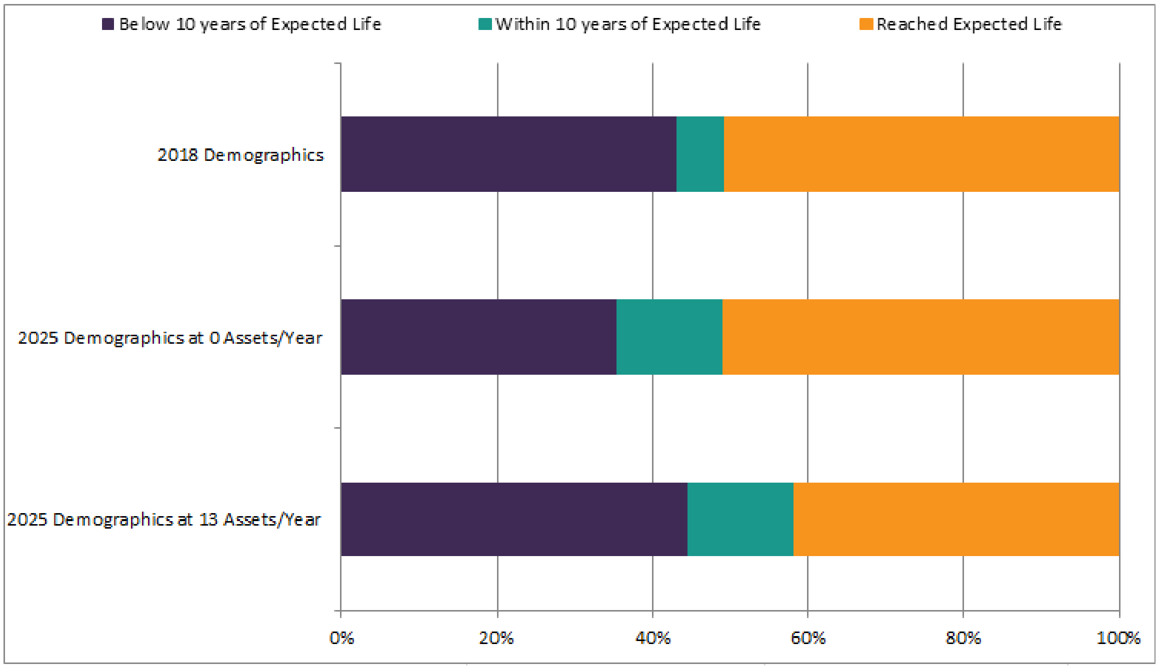
1.1.2.4. Prioritization

1.1.2.4.1. Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved, station switchgear will pose an increased risk to safety and reliability, as a result of the increased potential for in-service failures. As shown in Figure 1.13, Hydro Ottawa is expected to experience significantly higher failure rates within the next five years without this program in place.

In the long term, deferral of station switchgear replacements will also create a backlog of assets in poor condition requiring additional future capital investment to bring the overall condition of the entire asset class to an acceptable level. This will place a high stress on Hydro Ottawa's financial and staffing resources. Figure 1.14 below shows how Hydro Ottawa's station breaker demographics compare at the end of the 2021 to 2025 rate period with and without the execution of this program.

Figure 1.14 – Hydro Ottawa's Station Switchgear Alternatives Comparison



This graph was made with the assumption that all breakers have an expected life of 42 years, regardless of their type. This assumption represents a conservative approach due to the fact that 42 years is the expected life of air breakers, which represent approximately half of Hydro Ottawa's breaker population, and that air breakers have the lowest expected operating life of the four breaker types installed in Hydro Ottawa's system. Breaker failures were also projected in this analysis.

1.1.2.4.2. Priority

Station switchgear renewal projects are some of the highest-priority projects conducted by Hydro Ottawa. Due to the risk mitigated by renewing switchgear, they are almost always prioritized over other projects. The exception would be in the case of an emergency situation that would need to be addressed immediately.

1.1.2.5. Execution Plan

1.1.2.5.1. Implementation Plan

Station switchgear replacement projects typically span 2-3 years. The project starts with the design, followed by equipment procurement, installation, and commissioning. Hydro Ottawa is planning for the following switchgear replacements to be completed from 2020 to 2025:

- Overbrook TO Switchgear Renewal (2021 to 2024)

Hydro Ottawa is planning for the following switchgear renewals as part of the station major rebuild program from 2021 to 2025:

- Bell's Corners Rebuild (2019 to 2023)
- Fisher Rebuild (2021 to 2024)
- Dagmar Rebuild (2023 to 2026)
- Shillington (2024 to 2028)

1.1.2.5.2. Risks to Completion and Risk Mitigation Strategies

Table 1.15 below describes the various risks of performing station major rebuild projects, as well as their mitigation strategies.

Table 1.15 - Program Risks and Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: ● Project planning required to minimize outages to customers and that coordinate with other planned work in the area; ● Adherence to schedules; ● Timely procurement of equipment; ● Quality of materials	Hydro Ottawa has dedicated project managers who oversee the project to ensure that risk is managed accordingly. It is Hydro Ottawa's practice to schedule and coordinate all work (planned and emergency) through our System Office to ensure effective use of resourcing and ensure continued system operability and safety in areas where crews are working.

1.1.2.5.3. Timing Factors

Switchgear projects are typically planned to include any civil construction outside of the winter months to avoid winter-related issues. Construction timing at the manufacturing plant typically dictates the schedule of the project.

1.1.2.5.4. Cost Factors

Cost factors that affect replacement projects are listed below:

- Project scope creep including additional assets to be replaced. Most are identified early on in the project.
- Delays in the project schedule.
- Compatibility with existing equipment.

1.1.2.5.5. Other Factors

(Not applicable to this program)

1.1.2.6. Renewable Energy Generation

(Not applicable for this program)

1.1.2.7. Leave-To-Construct

(Not applicable for this program)

1.1.2.8. Project Details and Justification

Table 1.16 - Station Switchgear Renewal Overview

Project Name:	Station Switchgear Renewal
Capital Cost:	$6.7M
O&M:	$0
Start Date:	2021
In-Service Date:	2024
Investment Category:	System Renewal
Main Driver:	Failure Risk
Secondary Driver(s):	Reliability
Customer/Load Attachment:	
Project Scope	
The scope of this program is replacing the switchgear and breakers at Overbrook TO and upgrading the protection and control equipment.	
Priority	
Station switchgear renewal projects are some of the highest-priority projects conducted by Hydro Ottawa. Due to the risk mitigated by renewing switchgear, they are almost always prioritized over other projects. The exception would be in the case of an emergency situation that would need to be addressed immediately.	
Work Plan	
The switchgear renewal program will be executed from 2021 to 2024, at the cost of $6.7M.	
Customer Impact	
Hydro Ottawa customers will experience improved reliability due to decreased switchgear failures, greater availability of redundant systems, and improved reliability and safety through upgraded protection and control systems. The customer benefits from a program that prioritizes renewal of station switchgear based on condition, ensuring the reliability and cost effectiveness of the distribution system.	

1.1.3. STATION P&C RENEWAL PROGRAM

1.1.3.1. Program Summary

Station protection and control (P&C) systems provide protection of the equipment and personnel during abnormal system events, such as short circuit conditions, and to enable remote control of station devices such as breakers and switches. P&C systems typically consist of substation protective relays, and associated equipment such as instrument transformers, auxiliary relays, control switches, and station Remote Terminal Units (RTUs), which are needed to enable remote operability of station equipment from the System Control Centre. The replacement and maintenance of these systems is critical to the safety and operational effectiveness of Hydro Ottawa's distribution system.

1.1.3.2. Program Description

1.1.3.2.1. Assets in Scope

Hydro Ottawa's station relays consist of electromechanical, electronic and microprocessor relays. Each of the above relay types has a finite life expectancy that varies depending on the relay type. Additionally, associated auxiliary devices such as instrument transformers, auxiliary relays, control switches, ancillary tripping relays and control wiring are used by station relays. Station RTUs with associated telecommunications equipment such as telephone modems, fibre optic devices and substation LAN (local area network) are also within the P&C scope.

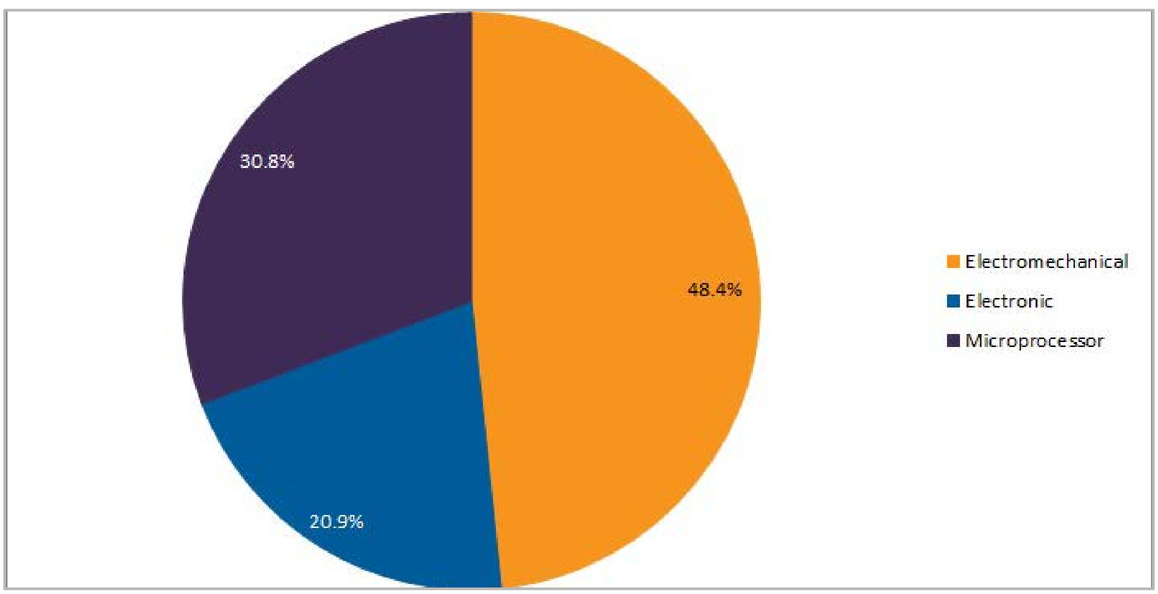
Hydro Ottawa typically replaces electromechanical relays as a part of the switchgear replacement program. Electronic and microprocessor relays are typically replaced once they reach the end of their life expectancy. Historically, Hydro Ottawa did not have a replacement program in place for these two types of devices as they were first installed in the mid-1990s and have just started reaching the end of their functional life recently. The majority of RTUs also fall into the category of electronic and microprocessor devices and as such, they were getting replaced with modern upgraded devices at the time of station switchgear replacement.

Starting in 2017 Hydro Ottawa initiated its annual P&C renewal program, which prioritizes renewal according to the life expectancy of each device type.

1.1.3.2.2. Asset Life Cycle and Condition

Electromechanical relays have a 40-year lifespan, and Hydro Ottawa typically replaces these relays and its associated switchgear at the same time. Electronic relays have a useful lifespan of 15 years due to the use of electronic components such as capacitors, transistors and power supplies, which have shorter lives compared to electromechanical devices. Both electromechanical and electronic relays are typically replaced with modern microprocessor relays. Microprocessor relays have a lifespan of 25 years, with the lack of spare components being the main contributing factor driving the need for replacement. Hardware compatibility in aging microprocessor components is another issue, as compatibility with modern firmware revisions are required by equipment manufacturers. Figure 1.15 describes Hydro Ottawa population of relays by type.

Figure 1.15 - Relay Population by Type



Electromechanical systems use relays that rely on physical, electrical and magnetic properties to detect fault conditions. There are mechanical parts (contacts, springs, rotating disks, etc.) and electrical components (coils, capacitors, resistors, etc.) whose characteristics can change over time and render the device unable to function. Figure 1.16 illustrates the age distribution of Hydro Ottawa's electromechanical relays.

Electronic relay systems have fewer moving parts than electromechanical relays, but nonetheless have many analog electronic components such as transistors, op-amps, capacitors, etc., and, for some devices, electromechanical relays for their output contacts. These types of systems are susceptible to overcurrent and overvoltage stresses on the sensing circuits and mechanical failure of output relays. Figure 1.17 illustrates age distribution of Hydro Ottawa's Electronic relays.

In contrast, microprocessor systems make use of software algorithms with the numerical processing capabilities of high-speed microprocessor components such as Digital Signal Processor chips. They have much broader capabilities than the electromechanical or electronic types, but their useful life is limited by items such as voltage or current surges, software compatibility and obsolescence. Figure 1.18 illustrates the age distribution of Hydro Ottawa's microprocessor relays.

All relays are subjected to periodic inspections, maintenance and testing. The interval of testing is based on relay type, with a 5-year interval for electromechanical and electronic and 10-year interval for microprocessor relays. The relay functionality and timing test results are recorded in a database and compared to a previous set of tests.

Figure 1.16 - Electromechanical Relay Age Demographics

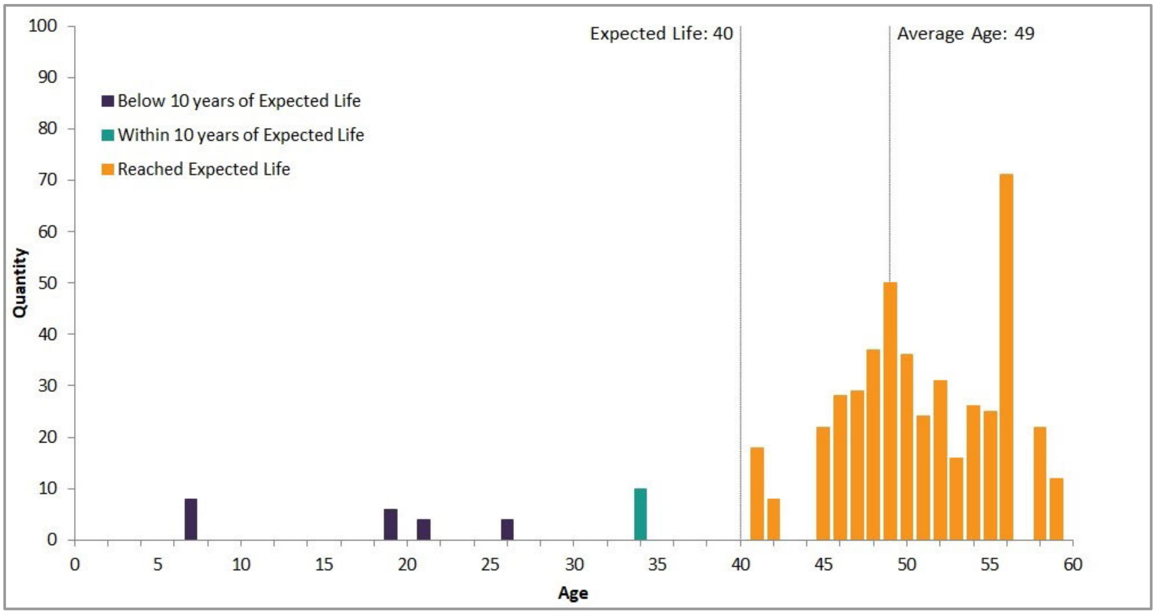


Figure 1.17 – Electronic Relay Age Demographics

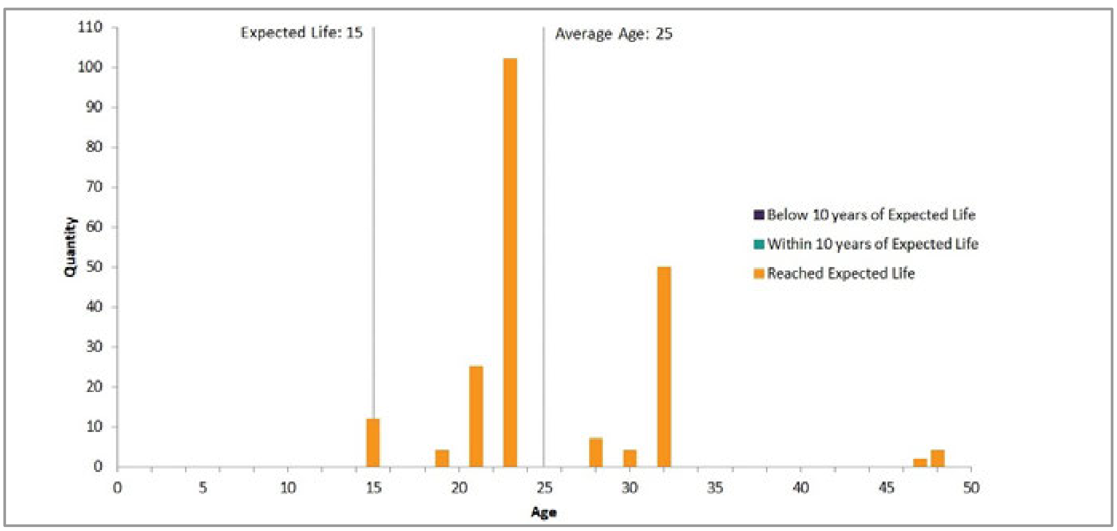
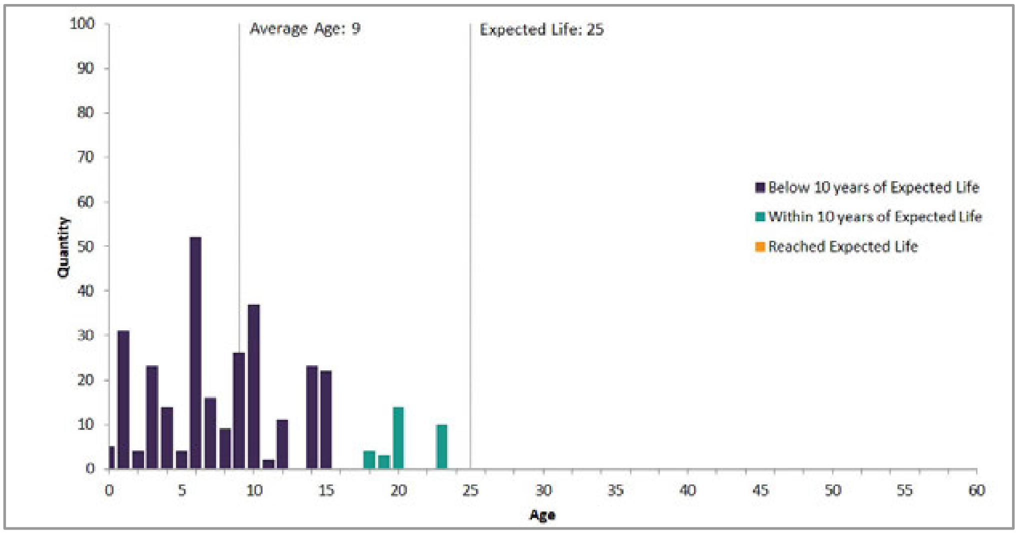


Figure 1.18 - Microprocessor Relay Age Demographics



1.1.3.2.3. Consequence of Failure

P&C system failures do not necessarily result in customer outages, particularly where relay health status is monitored by SCADA, as is the case with modern microprocessor relays. A failure of an unmonitored relay typically results in a widespread customer outage, extensive damage to equipment, longer outage duration and a detrimental impact on the safe and reliable operation of the distribution system. Failure of RTU equipment would result in extending outage duration as the System Control Centre would not be able to monitor and control the station equipment remotely.

1.1.3.2.4. Main and Secondary Drivers

The program's main and secondary drivers are described in Table 1.17 below.

Table 1.17 - Main and Secondary Drivers

	Driver	Explanation
Primary	Failure Risk	665 individual relays in Hydro Ottawa`s system are at or past their useful life. This will grow to 728 units over the next 10 years if no replacement program is undertaken.
Secondary	Reliability	Protection relays have a direct impact on system reliability. If a failure on the system were to occur at the same time as during system fault conditions, the resulting short circuit current would not be interrupted on time, and would result in an extended or cascading outages and damage to other equipment.
	Safety	Protection failures could result in a safety risk to Hydro Ottawa staff who are on-location and rely on timely interruption of short circuit conditions. A failure to operate in a timely matter could potentially damage customer property and endanger the safety of crews or the general public.

1.1.3.2.5. Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the P&C renewal program, improvements are expected in the KPI metrics shown in Table 1.18, due to P&C devices being renewed before failing.

Table 1.18 - Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	Customer Engagement	Maintain Customer Satisfaction
		System Reliability	Maintain SAIFI and SAIDI
Cost Efficiency & Effectiveness	Resource Efficiency	Cost Efficiency	Reduce Cost due to emergency replacement
		Labour Utilization	Reduce Labor Allocation to Outage Restoration
Asset Performance	Asset Value	Defective Equipment Contribution to SAIFI	Maintain Defective Equipment SAIFI

1.1.3.3. Program Justification

1.1.3.3.1. Alternatives Evaluation

Alternatives Considered

Hydro Ottawa has considered a few alternatives to the station P&C renewal program.

Do Nothing

In this case, relays would be replaced upon failure. Historical trends indicate that failure rates are relatively low with only a few units malfunctioning on an annual basis. Given the aging relay population, it is anticipated that this trend will increase. The investment level required to sustain this option is $113,000 based on historical failure rates of 10 units per year. The Do Nothing scenario exposes Hydro Ottawa to the combination of high-risk and high-impact system events and is not tolerable from a system operations point of view.

Condition Based Relay Replacement

This case proposes that replacements are scheduled based on test results that identify particular relays as problematic during their regular maintenance cycle. Any relays that have failed a test during the regular maintenance cycle would be replaced on an emergency basis.

Age Based Relay Replacement

The third option would be to replace relays based on age, expected life and historical failure trend data for each relay type and manufacturer.

Coincidental Relay Replacement

The fourth option is to upgrade relays in conjunction with replacement of substation equipment such as breakers, switchgear and station transformers. This option would be the most economical in cases where both types of equipment are at their end-of-life, as it minimizes internal resource requirements for replacement. This option mostly applies to stations with electromechanical relays as the life expectancy is typically aligned with the station switchgear.

Evaluation Criteria

Hydro Ottawa evaluates all alternatives with consideration of the following criteria:

Failure/Reliability

The selected alternative shall maintain or improve the reliability performance of the system. Reliability of P&C equipment is of critical importance to the performance of Hydro Ottawa's distribution system. Failure of protective relays during system faults has a detrimental effect on SAIDI, SAIFI and may cause failures of major substation equipment such as breakers, station transformers and switchgear.

Safety

Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The increased potential of failure posed by these ageing assets will negatively impact Hydro Ottawa's ability to guard worker and public safety. The preferred alternative must not impose additional risks on the safety of Hydro Ottawa's employees and the public.

Resources

Unplanned replacements are usually carried out by Hydro Ottawa's own crews, whereas planned replacements can utilize both internal and external resources. Therefore, alternatives that anticipate more replacements upon failure would be less favourable as resourcing is more challenging perspective.

Financial

Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates.

Preferred Alternative

Hydro Ottawa's preferred alternative is a combination of two approaches. The first approach will be to upgrade P&C systems based on the results of a regular maintenance cycle, recorded historical data of failure rates for each relay type and manufacturer, life expectancy of relay types, and functional obsolescence. Planning for replacements will minimize the strain on Hydro Ottawa's resources and ensures a proactive approach to system integrity and public safety. It will be combined with the second approach, which will involve upgrading P&C systems in conjunction with station high voltage apparatus replacement such as power transformers, high voltage switchgear and high voltage breakers.

1.1.3.3.2. Program Timing & Expenditure

Table 1.19 below provides information on station P&C relay replacement expenditures to be completed, starting in 2019. The P&C renewal program is relatively new to Hydro Ottawa as some of the relay population is just starting to reach the end of life.

Table 1.19 – Expenditure History and Projected Spending

	Historical			Bridge		Test	
	2016	2017	2018	2019	2020	2021	2022
Total Expenditure ($'000s)	$0	$388	$167	$437	$920	$576	$618
Units	0	0	0	24	24	12	12

1.1.3.3.3. Benefits

Key benefits that will be achieved by implementing the station P&C relay replacement program are summarized in Table 1.20.

Table 1.20 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Other assets are typically replaced in conjunction with these projects such as: RTUs and communications systems. This collaboration of asset replacement has been found to be cost effective. Planned replacement program and reduction in emergency replacements enhances operation efficiency.
Customer	Improved system reliability.
Safety	P&C system is at the core of the safe and reliable operation of distribution system. As such, the integrity and reliability of the system is of critical importance to worker and public safety
Cyber-Security, Privacy	The cyber-security of digital systems is greatly improved by installation of modern equipment, which addresses the vulnerability of previous generation of microprocessor equipment.
Coordination, Interoperability	Modern P&C equipment allows for integration of distributed generation.
Economic Development	Not applicable
Environment	Not applicable

1.1.3.4. Prioritization

1.1.3.4.1. Consequences of Deferral

If this program is deferred to the next planning period or adequate replacement levels are not achieved, this asset class will pose an increased risk to safety and reliability as a result of the increased potential for system in-service failures. These failures will also cost more to fix, as planned replacements are always less expensive than reactive replacements.

In the long term, deferral of station P&C renewal will also create a backlog of assets in poor condition that will require more capital investment in the future in order to bring the overall condition of the asset population to an acceptable level. This will place a high stress on Hydro Ottawa's internal resources.

1.1.3.4.2. Priority

Hydro Ottawa strives to maintain functionality of its P&C system to the highest possible standard. The P&C system has a direct impact on distribution system reliability and the safety of

Hydro Ottawa staff and the general public. As such, Hydro Ottawa places a high priority on relay replacement projects. Historically, Hydro Ottawa did not have a formal P&C renewal program as the age of equipment was in line with the life expectancy of each particular relay type. As the equipment ages, the early electronic and microprocessor relays start to reach the end of their functional life, and cannot be replaced in a like-for-like manner due to technology obsolescence.

1.1.3.5. Execution Path

1.1.3.5.1. Implementation Plan

Station P&C renewal projects typically span several months as they involve complete refurbishment of switchgear wiring. Hydro Ottawa will replace existing electronic and electromechanical relays with modern microprocessor relays, LAN-based communications, and RTU systems. These projects are very labour-intensive and require significant human resources to design and implement. Stations with poor historical P&C system performance will be prioritized for early replacement, and stations where relays are technologically obsolete but are performing well will be given lower priority.

1.1.3.5.2. P&C Renewal Proposed Projects

Proposed projects for the years 2021 to 2025 are included in Table 1.21.

Table 1.21 - Proposed Projects 2021 to 2025

Year	Proposed Projects
2021	- Lincoln Heights P&C renewal (part 1) - Fisher station renewal (part 1) - Bells Corners station renewal (part 1) - Kanata MTS RTU replacement
2022	- Lincoln Heights P&C renewal (part 2) - Barrhaven DPU replacement - Station RTU renewal (central) - Fisher station renewal (part 2) - Rideau Heights T1 renewal (part 1) - Bells Corners station renewal (part 2)
2023	- Fisher station renewal (part 3) - Dagmar station renewal (part 1) - Rideau Heights T1 station renewal (part 1) - Bells Corners station renewal (part 3)
2024	- Overbrook switchgear replacement (part 1) - Station RTU renewal (Central) - Shillington station renewal (part 1) - Fisher station renewal (part 4) - Dagmar station renewal (part 1) - Rideau Heights T1 station renewal (part 2)
2025	- Overbrook switchgear replacement (part 1) - Dagmar station renewal (part 2) - Shillington station renewal (part 2)

1.1.3.5.3. Risks to Completion and Risk Mitigation Strategies

Due to the level of labour required to design and execute station P&C renewal projects, the largest anticipated risks are the scheduling of field crews and allocating designer time. These risks can be mitigated by utilizing external resources for design and optimizing internal crews for execution throughout the year. Projects are typically implemented in such a way as to minimize system operational constraints and reduce requirements for equipment outages. Projects are coordinated with the System Office early in the design process.

1.1.3.5.4. Timing Factors

Since most station P&C equipment is installed indoors, replacement projects are typically scheduled for the winter months. when more resources are available.

1.1.3.5.5. Cost Factors

There are several factors that impact P&C replacement projects. These projects typically include refurbishment of switchgear wiring, removal of existing relays and transducers, replacement of communications wiring, installation of LAN-fibre optic communication systems, and installation of modern microprocessor relays. P&C renewal projects are labour intensive and labour factors contribute approximately 80% of project cost, with approximately 20% of material cost.

1.1.3.5.6. Other Factors

Another factor that could impact the overall project execution is the availability of space at the station. If the station isn't large enough to accommodate all the equipment, then special considerations must be made for the specific project.

1.1.3.6. Renewable Energy Generation (if applicable)

With an increase of renewable generation projects coming online over the last decade, Hydro Ottawa has embarked on upgrading the protection systems on the distribution lines that supply renewable generation projects. Newer microprocessor relays can accommodate the requirement of transfer trip schemes for certain renewable generation projects. Typically, Hydro Ottawa has initiated upgrades to the protective relaying systems connected to feeders supplying generator customers. In addition to station equipment upgrades, generation customers are required to install communications systems to provide Hydro Ottawa with situational awareness in the event of system faults. By installing additional protection schemes, Hydro Ottawa ensures that any system disturbance events on the Generator side do not impact customers.

1.1.3.7. Leave-To-Construct (if applicable)

Not applicable.

1.1.3.8. Project Details and Justification

Table 1.22 - Slater Relay Replacement Overview

Project Name:	Slater Relay Replacement
Capital Cost:	$1.95M
O&M:	0
Start Date:	July 2019
In-Service Date:	July 2020
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	7,384 customers
Project Scope	
The scope of this project includes replacement of the old relays (8/bus = 48) on the 13kV switchgear at Slater TS with new SEL 751 relays. It also includes installing new RTAC units (likely three), installing communication switches (one or two), new plates to be installed on the cells, drawings and as-builts to be drafted, and the completion and implementation of updated protection settings. CT inspection and potential replacement is also in scope.	
Work Plan	
Slater TS switchgear will be isolated one breaker at a time and the existing SPAJ relay will be replaced with SEL751. It is anticipated that the timeline of the project is one week per breaker with a total anticipated duration of 48 weeks.	
Customer Impact	
It is anticipated that the new relays will offer improved reliability of the downtown distribution system	

Table 1.23 - Lincoln Heights P&C Renewal Overview

Project Name:	Lincoln Heights P&C renewal
Capital Cost:	$1.07M
O&M:	
Start Date:	July 2020
In-Service Date:	July 2021
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	12,763 customers
Project Scope	
Upgrading existing EOL electromechanical relays with SEL electronic relays. Will improve overall protection and coordination with downstream switchgear and fusing. Scope includes all feeder and emergency buss-tie breakers; 28 in total. Transformer and incoming buss breakers are out of scope due to HONI ownership.	
Work Plan	
Lincoln Heights TS switchgear will be isolated one breaker at a time and the existing SPAJ relay will be replaced with SEL751. It is anticipated that the timeline of the project is one week per breaker with a total anticipated duration of 48 weeks.	
Customer Impact	
The relays at Lincoln Heights station have been identified by the Maintenance group as being at end-of-life condition. They are legacy electromechanical relays, which limit coordination ability with downstream protection, especially at 4kV substations. Replacement with electronic relays, in-line with best practices and internal guidelines, will improve system performance and permit future initiatives such as Group 1 and Group 2 settings for contingency/emergency scenarios. Protection equipment and settings will be aligned with new Station Protection Guideline and best practices.	

1.1.4 STATION BATTERY RENEWAL PROGRAM

Table 1.24 - Station Battery Renewal Overview

Project Name:	Station Battery Renewal
Capital Cost:	$420k ($84k per year from 2021 to 2025)
O&M:	$0
Start Date:	2021
In-Service Date:	2021
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	N/A

Project Scope

Hydro Ottawa's station battery asset class consists of individual battery cells, connections, racks, and chargers. Hydro Ottawa plans to replace battery banks based on their condition as determined through an annual testing program. A battery bank consists of between 10 and 60 individual batteries, depending on the cell voltages, in order to provide a 130V DC source.

There are two main types of batteries installed in Hydro Ottawa's stations, vented lead acid (VLA), and valve-regulated lead acid (VRLA). The demographics for each type are shown in Figure 1.19 and Figure 1.20. As part of the station battery renewal program, Hydro Ottawa expects to replace, on average, 2.6 battery banks per year over the course of the 2021 to 2025 rate period. This replacement level is consistent with historical replacement quantities.

Below is a list of potential station battery banks to be replaced as part of the battery renewal program, based on their age and expected service life for each type of battery. Ultimately, battery test results will be used to determine whether or not they will be scheduled for replacement.

- Bridlewood batteries, rack, and charger (2021)
- Ellwood batteries, and rack (2024)
- Slater SA batteries, and rack (2025)

Additionally, based on historical failure rates Hydro Ottawa expects to replace an additional 10 battery banks over the course of the 2021 to 2025 period. These batteries will be identified through annual battery maintenance and testing.

Priority

Battery renewal projects are some of the highest-priority projects for Hydro Ottawa. Without reliable DC power, the station does not have reliable protection from faults on the distribution system, nor does it have any ability to communicate with Hydro Ottawa's Control Centre. In the event of a fault while the DC system is out of service, SAIDI would be greatly impacted as power could only be restored by sending a crew to the station to perform manual switching.

Work Plan

Table 1.20 below provides information on the expenditures and station battery banks replaced that were completed during the historical period. When appropriate, battery renewal is performed as part of a switchgear renewal or rebuild project.

Customer Impact
Battery failures do not typically result in customer outages. However, since the batteries provide power to the station's DC system, protection relays and communication equipment shut down if the bank voltage drops. Public and employee safety would be at risk if the protection relays were not monitoring the station's load or sending trip signals to the breakers in the event of a fault. This could result in extensive damage to other station equipment, or more severe outages if a failure were to occur and the protection could not operate. Further, all communications to Hydro Ottawa's control room would be shut down, resulting in the need for a crew to travel to the station to monitor the equipment and transfer load to another station. The battery renewal program will be executed in order to mitigate these risks.

Table 1.25 - Expenditure History of Comparable Projects

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Battery Replacement Cost ($'000s)	$108.8	$7.6	$15.4	$25	$0	$80	$80	$80	$80	$80
Battery Replacement Units	5	1	7	1	0	2.6	2.6	2.6	2.6	2.6

Figure 1.19 - Count of Hydro Ottawa's VLA Batteries

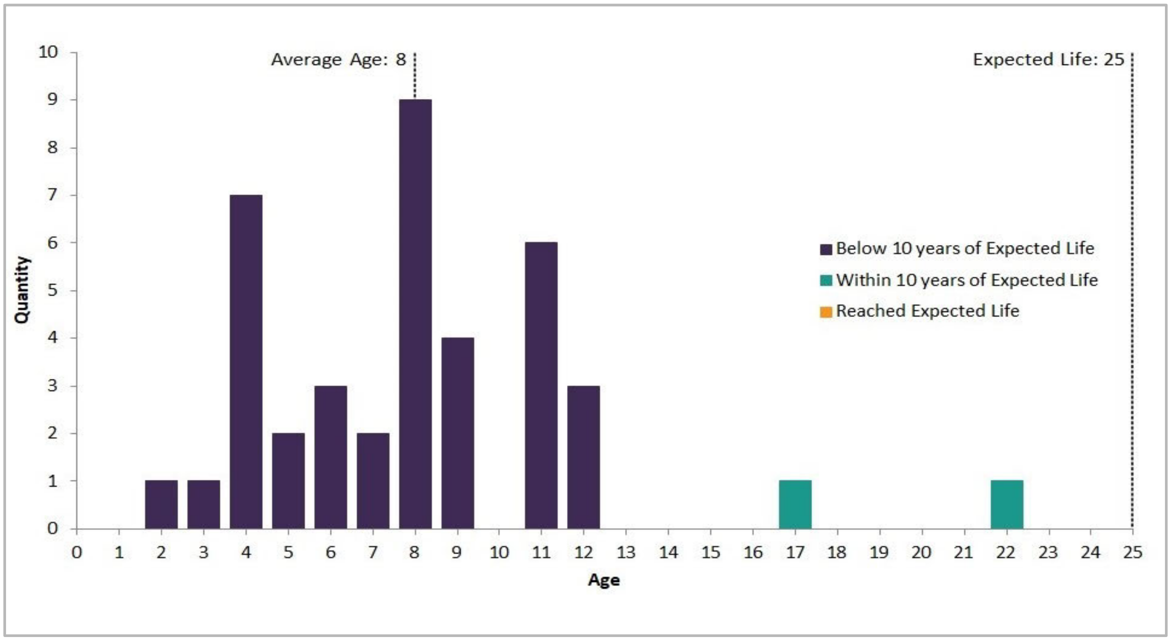
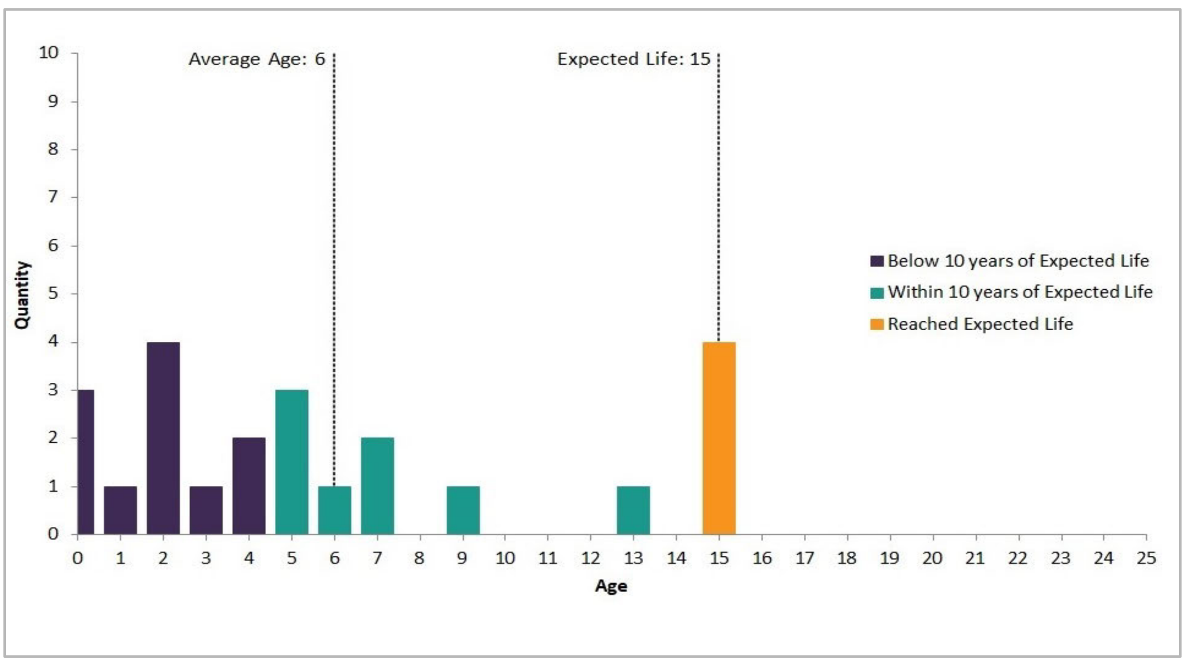


Figure 1.20 - Count of Hydro Ottawa's VRLA Batteries



1.1.5 STATION MINOR ASSET RENEWAL PROGRAM

Table 1.26 - Station Minor Asset Renewal

Project Name:	Station Minor Asset Renewal
Capital Cost:	$3,108,605
O&M:	N/A
Start Date:	January 2021
In-Service Date:	N/A
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	Project impacts all Hydro Ottawa stations
Project Scope	
Costs associated with the Stations Minor Asset Renewal cover the replacement of non-distribution equipment such as building assets and cable racking that have reached their end of functional life. The cost of sustaining building assets includes civil, electrical, mechanical, structural and security/life safety assets, such as work on roof, windows, doors, fencing and security equipment.	
Priority	
Station Minor Asset Renewal is assigned a high priority because of the amount of risk mitigated through the renewal of building components and the criticality of Hydro Ottawa's station assets.	
Work Plan	
Work is carried out throughout the year based on the highest priority items determined through inspection.	
Customer Impact	
This program impacts all customers supplied by the stations impacted by this project. This has a high customer impact due to the criticality of Hydro Ottawa's substation assets.	

1.1.6 STATION MAJOR REBUILD PROGRAM

1.1.6.1 Program Summary

Hydro Ottawa's stations consist of critical assets whose failure poses a high risk to the distribution system. Station assets include power transformers, station-class switchgear assemblies, DC power systems, protection and control (P&C) systems, and communication systems. The Station Major Rebuild program targets ageing substations where the overall age and condition of several individual assets justifies the rebuild of the entire station as opposed to individual components such as transformers and switchgear.

Hydro Ottawa plans to perform renewal work at five stations during years 2021 to 2025, representing 6.9% of 73 the fully-owned Hydro Ottawa stations.

Hydro Ottawa performs System Capacity Assessment as per Section 7 of the Distribution System Plan to determine whether or not an upgraded capacity rating is required to support system requirements when undertaking a station major rebuild project. Further, if the station is part of the 4 kV distribution system, considerations for a voltage conversion will be reviewed as an alternative to renewing the station.

1.1.6.2. Program Description

1.1.6.2.1. Assets in Scope

The scope of this program encompasses stations where the age and condition of the station's major distribution equipment justifies the need to rebuild the entire station. Major equipment includes station transformers, switchgear, and P&C assets.

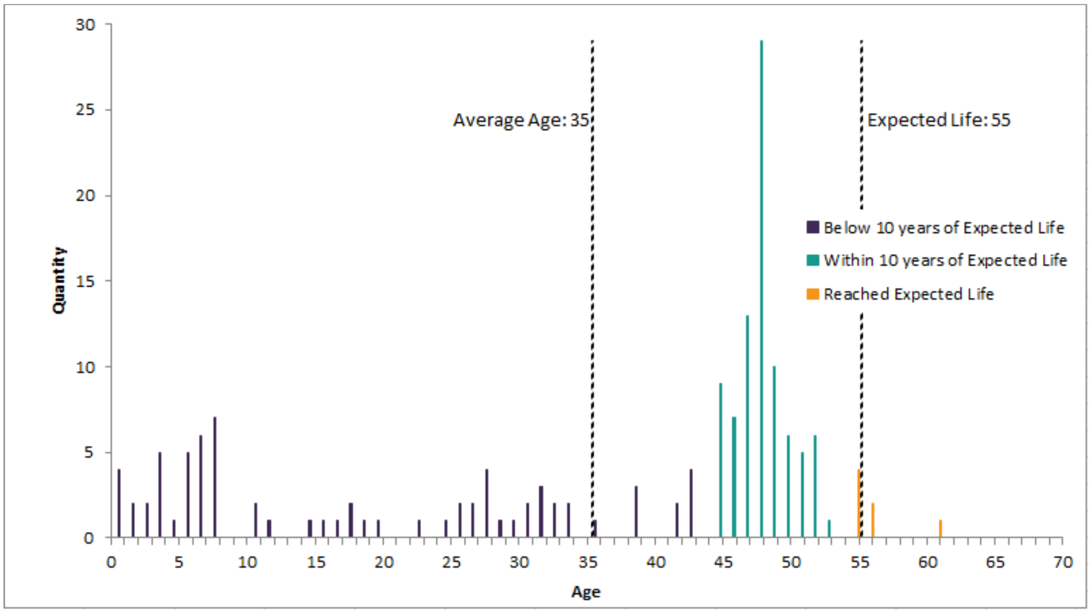
Hydro Ottawa fully owns and operates 73 substations throughout its service territory, and partially owns an additional 12. Only fully Hydro Ottawa-owned stations are eligible to be renewed as part of the station major rebuild program. Hydro Ottawa assets in partially owned stations get renewed under the other Station Asset Renewal programs.

For additional information on the individual assets renewed through the Station Major Rebuild program, refer to the Station Transformer Renewal Program business case (project ID 92002614), the Station Switchgear Renewal (project ID 92003371), Station Battery Renewal (project ID 92014438), and Station P&C Renewal business case (project ID 92003405).

1.6.2.2. Asset Life Cycle and Condition

The age demographics of Hydro Ottawa's station transformers are illustrated in Figure 1.21 below.

Figure 1.21 – Station Transformer Demographics



The age demographics of Hydro Ottawa's station breakers are illustrated in Figure 1.22, Figure 1.23, Figure 1.24, and Figure 1.25 below.

Figure 1.22 – Station Air breaker Age Demographics

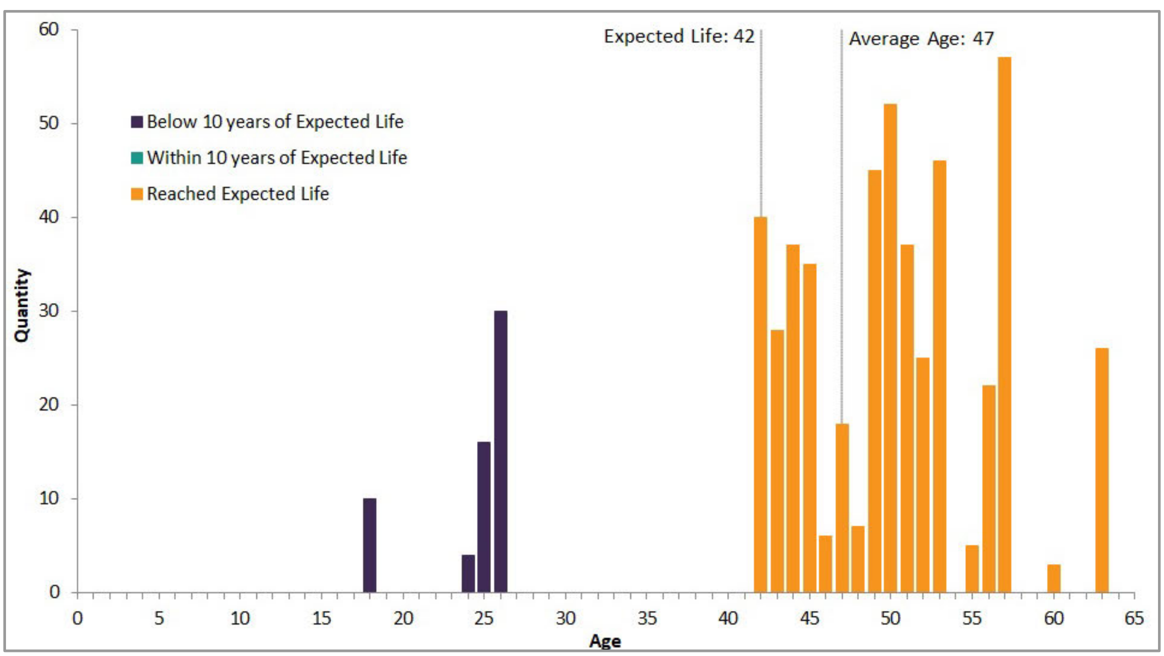


Figure 1.23 – Station Oil Breaker Age Demographics

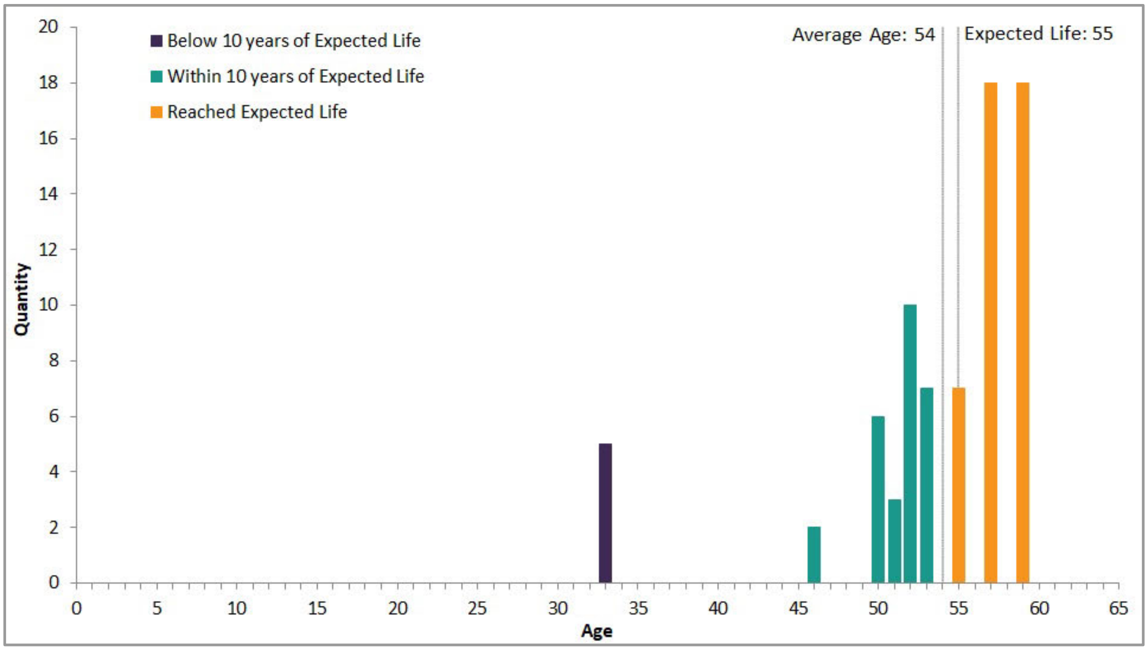


Figure 1.24 – Station SF6 Breaker Age Demographics

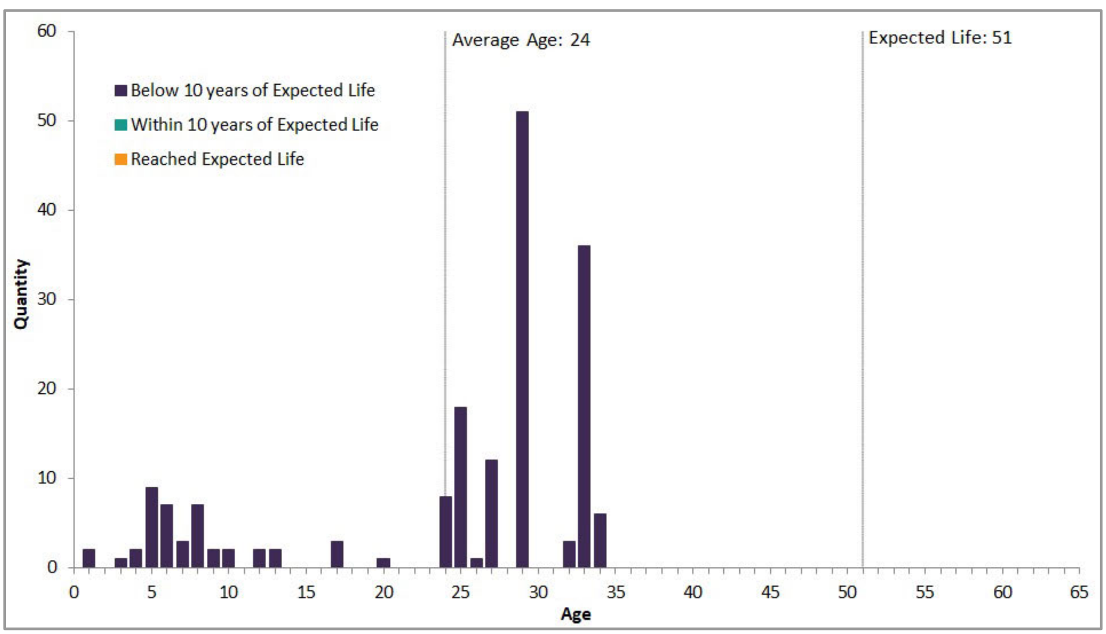
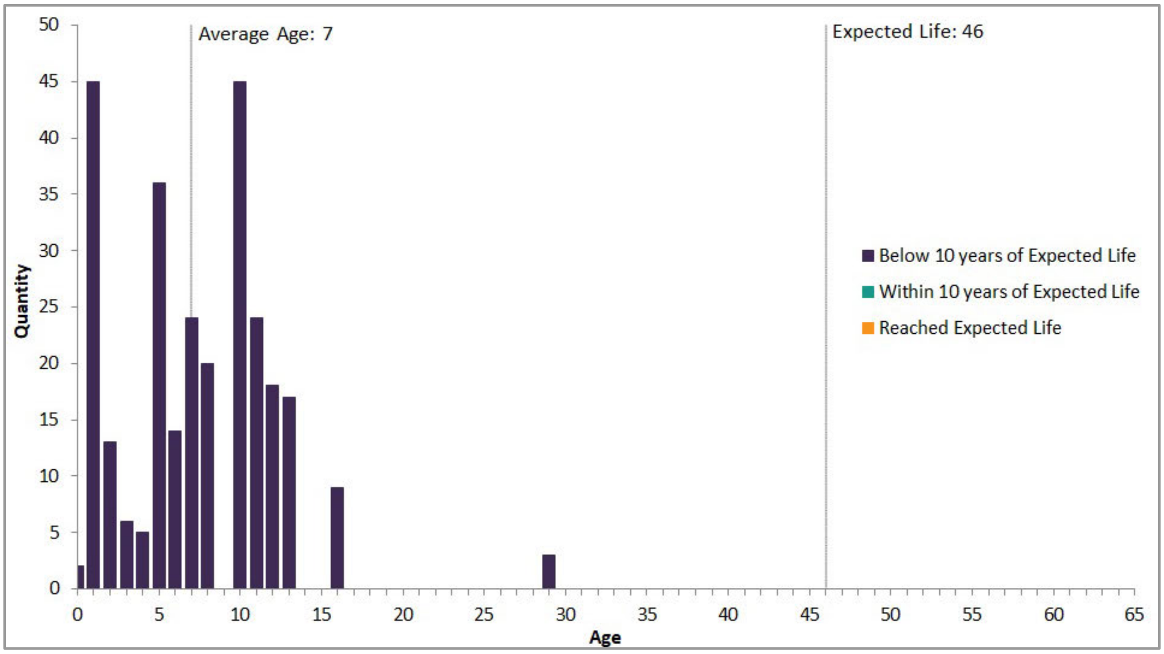


Figure 1.25 – Station Vacuum Breaker Age Demographics



The age demographics of Hydro Ottawa's station batteries are illustrated in Figure 1.26 and Figure 1.27 below.

Figure 1.26 - Count of Hydro Ottawa's VLA Batteries

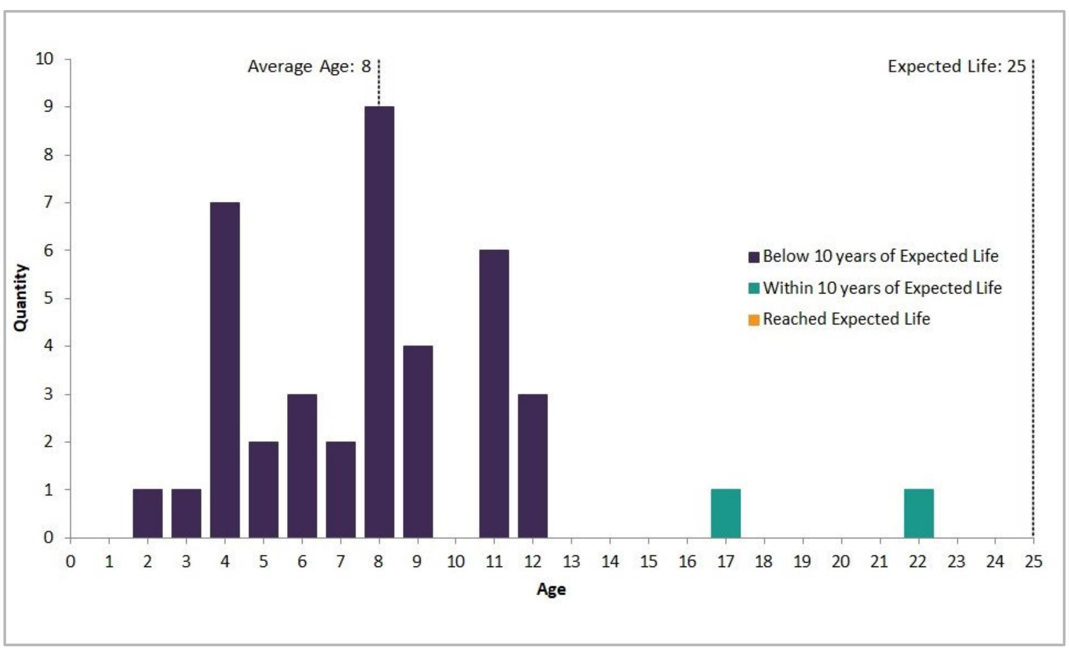
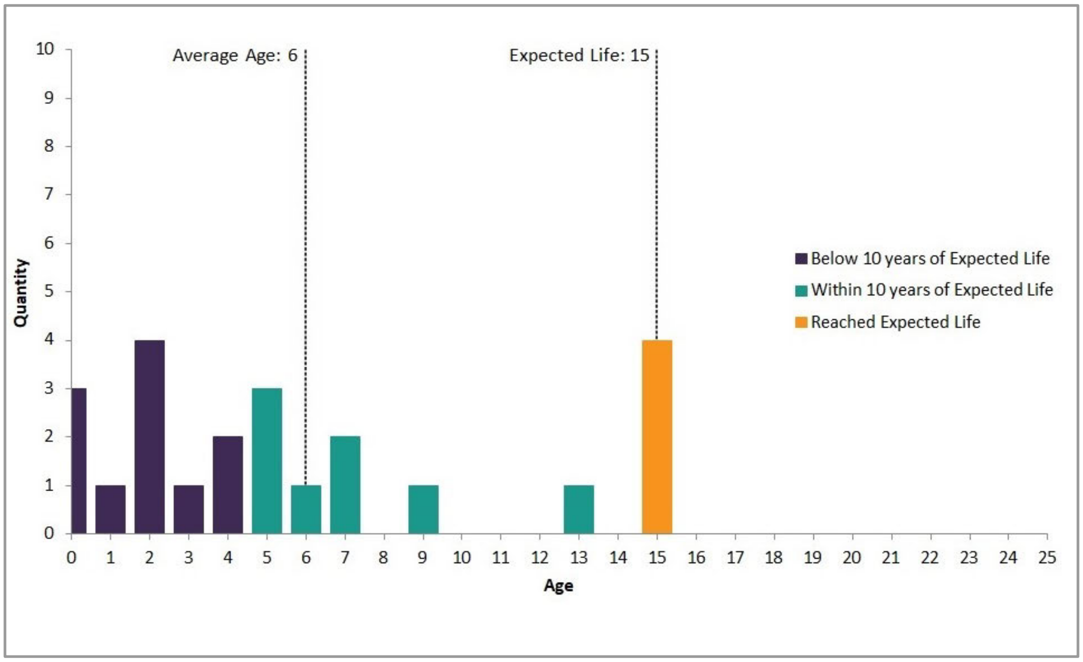


Figure 1.27 - Count of Hydro Ottawa's VRLA Batteries



The transformer and breaker health indices are based on degradation factors that are obtained from Hydro Ottawa's testing and inspection programs. The details of the health index formulations, including a list of degradation factors and health index formulas can be found in Hydro Ottawa's Health Index Formulation standard GEG0001.

Figure 1.28 below shows Hydro Ottawa's transformer demographics in terms of condition based on their health indices.

Figure 1.28 – Station Transformer Health Demographics

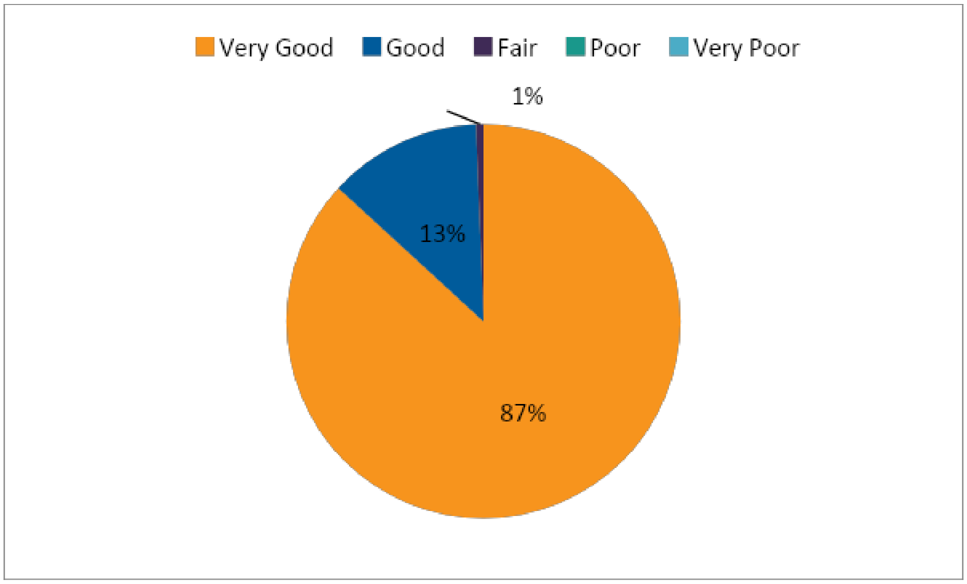
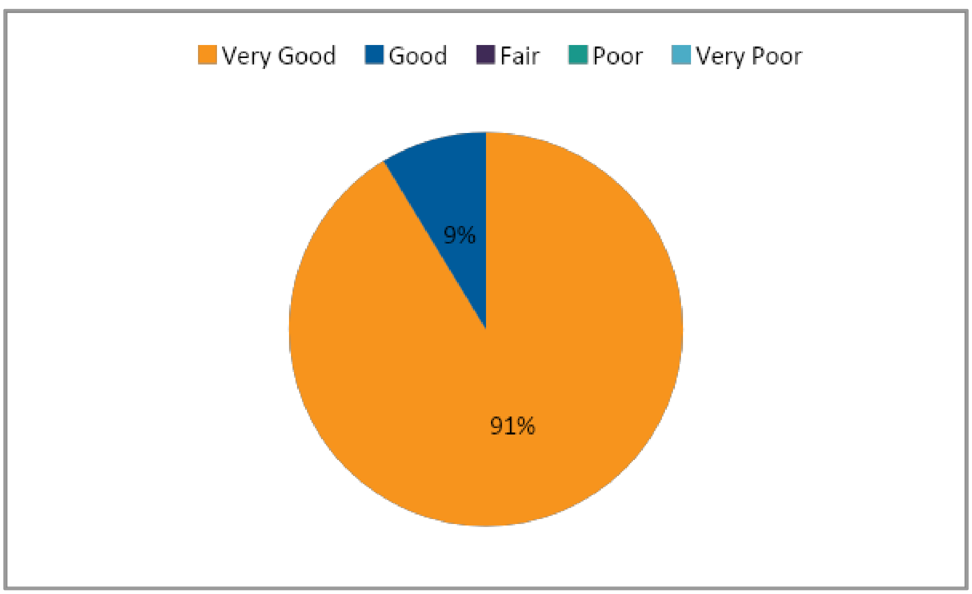


Figure 1.29 below shows Hydro Ottawa's breaker demographics in terms of condition based on their health indices.

Figure 1.29 – Station Breaker Health Demographics



1.6.2.3. Consequence of Failure

For information on the consequence of failures of the assets renewed through the Station Major Rebuild program, refer to the Station Transformer Renewal Program business case (project ID 92002614), the Station Switchgear Renewal (project ID 92003371), Station Battery Renewal (project ID 92014438), and Station P&C Renewal business case (project ID 92003405).

1.6.2.4. Main and Secondary Drivers

A station rebuild project will be considered as an alternative to individual asset renewal if ;the drivers identified in their individual business cases warrant the replacement of more than one asset type.

For information on the drivers for individual assets within the scope of the Station Major Rebuild program, refer to the Station Transformer Renewal Program business case (project ID 92002614), the Station Switchgear Renewal (project ID 92003371), Station Battery Renewal (project ID 92014438), and Station P&C Renewal business case (project ID 92003405).

1.6.2.5. Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the Station Major Rebuild program, improvements are expected in the "Defective Equipment SAIFI" metric for the station transformers, station switchgear, and station P&C asset classes.

The station major rebuild program will help Hydro Ottawa reduce the number of station asset failures over the course of the next 50 years by replacing high-risk assets before they fail. This will manage station asset risks to an acceptable level.

1.1.6.3. Program Justification

1.1.6.3.1 Alternatives Evaluation

Alternatives Considered

When multiple asset renewals are justified for assets within a station, a major rebuild will be considered. A common alternative to station rebuild projects are individual asset replacements, such as transformer renewal or switchgear renewal. These individual asset renewals are performed when the risk posed by the asset justifies its replacement, but the mitigated risk from renewing other assets and cost-savings to be achieved from a full station rebuild do not justify a full station rebuild.

Another alternative considered in the case of 4 kV stations is voltage conversion. In this case, the entire area serviced by the station is to be converted to a 13 kV distribution system. This includes overhead and underground system renewals, which may prove to be more cost-effective than rebuilding the station and maintaining it for another lifecycle.

Refer to the Station Transformer Renewal Program business case (project ID 92002614), the Station Switchgear Renewal (project ID 92003371), Station Battery Renewal (project ID 92014438), and Station P&C Renewal business case (project ID 92003405) for the alternatives considered for each asset class.

Alternatives Evaluation

Hydro Ottawa evaluates all alternatives with consideration of the following risk criteria:

Failure/Reliability

The increased potential of failure posed by these ageing assets will impact Hydro Ottawa's ability to deliver reliable power. The selected alternative shall maintain or improve the reliability performance of the system.

Safety

Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must mitigate any present risks to Hydro Ottawa's employees and the public safety.

Resources

Unplanned replacements are usually carried out by Hydro Ottawa's own crews, whereas planned replacements can be performed by both internal and external resources. The preferred alternative shall lead to more planned renewal projects, where appropriate staffing resources can be allocated, rather than unplanned renewal projects that would take resources away from other work.

Financial

Financial costs and benefits shall include all direct and indirect impacts on the utility's performance and rates.

Preferred Alternative

Hydro Ottawa has identified five stations where a station rebuild is justified over individual asset renewals. This is due to the condition of both the switchgear and transformers. They are listed in Section 1.1.6.4.1.

1.1.6.3.2. Program Timing & Expenditure

Table 1.27 below provides information on the expenditures and station rebuild projects that were completed in the past, as well as the number of station rebuilds that will be completed in the 2020 to 2025 period.

Table 1.27 - Expenditure History and Forecast of Comparable Projects

	Historical			Approved		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Program Cost ($'000s)	$3.95	$5.24	$8.75	$2.79	$4.18	$4.72	$8.34	$6.19	$5.44	$8.70
Station Rebuild Units	0	1	0	1	0	0	0	1	1	0

Historically, full station rebuilds have also been executed as part of the station switchgear renewal program. Table 1.28 below provides information on the expenditures and station rebuild units that were completed in the historical period as part of the switchgear renewal program.

Table 1.28 – Expenditure History and Forecast of Switchgear Renewal Projects

	Historical			Approved		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Program Cost ($'000s)	$5.02	$6.58	$8.79	$4.54	$0.40	$1.57	$2.24	$1.67	$1.20	$0.03
Station Rebuild Units	0	0	0	1	0	0	0	0	0	0

Station rebuild projects vary depending on their ability to supply load from alternative locations. Some projects require to be staged such that the new equipment is constructed while keeping the existing equipment in-service. Once constructed, the connections are transferred to the new equipment with minimal interruption to the customers.

Assets that are typically replaced in these projects include transformers, protections and control systems, egress cables, monitoring devices, and switchgear lineups

1.1.6.3.3. Benefits

Key benefits that will be achieved by implementing the station rebuild program are summarized in Table 1.29 below.

Table 1.29 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Assets that are typically replaced in these projects include transformers, protection and control systems, egress cables, monitoring devices, and switchgear lineups. Replacing these assets concurrently provides cost efficiencies due to cost efficiencies that can be achieved, and reduces required system interruptions.
Customer	Improved reliability due to decreased station equipment failures and increased availability of redundant systems. Improved reliability and safety due to upgraded protection and control systems, and monitoring.
Safety	Station equipment has the potential to fail in a manner that may present a safety hazard. Replacing these assets reduces the risk of failure. Upgraded protection and control systems and switchgear lineups can increase protection from these failure modes.
Cyber-Security, Privacy	(Not applicable)
Coordination, Interoperability	For station rebuild projects that involve transmission connection requirements, Hydro Ottawa coordinates with Hydro One to complete the transmission connection.
Economic Development	Hydro Ottawa hires third party contractors to complete certain projects when the projects cannot be completed with its own internal resources.
Environment	Hydro Ottawa aims to minimize oil spills by the installation of oil containment unit underneath each transformer.

1.1.6.4. Prioritization

1.1.6.4.1. Consequences of Deferral

The deferral of a station renewal project results in increased potential for in-service failures. In this case, the benefits of concurrent asset renewal would not be achieved. Furthermore, deferring station rebuild projects impacts the management of each asset class.

Further information on the impact of these deferrals can be found in their separate business cases, refer to the Station Transformer Renewal Program business case (project ID 92002614), the Station Switchgear Renewal (project ID 92003371), Station Battery Renewal (project ID 92014438), and Station P&C Renewal business case (project ID 92003405) for the consequences of deferring the renewal of each asset class.

1.1.6.4.2. Priority

Due to the high consequence of failure for the assets involved, station major rebuild projects are generally higher-priority renewal projects. Due to the risk mitigated by renewing station equipment, they are almost always prioritized over other projects. The exception would be in the case of an emergency situation that would need to be addressed immediately.

1.1.6.5. Execution Path

1.1.6.5.1. Implementation Plan

Station major rebuild projects typically span 3-5 years. The project starts with the design, followed by equipment procurement, installation, and commissioning. Below is a list of station rebuild projects to be executed during the 2021 to 2025 period:

- Bell's Corners Rebuild (2019 to 2023)
- Fisher Rebuild (2021 to 2024)
- Rideau Heights (2022 to 2025)
- Dagmar Rebuild (2023 to 2026)
- Shillington (2024 to 2028)

1.1.6.5.2. Risks to Completion and Risk Mitigation Strategies

Table 1.30 below describes the various risks of performing station major rebuild projects, as well as their mitigation strategies.

Table 1.30 – Program Risks and Mitigation Strategies

Risk	Mitigation
Typical risks to completion include: • Project planning to minimize outages to customers and that coordinate with other planned work in the area; • Adherence to schedules; • Timely procurement of equipment; • Quality of materials	Hydro Ottawa has dedicated project managers who oversee the project to ensure that risk is managed accordingly. It is Hydro Ottawa practice to schedule and coordinate all work (planned and emergency) through our System Office to ensure effective use of resourcing and ensure continued system operability and safety in areas where crews are working.

1.1.6.5.3. Timing Factors

Station rebuild projects are typically planned to include any civil construction outside of the winter months to avoid costs and challenges associated with cold weather civil construction. Construction timing at the manufacturing plant typically dictates the project schedule.

1.1.6.5.4. Cost Factors

Cost factors that affect replacement projects are:

- Project creep with including additional assets to be replaced. Most are identified early on in the project.
- Delays in the project schedule.
- Compatibility with existing equipment.
-

1.1.6.5.5. Other Factors

(Not applicable for this program)

1.1.6.6. Renewable Energy Generation (if applicable)

Upgraded on-load tap changer controls and P&C on new transformers allow for reverse power flow. This upgrade allows for renewable generation to be connected to a circuit supplied by a new transformer, where it might not have been allowable if the transformer didn't have the required tap changer or P&C equipment. Therefore, a transformer renewal performed as part of a station rebuild project may allow for new renewable generation to be connected to Hydro Ottawa's system.

1.1.6.7. Leave-To-Construct (if applicable)

(Not applicable for this program)

1.1.6.8. Project Details and Justification

Table 1.31 – Program Risks and Mitigation Strategies

Project Name:	Station Major Rebuild
Capital Cost:	$33.4M
O&M:	$0
Start Date:	2021
In-Service Date:	2023
Investment Category:	Renewal
Main Driver:	Failure Risk
Secondary Driver(s):	Reliability
Customer/Load Attachment	
Project Scope	
The scope of this program is to rebuild the Bell's Corners, Fisher, Rideau Heights, Dagmar, and Shillington substations at a total cost of $33.4M.	
Priority	
Station rebuild projects are prioritized based on the individual asset failure probabilities assessed through asset condition, and consequence of failure. Due to the high reliability impact of older stations, these projects are of significant priority.	
Work Plan	
Below is the list of projects to be executed as part of the Station Major rebuild program, as well as their timelines. ● Bell's Corners Rebuild (2019 to 2023) ● Fisher Rebuild (2021 to 2024) ● Rideau Heights (2022 to 2025) ● Dagmar Rebuild (2023 to 2026) ● Shillington (2024 to 2028)	
Customer Impact	
Customers will experience improved reliability due to decreased equipment failures and availability of redundant systems, as well as improved reliability and safety due to upgraded protection and control systems. The customer benefits from a program that prioritizes renewal of stations based on condition, providing cost efficiencies, and ensuring the reliability of the distribution system.	

1.2. OH DISTRIBUTION RENEWAL

1.2.1. POLE RENEWAL

1.2.1.1. Program Summary

Hydro Ottawa's overhead distribution system is supported both electrically and mechanically by a system of poles and fixtures. The continued reliability and safety of the overhead distribution system is reliant on the performance of these assets.

The pole renewal program targets wood poles and related fixtures that are determined to be in poor condition as they comprise the majority of this asset type; poles made of other materials are managed alongside adjacent assets they support. The scope of each of Hydro Ottawa's pole renewal projects are evaluated based on the following standards and design practices:

- Poles and fixtures that are scheduled for replacement will be evaluated for future system requirements to determine if additional capacity and therefore increased height is needed;
- New wooden poles are fully treated western red cedar or red pine;
- Porcelain insulators are replaced with functionally equivalent polymer insulators suited for the voltage class.
- Conversion from horizontal construction (cross-arms) to vertical construction where feasible;
- Pole attachments such as transformers and secondary services will be evaluated for renewal on a case-by-case;
- When primary overhead conductors are non standard or undersized, they are replaced along with pole renewal

Under specific conditions, the use of composite poles as an alternative replacement is considered. Composite poles are manufactured using a fiber-reinforced material and are installed in targeted areas with increased incidents of woodpecker damage or high soil moisture conditions. Composite poles are also used in self-supporting applications when proper support guying and anchoring is not feasible.

Based on analysis, Hydro Ottawa has determined an average planned replacement rate of 550 wooden poles per year for the period 2021-2025; this total includes replacing 400 poles on a proactive planned basis funded at an average rate of $8.03M annually and 150 poles replaced in a reactive unplanned emergency and critical renewal basis funded at an average rate of $2M annually.

1.2.1.2. Program Description

1.2.1.2.1. Assets in Scope

The primary purpose of the 48,506 poles owned by Hydro Ottawa is to mechanically support the assets that comprise the overhead distribution system. Of these poles, 1,000 are comprised of material other than wood. Given the large number of wood poles, a dedicated planned program of inspection examines approximately 5,000 wood poles annually to monitor their condition. Data collected during inspection is used to assess the pole's condition and is also used in prioritizing replacements. Poles remain in service until their condition is such that it poses an increased risk to public safety, worker safety, or the continued reliability of the distribution system. Poles identified as requiring replacement typically have either reached, or exceeded, their expected service life. In the course of pole renewal attachments such as transformers, insulators, secondary bus and connections are typically replaced.

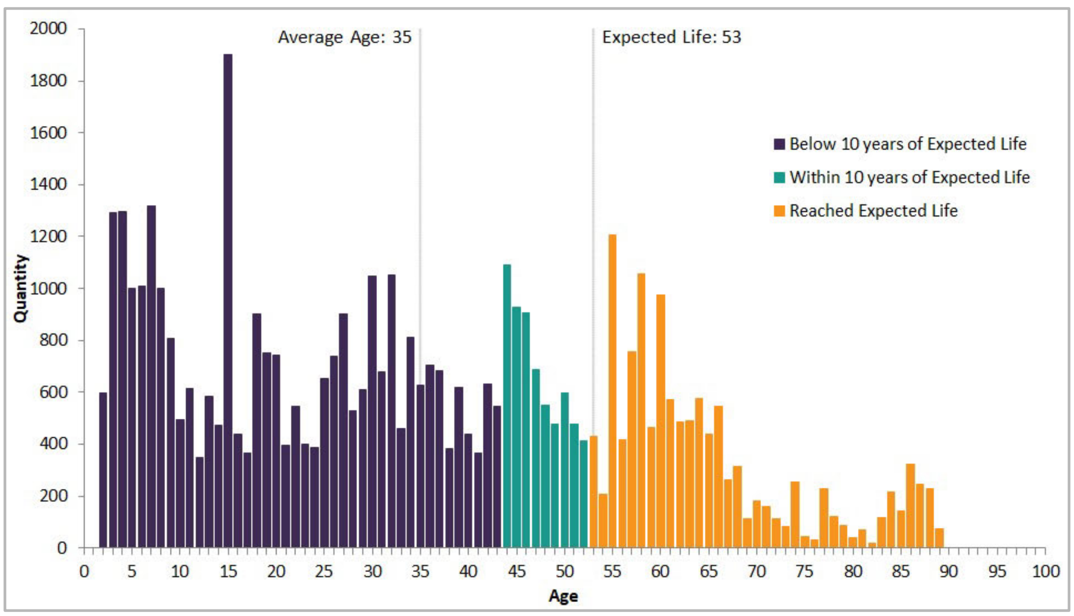
In addition to poles identified for reactive and planned proactive replacement, poles may require replacement as identified through other construction projects including projects that are complemented by replacing the pole(s) adjacent to the work, either due to the pole condition or if the pole is no longer suitable. Specific poles for planned replacement in the period 2021-2025, are identified in projects listed in Section 8 of this document.

1.2.1.2.2. Asset Life Cycle and Condition

Hydro Ottawa collects condition data on its wooden poles through a 10-year, planned program of inspection that includes visual inspection and non-destructive digital resistograph testing. These two means of inspection are used to collect condition data to identify poles for either reactive (if deemed necessary) or planned proactive replacement. When identifying poles for planned proactive replacement, the condition data is used to prioritize replacements, thus enabling Hydro Ottawa to focus its resources on poles that pose an increased risk compared to other poles. This approach, versus a strictly age based approach, enables Hydro Ottawa to utilize these assets over a longer service life.

The expected service life of a wooden pole is 53 years. The percentage of wood poles that have either reached or exceeded their expected service life is 25.0%; in the absence of planned replacement this is expected to increase to 26.4% by 2025. Age demographic information for wood poles is summarized in Figure 1.30 below.

Figure 1.30 - Hydro Ottawa Wood Pole Demographics

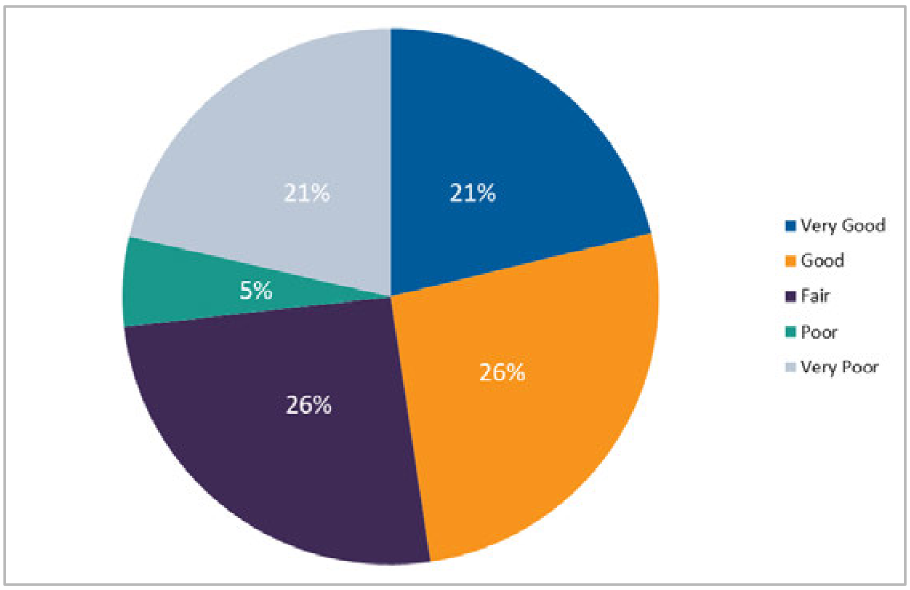


Age demographic information for poles are kept in Hydro Ottawa's GIS system. When an installation date was not available for a given asset, an estimated installation date was determined using the proportions of overhead switches with a known age.

As mentioned above, Hydro Ottawa does not rely solely on age when determining the condition of a pole. Wood pole condition is assessed largely based on the pole's ability to perform its designed function: support overhead plant under anticipated stresses. The Asset Condition Assessment for wood poles also considers other factors such as shell condition, pole top condition, and woodpecker damage. These factors are combined in the pole Health Index which is utilized to assess and prioritize renewal.

Hydro Ottawa annually tests approximately 5,000 poles, as part of its wooden pole inspection program on a 10 year cycle to collect data used to evaluate the condition of the poles. The condition of Hydro Ottawa's poles is summarized in Figure 1.31 below:

Figure 1.31 - Hydro Ottawa's Distribution Wood Pole Condition



If a pole is deemed to be in emergency or critical condition, it is replaced under the Emergency and Critical Renewal program, as described in Section 1.4, Emergency and Critical Renewal.

1.2.2.3. Consequence of Failure

Pole failures have a safety, financial, and, system reliability impact. Broken poles can result in downed wires, posing a safety consequence to public or staff in proximity. Further, when the pole supports oil-filled equipment, there is an additional consequence of an environmental impact due to the potential release of oil.

Emergency replacement of failed poles is more costly than the planned replacement of a pole. Furthermore, emergency renewal limits the ability to coordinate the replacement of adjacent aged assets, and incorporate upgrades yielding less effective replacement outcomes.

Pole failure can also impact system reliability; pole failure may result in an outage to the circuit, impacting customer reliability. Through active inspection and testing, most degraded poles are identified before they fall, allowing them to be replaced in a planned fashion minimizing the experienced reliability impact on the system. Historical reliability impact for defective poles is summarized in Figure 1.32 and Table 1.32 below:

Figure 1.32 - Hydro Ottawa Pole Failure SAIFI

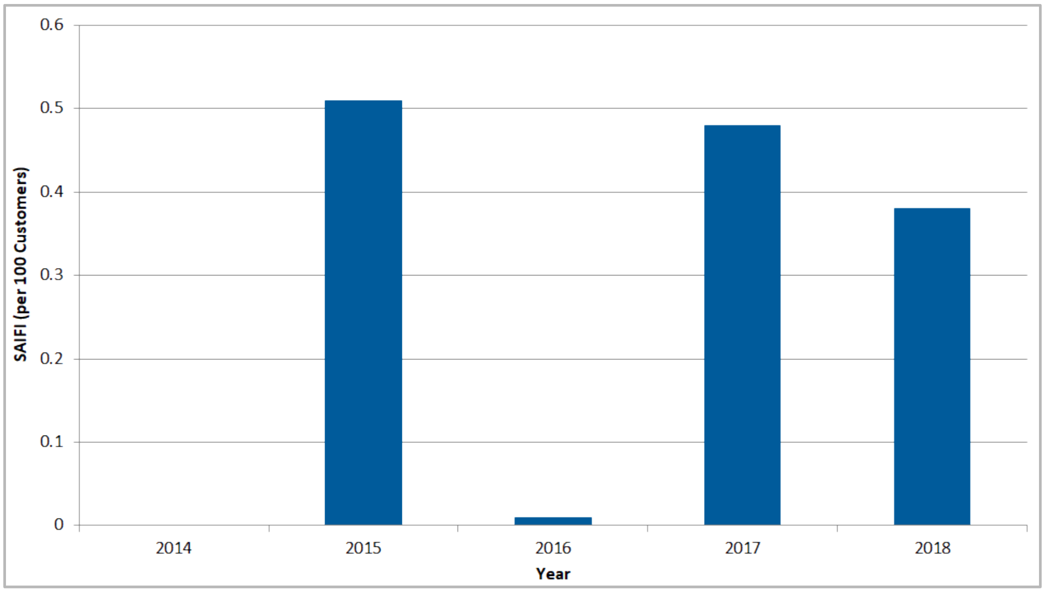


Table 1.32 – Historical SAIFI (per 100 Customers) for Failed Poles

	2014	2015	2016	2017	2018
Poles	0.00	0.05	0.01	0.48	0.38

1.2.1.2.4. Main and Secondary Drivers

The goal of the pole renewal program is to minimize the impact failed poles have on reliability, and by extension SAIFI and SAIDI (by replacing the pole before it fails), and to mitigate safety impacts associated with failed poles while undertaking renewal in a cost efficient planned manner. Further, given that many of Hydro Ottawa's poles mechanically support assets containing oil, including overhead transformers, the proactive replacement of poles will also reduce the risk of oil released to the environment due to unforeseen pole failures.

1.2.1.2.5. Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the Pole Renewal Program, improvements are expected in the KPI metrics shown in Table 1.33.

Table 1.33 - Pole Replacement Drivers

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Improve SAIFI and SAIDI
Cost Efficiency & Effectiveness	Resource Efficiency	Cost Efficiency	Reduce cost due to emergency replacement
		Labour Utilization	Reduce labour allocation to emergency renewal
Asset Performance	Asset Value	Defective Equipment to Contribution to SAIFI	Improve SAIFI and SAIDI
	Health, Safety & Environment	Public Safety Concerns	Not to contribute to this metric
		Oil Spilled	Not to contribute to this metric

Planning objectives may be accommodated simultaneously during the planned and unplanned renewal of poles. This includes replacing other potential end of life assets including pole mounted transformers, switches and insulators.

1.2.1.3. Program Justification

1.2.1.3.1. Alternatives Evaluation

Alternatives Considered

The alternatives considered are based on various funding levels and their impact they would have on the pole population and the expected number of unplanned replacements.

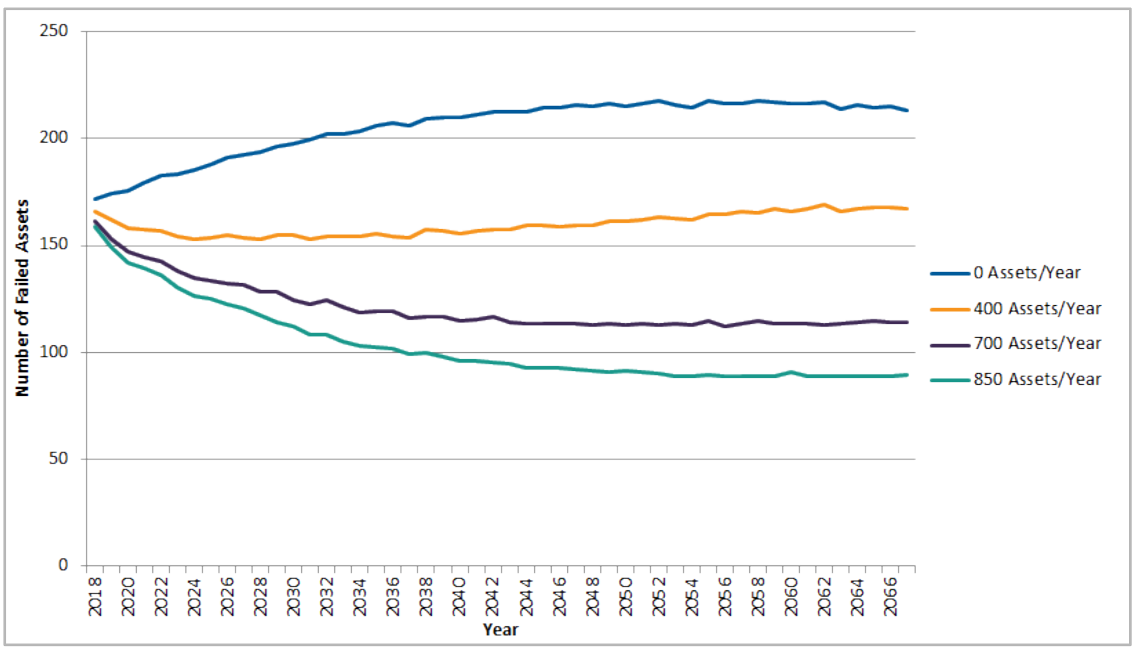
Hydro Ottawa has considered the following scenarios:

- Only reactively replace poles that have failed;
- Reactively replace poles that have failed with the proactive planned replacement of 400 poles on a like-for-like basis;

- Reactively replace poles that have failed with the proactive planned replacement of 700 poles on a like-for-like basis;
- Reactively replace poles that have failed with the proactive planned replacement of 850 poles on a like-for-like basis.

The expected numbers of failed poles annually, under each alternative as a function of various rates of replacement, are summarized in Figure 1.32 below. Currently, Hydro Ottawa undertakes an average of 400 poles replacements annually under its corrective renewal program, with 13 emergency replacement of failed poles, and 150 critical replacements.

Figure 1.33 - Number of Expected Failed Wooden Poles versus Annual Rates of Renewal



Evaluation Criteria

The intent of the pole replacement scenarios is to continue to use poles already in service, until their condition is such that it poses an unacceptable risk to the public, workers, or system reliability, while ensuring adequate resources are in place to execute the replacements. This approach requires the immediate replacement of poles that have failed, resulting in an unacceptable risk, while prioritizing poles that have failed, but pose a reduced risk, for replacement based on their condition.

Hydro Ottawa evaluates all pole renewal alternatives with consideration of the criteria in Table 1.34 below:

Table 1.34 – Pole Renewal Criteria

Criteria	Description
Reliability	The increased potential of failure posed by aging poles will impact Hydro Ottawa's customer reliability. Unforeseen pole failures may also result in the release of oil to the environment, contained in assets mechanically supported by the pole including overhead transformers. The selected alternative must maintain or improve the reliability performance of the system.
Safety	Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The increased potential of failure posed by aging poles will impact Hydro Ottawa's ability to protect worker and public safety. The selected alternative must maintain or improve the safety of Hydro Ottawa's employees and the public.
Resource	Unplanned replacements are typically executed by Hydro Ottawa's internal resources, whereas planned replacements can utilize both internal and external resources. Additionally, single pole failures are less efficient than planned replacement projects. Therefore, alternatives that incur more pole failures requiring unplanned replacements are less favorable due to reduced resource efficiency.
Economics	Financial costs and benefits shall include all direct and indirect impact on Hydro Ottawa's performance and rates. The preferred alternative shall provide the most benefit at the least cost to Hydro Ottawa's stakeholders and customers.

Preferred Alternative

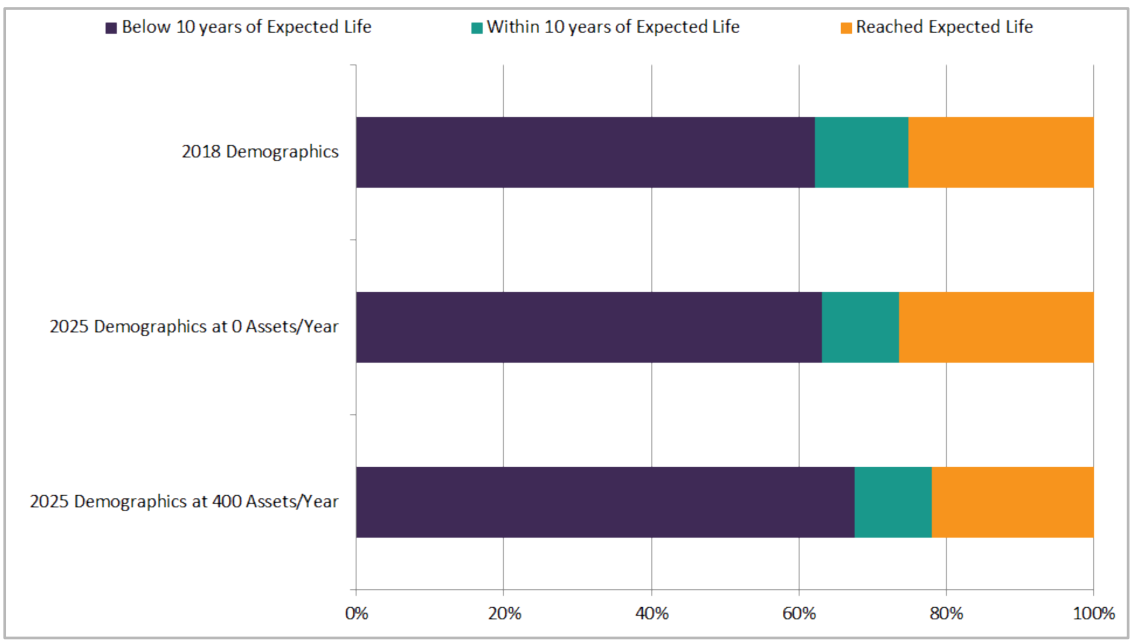
Hydro Ottawa's preferred alternative is to proceed with 400 Planned Replacements annually. Based on the above criteria, alternatives that replace less than 400 poles per year on a proactive basis will not meet Hydro Ottawa's objectives. Further, alternatives that replace more than 400 poles per year may mitigate the number of unforeseen failures, but would not be economically viable compared to the benefits.

With replacement of 400 poles annually, Hydro Ottawa is forecasting a corrective renewal of an average of 154 poles in 2025. Of these 154 annually, 13 are expected to be replaced on an Emergency basis. The preferred alternative is to reactively replace poles that have failed while proactively replacing 400 poles on a planned basis annually. The average amount of funding for this alternative is approximately $8.03M annually for planned pole renewal and $2.88M annually for reactive renewal.

These demographics do not consider poles replaced as part of plant relocation, or service connection, so the forecasted demographics are inherently conservative.

Figure 1.34 below summarizes the impact the preferred alternative would have on the age demographics of Hydro Ottawa's wood poles compared to no planned replacements:

Figure 1.34 - Impact of various rates of annual renewal on Age Demographics of Wooden Poles



1.2.1.3.2. Program Timing & Expenditure

Table 1.35 provides information on the projected expenditures and volume of poles to be replaced in the period 2021-2025. The average projected cost for replacing a pole in a planned manner is anticipated to be approximately $20k each.

Table 1.35 - Historical, Approved, and Projected Expenditure for Planned Pole Renewal ($'000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$11.07	$10.52	$10.46	$6.19	$6.92	$8.00	$8.04	$8.04	$8.04	$8.04
Units Replaced	498	506	355	354	362	400	400	400	400	400

Specific pole replacement projects are coordinated and scheduled to allow for optimal efficiency of crew resources by subdividing the work into suitable packages by geographic region. To ensure cost effectiveness, in conjunction with the pole replacement, pole fixtures are replaced and connecting transformers are reviewed and identified for replacement as needed based on their condition and other upcoming project requirements; note the converse can also occur, where the replacement of poles is funded under other asset replacement programs. In addition to the projected funding in the Table 1.35, Hydro Ottawa anticipates to spend an additional $2.88M per year, starting in 2021, to fund replacements under the corrective renewal program.

1.2.1.3.3. Benefits

Key benefits that will be achieved by implementing the pole replacement program are summarized below.

Table 1.36 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The costs associated with replacing wood poles on an unplanned basis can exceed the cost of replacing the pole on a planned basis. A do-nothing policy increases the risk of unforeseen pole failures resulting in a higher renewal costs. By replacing the recommended number of poles on a planned basis, the overall average cost to renew poles will be reduced and provide long-term financial benefit.
Customer	Improvement to Defective Equipment related reliability statistics due to anticipated decrease in unforeseen pole and pole fixture failures.
Safety	Pole replacement reduces the risk of pole failures thereby reducing the potential health and safety risk to employees and the public.
Cyber-Security, Privacy	N/A
Coordination, Interoperability	N/A
Economic Development	Hydro Ottawa uses external resources to complete certain projects when there are insufficient internal resources or for incidents when internal resources will not be available in a timely manner.
Environment	Proactive pole replacement mitigates the risk of environmental contamination from overhead oil-filled transformers in the event of a pole failure.

1.2.1.4. Prioritization

1.2.1.4.1. Consequences of Deferral

Deferral of planned pole replacements to the next planning period, or in the event sufficient rates of renewal are not realized, will pose an increased risk to safety and reliability resulting from the increased potential for pole failures. Additionally, deferral of pole renewal can lead to cascading pole failures, and/or simultaneous pole failures during severe weather. Hydro Ottawa has reviewed measures available to enable a pole to temporarily remain in service, ex. bracing and patching-type products. These measures do not improve the condition of the pole, but enable it to remain in service until it can be scheduled for replacements. Temporary support measures are funded by O&M budgets resulting in an increase in O&M spending if replacements are deferred. Further, deferral of planned pole replacements may create a backlog of poles that will incur an increased replacement cost in the future and strain on resources.

1.2.1.4.2. Priority

Poles selected for proactive replacement are also prioritized based on their asset risk. Their failure probability is assessed by their condition, and the impact is assessed based on the pole configuration considering potential impact to public safety, worker safety, or system reliability.

Pole renewal is a high priority program as these assets mechanically support the overhead distribution system. The continued reliability and safety of the overhead distribution system is reliant on the performance of these assets.

1.2.1.5. Execution Path

1.2.1.5.1. Implementation Plan

Planned pole replacements are prioritized based on the pole's condition which in turn is used to determine the level of risk it poses to Hydro Ottawa. Using the recommended rate of planned renewal, a program of planned renewal will begin in 2021 addressing poles whose condition poses an increased risk compared to other poles.

Renewal of aged and decayed overhead infrastructure to withstand climatic forces from storm events is key to resilience over the long term for the system. Hydro Ottawa will augment the impact of the pole renewal program over the 2021-2025 period through the development of new anti-cascade standards, and risk based application guides to further mitigate damage in high risk installations when damage does occur.

1.2.1.5.2. Risks to Completion and Risk Mitigation Strategies

Table 1.37 - Risks and Mitigation

Risk	Mitigation
Typical risks to completion include: • Coordinating activities in areas where multiple parties are working; • Availability of internal and external resources; • Increased frequency of severe weather events could lead to premature failures of poles which are already in poor condition	It is standard practice to engage early and communicate plans, and the associated benefits, with the customer.

1.2.1.5.3. Timing Factors

As planned inspections progress, higher priority assets might be identified prompting a reprioritization of the targeted poles. Apart from the poles identified for planned renewal, Hydro Ottawa regularly reviews its poles and their condition requiring replacement to ensure poles that pose an increased risk are addressed ahead of those that pose a comparatively lesser risk.

1.2.1.5.4. Cost Factors

Typical factors that impact the cost of replacement include the location of the pole, quantity of circuits installed on it, the type and quantity of other distribution assets installed on the pole, and if a pole is comprised of a different material (using a composite pole in an area with higher incidence of woodpecker damage) is required.

Additionally, reactive pole replacement is higher than planned proactive replacement. Therefore, Hydro Ottawa is actively seeking to reduce unforeseen pole failures.

1.2.1.5.5. Other Factors

(Not applicable for this program)

1.2.1.6. Renewable Energy Generation (if applicable)

(Not applicable for this program)

1.2.1.7. Leave-To-Construct (if applicable)

(Not applicable for this program)

1.2.1.8. Program Details and Justification

Table 1.38 - Planned Pole Renewal Overview

Project Name:	Planned Pole Renewal
Capital Cost:	$40,174,997
O&M:	N/A
Start Date:	January 2021
In-Service Date:	December 2025
Investment Category:	System Renewal
Main Driver:	Assets at End of Service Life
Secondary Driver(s):	Reliability
Customer/Load Attachment	
Project Scope	
Includes replacement of 2,000 poles between 2021-2025 in the following areas: Britannia Park Area (from Maplehurst Ave to the West Carling Ave, from South Scrivens St to East Britannia Bay to the North); Area bordered by Junction Ave, Gregg St, and Kaladar Ave; Area bordered by Harwick Cres, Evergreen Dr, and Stinson Ave; Area bordered by Links Dr, Carlisle Cir, and Sawgrass Cir; Fisher Area; Clifton and Tweedsmuir Ave area; UZ06 (Walkley Station) egress poles; Poles located south of Slack Rd. This project may also require replacement of adjacent assets in poor condition including overhead switches, insulators, and overhead transformers.	
Work Plan	
Procurement of replacement poles and coordinating work with Hydro Ottawa's system office while replacements are executed. This project may also require replacement of adjacent assets, as already described, if found to be in poor condition. Expected completion date of all pole replacements included in scope of work of December 2025.	
Customer Impact	
Customers benefit from reliability improvement resulting from the replacement of aging assets and equipment upgrades. The customer benefits from a program that prioritizes poles by their condition and criticality, ensuring the reliability and cost effectiveness of the distribution system.	

1.2.2. OVERHEAD SWITCH / RECLOSER RENEWAL

1.2.2.1. Program Summary

Overhead distribution switches and reclosers are used to isolate sections of the distribution system in the event of a fault condition or to re-route the electrical supply while executing planned work to minimize the impact to the customer. These assets provide a means of protecting major system equipment as well as allowing circuits to be used as a backup supply.

Hydro Ottawa uses planned programs of inspection to monitor the condition of all its overhead switches and reclosers. This is complemented by a focused planned program of maintenance for its overhead load break/gang operated switches as these assets have a greater impact, compared to other overhead switch types within Hydro Ottawa's distribution system, in the event of unforeseen failure. Non gang-operated/load-break switches and reclosers are subject to reactive maintenance activities and a run-to-failure maintenance strategy. Further, Hydro Ottawa inspects its overhead reclosers on a regular basis through planned programs of inspection.

The overhead switch/recloser renewal program targets overhead switching assets that pose an increased risk of failure; in the period 2021-2025, this includes the replacement of Hydro Ottawa's aging and deteriorating porcelain insulated switches. Porcelain was a common insulation medium used in legacy assets, but has a tendency to pit, crack, and fracture as it ages. This has the effect of decreasing the switch's mechanical strength and increases the risk of the switch failing during operation, thereby increasing the risk of a fault. Hydro Ottawa's practice is to replace these devices with functionally equivalent polymer insulated switches. Hydro Ottawa has determined that replacing an average of 230 overhead switches per year during 2021-2025 is sufficient to mitigate the risk porcelain insulated switches presents with funding of $2.3M over the same period.

1.2.2.2. Program Description

2.2.2.1. Assets in Scope

Hydro Ottawa's overhead distribution switch and reclosers collectively refer to all Hydro Ottawa owned overhead pole mounted switches, in-line switches, fuse cut-outs, and reclosers connected to a primary voltage distribution circuit. These assets are used to segment overhead distribution circuits during a fault condition and to reroute electrical supply during planned work or restoring service to the customer after an outage.

Hydro Ottawa owns 34,932 overhead switches and 52 reclosers. With the exception of Hydro Ottawa's load-break/gang-operated switches, the other overhead switches types and reclosers are subjected to a planned program of inspection (including both a visual and thermographic inspection) and a run-to-failure maintenance strategy. Hydro Ottawa's load-break/gang-operated switches are more complex, compared to other overhead switches, and supply a large number of customers; because of this complexity, these types of switches have a dedicated program of inspection and proactive maintenance to ensure their continued reliable operation. Overhead switches whose condition indicates an increased risk of failure, compared to other switches, are prioritized for replacement ahead of those that pose a reduced risk of failure. Further, Hydro Ottawa has determined its overhead reclosers pose a comparatively lower risk, and are therefore not a focus for renewal during 2021-2025; Hydro Ottawa will continue to monitor their condition through planned programs of inspection and will review and possibly modify this approach should the condition of its overhead reclosers warrant it.

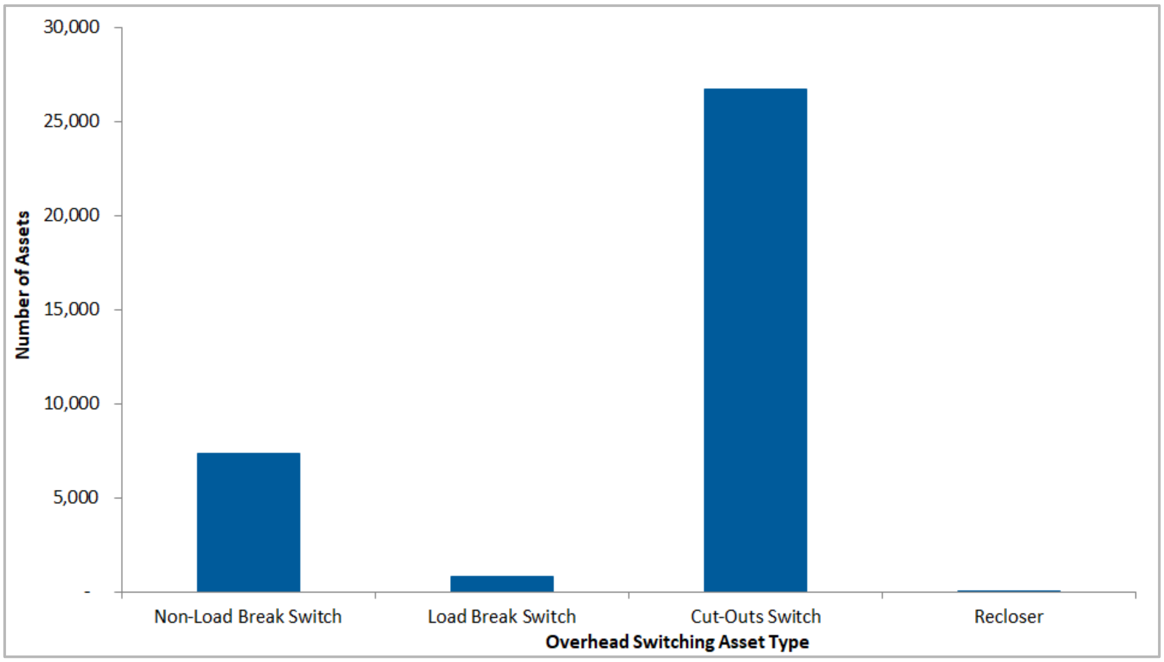
Hydro Ottawa has identified aging porcelain insulated switches as an increased risk to reliability. Porcelain was used as an insulating medium in Hydro Ottawa's legacy assets and is known to pit and crack as it ages. This increases the risk of a fault occurring, resulting in an interruption of service. Porcelain insulated switches connected to a limited number of distribution circuits have been selected to be included in the scopes of work for 2021-2025.

Before replacing an overhead switch on a planned basis, Hydro Ottawa considers the function it performs within its distribution system; if the asset can be removed without adversely affecting the operability or reliability of its distribution system (as circuit topology or engineering requirements may have changed since the switch was initially installed) the overhead switch can be removed from service without replacement.

In addition to overhead switches identified as part of planned replacements, additional candidate switch replacements are identified in coordination with other construction projects, including pole replacements located adjacent to the work. Hydro Ottawa will continue to use the same approach to identify additional candidate switches for proactive replacement in the period

2021 −2025. A summary of the types and quantities of overhead switching assets used by Hydro Ottawa appears in Figure 1.35 below.

Figure 1.35 – Hydro Ottawa Overhead Switching Asset Summary



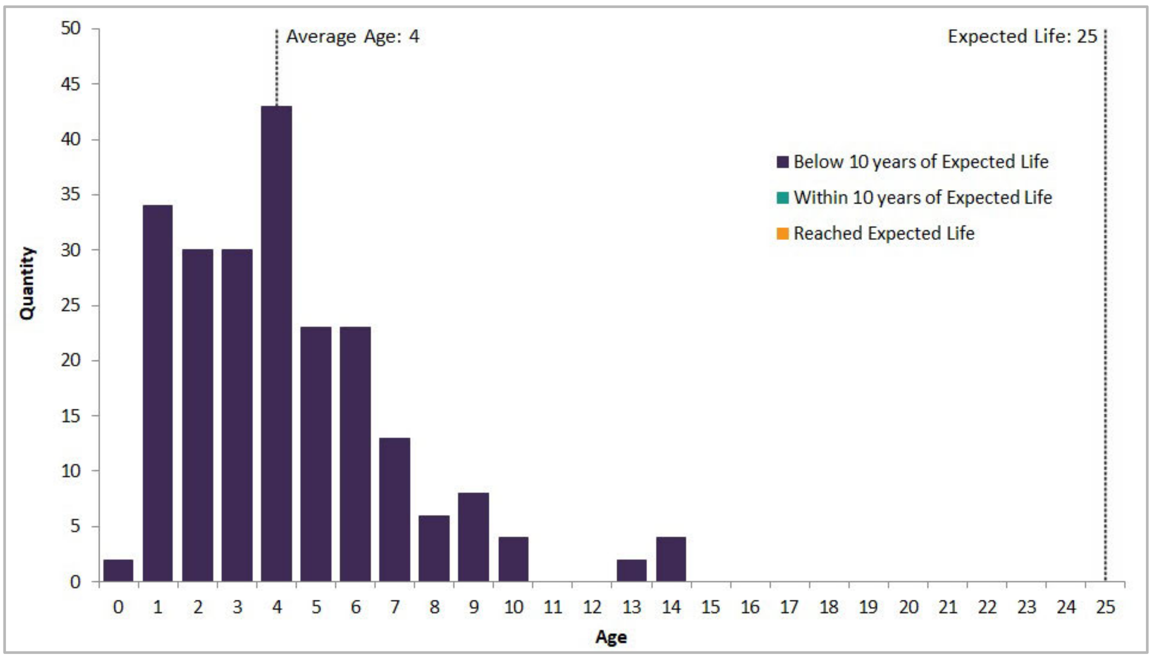
1.2.2.2.2 Asset Life Cycle and Condition

Hydro Ottawa leverages the condition data it has on its distribution overhead switches collected through various planned programs of inspection, including the use of non-destructive inspection methods such as visual inspection and thermography.

Data collected from the planned programs of inspection are combined with historical outage data to determine the condition of overhead switches under review. For those overhead switches under review that Hydro Ottawa does not have detailed condition data, the asset age is used in combination with historical reliability data to infer the switch's condition. Hydro Ottawa maintains detailed condition data on its load-break/gang-operated switches collected through a dedicated program of inspection used to monitor their condition. These switches are maintained through a proactive planned maintenance program and replaced when repair or maintenance is no longer deemed economical.

Using the available data for overhead gang-operated/load-break switches, Figure 1.36 shows that none of these switches have exceeded their expected service life of 25 years as of 2018.

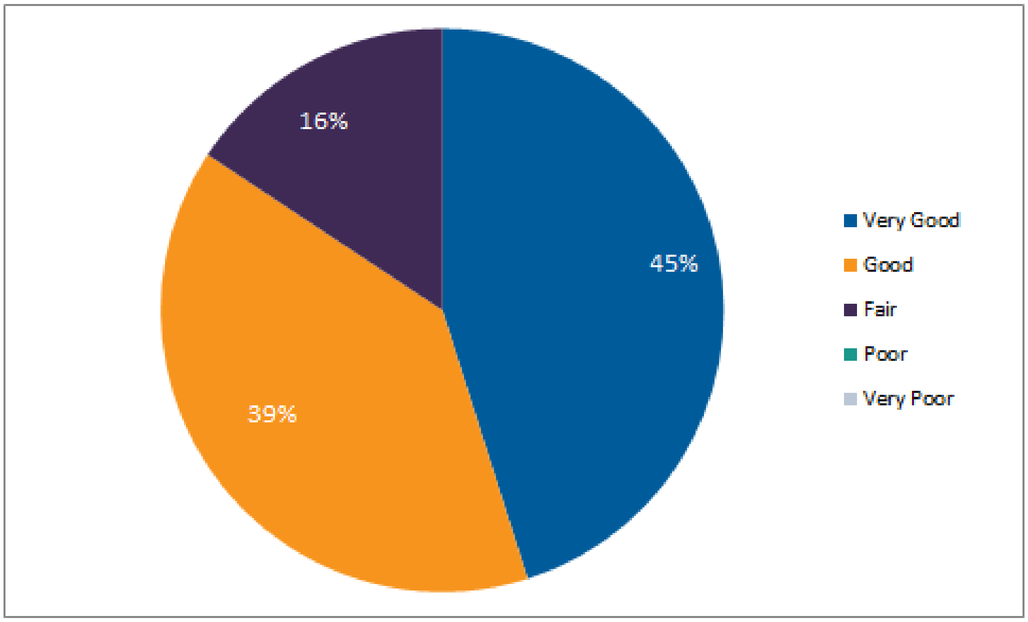
Figure 1.36 – Hydro Ottawa Overhead Load-Break/Gang-Operated Age Demographics



Age demographic information for overhead switches are kept in Hydro Ottawa's GIS system. When an installation date was not available for a given asset, an estimated installation date was determined using the proportions of overhead switches with a known age.

When determining the condition of an overhead switching asset, calendar age is not the sole factor. Other factors including condition of the asset's insulators, condition of visible components, operating conditions and Hydro Ottawa's experience with that asset type are important factors to consider. To monitor the condition of its overhead switches, Hydro Ottawa inspects all its overhead switches based on a 3-year cycle and conducts a detailed inspection and proactive maintenance of its gang-operated/load-break switches based on an 8-year cycle. The condition of Hydro Ottawa's gang-operated/load-break switches is summarized in Figure 1.37.

Figure 1.37 – Hydro Ottawa Overhead Load-Break/Gang-Operated Switch Condition Summary



For the period 2021-2025, Hydro Ottawa will actively replace its aging porcelain insulated overhead switches, with functionally equivalent polymer insulated switches, that pose a comparatively increased risk compared to other overhead switching assets.

1.2.2.2.3. Consequence of Failure

Unforeseen overhead switch failures have a safety, financial, and, system reliability impact. Broken switches can negatively impact the operability of the distribution system, posing an increased risk to reliability and safety to workers during the switch's operation.

Emergency replacement of failed overhead switches are more costly than planned replacement. Further, emergency renewal limits Hydro Ottawa's ability to coordinate the replacement of adjacent candidate assets resulting in a less effective replacement strategy. The historical SAIFI associated with overhead switch is summarized in Figure 1.38.

Figure 1.38 – Defective Equipment Overhead Switch SAIFI

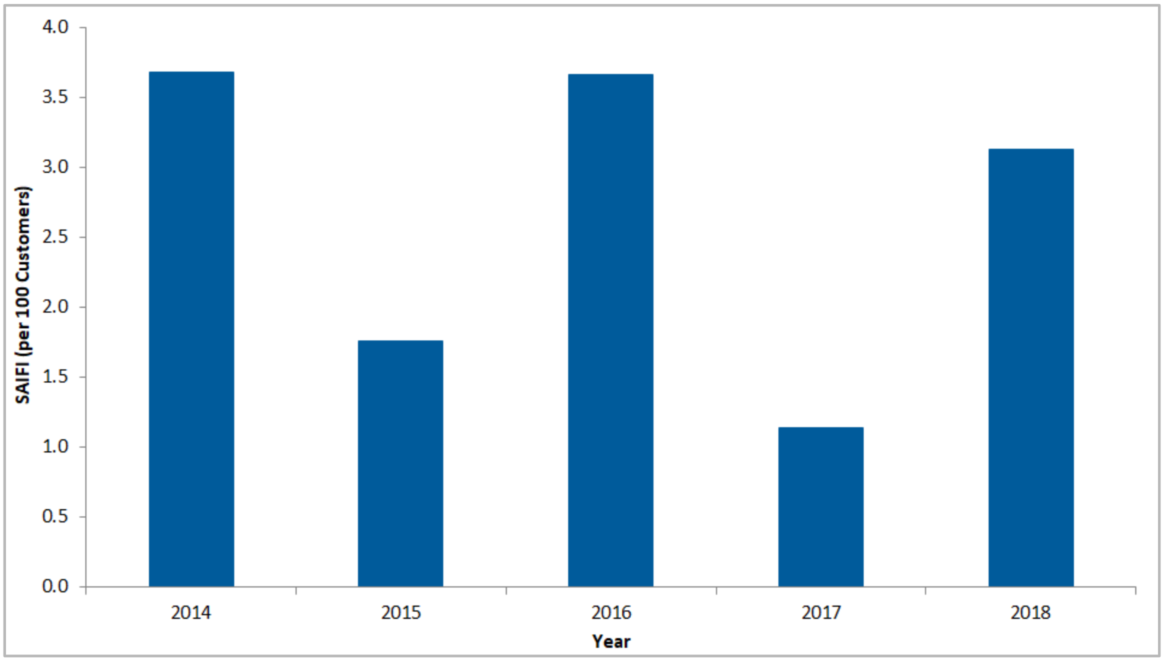


Table 1.39 – Historical SAIFI (per 100 Customers) for Overhead Switch

	2014	2015	2016	2017	2018
Overhead Switch	3.68	1.76	3.66	1.14	3.13

1.2.2.2.4. Main and Secondary Drivers

The goals of the overhead switch renewal program is to minimize the impact failed switches have on reliability, and by extension SAIFI and SAIDI (by replacing the switch ahead of unforeseen failure), and mitigating safety impacts associated failed switches, particularly in regard to worker safety while operating the switch. These efforts are carried out in a cost efficient planned fashion.

1.2.2.2.5. Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the overhead switch replacement program, improvements are expected in KPI metrics shown in Table 1.40.

Table 1.40 - Pole Replacement Drivers

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Reduction in SAIFI and SAIDI
Asset Performance	Asset Value	Defective Equipment Contribution to SAIFI	Reduction in SAIFI and SAIDI

Additional planning objectives may be accommodated during the planned and unplanned renewal of overhead switches. This includes replacement of other adjacent assets that have reached the end of their expected life including pole mounted transformers and insulators.

1.2.2.3. Program Justification

1.2.2.3.1. Alternatives Evaluation

Alternatives Considered

The alternatives considered focus on the replacement of aging porcelain insulated switches. Other overhead switching asset types are excluded from consideration as they pose a comparatively lower risk compared to porcelain insulted switches.

The alternatives below are based on various funding levels and the impact they would have on Hydro Ottawa's longer term strategy of replacing its aging porcelain insulated overhead switches with functionally equivalent polymer insulated switches. Hydro Ottawa has considered the following alternatives:

- Reactive replacement of overhead switches that have failed such that immediate unplanned replacement is required with no proactive planned replacements;
- Reactive replacement of distribution switches that have failed such that immediate unplanned replacement is required and proactively replace 230 overhead switches, on average, annually on a planned basis;

Evaluation Criteria

The intent of any asset replacement scenario is to continue to use in-service overhead switches, until its condition or Hydro Ottawa's experience indicates it poses an unacceptable risk to reliability or worker safety, while ensuring sufficient resources are available to execute the work. This approach requires the immediate replacement of failed overhead switches that result in interruption of service to customers while prioritizing other switches, based on their condition, that have functionally failed or have exceeded their expected service life. In the framework of this discussion, the following criteria are considered:

Table 1.41 - Evaluation Criteria

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging assets will influence Hydro Ottawa's ability to protect worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The impact to safety between the different alternatives can be material as air-insulated equipment in poor condition can pose a significant risk to worker safety.
Resource	Hydro Ottawa typically uses internal resources to repair damaged air-insulated equipment and is typically funded as an O&M expense. This means that increased incidents of damaged air-insulated switchgear will result in a negative impact to Hydro Ottawa's O&M budget. Further, unplanned replacements are more challenging from scheduling perspective to deploy internal resources.
Economics	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Preferred Alternative

Hydro Ottawa's preferred alternative is to proceed with an annual average of 230 planned replacements of its aging porcelain insulated switches. Based on the above criteria, alternatives that replace less than this rate per year on a planned basis will not achieve Hydro Ottawa's objectives for its overhead switching assets. The replacement of these assets will enhance reliability as it removes from service an asset whose dielectric is known to weaken over time, increases worker safety when the asset is operated, and does so in an economic manner as the cost of planned replacement is less compared to unplanned replacement.

With the preferred alternative, the average rate of replacement of 230 overhead switches annually, for 2021-2025, is sufficient to address the risks posed by Hydro Ottawa's aging porcelain insulated overhead switches. The amount of funding for this alternative requires, on average, is $459.7k annually for 2021-2025.

1.2.2.3.2. Program Timing & Expenditure

Table 1.42 provides information on the projected expenditures and volume of overhead switches to be replaced in the period 2021-2025.

Table 1.42 - Historical, Approved, and Projected Expenditure for Planned Overhead Switch Renewal ($'000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$441.9	$268.2	$14.5	$326.2	$0.0	$0.0	$750.9	$750.9	$796.9	$0.0
Units Replaced	249	136	92	58	0	0	375	375	398	0

Historically, Hydro Ottawa has focused on the replacement of other overhead switching asset types, other than porcelain, that are comparatively more costly to procure or are more complex to replace compared to a typical porcelain insulated switch. Further, historic costing can also be misleading as the replacement of adjacent assets, including insulators supporting the adjacent conductor, may also be funded under the same program; the converse can also occur, where the replacement of overhead switches are funded under other asset replacement programs. This is part of ensuring cost effectiveness by replacing adjacent assets whose condition warrants it instead of replacing it separately at another time.

1.2.2.3.3. Benefits

Key benefits that will be achieved by implementing the overhead switch/recloser renewal program are summarized below.

Table 1.43 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The cost of replacing overhead switches on an unplanned basis can exceed the cost performing similar work on a planned basis. A do-nothing policy will increase the risk of failure for its porcelain insulated switches ultimately resulting in increased renewal costs.
Customer	Improvements to Defective Equipment related reliability statistics resulting from the anticipated decrease in unforeseen failures of its aging porcelain insulated overhead switches by removing them from service and replacing them with a functionally equivalent polymer insulated switch.
Safety	Overhead switch replacement reduces the risk of unforeseen failures with this asset type, and simultaneously reduces potential health and safety risk to employees and the public.
Cyber-Security, Privacy	N/A
Coordination, Interoperability	N/A
Economic Development	Hydro Ottawa uses external resources to complete certain projects when there are insufficient internal resources or for incidents when internal resources will not be available in a timely manner.
Environment	N/A

1.2.2.4. Prioritization

1.2.2.4.1. Consequences of Deferral

Deferral of planned overhead porcelain insulated switch replacements to the next planning period, or if sufficient rates of renewal are not realized, will pose an increased risk to safety and reliability. When an overhead porcelain insulated switch fails it can also damage adjacent assets, including causing pole fires on the wooden utility pole it is installed on and causing mechanical damage to adjacent overhead transformers. Further, when an overhead switch fails, temporary measures can be put in place, in some instances, to restore service to the customer, that are funded under O&M. Apart from funding the replacement of damaged adjacent assets, an increased rate of overhead switch failures can also have a negative O&M impact as well.

1.2.2.4.2. Priority

Overhead switches selected for proactive replacement are also prioritized based on their condition and Hydro Ottawa's experience. Candidate switches are identified by assessing their condition in combination with the impact their unforeseen failure has on public safety, worker safety, and system reliability.

Overhead switch/recloser renewal is a priority program as it enables Hydro Ottawa to replace overhead switching assets which are required for reliability and operability, and pose a risk when they are in poor condition.

1.2.2.5. Execution Path

1.2.2.5.1. Implementation Plan

Planned overhead switch renewals are prioritized based on the overhead switch's condition in combination with Hydro Ottawa's experience to determine the level of risk it poses to Hydro Ottawa. Using the recommended rate of planned renewal, a program of planned renewal will begin in 2022 addressing overhead switches that poses an increased risk compared to other overhead switches in Hydro Ottawa's distribution system.

1.2.2.5.2. Risks to Completion and Risk Mitigation Strategies

Table 1.44 - Risks and Mitigation

Risk	Mitigation
Typical risks to completion include: ● Coordinating replacement while keeping interruptions in service to the customer to a minimum ● Coordinating activities in areas where multiple parties are working; ● Availability of internal and external resources	Use of distribution switching to maintain supply to the customer; in the event a planned outage is needed, it is standard practice to engage early and communicate plans, and the associated benefits, with the customer.

1.2.2.5.3. Timing Factors

As other planned inspection programs progress, higher priority assets may be identified prompting a reprioritization of the targeted overhead switches. Apart from the switches identified for planned renewal, Hydro Ottawa regularly reviews the condition of its overhead switches to ensure those that pose a comparatively increased risk are addressed ahead of those that pose a comparatively reduced risk.

1.2.2.5.4. Cost Factors

Typical factors that impact the cost of replacement include the type and location of the candidate switch and if additional assets require simultaneous replacement (including the pole it may be resting on). Further, the costs associated with reactive switch replacement is typically higher than planned proactive replacement; therefore Hydro Ottawa actively tries to reduce the incidents of unforeseen overhead switch failures.

1.2.2.5.5. Other Factors

(Not applicable for this program).

1.2.2.6. Renewable Energy Generation (if applicable)

(Not applicable for this program).

1.2.2.7. Leave-To-Construct (if applicable)

(Not applicable for this program).

1.2.2.8. Project Details and Justification

Table 1.45 - Planned Overhead Switch/Recloser Renewal Overview

Project Name:	Planned Overhead Switch / Recloser Renewal
Capital Cost:	$2,298,720
O&M:	N/A
Start Date:	January 2022
In-Service Date:	December 2024
Investment Category:	System Renewal
Main Driver:	Assets at End of Service Life
Secondary Driver(s):	Reliability
Customer/Load Attachment	6,591 kVA (TD07)
Project Scope	
Replacement of porcelain insulated overhead switches, and adjacent fusing, connected to feeder TD07, located in the Lincoln Heights area. Includes the replacement of all porcelain insulated cut-outs, in-line switches, and re-fusing of adjacent taps. This project also includes the replacement of similar porcelain switches connected to feeders TD05, TD12, TD14 and TW22.	
Work Plan	
Procurement of replacement switches, coordinating work with Hydro Ottawa's system office while replacements are executed, replacement of porcelain insulated switches, and update of adjacent fusing along the circuit to improve coordination and to add additional fusing. This project may also require replacement of adjacent assets, including poles, if found in poor condition. Expected completion date of all switches included in scope of work of December 2024.	
Customer Impact	
Customer to benefit from reliability improvement resulting from the replacement of aging assets and equipment upgrades. The customer benefits from a program that addresses known problem switch types, ensuring the reliability and cost effectiveness of the distribution system.	

1.3 UG DISTRIBUTION RENEWAL

1.3.1. VAULT RENEWAL

1.3.1.1. Program Summary

The Hydro Ottawa underground distribution system is comprised of multiple asset types, including those installed in specialized electrical rooms referred to as vaults. The continued reliability and safety of the underground distribution system is reliant on the performance and condition of equipment installed in vaults throughout Hydro Ottawa's service territory.

The vault planned renewal program targets transformers that are past their expected service life or are determined to be in poor condition. Other types of assets installed in vaults (including switchgear) are outside the scope of this program as they have been deemed to have comparatively lower risk of unforeseen failure compared to vault transformers. Further, Hydro Ottawa only considers the replacement of vaut transformers, with the current technical standard equivalent, on a like-for-like basis.

Hydro Ottawa has determined that an average planned replacement rate of 25 vault transformers per year for 2021-2025 is required. This rate of annual planned replacement represents approximately 0.6% of the entire vault transformer population. The required funding for this program is approximately $2.48M over 2021-2025.

1.3.1.2. Program Description

1.3.1.2.1. Assets in Scope

Hydro Ottawa owns 3,652 vault transformers installed within dedicated electrical rooms referred to as vaults. Vault transformers selected for proactive replacement typically have either reached, or exceeded, their expected service life and are prioritized based on their condition. This approach enables Hydro Ottawa to leverage the resources at its disposal to mitigate the risk that vault transformers pose to the distribution system in the event of their unforeseen failure.

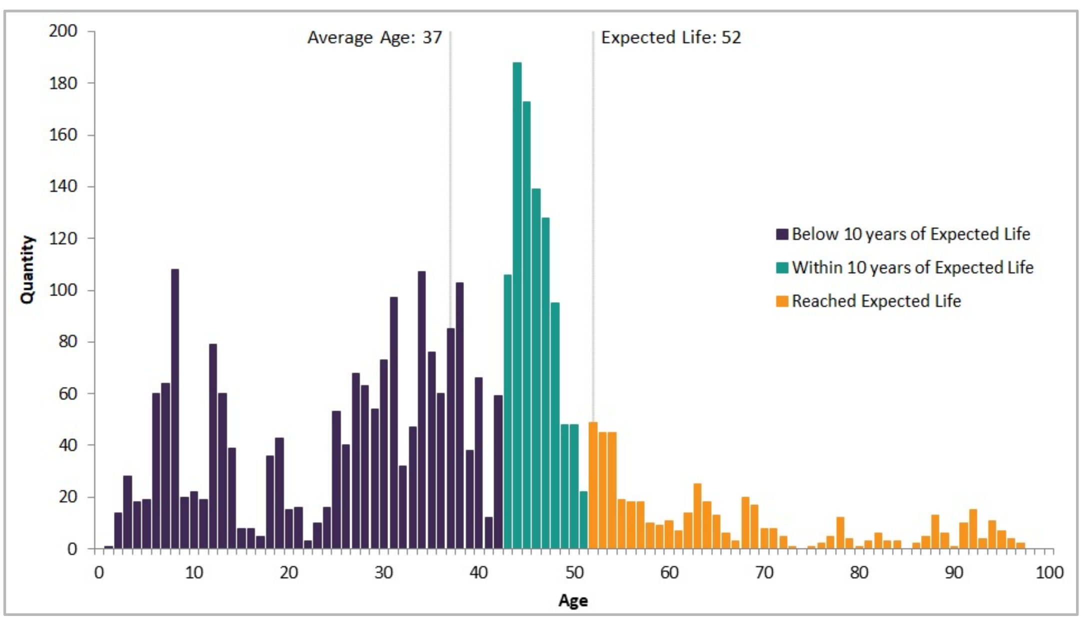
In addition to transformers identified for reactive and planned proactive replacement, additional vault transformers are identified with other construction projects including projects that are complemented by replacing vault transformers adjacent to the work. Hydro Ottawa will continue to use the same approach to identify these vault transformers for replacement in 2021-2025.

1.3.1.2.2. Asset Life Cycle and Condition

Hydro Ottawa collects condition data of its assets installed inside vaults through a planned program of inspection. The inspections are used to collect condition data to identify assets targeted for reactive (if deemed necessary) or planned proactive replacement. When identifying vault transformers for planned proactive replacement, condition data is used to prioritize replacements enabling Hydro Ottawa to focus its resources on vault transformers that pose an increased risk compared to other vault transformers.

The expected service life of vault transformers is approximately 53 years. The overall age demographics of Hydro Ottawa owned vault transformers is shown in Figure 1.39. The percentage of Hydro Ottawa owned vault transformers that have passed their expected service life is 14.9%. In the absence of planned replacement, this proportion will climb to over 33% by 2025.

Figure 1.39 – Hydro Ottawa Vault Transformer Age Demographics



Age demographic information for vault transformers are kept in Hydro Ottawa's GIS system. When an installation date was unavailable for a given asset, an estimated installation date was determined using the proportions of vault transformers with a known age.

Hydro Ottawa inspects its vault transformers on a predetermined scheduled basis through a planned program of inspection that includes visual and thermographic inspection. This enables Hydro Ottawa to monitor the condition of its vault transformers on a timely basis.

Each vault asset is evaluated to determine if it poses an increased risk to worker safety or reliability, enabling Hydro Ottawa to include these assets as a candidate for proactive replacement.

1.3.1.2.3. Consequence of Failure

The modes of failure of a vault transformer are not materially different from those experienced by distribution transformers installed outside of a vault. These include transformers that have suffered an internal fault or a loss of most of the oil contained inside. Transformers that have failed like this require immediate replacement so that service to the customer can be restored. Transformers that have functionally failed can be prioritized for critical renewal, planned replacement, but can be left temporarily in service until replaced. These include vault transformers that have suffered minor loss of oil, have minorly damaged components (including cracked bushings), or have suffered extreme corrosion. Transformers that have failed in such a manner can be scheduled for critical renewal enabling Hydro Ottawa to coordinate with the customer to replace the vault transformer at a mutually beneficial time. Further, vault transformers that have failed in this manner are typically not left in service for a prolonged period as their condition may degrade significantly in the interim and may eventually result in failure and interruption of service to the customer.

Historically, vault transformers pose a relatively low risk in terms of unforeseen failure to Hydro Ottawa's distribution system as shown in Figure 1.40.

Figure 1.40 – Historical SAIFI (per 100 Customers) for Vault Transformers

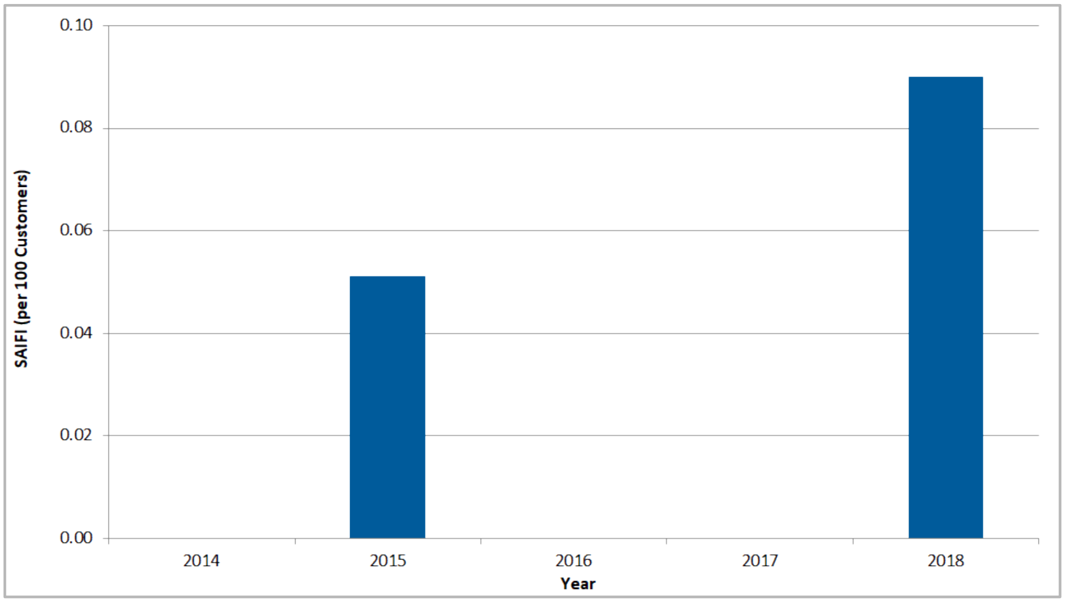


Table 1.46 – Historical SAIFI (per 100 Customers) for Vault Transformers

	2014	2015	2016	2017	2018
Vault Transformer	0.00	0.05	0.00	0.00	0.09

In the years leading up to 2018, the SAIFI experienced by vault transformers was flat with a modest increase in 2018. This indicates that unforeseen failure of vault transformers, as a whole, is a modest risk requiring a similarly modest investment to address the risk.

1.3.1.2.4. Main and Secondary Drivers

The main driver for this program is to replace assets that are at the end of their service life. The secondary drive for this program is reliability.

Goals of the vault renewal program include minimizes the impact failed vault transformers on reliability, and by extension SAIFI and SAIDI, as well as reducing the risk of oil released to the environment. Given that 15% of Hydro Ottawa's vault transformers already either reached, or surpassed, its expected service life, achieving these goals will carry an increased importance in the period 2021-2025.

1.3.1.2.5. Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the Vault Renewal Program, improvements are expected in the KPI metrics listed in Table 1.47.

Table 1.47 – Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Reduction in SAIFI and SAIDI
Asset Performance	Asset Value	Defective Equipment Contribution to SAIFI	Reduction in SAIFI and SAIDI
	Health, Safety & Environment	Oil Spilled	Not to contribute to this KPI

1.3.1.3. Program Justification

1.3.1.3.1. Alternatives Evaluation

Alternatives Considered

The alternatives considered are based on various funding levels and the impact they would have on the vault transformer population and the expected number of unplanned replacements. Further, these alternatives do not consider the replacement of other vault assets, including switchgear, as they have been deemed to pose a comparatively reduced risk to worker safety and reliability compared to vault transformers.

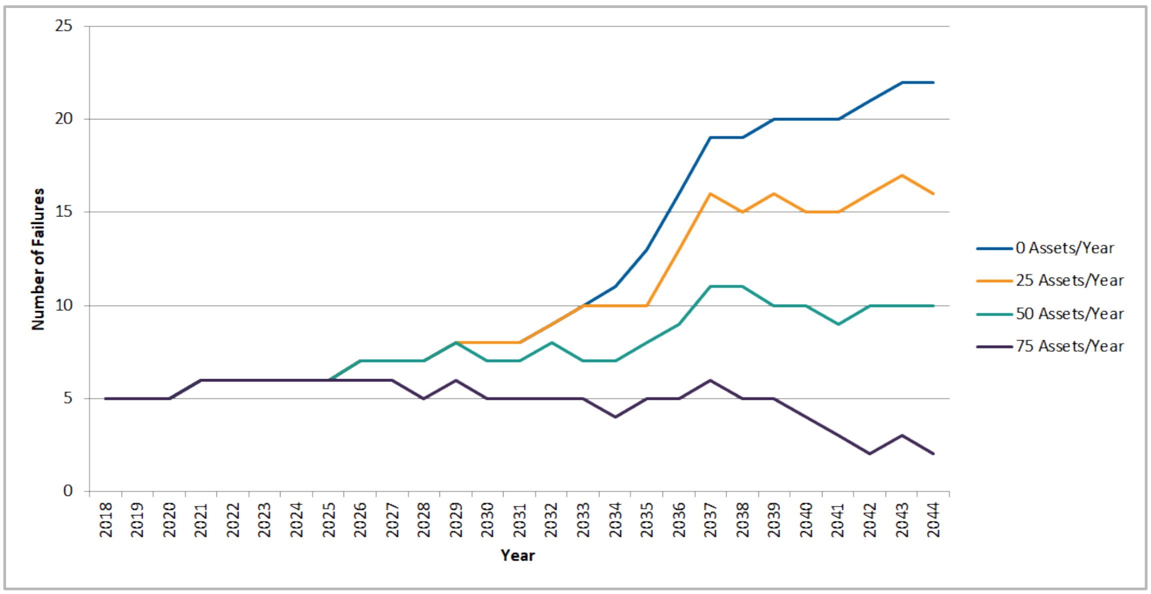
The following scenarios are considered:

- Reactive replacement of vault transformers that have failed such that immediate unplanned replacement is required with no proactive planned replacements (labelled as “0 Assets/Year”);
- Reactive replacement of vault transformers that have failed such that immediate unplanned replacement is required and proactively replace 25 vault transformers per year on a planned basis;

- Reactive replacement of vault transformers that have failed such that immediate unplanned replacement is required and proactively replace 50 vault transformers per year on a planned basis;
- Reactive replacement of vault transformers that have failed such that immediate unplanned replacement is required and proactively replace 75 vault transformers per year on a planned basis;

The anticipated number of unforeseen transformer failures that will require immediate replacement is shown in Figure 1.41.

Figure 1.41 – Expected number of Unplanned Replacements as a function of planned renewal rates



Evaluation Criteria

The intent of the vault transformer replacement scenarios is to continue to use vault transformers already in service, until its condition degrades such that it poses an unacceptable risk to the public, workers, or system reliability, while ensuring adequate resources are in place to execute the replacements. This approach requires the immediate replacement of failed vault transformers to restore service to customers while prioritizing vault transformers whose condition indicates that they have functionally failed or have exceeded their expected service life. Hydro Ottawa evaluates all vault transformer renewal alternatives with consideration of the criteria in Table 1.48.

Table 1.48 – Vault Renewal Criteria

Criteria	Description
Reliability	The increased potential of failure posed by aging vault transformers will impact Hydro Ottawa's customer reliability. The selected alternative must maintain or improve the reliability performance of the system.
Safety	Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The increased potential of failure posed by aging vault transformers will impact Hydro Ottawa's ability to protect worker and public safety. The selected alternative must maintain or improve the safety of Hydro Ottawa's employees and the public.
Resource	Hydro Ottawa internal resources usually carry out unplanned replacements, where planned replacements can utilize both internal and external resources. Therefore, alternatives that incur more on-failure replacements are less favourable as it will be more challenging from a resource perspective.
Economics	Financial costs and benefits shall include all direct and indirect impact on Hydro Ottawa's performance and rates. The preferred alternative shall provide the most benefit at the least cost to Hydro Ottawa's stakeholders and customers.

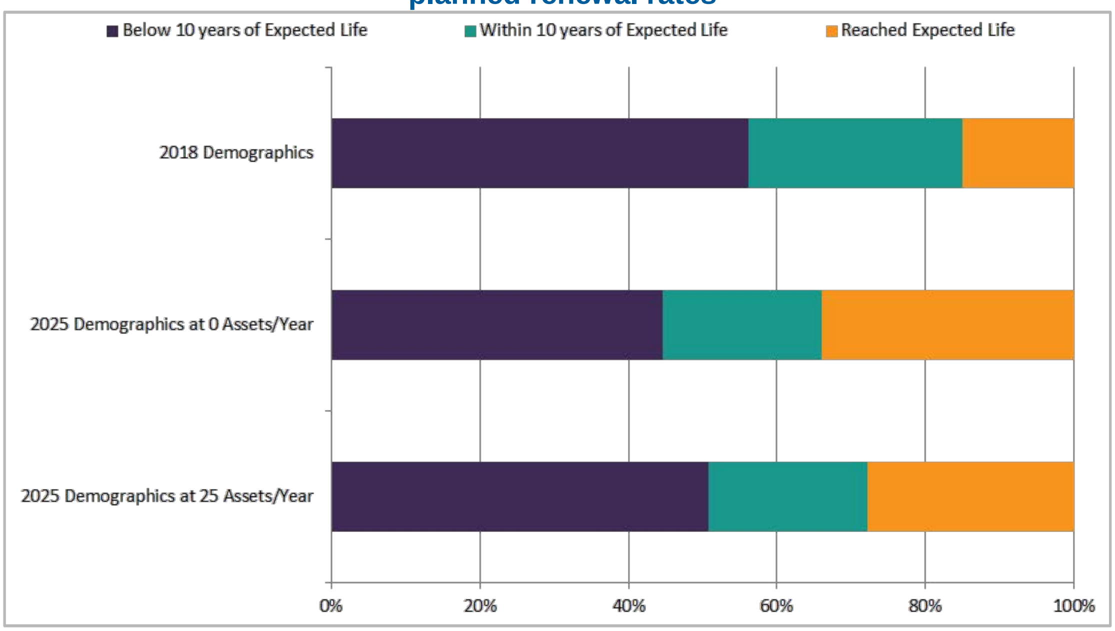
Preferred Alternative

Hydro Ottawa's preferred alternative is to reactively replace vault transformers that have failed on a reactive basis while proactively replacing 25 vault transformers annually. Based on the above criteria, alternatives that replace less than this rate per year on a planned basis will not achieve Hydro Ottawa's objectives for its vault transformers. The removal of these assets will enhance reliability as it removes from service assets that have either reached the end of their expected life or are in comparatively poor condition, increase worker safety by removing assets (with a comparatively increased risk of failure) from service, and accomplishes these objectives in a resource and cost effective manner since the cost and resources needed to execute a planned replacement is less compared to unplanned replacement.

With the preferred alternative, Hydro Ottawa's experience shows the preferred rate of replacement for 2021-2025 is sufficient to address the risks posed by these assets. The amount of funding for this alternative requires, on average, $496k annually for 2021-2025.

Figure 1.42 summarizes the impact the preferred alternative would have on the age demographics of Hydro Ottawa's vault transformers compared to the alternative of no planned replacements.

Figure 1.42 – Hydro Ottawa Vault Transformer age demographics as a function of planned renewal rates



1.3.1.3.2. Program Timing & Expenditure

The historical SAIFI impact of vault transformers indicated pro-active replacement was not required until recently. Given the increase in SAIFI observed in 2018, a proactive replacement program will begin in 2021 to address the increased rate of failure as shown in Table 1.49.

Table 1.49 – Historical and Projected Renewal Spend for Vault Transformers ($'000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0	$0	$0	$0	$0	$496	$496	$496	$496	$496
Units Replaced	0	3	0	0	0	25	25	25	25	25

Additionally, the benefits achieved compared to the costs associated with the replacement of a failed vault transformer are maximized by using the replacement as an opportunity to optimize system design in that region. It is resource efficient to account for system enhancements within a vault transformer renewal job; the converse can also occur, where the replacement of a vault transformer is funded under a different asset replacement program. Hydro Ottawa attempts to address all issues related to the vault transformer within the scope of one construction period, rather than sending crews out later for a second time.

1.3.1.3.3. Benefits

Key benefits that will be achieved by implementing the vault transformer renewal program as summarized below.

Table 1.50 – Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The costs associated with replacing vault transformers on an unplanned basis exceeds the cost of replacing the vault transformers on a planned basis. The do-nothing policy increases the risk of unforeseen vault transformer failures resulting in a higher renewal costs. By replacing the recommended number of vault transformers on a planned basis, the overall average cost to renew vault transformers will be reduced and provide long-term financial benefit.
Customer	Improvement to Defective Equipment related reliability statistics due to anticipated decrease in unforeseen vault transformer failures.
Cyber-Security, Privacy	N/A
Coordination, Interoperability	N/A
Safety	Vault transformer renewal reduces the risk of vault transformer failures thereby reducing the potential health and safety risk to employees and the public.
Economic Development	Hydro Ottawa uses external resources to complete certain projects when there are insufficient internal resources or internal resources will not be available in a timely manner.
Environment	N/A

1.3.1.4. Prioritization

1.3.1.4.1. Consequences of Deferral

Deferral of planned vault transformer renewal to the next planning period, or in the event sufficient rates of renewal are not realized, vault transformers will pose an increased risk to safety and reliability resulting from the increased potential for vault transformer failures. Deferral of vault transformer renewal can lead to a backlog of vault transformers that will incur an increased replacement cost in the future and strain on resources.

1.3.1.4.2. Priority

Vault transformers that have suffered an unforeseen failure that pose an immediate risk to public safety, worker safety, or system reliability are prioritized for replacement as it is necessary to restore service to the customer. The proactive replacement of vault transformers that have functionally failed, or have exceeded their expected service life, are prioritized based on the vault transformer's condition.

1.3.1.5. Execution Path

1.3.1.5.1. Implementation Plan

Vault transformer replacements are prioritized based on the vault transformer's condition that in turn is used to determine the likelihood of its unforeseen failure. Using the recommended rate of planned renewal, the program will begin in 2021 addressing the vault transformers whose condition indicates that it poses an increased risk compared to other vault transformers.

1.3.1.5.2. Risks to Completion and Risk Mitigation Strategies

Table 1.51 - Risks and Mitigation

Risk	Mitigation
Typical risks to completion include: • Coordinating activities in areas where multiple parties are working; • Getting access and coordinating the shutdown with the customers affected	It is standard practice to engage early and communicate plans, and the associated benefits, with the customer.

1.3.1.5.3. Timing Factors

Timing factors are limited to coordinating the work to minimize the impact on the customer and availability of internal (or external) resources to execute the work.

1.3.1.5.4. Cost Factors

Typical factors that influence the cost of replacement include available floor-space to accommodate modern transformers and access to that space in order to remove the replaced asset and add it to the new assets.

1.3.1.5.5. Other Factors

Not Applicable.

1.3.1.6. Renewable Energy Generation (if applicable)

Not Applicable.

1.3.1.7. Leave-To-Construct (if applicable)

Not applicable.

1.3.1.8. Project Details and Justification

Table 1.52 - Vault Renewal Overview

Project Name:	Vault Renewal
Capital Cost:	$2,479,899
O&M:	n/a
Start Date:	January 2021
In-Service Date:	December 2025
Investment Category:	System Renewal
Main Driver:	Assets at End of Service Life
Secondary Driver(s):	Reliability
Customer/Load Attachment	
Project Scope	
Replacement of Hydro Ottawa owned vault transformers deemed to pose an increased risk or worker safety or system reliability.	
Work Plan	
Procurement of replacement transformers, coordinating work with Hydro Ottawa's system office and customers supplied by the transformers while replacements are executed. Expected completion date of all transformer replacements included in scope of work by December 2025.	
Customer Impact	
Customer to benefit from reliability improvement resulting from the replacement of aging assets and assets in comparatively poor condition. The customer benefits from a program that prioritizes assets by their condition, ensuring the reliability and cost effectiveness of the distribution system.	

1.3.2. CIVIL RENEWAL

1.3.2.1. Program Summary

Hydro Ottawa's Underground Civil Structure assets consist of a collection of underground cable chambers (colloquially referred to as manholes), hand holes, and duct banks forming an underground distribution system. Underground distribution structures are used when underground infrastructure is desirable for aesthetics, clearances, improvement of reliability, reduction in time to access and correct a fault condition, or permit faster access in congested areas.

Certain underground civil assets including duct structures, handholes, and pads are typically run-to-failure while underground chambers are maintained through a renewal program based on regular condition assessment. This approach is undertaken as Hydro Ottawa's experience has shown that underground chambers are more economical to inspect and repair than to replace, and have a greater impact to public safety, worker safety, and system reliability in the event of failure compared to other underground civil assets. Thus, the primary focus of Hydro Ottawa's underground civil renewal program is on maintaining and improving the condition of its cable chambers.

On the basis of available condition data and Hydro Ottawa's experience, the required level of funding for the Civil Renewal Program is $5.05M over 2021-2025.

1.3.2.2. Program Description

1.3.2.2.1. Assets in Scope

A vast network of underground civil structures ranging from cable chambers to duct banks supports Hydro Ottawa's underground distribution system. Of these asset types, cable chambers pose the largest risk to public safety, worker safety, and continued reliability compared to Hydro Ottawa's other civil asset types. As a result, Hydro Ottawa focuses its Civil Renewal program on its cable chambers. Further, Hydro Ottawa operates and maintains its other civil assets on a run-to-failure strategy.

Hydro Ottawa owns 3,878 cable chambers and monitors their condition through a dedicated planned program of inspection. Data collected in the field is then used to assess the cable chamber's condition to prioritize renewal activities.

The majority of the activities conducted under this program are done to improve the condition of candidate cable chambers whose condition poses an increased risk to the public, workers, and system reliability, as this is more economical than replacing the entire asset. If the cable chamber's condition is such that maintenance or repair isn't sufficient or economical, Hydro Ottawa then considers replacing the entire asset, typically as a last resort.

In addition to cable chambers identified for a proactive renewal activity, additional cable chambers are identified in conjunction with other construction projects, including City of Ottawa road rehabilitation projects when possible. Based on available inspection data and Hydro Ottawa's experience, the required level of annual funding for Civil Renewal, beginning in 2021, is approximately $1.01M.

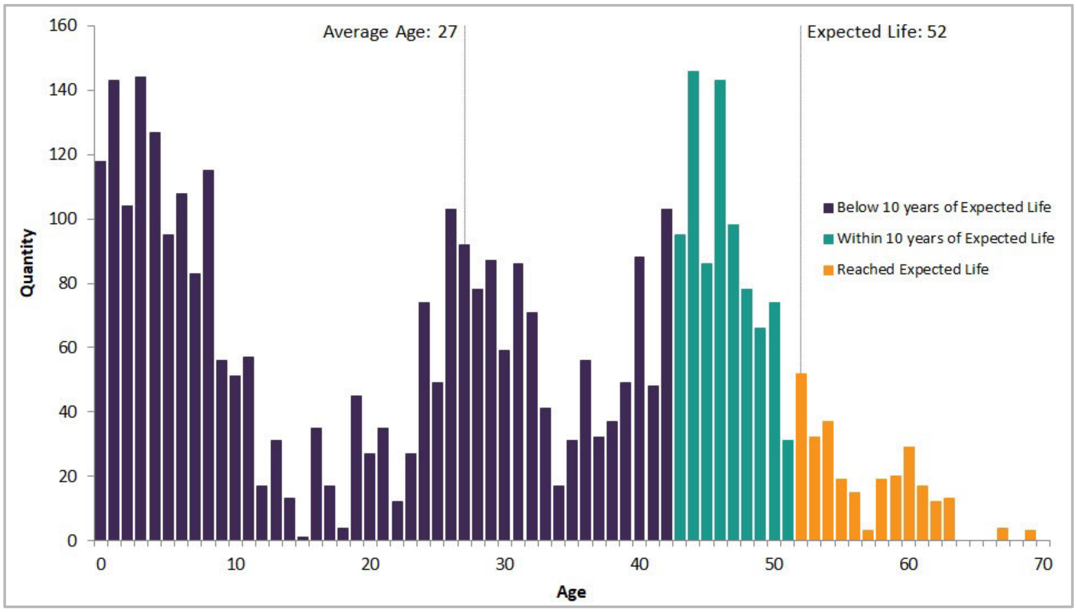
Candidate cable chambers are selected for a renewal activity at the beginning of the budget year using inspection data collected the previous year. The types and quantities of renewal activities are based on the inspection data. Chambers whose condition poses an increased risk, compared to other cable chambers, are prioritized ahead of those posing a lesser risk.

1.3.2.2.2. Asset Life Cycle and Condition

Hydro Ottawa collects condition data on its cable chambers through a planned program of inspection that includes visual inspection and non-destructive hammer testing used to detect voids behind the concrete. Approximately 400 cable chambers are inspected annually. Data collected through its planned inspections is used to identify suitable candidate cable chambers and prioritizes them for an appropriate type of renewal activity. This approach enables Hydro Ottawa to focus its resources on those cable chambers that pose an increased risk compared to others.

The expected service life of a cable chamber is 52 years. At the end of 2018, the proportion of Hydro Ottawa's cable chambers that have either reached, or exceeded, their expected service life is approximately 7.3%. Age demographic information for Hydro Ottawa's cable chambers is summarized in Figure 1.43.

Figure 1.43 - Hydro Ottawa Civil Structure Age Demographics

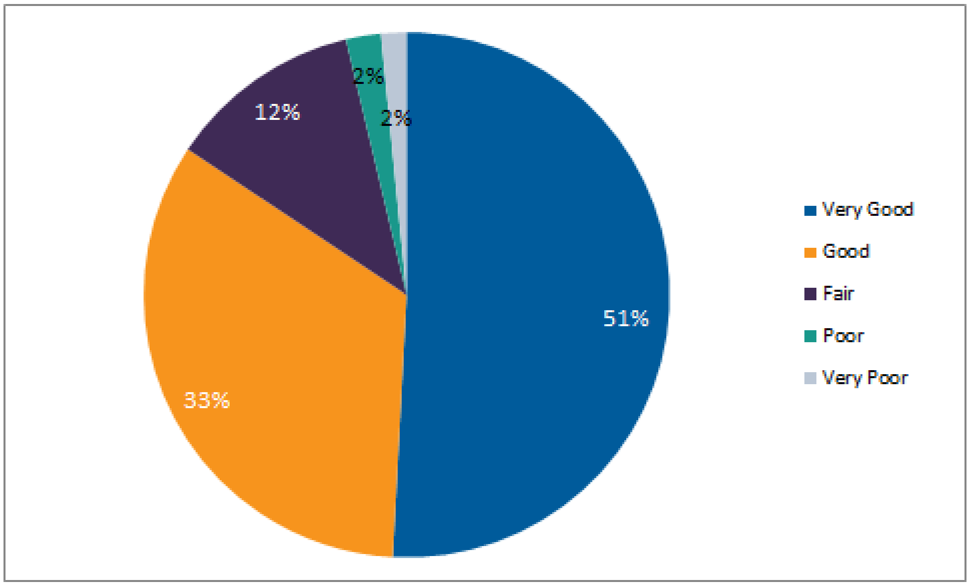


Age demographic information for cable chambers is kept in Hydro Ottawa's GIS system. When the installation date was unavailable for a given asset, an estimated installation date was determined using the proportions of cable chambers with a known age.

Hydro Ottawa does not rely solely on calendar age when determining the condition of its cable chambers. Cable chamber condition is assessed largely relative to the asset's ability to perform its intended function, housing and supporting its underground distribution system. The Asset Condition Assessment for cable chambers also considers other factors such as collar condition, roof condition, and the condition of the walls and floor. These factors are combined in the cable chamber Health Index which is utilized to identify candidate cable chambers and prioritize them for an appropriate reactive renewal activity.

Hydro Ottawa annually inspects approximately 400 cable chambers as part of its 10-year cycle cable chamber inspection program. Data is collected to evaluate the condition of cable chambers. Further, underground chambers are also inspected as part of work activities performed by internal resources as part of their day-to-day activities. Hydro Ottawa has condition data on file for 3,291 (approximately 85%) of its underground chambers. The condition of Hydro Ottawa's cable chambers are summarized in Figure 1.44 below.

Figure 1.44 – Condition of Hydro Ottawa's Cable Chambers



1.3.2.2.3. Consequence of Failure

The majority of underground chambers are located under roadways and sidewalks. Failure of an underground chamber results from deteriorating structural integrity of its concrete due to spalling and corrosion of its metal rebar may lead to the eventual collapse. Renewal activities target structural components such as collars, roofs, and walls are vital to improve the cable chamber's condition and mitigate the risk they pose to the public, employees, and continued reliability when deteriorated. Furthermore, the collapse of underground chambers poses an immediate risk to the public and can damage electrical distribution assets. The number of customers impacted by this type of failure depends on the quantity and types of assets located inside the cable chamber.

Affected customers could expect to be without power for a minimum of four hours (if service can be restored through switching within the distribution system) and up to twenty-four hours if it is not part of a looped system.

Historically, Hydro Ottawa's experience has shown that its underground civil assets pose a comparatively low risk in terms of impact to the continued reliability of the distribution system. The SAIFI for this asset type for the previous five years has been flat at 0.0 as shown below in Table 1.53.

Table 1.53 – Historical SAIFI (per 100 Customers) for Underground Civil Structures

	2014	2015	2016	2017	2018
Underground Civil Structures	0.00	0.00	0.00	0.00	0.00

This indicates when this type of asset fails it typically does not result in an interruption of service to the customer. However, a failure may still pose an increased risk to the public as it could permit access to energized components that are otherwise inaccessible or introduce a slip, trip, or fall hazard on a roadway or sidewalk.

1.3.2.2.4. Main and Secondary Drivers

The main driver for this program is to replace assets that are at the end of their service life. The secondary drive for this program is reliability.

Goals of the Civil Renewal program include continuing to maintain the impact failed cable chambers have on reliability, given its flat SAIFI, and mitigating the safety impacts associated failed cable chambers while undertaking renewal activities in a cost efficient planned manner.

1.3.2.2.4. Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the Civil Renewal Program, improvements are expected in the KPI metrics shown in Table 1.54.

Table 1.54 – Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Cost Efficiency & Effectiveness	Compliance	Cost Efficiency	Reduce costs by intervening early with appropriate renewal activity.
Asset Performance	Asset Value	Defective Equipment Contribution to SAIFI	Maintain current level of SAIFI and SAIDI associated with this asset type.
	Health, Safety & Environment	Public Safety Concerns	Not contribute to metric with failures associated with this asset type.

The primary goal of the civil renewal program is to minimize the costs associated with this asset type by early intervention with an appropriate renewal activity that prevents further degradation that can lead to the asset's eventual replacement. Each candidate cable chamber considered for the planned renewal program is evaluated to determine if its condition warrants a renewal activity. The variety of renewal activities executed by Hydro Ottawa are intended to prevent further degradation, in a cost effective manner, versus a more costly renewal activity in the future or complete replacement if deferred. These renewal activities are an integral part of Hydro Ottawa's strategy to maintain the historical reliability trend of zero outages caused by a failed civil structure.

1.3.2.3. Program Justification

1.3.2.3.1. Alternatives Evaluation

Alternatives Considered

The alternatives considered are based on various funding levels and their impact they would have on the cable chamber population.

Hydro Ottawa has considered the following scenarios:

- Reactively replace cable chambers that have failed in a manner that poses an increased risk to public safety, worker safety, or system reliability in the absence of any other type of renewal activity;

- Reactively perform a variety of renewal activities selected as appropriate based on the asset's condition data to improve its condition, and prevent further degradation, funded at approximately $1.01M annually.

Evaluation Criteria

The intent of the civil renewal scenarios is to continue to use cable chambers already in service, until its condition indicates that it poses an unacceptable risk to the public, workers, or system reliability, and therefore warrants a renewal activity. Further, Hydro Ottawa also ensures adequate resources are in place to execute renewal activities on the prioritized candidate cable chambers.

Hydro Ottawa evaluates all renewal alternatives with consideration of the criteria in Table 1.55.

Table 1.55 – Civil Renewal Criteria

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging and deteriorating assets will influence Hydro Ottawa's ability to safeguard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of Hydro Ottawa's employees and the public.
Resource	Hydro Ottawa typically uses external resources to repair and maintain its cable chambers. Alternatives that focus on maintenance and repair require less economic and contracted resources and do not have material impacts to public safety, worker safety, and system reliability compared to relying on outright replacement.
Economics	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be the most beneficial in the long-term to the stakeholder and to the customers.

Preferred Alternative

Hydro Ottawa's preferred alternative is to continue with its current strategy of performing a variety of reactive renewal activities, based on the cable chamber's condition, to improve the condition of its cable chambers. Hydro Ottawa has demonstrated the success of this strategy as the associated SAIFI shows cable chambers do not impact reliability when they fail. Further, this approach enables Hydro Ottawa to address cable chambers whose condition poses a comparatively increased risk to public safety, workers, and reliability in a cost effective manner compared to a complete cable chamber replacement, as these renewal activities require fewer resources and are far less costly to complete.

A list of commonly performed cable chamber renewal activities are summarized in Table 1.56. The activities are listed in increasing order of complexity and cost. Activities listed near the top of the table are used to prevent additional degradation that would be addressed by a renewal activity listed below it.

Table 1.56 – Commonly Performed Cable Chamber Renewal Activities ($’000s)

Renewal Activity	Approximate Cost per Cable Chamber
Replacing Damaged/Worn Cover	$1.0
Collar Replacement	$2.5
Roof Replacement	$60.0
Complete Cable Chamber Replacement	$100.0

Hydro Ottawa’s experience has shown this strategy can be effectively executed at an average of $790k annually (refer to Table 8 for more information). This level of funding enables Hydro Ottawa to perform a sufficient quantity of renewal activities to maintain SAIFI and SAIDI and improve the associated asset condition demographics for this asset type. To continue to achieve these objectives, Hydro Ottawa anticipates the quantity of renewal activities will increase during 2021-2025 due to the anticipated number of aging assets. The required level of funding to fund this strategy during 2021-2025 is approximately $1.01M annually.

1.3.2.3.2. Program Timing & Expenditure

The required level of investment for the Civil Renewal program, in the period 2021-2025, is approximately $1.01M annually as shown in Table 1.57.

Table 1.57 – Historical Averaged Costing and Projected Average Costing for Cable Chamber renewal ($’000,000s)

	2016 – 2020 Average	2021 – 2025 Average
Total Expenditure	$0.79	$1.01

Candidate cable chambers selected for a renewal activity are identified the year before the work takes place, prioritizing those whose condition indicates they pose a higher risk compared to other cable chambers. Additional cable chambers are identified for a proactive renewal activity in conjunction with other construction projects including City of Ottawa road rehabilitation projects, when possible, as this permits better access to cable chambers and promotes efficient use of Hydro Ottawa's construction resources. Based on the available inspection data and Hydro Ottawa's experience, the required level of annual funding for Civil Renewal, beginning in 2021, is approximately $1.01M annually.

1.3.2.3.3. Benefits

Key benefits that will be achieved by implementing the civil rehabilitation program are summarized table 1.58 below.

Table 1.58 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Costs associated with remediating a collapsed chamber are significantly higher than planned rehabilitation or repair. Aging and deteriorating underground chambers also pose an increased risk of failure and safety concerns. This alternative is the most effective means to minimize the potential safety and reliability risks associated with collapsed structures.
Customer	There is a reduced likelihood of a cable chamber collapsing and damaging cables if the structure is in good health. System reliability will be preserved as vital electrical assets are usually housed in underground civil structures. Failure of the structure results in damage to electrical assets which will then impose customer outages.
Safety	Public safety is maintained as most cable chambers are located on sidewalks or on public roadways; a collapsing cable chamber has the possibility of incurring serious injury to the public.
Cyber-Security, Privacy	Not applicable.
Coordination, Interoperability	Not applicable.
Economic Development	Hydro Ottawa hires external contractors to complete the work in the Civil Rehabilitation program.
Environment	Transformer bases and switchgear manholes are intended to contain potential oil leaks. These structures are unable to contain oil if they have cracks or holes and oil will be spilled into the environment.

1.3.2.4. Prioritization

1.3.2.4.1. Consequences of Deferral

Deferral of renewal activities, in part or in whole, will result in an increased number of failed cable chambers whose condition could have been improved with a lower cost renewal activity. The risk to public and internal resources will likely increase resulting from an increased number of underground chambers in poor condition. Operating and Maintenance costs would likely increase due to increased costs of replacing the assets as the optimal intervention time to perform a lower cost renewal activity has elapsed. Annual spending would also increase if the work is not coordinated with City of Ottawa roadwork projects.

1.3.2.4.2. Priority

Cable chambers that have failed in a manner that poses an immediate risk to public safety, worker safety, or system reliability are prioritized for a renewal activity as it may permit unauthorized access to energized assets contained inside, or may present a slipping or tripping hazard to the public and also prevents further degradation of the cable chamber. The prioritization process is repeated, including identifying additional candidate cable chambers with an increased risk in the queue for reactive renewal activities until the budget for that year is consumed.

1.3.2.5. Execution Path

1.3.2.5.1. Implementation Plan

Cable chambers whose condition indicates that it poses an increased risk to the safety of the public and internal resources working in the vicinity are given a high priority. Cable chambers that are deemed in better condition are prioritized next. The priority of the renewal activity also considers if Hydro Ottawa has adjacent projects, including cable replacements, transformer replacements, and voltage conversions or if the City of Ottawa has planned work in the area that may affect the work's execution.

1.3.2.5.2. Risks to Completion and Risk Mitigation Strategies

Table 1.59 - Risk and Mitigation

Risk	Mitigation
Typical risks to completion include: ● Obtaining road cut permits from the City of Ottawa; ● Coordinating activities in areas where multiple parties are working; ● Getting approval for traffic plans where required ● Change in prioritized list of cable chambers as additional inspection results become available	Hydro Ottawa's mitigation strategy includes early planning with stakeholders, and coordination with the City of Ottawa to identify opportunities of resource use efficiency. Projects are chosen based on condition assessment and as new priorities arise, coordination can be adjusted with minimal impact to the program.

1.3.2.5.3 Timing Factors

As planned inspections progress, higher priority assets might be identified prompting a reprioritization of the list of candidate cable chambers. Apart from the cable chambers identified for renewal activity, Hydro Ottawa regularly reviews its cable chambers and their condition to ensure cable chambers that pose an increased risk are addressed ahead of those that pose a comparatively lesser risk.

1.3.2.5.4. Cost Factors

The final cost of the project is determined by the number of underground chambers to be targeted and the type of renewal activity performed. In addition, cost savings are realized through coordinating with other City of Ottawa roadwork projects. If an underground chamber fails before the planned renewal activity is performed, the cost of replacing the failed underground chamber will be more than if the work is executed in a planned fashion. Failure of the underground chamber will also incur increased costs as it will negatively affect service to the customer if additional assets are damaged.

1.3.2.5.5. Other Factors

Other factors to consider include the ad hoc discovery of cable chambers in poor condition, by workers performing their day-to-day duties, and project overlap with another planned programs. Further, additional cable chambers may be selected for a renewal activity as part of other projecting including cable replacement, line extension, switchgear replacement or voltage conversion projects (transformer replacements).

1.3.2.6. Renewable Energy Generation (if applicable)

Not Applicable.

1.3.2.7. Leave-To-Construct (if applicable)

Not Applicable.

1.3.2.8. Project Details and Justification

Table 1.60 - Civil Renewal Overview

Project Name:	Civil Renewal
Capital Cost:	$5,050,351
O&M:	N/A
Start Date:	January 2021
In-Service Date:	N/A
Investment Category:	System Renewal
Main Driver:	Assets in Poor Condition
Secondary Driver(s):	Reliability
Customer/Load Attachment	
Project Scope	
Includes performing a variety of reactive renewal activities including replacing worn cable chamber lids, collar replacements, roof replacements, and complete replacements. The type of and volume of renewal activities is based on condition data collected the year before from planned programs of inspection. This project may also include additional cable chambers in conjunction with City of Ottawa road projects and Hydro Ottawa cable replacement, switchgear replacement, transformer replacement, and voltage conversion projects.	
Work Plan	
Inspection of cable chambers to collect condition data, identification of candidate cable chambers and appropriate renewal activity, queuing of contracted resources to execute work. This project does not have a completion date as the maintenance and renewal of Hydro Ottawa's cable chambers is a continual process.	
Customer Impact	
Customer to benefit from continued reliability resulting from Hydro Ottawa maintaining its cable chamber assets. The customer benefits from a program that prioritizes cable chambers renewal by condition and criticality, ensuring the continued reliability and cost effectiveness of the distribution system.	

1.3.3. CABLE REPLACEMENT

1.3.3.1. Program Summary

Hydro Ottawa's underground distribution system is comprised of underground feeders connecting distribution stations, overhead lines, transformers, and switches. Underground cables are primarily used in urban and newer residential areas where it is not practical to use overhead lines due to aesthetic, legal, environmental, or safety considerations. The reliability of the overhead (when connected to underground lines) and underground distribution systems is contingent on the performance of underground cable.

The planned cable replacement program manages the replacement of Hydro Ottawa's underground electrical infrastructure. Underground cable is replaced typically on a like-for-like basis; not-for-like replacements are considered when there are drastic changes in technical standards or gains in efficiency that can be realized in using a different solution. For direct buried cable, the current standard is to bury the cable encased in a Poly Vinyl Chloride (PVC) ducts in non-roadway applications. For roadway applications, the duct is concrete encased to reduce risk of mechanical damage resulting from dig-ins and chronic effects of passing vehicles.

Hydro Ottawa requires an average funding level of $8.88M annually for the period 2021-2025 for the Cable Replacement program. Hydro Ottawa prioritizes cable replacements based on the combination of historical reliability data and condition data collected through non-destructive testing as part of its planned inspection program for underground cable.

In total, Hydro Ottawa plans to invest an estimated $44.4M in cable replacement in the 2021-2025 period compared to a historical spending of $35M in the 2016-2020 period. Hydro Ottawa expects to renew approximately 130km of cable as a result of this program.

1.3.3.2. Program Description

1.3.3.2.1. Assets in Scope

Hydro Ottawa owns and manages approximately 3,022 circuit km of primary voltage underground cable in its service territory. This includes approximately 367km of paper insulated lead cable (PILC) and approximately 2,578km of polymer insulated cable (including EPR, XLPE, and TRXLPE cable). Cables are left in service until their condition, or Hydro Ottawa's experience with a given segment, indicates they pose a comparatively increased risk to reliability compared to other underground cables.

In addition to cables identified for reactive and planned proactive replacement, additional underground cable segments may require replacement as identified through other construction projects, such as projects that are complemented by replacing the cable segment adjacent to the work, including switchgear replacements, transformer replacements, or civil asset replacement.

1.3.3.2.2. Asset Life Cycle and Condition

Hydro Ottawa collects condition data on its underground cable through a number of planned inspection programs. This includes the use of non-destructive electronic testing of its XLPE and TRXLPE cables and use of thermography on visible portions of underground cables installed in civil structures and terminations located at dips, risers, switches, pole and pad-mounted transformers.

The non-destructive testing used on polymer insulated cables began as a pilot testing program initiated in 2011 along with National Research Council Canada that has since evolved into a stand-alone entity housed in Hydro Ottawa’s competitive affiliate. This testing method is deemed non-destructive and is employed as part of Hydro Ottawa’s planned cable testing program.

The collected condition data is used, in part, to prioritize replacements, which enables Hydro Ottawa to delay replacing the asset until necessary. This approach, when compared to a strictly age based approach, enables Hydro Ottawa to keep the asset in service as long as possible.

Data collected from these efforts is combined with historical reliability data to determine the condition of the underground cables under review. For cable segments under review that do not have condition data available, Hydro Ottawa instead uses a combination of the underground cable’s age and historical reliability data to estimate the cable’s condition.

At the end of 2018, the percentage of polymer insulated cable that have either reached, or exceeded, their expected service life is 17.4%; the percentage for PILC cable is 13.6%. In the absence of planned replacement, these percentages are expected to increase to 22.9% and

20.0%, respectively, by 2025. Age demographic information for these cable types are presented in figure 1.45 below.

Figure 1.45 – Age Demographics of PILC Underground Cable

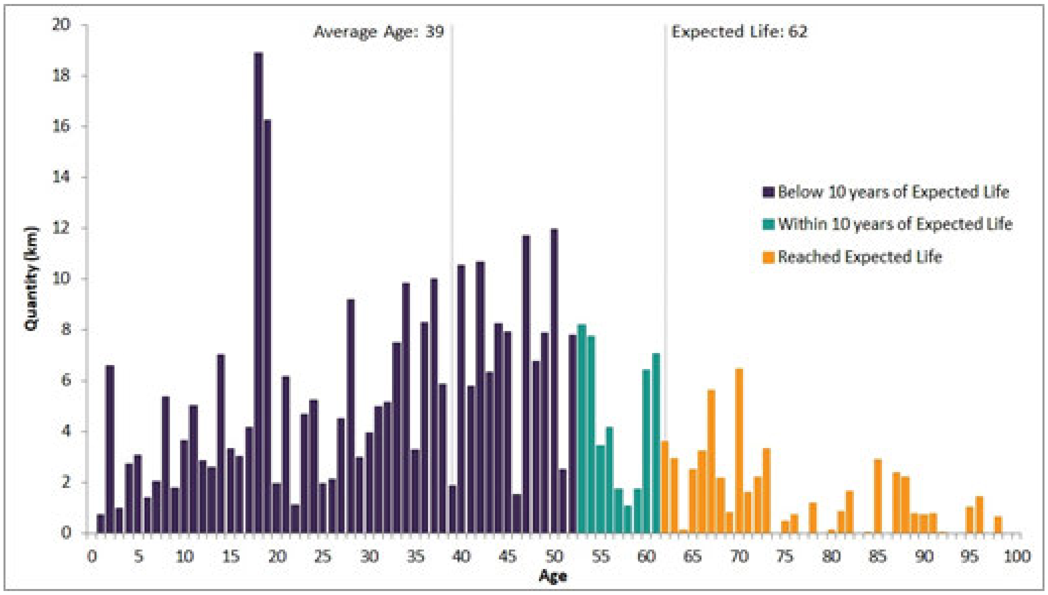
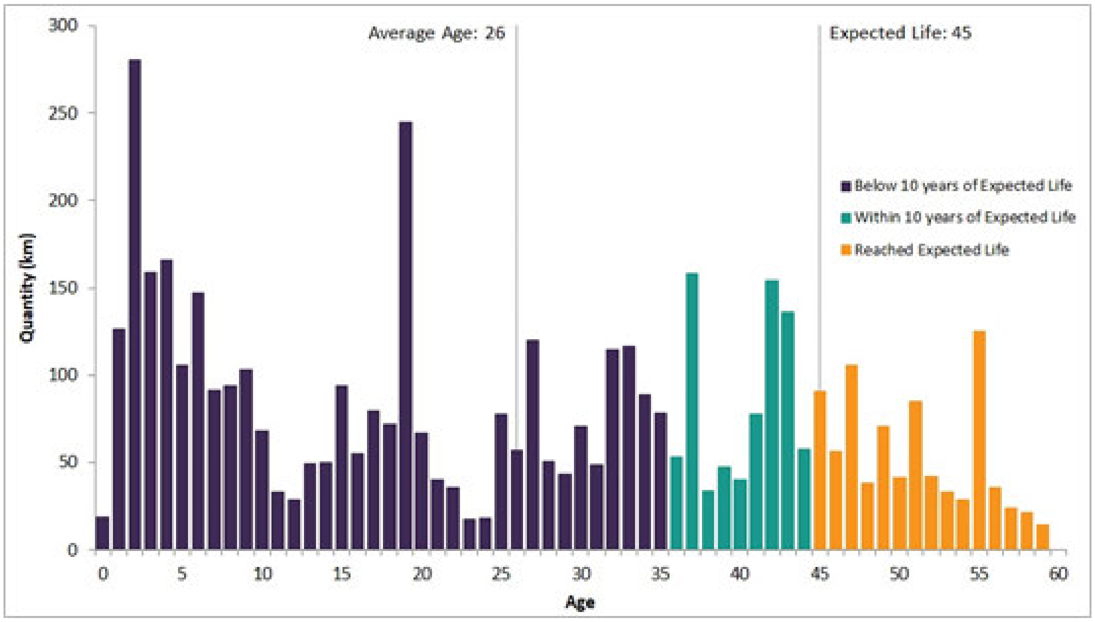


Figure 1.46 – Age Demographics of XLPE/TRXLPE Underground Cable



Age demographic information for underground cables is kept in Hydro Ottawa's GIS system. When the installation date is unavailable for a given asset, an estimated installation date is determined using the proportions of similar underground cable with a known age.

The expected service life for the types of underground cable that make up the majority of this asset type appears in Table 1.61.

Table 1.61 – Expected Service Life of Polymer and Lead underground cable

Cable Type	Expected Service Life (Years)
Underground Polymer Cable	45
Underground Lead (PILC) Cable	62

When determining the condition of an underground cable, calendar age is not the sole factor. Other factors including soil condition (particularly for unjacketed polymer underground cable), ground moisture, presence of a cable jacket, operating conditions, and the presence and extent of water trees (when evaluating polymer insulated cable) are important factors to consider when estimating the amount of cable degradation. Historically, candidate cable segments for planned replacement are selected and prioritized based on historical reliability data. This means the collection and review of condition data on underground cables under review carries an increased importance when managing this asset type as it can be leveraged as a leading indicator of performance.

Given the quantity of underground polymer insulated cable present in Hydro Ottawa's distribution system, compared to the amount of resources available to perform testing, Hydro Ottawa is strategic with its cable testing resources. Typically cables within a given limited area are of the same age, type, and were made using the same method of manufacturing; this enables Hydro Ottawa to test a representative sample of polymer insulated cables in each area to extrapolate the condition of cables not included in the sample, removing the need to test every segment. To this end, Hydro Ottawa has determined that testing approximately 400 representative polymer cable segments annually is sufficient to accomplish this goal.

For PILC cable, due to the absence of available non-destructive testing technology, Hydro Ottawa uses a combination of installation year and historical reliability data to estimate the cable's condition.

The condition of both polymer and PILC underground cable are summarized in Figure 1.47.

Figure 1.47 – Condition of PILC Cable

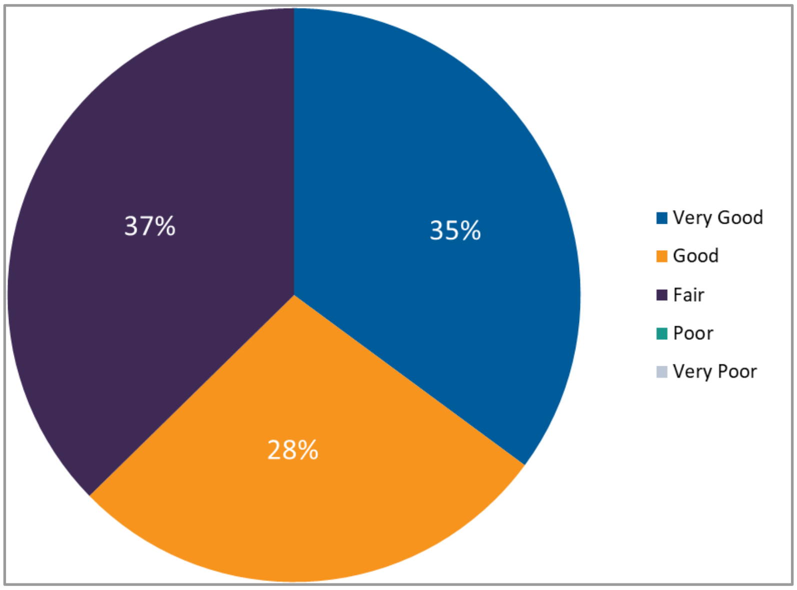
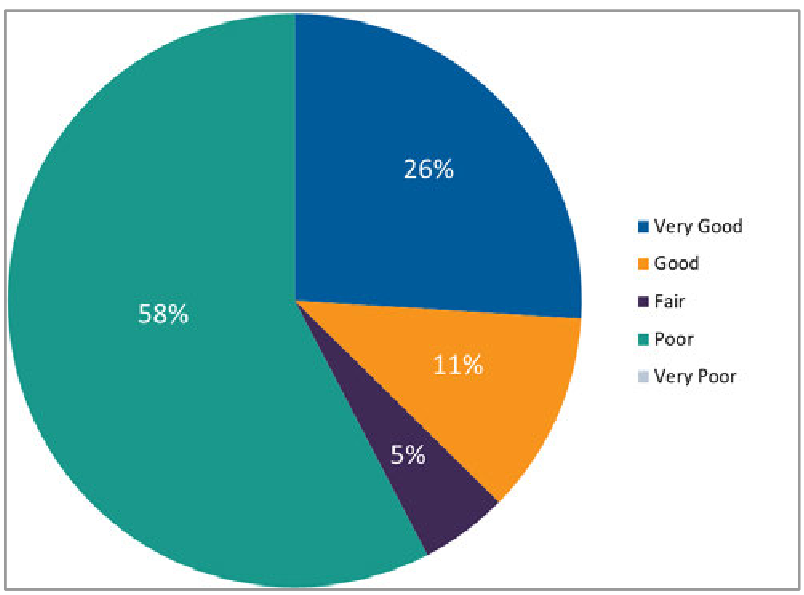


Figure 1.48 – Condition of Underground XLPE/TRXLPE cable



1.3.3.2.3. Consequence of Failure

The primary impact of cable failure is on system reliability, as cable faults on a circuit result in an outage to the customers supplied by that circuit. Outages caused by underground cable faults can have a significant duration due to the time needed to pinpoint, isolate (to restore service to as many customers as possible while repairs are in progress), and repair or replace the failed segment. This impact can be amplified if they occur on the main line (trunk) of a circuit. Given the underground location of cable, the risk to the public and workers is significantly reduced in the event of the cable's failure, compared to Hydro Ottawa's overhead assets, as the ground serves as a protective physical barrier.

A typical cable fault results in an interruption to the customer lasting, on average, between two and four hours depending on the availability of dispatch-able crews. Locating and isolating the faulted cable section is the most time consuming part of restoring service after a cable fault occurs. The faulted section may remain in an isolated (i.e. outage) state for some period until the segment can be scheduled for repair. While repairs are in progress, the looped segment loses redundancy, thus causing an extended outage if multiple faulted segments are present.

Historical reliability for defective polymer and PILC cable is provided in Figure 1.49 and Table 1.62.

Figure 1.49 – Defective Equipment Underground Cable SAIFI

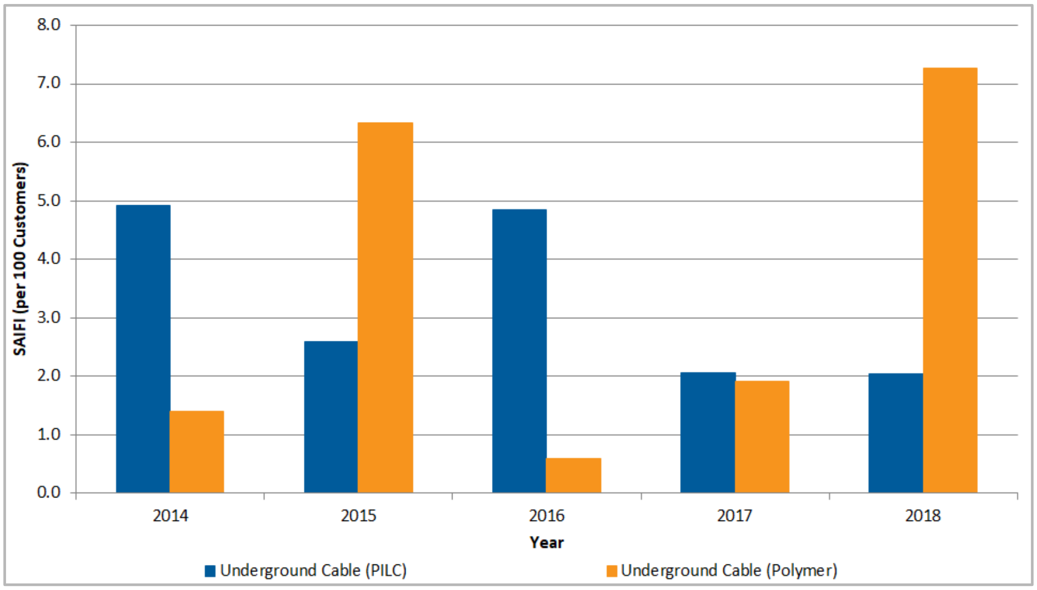


Table 1.62 – Historical SAIFI (per 100 Customers) for Polymer and PILC Cable

	Underground Cable SAIFI by Type and Year				
	2014	**2015**	**2016**	**2017**	**2018**
Underground Cable (PILC)	4.92	2.59	4.84	2.06	2.04
Underground Cable (Polymer)	1.40	6.33	0.59	1.91	7.26

1.3.3.2.4. Main and Secondary Drivers

The main driver for this program is to replace assets that are at the end of their service life. The secondary drive for this program is reliability.

Goals of the cable replacement program include minimizing the impact failed cable segments have on reliability, and by extension SAIFI, by proactively replacing cable segments before their condition deteriorates such that it will have a significant impact on reliability, and by extension impact the customer, in a cost efficient manner.

1.3.3.2.5. Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring performance. With the implementation of the cable segment replacement program, improvements are expected in the KPI metrics shown in Table 1.63.

Table 1.63 – Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Reduction in SAIFI
Asset Performance	Asset Value	Defective Equipment Contribution to SAIFI	Reduction in SAIFI

Planning objectives may be accommodated simultaneously during the planned and unplanned replacement of underground cable. This can include the replacement of other potential end of life assets, located adjacent to the cable segment, including pad-mounted transformers and switchgear.

1.3.3.3. Program Justification

1.3.3.3.1. Alternatives Evaluation

Alternatives Considered

The alternatives considered are based on various funding levels and their impact on the underground cable population, the anticipated number of faults and its effect on reliability statistics.

Note that Hydro Ottawa has evaluated the use of rejuvenation technologies (including cable injection) on its eligible underground cables as an alternative to replacement. Hydro Ottawa has determined that this is not an economically viable option given the residual book value of the remaining eligible cables compared to historical cost of performing this work.

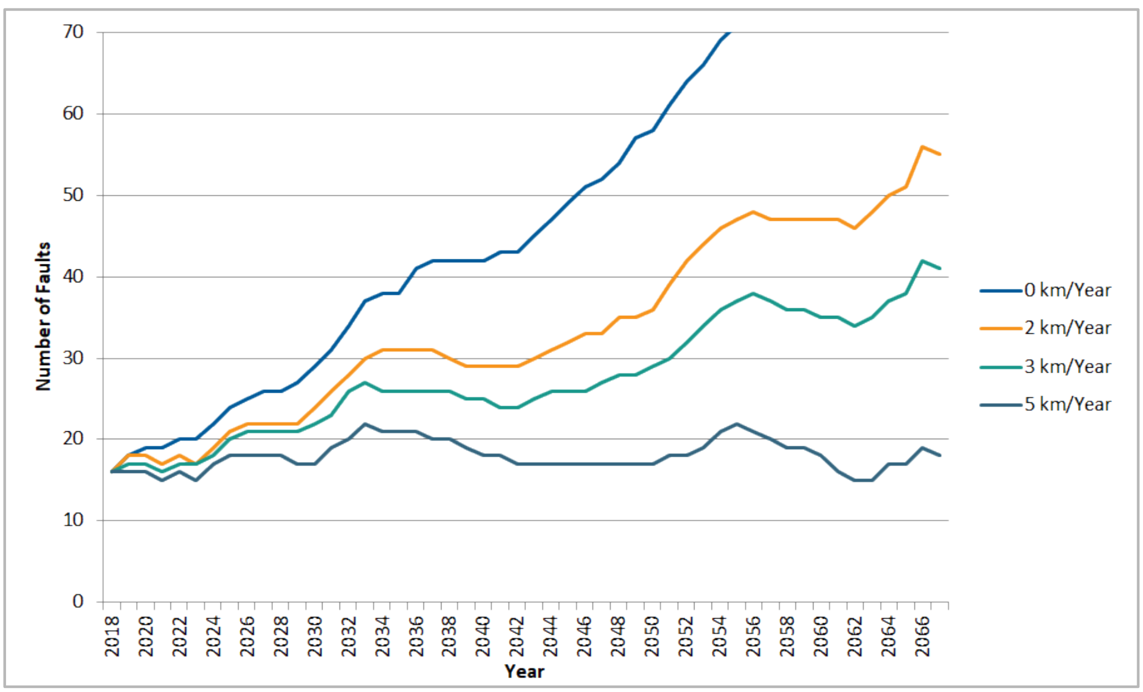
For PILC underground cables, the following scenarios are considered:

- Repair direct-buried cables when faulted, no dedicated planned program of replacement. Although this scenario also does not include a categorical planned program of replacement, this option replaces approximately 2km per year through passive replacements, as adjacent assets are replaced or when PILC cable faults mid-span when installed in duct;

- Repair existing cables when faulted, planned replacement of 3km annually in lieu of passive replacement;
- Repair existing cables when faulted, planned replacement of 7km annually in lieu of passive replacement;

The impact on the expected number of faults involving PILC cable annually, as a function of various rates of replacement, are summarized in Figure 1.50.

Figure 1.50 – Expected number of faults on PILC cable versus Annual Rates of Replacement



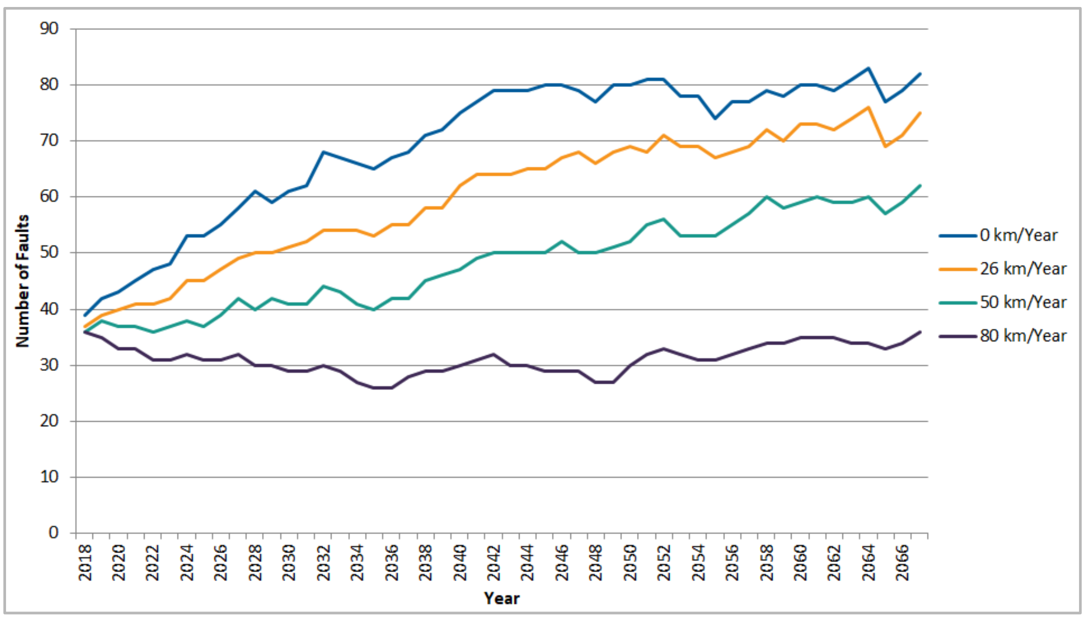
For polymer insulated underground cables, the following scenarios were considered:

- Repair existing cable segments when a fault occurs, with no planned proactive replacements;
- Repair of existing cables on fault, replacing approximately 26km of cable on a planned proactive basis annually;

- Repair of existing cables on fault, replacing approximately 50km of cable on a planned proactive basis annually;
- Repair of existing cables on fault, replacing approximately 80km of cable on a planned proactive basis annually.

The impact on the expected number of faults involving XLPE/TRXLPE cable annually, as a function of various rates of replacement, are summarized in Figure 1.51.

Figure 1.51 – Expected number of faults on XLPE/TRXLPE cable versus Annual Rates of Replacement



Evaluation Criteria

The intent of any asset replacement scenario is to continue to use cable segments, already in service, until its condition is such that it poses an unacceptable risk to reliability while executing planned replacements within a predefined budget envelope. This approach requires the immediate repair (or replacement) of cables that have failed on an Emergency basis to restore service to the customer while prioritizing cables, based on their condition, that have failed on a Critical basis or have exceeded their expected service life.

Hydro Ottawa evaluates all alternatives with consideration of the following criteria in Table 1.64.

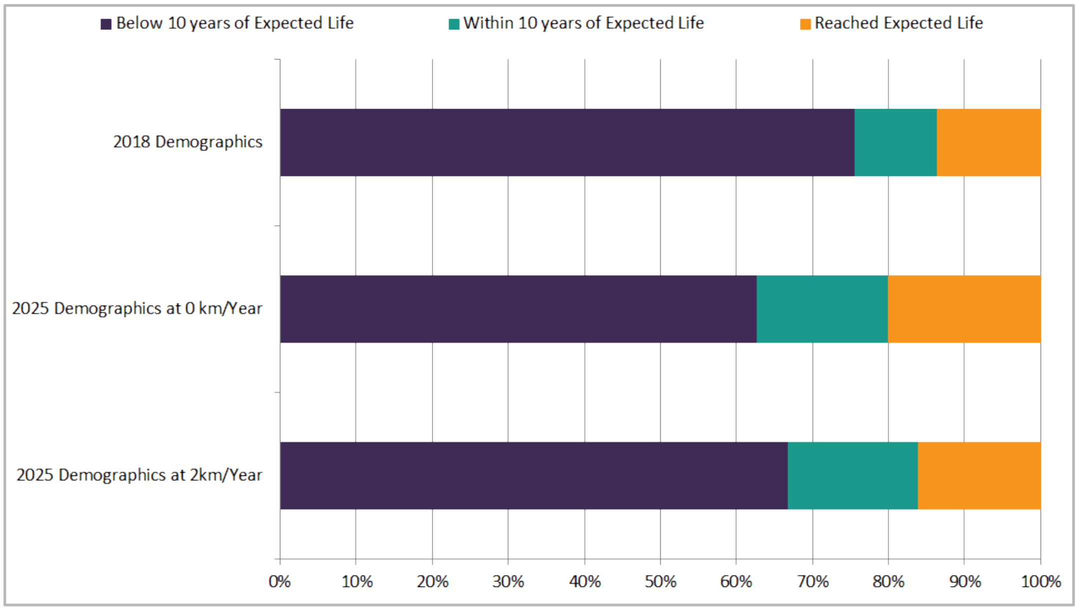
Table 1.64 – Underground Cable Replacement Criteria

Criteria	Description
Failure / Reliability	The selected alternative shall maintain or improve the reliability performance of the system.
Safety	Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose any additional safety risks.
Resource	Hydro Ottawa typically uses internal resources to repair faulted cable which is typically funded as an O&M expense. This indicates that an increase in the incidence of faulted cable will result in a negative impact to Hydro Ottawa's O&M budget. Alternatives that involve more unforeseen failures, including increased incidents of faults, will be more challenging from both an O&M budgeting and scheduling of internal resources.
Economics	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Preferred Alternative

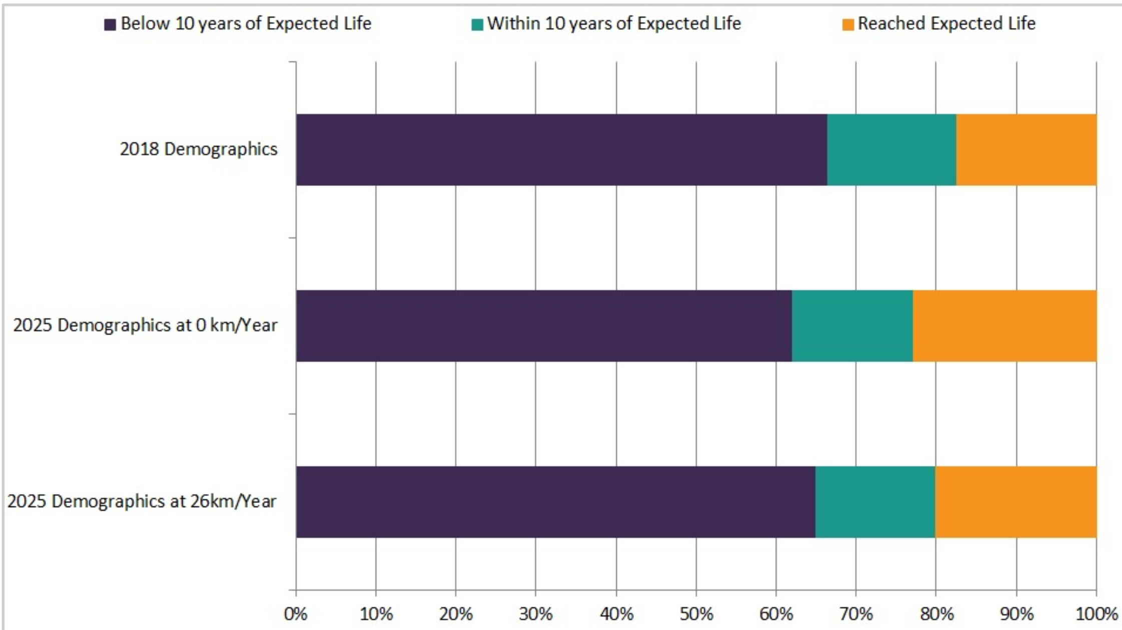
Hydro Ottawa's preferred alternative for PILC cable is to pursue the first alternative, the reactive repair of direct-buried cables when faulted and passively replace approximately 2km annually through replacement of adjacent assets in the absence of a dedicated planned program of replacement; this also represents the status quo strategy for Hydro Ottawa. This strategy has resulted in a generally positive impact on reliability as indicated by the overall downward trending SAIFI for this asset type. Note the impact to public safety and worker safety is not materially different between the different alternatives for reasons previously discussed. This alternative enables Hydro Ottawa to replace its existing PILC cable at a rate that has both a net-positive impact on reliability without putting undue strain on its resources. It should also be noted that if a material increase in this asset type's SAIFI is observed, Hydro Ottawa would re-visit this strategy and adjust as needed. This alternative also enables Hydro Ottawa to continue using its existing PILC cable assets longer while delaying its replacement. The impact of this strategy on the asset's age demographics is in Figure 1.52.

Figure 1.52 – Impact on the Age Demographics of PILC Underground Cable and Preferred Rate of Replacement



Hydro Ottawa's preferred alternative for underground polymer cable is the reactive repair of existing cables when faulted while proactively replacing an average of 26km of polymer insulated cable annually. This alternative may be most economical of those considered for polymer insulated cable in terms of resources needed to execute the work, it will not be sufficient to maintain or improve the current levels of reliability over the longer term. Note the impact to public safety and worker safety is not materially different between the alternatives considered for reasons previously discussed. As a result, in the near-term Hydro Ottawa will prioritize candidate polymer insulated cables for replacement that pose an increased risk, compared to other candidate cable segments, to reliability in the near term. The expected impact on the age demographics resulting from this alternative is shown in Figure 1.53.

Figure 1.53 – Impact on the Age Demographics of Polymer insulated Underground Cable and Preferred Rate of Replacement



1.3.3.3.2. Program Timing & Expenditure

Table 1.65 provides information on the length of cable issued as part of the planned underground cable replacement program for the period shown; funding is primarily for polymer insulated cable and associated assets near the end of their service life. The averaged projected cost for replacing polymer insulated cable, and associated civil support structure, is approximately $343 per meter.

Table 1.65 – Expenditure History of Comparative Projects ($'000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Planned Expenditure	$6.42	$6.18	$7.22	$3.63	$6.21	$8.97	$8.45	$9.05	$8.97	$8.97
Planned Replacements (km)	37.0	15.6	25.5	13.9	14.7	26.0	26.0	26.0	26.0	26.0
Other Programs Replaced (km)	4.6	2.8	4.7	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Historically, Hydro Ottawa has focused on the replacement of underground cable in areas and configurations that are comparatively more costly or more complex to replace compared to those selected for years 2021-2025. Further, historical costing can also be misleading as the replacement of adjacent assets, including pad-mounted transformers and pad-mounted switchgear, may also be funded under the same program; the converse can also occur, where the replacement of underground cable is funded under other replacement programs. This ensures cost effectiveness by replacing adjacent assets whose condition warrants it instead of replacing it separately at a later time.

1.3.3.3.3. Benefits

Key benefits that will be achieved by implementing the underground cable replacement program are summarized below in Table 1.66.

Table 1.66 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	For polymer insulated cable, proactive replacement is more economical than reactive repair and replacement. The selected alternative means Hydro Ottawa will need to prioritize candidate cables to those that pose the greatest risk of unforeseen failure. For PILC cable, the current strategy of passive replacement has resulted in mostly favourable reliability statistics indicating the general success of this strategy.
Customer	For polymer insulated cable, the selected alternative indicates that an increased number of faults can be expected. This means prioritizing cable that impact customers for replacement ahead of those that would have a reduced impact. For PILC cable, historical SAIFI has been trending downward indicating an improved customer experience.
Safety	Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. Given the location cables are typically installed in, the impact to safety is not materially different between the alternatives for both types of underground cable considered.
Cyber-Security, Privacy	This program does not affect neither cyber-security nor customer privacy.
Coordination, Interoperability	This program does not affect neither co-ordination nor interoperability.
Economic Development	Hydro Ottawa uses external resources to complete certain projects when there are insufficient internal resources or internal resources are not available in a timely manner.
Environment	This program does not affect environmental factors.

1.3.3.4. Prioritization

1.3.3.4.1. Consequences of Deferral

Deferral of planned cable replacement to the next planning period, or in the event sufficient rates of replacement are not realized, will pose an increased risk to reliability resulting from the increased rate of cable faults resulting from cable segments in poor condition that remained in service.

Deferral of polymer insulated cable replacement will create a backlog of poor condition underground cable that will require an increased level of funding and resources to mitigate in the future. As evident in Figure 1.54, deferral of proactive replacement of polymer insulated cable replacements will result in an increased number of expected faults and will ultimately impact reliability and also require an increased level of resources to repair in order to restore service to the customer.

The deferral of PILC cable replacement is not considered as it is passively replaced as needed.

1.3.3.4.2. Priority

Candidate cable segments are prioritized for replacement using a combination of condition data collected in the field, reliability data, and Hydro Ottawa's experience. Cables prioritized for replacement in 2021-2025 were selected from a pool of candidates identified using this method to ensure those cables that pose a comparatively increased risk to reliability are addressed ahead of those cable segments that pose a comparatively reduced risk.

Note that direct buried cables that have failed on an Emergency basis will continue to be prioritized for repair, or replacement, as it's typically necessary to restore service to the customer. The proactive replacement of polymer insulated cable whose condition and historical reliability data indicate it poses a comparatively increased risk compared to other polymer cable segments, or has exceeded it's expected useful service life, are prioritized for replacement. PILC cable will continue to be replaced passively on an as-needed basis as adjacent assets are replaced or when faulted and installed in duct.

1.3.3.5. Execution Path

1.3.3.5.1. Implementation Plan

Underground polymer insulated cable is prioritized based on the combination of asset condition data and historical reliability data. In executing the preferred alternative, a program of planned replacement will begin in 2021 addressing those segments whose condition indicates that it poses an increased risk compared to others. This strategy will be followed until the end of 2025 when Hydro Ottawa will revisit and adjust this approach, adjusting the underground cable replacement program to achieve the targeted level of reliability. For underground PILC cable, the preferred approach will be followed until 2025 in the absence of a material change in reliability metrics.

1.3.3.5.2. Risks to Completion and Risk Mitigation Strategies

Table 1.67 - Risk and Mitigation

Risk	Mitigation
Typical risks to completion include: ● Obtaining road cut permits from the City of Ottawa; ● Coordinating activities in areas where multiple parties are working; ● Getting approval for traffic plans where required; ● Access to residential backyards and removal of customer installed structures; ● Availability of external and internal resources to repair direct buried cables that have faulted	● It is standard practice to engage early and communicate plans for future work with the City of Ottawa to coordinate effort and potential resources. ● Outages associated with planned work are publicly available through Outage Map website ● Planned Work further communicated to the public through open house workshops ● Hydro Ottawa has standing offers with number of contracted resources to provide excavation services in the event the splice of a direct buried cable is required

1.3.3.5.3. Timing Factors

As planned inspection programs progress, higher priority assets may be identified prompting a reprioritization of the candidate cable segments selected for replacement. Apart from the cable segments identified for planned replacement, Hydro Ottawa regularly reviews the condition of its cable segments to ensure those that pose a comparatively increased risk are addressed ahead of those that pose a comparatively reduced risk.

1.3.3.5.4. Cost Factors

Cost factors that typically affect the cost of replacing cable include location (including direct buried versus duct), geographic location (including back yard installation), and the cost of replacing associated assets (including pad-mounted transformers and switchgear) to ensure replacements are executed in a cost effective manner.

1.3.3.5.5. Other Factors

Not applicable for this program.

1.3.3.6. Renewable Energy Generation (if applicable)

Not applicable for this program.

1.3.3.7. Leave-To-Construct (if applicable)

Not applicable for this program.

1.3.3.8. Project Details and Justification

Table 1.68 - Underground Cable Replacement

Project Name:	Underground Cable Replacement
Capital Cost:	$44,413,624
O&M:	n/a
Start Date:	January 2021
In-Service Date:	December 2025
Investment Category:	System Renewal
Main Driver:	Assets at End of Service Life
Secondary Driver(s):	Reliability
Customer/Load Attachment	
Project Scope	
Includes replacement of underground cable in the following areas: Beaverbrook, area between Bilberry Dr and Jeanne d'Arc Blvd, Grenoble Cres, Sunview Dr, area along Jeanne d'Arc Blvd between Boyer Rd and Beausejour Dr, along Beausejour Dr between Frank Bender St and Boyer Rd, Steeple Hill Cres, Varley Drive between Carr Cres N and Casson Way (incl. Lismer Cres, Holgate Crt, Binning Crt, Colville Crt, and Gagnon Crt), McCarthy Dr, and Plante Rd. This project also includes the replacement of adjacent end of life assets including pad-mounted transformers and pad-mounted switchgear.	
Work Plan	
Procurement of replacement cable, and adjacent assets (including pad-mounted transformers and pad-mounted switchgear) identified for simultaneous replacement, coordinating work with Hydro Ottawa's system office and customers supplied by the affected segments while replacements are executed. Expected completion date of all cable segments replacements included in scope of work by December 2025.	
Customer Impact	
Customer to benefit from reliability improvement resulting from replacement of aging assets. The customer benefits from a program that prioritizes cable segments by their condition and criticality, ensuring the reliability and cost effectiveness of the distribution system.	

1.3.4. UNDERGROUND SWITCHGEAR RENEWAL

1.3.4.1. Program Summary

Hydro Ottawa's underground distribution system is comprised of multiple asset types, including pad-mounted switches referred to as distribution switchgear. The continued reliability and safety of the underground distribution system is reliant on the performance of these assets.

The underground switchgear renewal program targets assets determined to be in poor condition or those which have functionally failed and are deemed obsolete (due to lack of parts availability). Hydro Ottawa determines the condition of its switchgear by analyzing data collected through field inspections. The primary focus of this program is Hydro Ottawa's aging and deteriorating air-insulated PMH style underground switchgear. Although this type of switchgear is repairable and can be maintained (through planned programs of maintenance), they incur a higher cost of ownership compared to functionally equivalent distribution switchgear insulated with sulfur-hexafluoride gas (referred to as SF6 gas; switchgear using this insulation medium is typically referred to as gas-insulated switchgear) as they are comparatively maintenance free.

Hydro Ottawa has determined an average planned replacement rate of four switchgear per year during the 2021-2025 period is required. Hydro Ottawa intends to replace a total of 20 underground switchgear, during 2021-2025, requiring a total of $3.02M of funding.

1.3.4.2. Program Description

1.3.4.2.1. Assets in Scope

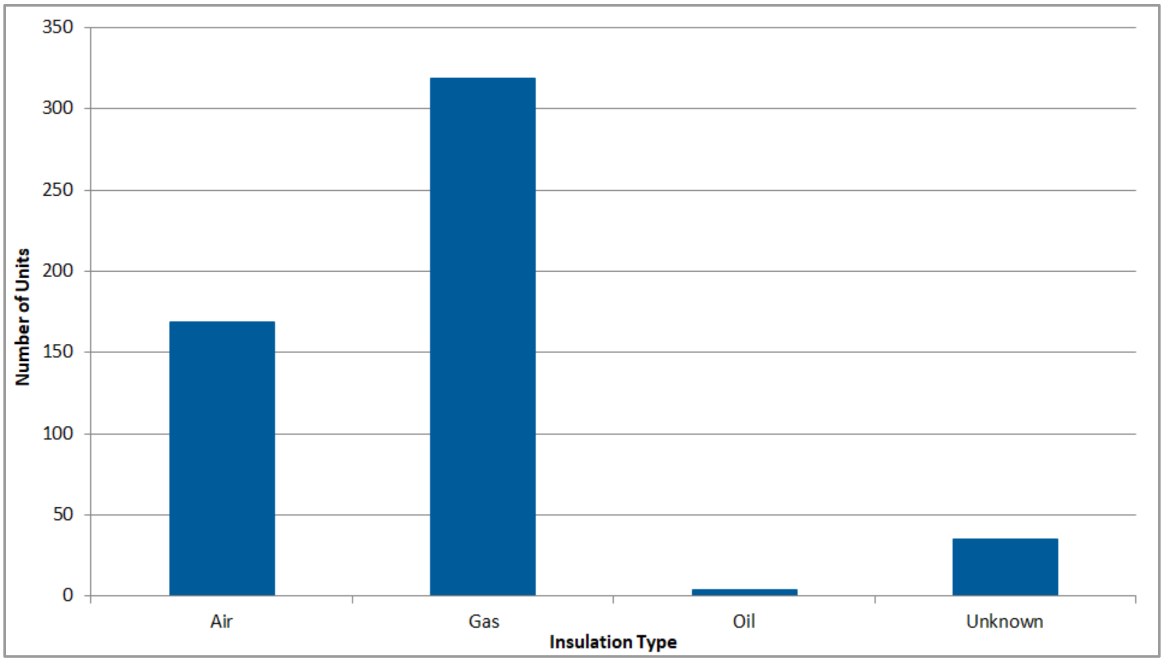
Hydro Ottawa owns 527 underground distribution switchgear units. Candidates for proactive replacement are prioritized based on their condition. Also considered is whether a switchgear has functionally failed and if repair is not viable or economic due to obsolescence or availability of parts. Replacement is typically required for older switchgear that have either reached, or exceeded, their expected service life. For Hydro Ottawa's distribution system, air-insulated PMH style switchgear is the area of focus as they form the older proportion of the population. Further, Hydro Ottawa typically installs gas-insulated switchgear for new construction and when replacing existing distribution switchgear, as these devices require fewer resources to maintain over their expected service life. The proportion of air-insulated switchgear present in Hydro Ottawa's distribution system will decrease over time as they are replaced with functionally equivalent gas-insulated switchgear.

When evaluating the replacement of a candidate switchgear, Hydro Ottawa considers the function it performs within its distribution system. If the asset can be removed (due to changes in circuit topology or engineering requirements since the switchgear was installed) without adversely affecting the operability or reliability of its distribution system, the candidate switchgear may be removed from service without replacement.

Hydro Ottawa intends to focus on replacing its air-insulated switchgear with functionally equivalent gas-insulated switchgear. A key reason is that gas-insulated switchgear generally has lower maintenance costs compared to its air-insulated equivalent. This is because the switching mechanism is housed in a hermetically sealed enclosure while the air-insulated switching mechanism is exposed to the atmosphere. This can be problematic for switchgear located adjacent to highways, arterial roads, and some industries, which can cause premature failure due to the switchgear's internal mechanisms becoming contaminated with road-salt spray and dust. These effects are mitigated through Hydro Ottawa's planned programs of maintenance for its underground switchgear, but this also contributes to the asset's cost of ownership. Although air-insulated switchgear can be repaired in lieu of replacement, additional maintenance costs associated with it make the total cost of ownership for gas-insulated switchgear lower.

In addition to switchgear identified as part of the planned replacement program, additional candidate switchgear are also identified with other construction projects, including planned cable replacements, that are complemented by replacing these switchgear located adjacent to the work simultaneously. Hydro Ottawa will continue to use this approach to identify candidate switchgear for proactive replacement during 2021-2025. The quantity and types of insulation types of Hydro Ottawa's distribution switchgear is summarized in Figure 1.54.

Figure 1.54 – Hydro Ottawa Distribution Switchgear Insulation Types



1.3.4.2.2. Asset Life Cycle and Condition

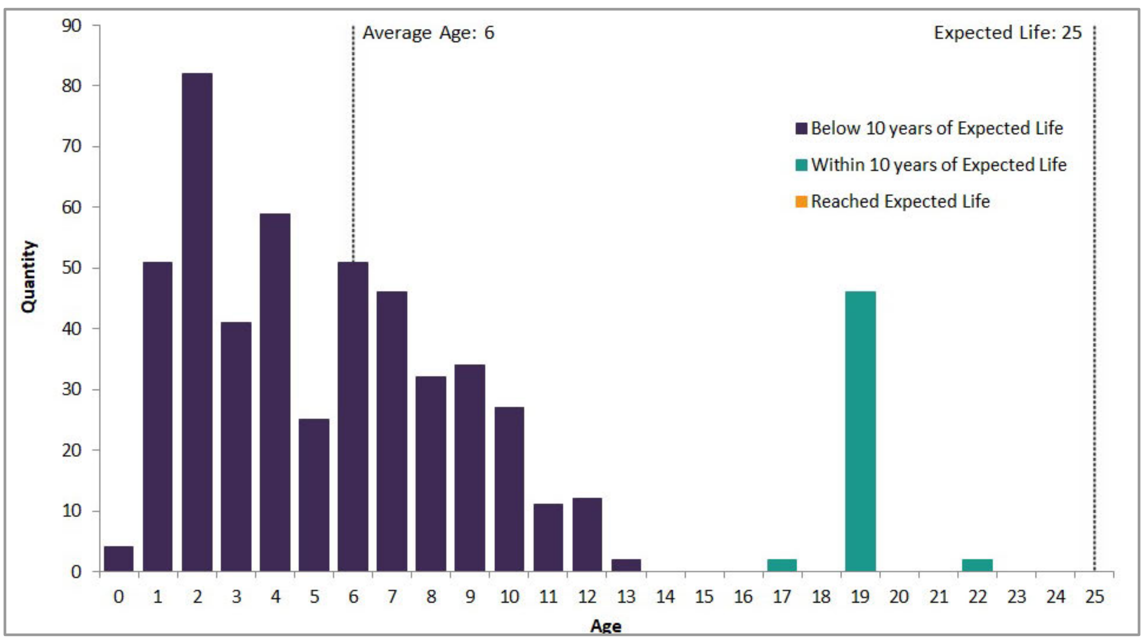
Hydro Ottawa collects condition data on its distribution switchgear through a planned program of inspection that includes both a visual and thermographic inspection. These two means of inspection are used to collect condition data to identify candidates for either reactive (if deemed necessary) or planned proactive replacement. When identifying switchgear for planned proactive replacement, the condition data is used to prioritize replacements, enabling Hydro Ottawa to focus its resources on switchgear that poses a higher risk than other switchgear units. This approach, compared to using a strictly age based approach, enables Hydro Ottawa to prioritize and delay replacements and leave lower risk assets in service longer.

Hydro Ottawa reviews the data collected from these programs in combination with historical outage data to determine the condition of its distribution switchgear. For switchgear without condition data, calendar age is used in combination with historical reliability data to infer the switchgear's condition.

Condition is used to prioritize the replacement of air-insulated switchgear, enabling Hydro Ottawa to address those switchgear that pose the greatest comparable risk amongst this asset type.

Hydro Ottawa asset data for its underground switchgear assets indicate none of its distribution switchgear have exceeded its expected service life of 25 years, as of 2018. The overrepresentation of younger switchgear is the result of better record accuracy for recently installed gas-insulated switchgear and the lack of accurate installation dates for legacy switchgear, which is predominantly air-insulated. Hydro Ottawa will address this deficiency by collecting technical nameplate data of its underground switchgear assets through its planned programs of inspection in future years. Using available data, a summary of the distribution switchgear assets age demographics is presented in Figure 1.55.

Figure 1.55 – Hydro Ottawa Distribution Switchgear Age Demographics

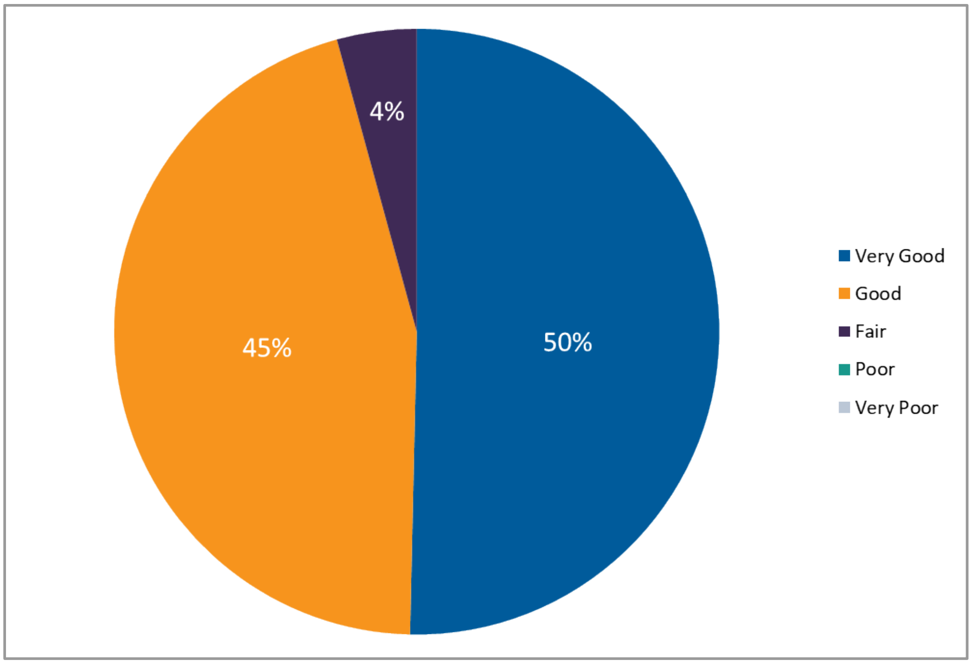


Age demographic information for switchgear is kept in Hydro Ottawa's GIS system. When an installation date is unavailable for a given asset, an estimated installation date was determined using the proportions of switchgear with a known age.

When determining the condition of a distribution switchgear, calendar age is not the sole factor. Other factors include the condition of the asset's enclosure, condition of internal components (particularly for air-insulated switchgear as they are exposed to the atmosphere) and operating conditions are important factors to consider. To monitor the condition of its switchgear assets Hydro Ottawa regularly inspects distribution switchgear as part of its on-going planned inspection programs, while collecting condition data in the field. The type of condition data collected depends on the switchgear's insulation medium. Air-insulated distribution switchgear includes both a visual and thermographic inspection. Inspection of gas-insulated distribution switchgear and its components are limited to a visual inspection, as thermographic inspection of internal components is impractical; thermography is reserved solely for terminations made at the switchgear.

Hydro Ottawa annually inspects approximately one-third of its distribution switchgear to as part of the on-going monitoring of its assets. The condition of Hydro Ottawa's distribution switchgear is summarized in Figure 1.56.

Figure 1.56 – Condition of Distribution Underground Switchgear



1.3.4.2.3. Consequence of Failure

Unforeseen switchgear failure has safety, financial, and system reliability impacts. Broken switchgear negatively impacts the operability of the distribution system, posing an increased risk to reliability. Given that switchgear is located inside a protective metal enclosure, the risk to the public when the asset fails is minimized. The risk to the worker, should the switchgear fail while manually operated, is increased compared to the risk to the public, but this risk is minimized by following approved work procedures.

Emergency replacement of failed switchgear is more costly than planned replacements. Further, emergency renewal limits Hydro Ottawa's ability to coordinate the replacement of adjacent assets, including underground cable, which results in a less effective replacement strategy. The historical SAIFI associated with underground switchgear is summarized in Figure 1.57 and Table 1.69.

Figure 1.57 – Defective Equipment Underground Switchgear SAIFI

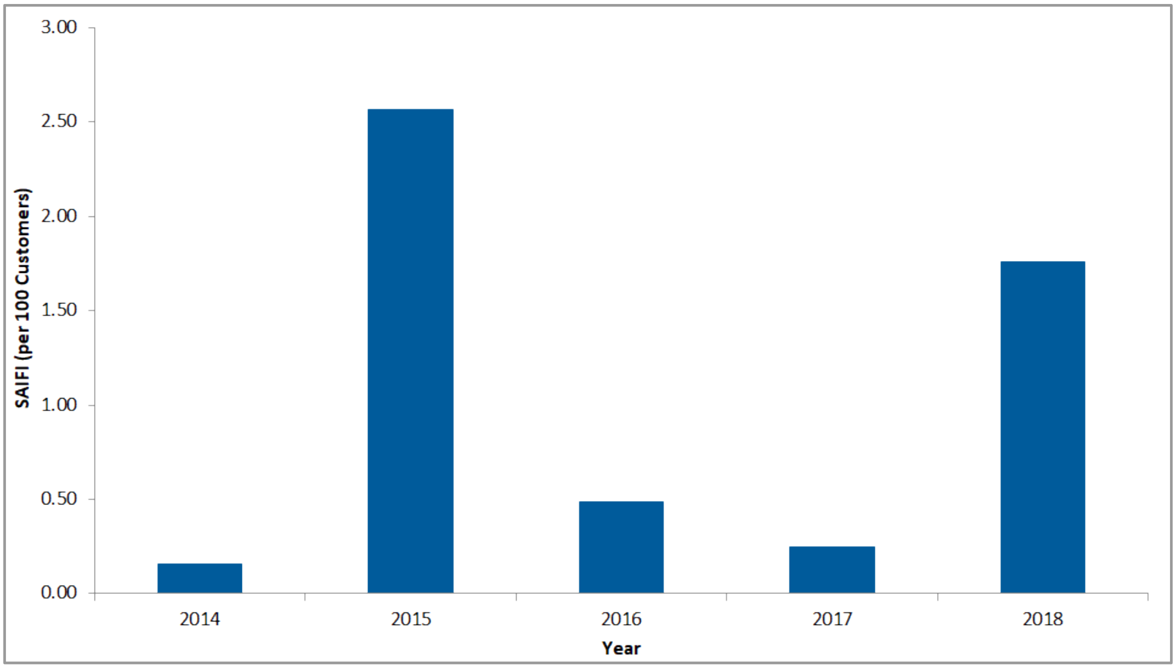


Table 1.69 – Historical SAIFI (per 100 Customers) for Distribution Switchgear

	2014	2015	2016	2017	2018
Distribution Switchgear	0.16	2.57	0.49	0.25	1.76

1.3.4.2.4. Main and Secondary Drivers

The main driver for this program is to replace assets that are at the end of their service life. The secondary drive for this program is reliability.

The goals of the underground switchgear renewal program include minimizing the impact Hydro Ottawa's aging air-insulated switchgear has on reliability, and by extension SAIFI (by replacing the asset ahead of unforeseen failure), and mitigating the safety impacts associated failed switchgear, particularly in regard to worker safety while operating the switchgear.

The planned renewal of air-insulated switchgear, included in the scopes of work for 2021-2025, is necessary for Hydro Ottawa to achieve reduction in SAIFI for this asset type.

1.3.4.2.5. Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the underground switchgear renewal program, improvements are expected in KPI metrics shown in Table 1.70.

Table 1.70 – Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Reduction in SAIFI and SAID
Asset Performance	Asset Value	Defective Equipment Contribution to SAIFI	Reduction in SAIFI and SAIDI

Additional planning objectives may be accommodated during the planned and unplanned renewal of underground distribution switchgear. This may include the replacement of other end of life assets including underground cable.

1.3.4.3. Program Justification

1.3.4.3.1. Alternatives Evaluation

Alternatives Considered

The alternatives considered are based on various funding levels and the impact they would have on Hydro Ottawa's longer term strategy of replacing its aging air-insulated switchgear with functionally equivalent gas-insulated switchgear.

Hydro Ottawa has considered the following scenarios:

- Reactive replacement of distribution switchgear that have failed such that immediate unplanned replacement is required with no proactive planned replacements;
- Reactive replacement of distribution that have failed such that immediate unplanned replacement is required and proactively replace 4 switchgear per year on a planned basis;
- Reactive replacement of distribution that have failed such that immediate unplanned replacement is required and proactively replace 8 switchgear per year on a planned basis;

Evaluation Criteria

The intent of any asset replacement scenario is to continue to use underground distribution switchgear already in service until its condition is such that it poses an unacceptable risk to the safety of the public, safety of the worker, or to distribution system reliability, while executing the work in a cost effective manner. This approach requires the immediate replacement of failed switchgear, typically required to restore service to the customer while prioritizing the replacement of other candidate switchgear that have exceeded their expected service life based on their condition.

In the context of this discussion, the following criteria in Table 1.71 are considered.

Table 1.71 – Underground Switchgear Replacement Criteria

Criteria	Description
Failure / Reliability	The increased potential of failure posed by these aging and deteriorating assets will impact the organization's ability to safeguard worker and public safety. The selected alternative shall maintain or improve the reliability performance of the system.
Safety	Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The impact to safety between the different alternatives can be material as air-insulated equipment in poor condition can pose a significant risk to worker safety.
Resource	Hydro Ottawa typically uses internal resources to repair damaged air-insulated equipment and is typically funded as an O&M expense. This means that increased incidents of damaged air-insulated switchgear will result in a negative impact to Hydro Ottawa's O&M budget. Further, unplanned replacements are more challenging from scheduling perspective to deploy internal resources.
Economics	Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative shall be at least cost or the most beneficial in the long-term to the stakeholder and to the customers.

Preferred Alternative

The preferred alternative is to replace four aging air-insulated pad-mounted switchgear annually. Based on the evaluation criteria, alternatives that replace less than this rate per year on a planned basis will not achieve Hydro Ottawa's objectives for replacing aging air-insulated pad-mounted switchgear in a timely manner. The replacement of these assets will enhance reliability and also reduce some ongoing maintenance expenses as it removes aging assets from service with those that require fewer resources to maintain. This will also have the effect of increasing worker safety when the asset is operated.

These replacements will be executed in a cost effective manner as the cost of planned replacement is less compared to unplanned replacement. The amount of funding required to execute this alternative is $3.02M over the period 2021-2025.

1.3.4.3.2. Program Timing & Expenditure

Table 1.72 provides information on the projected expenditures and volume of underground air-insulated switchgear to be replaced in the period 2021-2025.

Table 1.72 - Historical, Approved, and Projected Expenditure for Planned Underground Switchgear Renewal ($'000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$1.47	$1.29	$0.58	$0.43	$0.76	$0.60	$0.60	$0.60	$0.60	$0.60
Units Replaced	10	5	2	3	5	4	4	4	4	4

Historically, Hydro Ottawa has focused on other drivers for pad-mounted switchgear, including distribution system automation and remote operability, which are comparatively more costly to procure or are more complex than replacement. Further, historic costing can also be misleading as the replacement of adjacent assets may also be funded under the same program; the converse can also occur, where the replacement of switchgear is funded under other replacement programs. This is part of ensuring cost effectiveness by replacing adjacent assets whose condition warrants it, instead of replacing them separately at another time as part of a separate project.

1.3.4.3.3. Benefits

Key benefits that will be achieved by implementing the underground switchgear renewal program are summarized below in Table 1.73.

Table 1.73 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The increased potential of failure posed by these aging and deteriorating assets will affect Hydro Ottawa's ability to guard worker safety and continue to deliver reliable service. The selected alternative shall maintain or improve the reliability performance of the system.
Customer	Improvement to Defective Equipment related reliability statistics due to anticipated decrease in unforeseen asset failures.
Safety	Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must not impose additional risks on the safety of Hydro Ottawa's employees and the public.
Cyber-Security, Privacy	(Not applicable)
Coordination, Interoperability	(Not applicable)
Economic Development	Hydro Ottawa uses external resources to complete certain projects when there are insufficient internal resources or during instances when internal resources will not be available in a timely manner.
Environment	(Not applicable)

1.3.4.4. Prioritization

1.3.4.4.1. Consequences of Deferral

Deferral of planned underground switchgear replacements to the next planning period, or if sufficient rates of renewal are not realized, will pose an increased risk to reliability and safety. When an underground switchgear fails, temporary measures can be put in place to speed the restoration of service to the customer; these additional efforts also have the effect of increasing the total cost of replacing the failed switchgear on an unplanned basis. In addition, Hydro Ottawa's ability to source parts for these assets, in an economical manner, will become an increasing challenge in the coming years. Lastly, the deferral of these replacements may result in a backlog requiring additional funds and resources to execute in a timely manner.

1.3.4.4.2. Priority

Underground switchgear selected for planned replacement are prioritized based on their condition and Hydro Ottawa's experience. Candidates for planned renewal are identified by assessing their condition in combination with the impact that unforeseen failure has on public safety, worker safety, and system reliability.

In the context of replacing its aging air-insulated switchgear, Hydro Ottawa also prioritizes the replacement of its air-insulated switchgear based on their location. In addition to poor condition, candidate switchgear located adjacent to highways, arterial roads, and certain industries are prioritized for replacement ahead of those not located adjacent to these places.

Underground distribution switchgear renewal is a priority program as it enables Hydro Ottawa to replace its aging air-insulated switchgear which are required for the continued reliability and operability of its distribution system, and pose an increased risk to them when these assets are in poor condition.

1.3.4.5. Execution Path

1.3.4.5.1. Implementation Plan

A program of planned renewal will begin in 2021 replacing candidate air-insulated switchgear whose condition indicates that it poses increased risk to worker safety and system reliability compared to other air-insulated distribution switchgear. Hydro Ottawa's existing underground gas-insulated switchgear is exempt given they are relatively new and are expected to perform reliably over the near term. If any are found in a deteriorated condition, through the planned programs of inspection or through the day-to-day activities of internal resources, that warrants replacement, these will be performed reactively on an as-needed basis.

1.3.4.5.2. Risks to Completion and Risk Mitigation Strategies

Table 1.74 - Risks and Mitigation

Risks	Mitigation
Typical risks to completion include: ● Coordinating activities in areas where multiple parties are working; ● Getting approval for traffic plans where required ● Access to switchgear in off-road locations ● Material changes in equipment ordering lead times ● Accommodating sensitive customers including key account customers	● It is standard practice to engage early and communicate plans for future work with the City of Ottawa to coordinate effort and potential resources. ● Planned replacements are typically organized year in advance enabling material to be readied when the project is executed ● Coordinate outages with customers to replace equipment at a mutually beneficial time

1.3.4.5.3. Timing Factors

Timing factors are limited to coordinating the work to minimize the impact on the customer and availability of internal (or external) resources to execute the work.

1.3.4.5.4. Cost Factors

Typical factors that impact the cost of replacement include the location of the candidate switchgear, condition and compatibility of the existing civil support structures with the replacement switchgear, and coordination of replacement with other assets, such as underground cable, if applicable. Further, the costs associated with reactive switchgear replacement is typically higher than planned proactive replacement; therefore, Hydro Ottawa actively seeks to reduce the incidents of unplanned switchgear replacement.

1.3.4.5.5. Other Factors

Not applicable for this program.

1.3.4.6. Renewable Energy Generation (if applicable)

Not applicable for this program.

1.3.4.7. Leave-To-Construct (if applicable)

Not applicable for this program.

1.3.4.8. Project Details and Justification

Table 1.75 - Underground Switchgear Renewal Overview

Project Name:	Underground Switchgear Renewal
Capital Cost:	$3,023,851
O&M:	n/a
Start Date:	January 2021
In-Service Date:	December 2025
Investment Category:	System Renewal
Main Driver:	Assets at End of Service Life
Secondary Driver(s):	Reliability
Customer/Load Attachment	
Project Scope	
The scope of this project is the replacement of existing air-insulated underground switchgear that have either reached, or exceeded, their expected service life. Candidate switchgear for renewal will be prioritized based on condition from inspection data gathered through the annual inspection program. This project may also require the replacement of adjacent assets in poor condition, including underground cable.	
Work Plan	
The work plan includes procurement of replacement switchgear, coordinating work with Hydro Ottawa's system office, and coordinating with customers supplied by the switchgear while replacements are executed. This project will also likely require the replacement of existing civil support structures due to incompatibility with new replacement switchgear. Expected completion date of all switchgear included in scope of work by December 2025.	
Customer Impact	
Customers benefit from improved reliability resulting from the replacement of aging assets with new assets which also have a lower ownership cost associated with them. The customer benefits from a program that prioritizes assets by their condition, ensuring the continued reliability and cost effectiveness of the distribution system.	

1.4. CORRECTIVE RENEWAL

1.4.1. EMERGENCY AND CRITICAL RENEWAL

1.4.1.1. Program Summary

The Corrective Renewal Program consists of three Budget Programs: Emergency Renewal, Critical Renewal, and Damage to Plant. The Emergency Renewal Program includes replacement of assets that have failed and must be replaced immediately. The Critical Asset Replacement Program involves replacement of assets that have degraded to a point of functional failure, and pose an imminent failure risk, but are able to be repaired or replaced in a planned fashion. The Damage to Plant Budget Program also falls under the Corrective Renewal Program to cover the unplanned replacement of damaged assets caused by a third party.

This program is focused on the Emergency and Critical Renewal Program. Evaluated in this document are assets considered for this program and the different alternatives in implementing the Emergency and Critical Renewal Programs.

1.4.1.2. Program Description

1.4.1.2.1. Assets in Scope

Hydro Ottawa's distribution system is comprised of a variety of asset classes. This program categorizes work into failed and critical : Overhead Switches, Underground Switches, Overhead Transformers, Underground Transformers, Polymer Cable, PILC Cable, Overhead Primary conductor and Insulators, Underground Secondary Service, Overhead Secondary Service, Underground Civil, Poles, Station Transformer, Station Switchgear, Station DC System, and Station P&C.

The asset classes above are covered by one of Hydro Ottawa's Renewal Programs (refer to Pole Replacement, Civil Renewal, Cable Replacement, Underground Switchgear Replacement, Overhead Switchgear/Recloser Renewal, Overhead and Underground Transformers, Station Battery Renewal, Station Enhancements, Station P&C Renewal, Station Switchgear Replacement, and Station Transformer Renewal Business Cases) with exception to the Overhead and Underground Secondary Services which are "run to failure".

1.4.1.2.2. Assets Life Cycle and Condition

Emergency Renewal includes failed assets which are quickly assessed and addressed by Hydro Ottawa's field staff. Critical assets are inspected and their condition assessed using Hydro Ottawa Health Indexing, and this information is used to prioritize for near term replacement based on asset risk.

Hydro Ottawa's Emergency and Critical program volumes are forecasted based on its asset management plans, and historical requirements.

1.4.1.2.3. Consequence of Failure

Consequences of failure will vary for each asset. For Critical Renewal events, assets are in a state of elevated failure probability and they must be prioritized based on their individual asset failure consequences. Typical consequences are: outages, a decrease in the reliability of the system, damage to other assets, potential danger to the public and employees, increased cost for repair and labour and hindrances in the operation of the distribution system..

1.4.1.2.4. Main and Secondary Drivers

Table 1.76 below displays the main and secondary drivers of the program.

Table 1.76 - Program Drivers

Driver	Explanation
Failure	Assets replaced under Emergency Renewal are in a failed state.
Failure Risk	Assets replaced under the Critical Renewal Program are in a state of high failure risk.

1.4.1.2.5. Performance Targets and Objectives

The objective of the Corrective Renewal is to reactively repair, refurbish, or replace assets in critical or emergency condition. Since this program involves employing immediate or near-term action, the proposed budget must be sufficient to cover all Emergency and Critical replacements that occur throughout the year. Hydro Ottawa aims to meet all key performance indicators (KPIs). KPI categories that are directly affected by the Critical Renewal Program are: System Reliability, System Power Quality, Cost Efficiency, Labour Utilization Defective Equipment Contribution to SAIFI, Public Safety Concerns, and Oil Spilled.

1.4.1.3. Program Justification

1.4.1.3.1. Alternatives Evaluation

Alternatives Considered

There are two alternatives considered for this program:

Option 1: Do Nothing

“Do nothing” is not feasible because the asset has already failed and the operation of the distribution system is dependent on the functionality of the asset. As a result this option reflects no allocated budget for Emergency or Critical Renewal projects. At the point of asset failure, immediate work would still need to be done to repair, refurbish, or replace the failed asset. This would impact the overall spending and timing of Hydro Ottawa capital projects. Option 1 results in several consequences: resources may be limited due to unplanned replacements, capital projects would need to be deferred in order to accommodate unexpected spending on assets in need of Emergency or Critical Renewal. This ongoing deferral of planned work would be in-effective and in-efficient.

Option 2: Allocate Budget Based on Historical Spending

This option allocates budget as presented in section 3.2, where future yearly spending has been determined from historical average spending (under Corrective Renewal, and predecessor Plant Failure Program), and the asset management plans. This approach allocates resources to address failed assets without deferring planned work, supporting overall more efficient program delivery.

Evaluation Criteria

Hydro Ottawa evaluates all alternatives with consideration of the following criteria in Table 1.77 below.

Table 1.77 - Evaluation Criteria

Criteria	Description
Failure / Reliability	Failed assets which result in outages or other risks that would be harmful to the system if replaced at a later time are to be avoided. Having such assets impairs the reliability of Hydro Ottawa's system. The alternative which maintains and improves the reliability and performance of the system will be selected.
Safety	Hydro Ottawa is committed to prioritizing the safety of its employees and the public. The alternative which facilitates maintained or improved safety and contributes to Hydro Ottawa's ability to guard employees and public safety will be selected.
Resource	Resources are reserved in order to act reactively towards failed assets in need of emergency replacement. The future reliability of the system, safety of employees and the public, the environment, and the utility's economics are considered when using internal or external resources. The alternative which is a prudent use of resources will be selected.
Economics	Different alternatives have the ability to have a direct or indirect impact on Hydro Ottawa's performance and rates charged to the customer. The alternative which benefits the customer and stakeholder in the long-term will be selected.

Preferred Alternative

The preferred alternative is to allocate the Corrective Renewal budget according to historical spending. This allows all failed assets to be covered by either the Emergency or Critical budget. This alternative effectively attends to failed assets which have caused an outage or other risks that would be harmful to the system if replaced at a later time. Reliability is maintained and improved by having a prepared budget in case of unplanned failures. With resources available through this reserved budget, Hydro Ottawa is able to act reactively to address failed assets. This budget ensures the reliability of the system and the safety of employees and the public by dedicating budget towards reactive spending.

1.4.1.3.2. Program Timing & Expenditure

Based on historical expenditures, a budget has been allocated for Corrective Renewal projects. Future spending of $4.48M is proposed for emergency renewal spending and $4.30M for Critical Renewal. Note that in 2018, the Plant Failure Capital Program was renamed as Corrective Renewal and re-structured into two new Budget Programs: Emergency Renewal and Critical Renewal.

Table 1.78 - Program Expenditure ($'000s)

	Historical				Future						
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure Plant Failure	$6679	$7815	$9304	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenditure Emergency Renewal	$0	$0	$0	$9931	$5344	$4461	$4482	$4482	$4482	$4482	$4482
Total Expenditure Critical Renewal	$0	$0	$0	$4520	$4457	$4278	$4297	$4297	$4297	$4297	$4297

1.4.1.3.3. Benefits

Table 1.79 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Reactively attending to assets in need of Emergency Renewal eliminates the damaging effect of failed assets in the system. The distribution system is then able to operate properly when newer, better rated, or more suitable assets are installed in a way which increases the efficiency of the system. It is more cost effective to repair emergency assets immediately to avoid increasing the risk, danger, and cost due to leaving assets in a failed state.
Customer	Replacing failed equipment restores system back-up capability, or enables power restoration directly affecting customer reliability. When an asset is replaced, system enhancement is often considered which benefits both system reliability and reduces customer disruption.
Safety	Acting upon failed assets ultimately facilitates safety with regards to the system, employees, and the public. Eliminating safety risks associated with failed assets also improves reliability metrics and KPIs.
Cyber-Security, Privacy	This program does not affect customer privacy or cyber-security.
Coordination, Interoperability	This program does not affect co-ordination or interoperability.
Economic Development	Maintaining a reliable and stable power supply encourages industries to begin, creates more job opportunities, and more taxes to the government overall.
Environment	The environment is benefitted by replacing failed assets which could be releasing contaminants or travel by remote crews, thereby releasing CO2 emissions to problem areas affected by the failed asset.

1.4.1.4. Prioritization

1.4.1.4.1. Consequences of Deferral

Deferring actions to replace failed assets and any harmful outcomes associated with it results in several negative consequences. System operation efficiency is severely impacted by assets deemed as in need of emergency repair. Cost effectiveness is also reduced due to the effect of the failed asset potential damage to adjacent equipment could occur thereby increasing spending. Deferral has direct customer impact due to emergency assets causing the sustainment of outages, and safety or environmental risks. Safety is reduced when known risks and hazards associated with emergency failures are not controlled or addressed immediately. The environment could also be negatively impacted if emergency assets are in a state which is harmful to the environment. Ultimately, corrective renewal is mandatory and deferral is not a feasible option for these assets.

1.4.1.4.2. Priority

The Corrective Renewal Budget Program is reserved for assets which have functionally failed requiring urgent intervention (Critical Renewal) and those which have fully failed and require immediate replacement (Emergency Renewal). Emergency Asset Replacements are of higher priority than Critical Asset Replacements. However, compared to other projects and programs, Corrective Renewal is the highest priority because functional failure has already occurred. Project spending in this program is reactive and occurs within the same year as opposed to programs which schedule work to occur in the following year.

1.4.1.5. Execution Path

1.4.1.5.1. Implementation Plan

The first step of implementation is determining whether the asset belongs in the Corrective Renewal Program. If the asset has functionally failed and falls into one of the categories, then the project is classified as either in the Emergency Renewal Program or the Critical Renewal Program. If the project falls into the Emergency Asset Replacement category, action must be taken as soon as possible. At this stage, a decision is made towards repairing, refurbishing, or replacing the failed asset. Factors such as the age, maintenance history, new standards, and immediate availability of spare parts are used to make the decision. The method of replacement is evaluated for opportunities to increase system efficiency. This may involve replacing assets in proximity in conjunction, coordinating this project with another project covering the same assets, accommodating future growth and demand, and possibly decommissioning the asset.

1.4.1.5.2. Risks to Completion and Risk Mitigation Strategies

Potential risks with the Corrective Renewal Program are delays which prevent the project from being executed immediately. These risks differ between different projects and are eliminated or mitigated once determined.

1.4.1.5.3. Timing Factors

Typical Corrective Renewal Projects occur immediately within the year. Since this program is reactive and involves high priority projects, it is intended to accommodate unexpected failures throughout the year. This program allows projects to be accelerated to accommodate urgent system needs.

1.4.1.5.4. Cost Factors

Additional cost factors that need to be considered are potential physical barriers that cause access issues, or unforeseen circumstances such as aged equipment failing while the work is being done. Cost may also be altered if the area of work overlaps with a separate planned capital project.

1.4.1.5.5. Other Factors

N/A

1.4.1.6. Renewable Energy Generation (if applicable)

N/A

1.4.1.6. Leave-To-Construct (if applicable)

N/A

1.4.1.8. Project Details and Justification

Table 1.80 - Emergency Renewal Overview

Project Name:	Emergency Renewal
Capital Cost:	$4,482,000.00
O&M:	N/A
Start Date:	N/A
In-Service Date:	N/A
Investment Category:	92099959 - Corrective Renewal
Main Driver:	Asset Failure
Secondary Driver(s):	Reliability, Safety, Resource, Economics
Customer/Load Attachment	N/A
Project Scope	
The Emergency Renewal Program consists of immediately replacing assets that have failed and resulted in an outage or have been found to pose a definite and immediate safety or environmental risk.	
Work Plan	
1. Identify whether the failed asset belongs in the Emergency or Critical Renewal program using Table 1 above 2. If the asset falls under the Emergency Renewal program, use the allocated Emergency Renewal budget to immediately attend to the failed asset 3. The asset is repaired, refurbished, or replaced depending on different factors such as age, maintenance history, new standards, availability of spare parts, assets in the area that can be replaced in conjunction, coordinating the project with other projects involving the same assets, future growth demand, the possibility of decommissioning the asset, etc.	
Customer Impact	
The customer directly benefits from improved reliability when failed equipment is eliminated from the system because it removes safety risks associated with the failed equipment. When an asset is replaced, system enhancement is often considered which benefits both system reliability and reduces customer disruption.	

Table 1.81 - Emergency Renewal Overview

Project Name:	Critical Renewal
Capital Cost:	$4,297,000.00
O&M:	N/A
Start Date:	N/A
In-Service Date:	N/A
Investment Category:	92099959 - Corrective Renewal
Main Driver:	Asset Failure
Secondary Driver(s):	Reliability, Safety, Resource, Economics
Customer/Load Attachment	N/A

Project Scope

The Critical Renewal Program consists of immediately replacing assets that have functionally failed requiring urgent intervention.

Work Plan

1. Identify whether the failed asset belongs in the Emergency or Critical Renewal program.
2. If the asset falls under the Critical Renewal program, use the allocated Critical Renewal budget to schedule a repair, refurbishment or replacement of the failed asset
3. The asset is repaired, refurbished, or replaced depending on different factors such as age, maintenance history, new standards, availability of spare parts, assets in the area that can be replaced in conjunction, coordinating the project with other projects involving the same assets, future growth demand, the possibility of decommissioning the asset, etc.

Customer Impact

The customer directly benefits from improved reliability when failed equipment is eliminated from the system because it removes safety risks associated with the failed equipment. When an asset is replaced, system enhancement is often considered which benefits both system reliability and reduces customer disruption.

1.4.2. DAMAGE TO PLANT

Table 1.82 - Emergency Renewal Overview

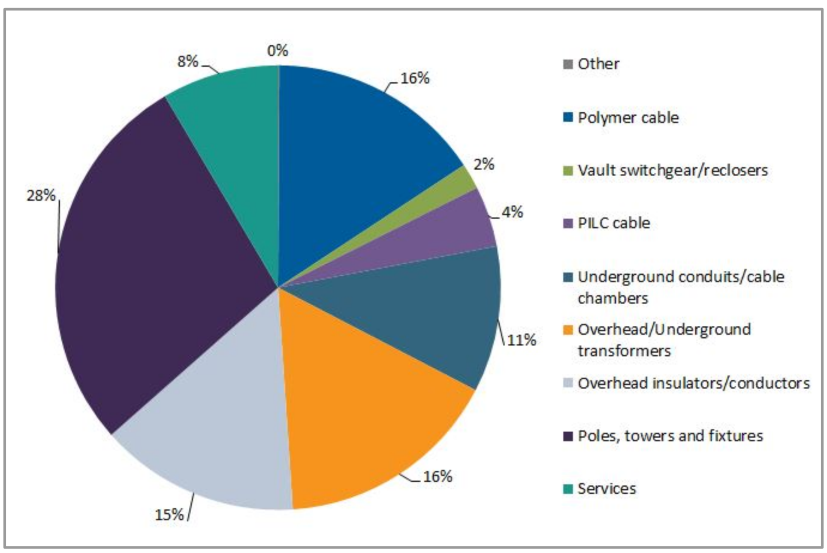
Project Name:	Damage to Plant
Capital Cost:	$5,198,091over 5 years , average of $1.04M annually
O&M:	N/A
Start Date:	2021
In-Service Date:	2021-2025
Investment Category:	System Renewal- Corrective Renewal
Main Driver:	Failure Risk
Secondary Driver(s):	Reliability
Customer	Varies
Project Scope	
The scope of this program is to replace assets that have failed due to damage caused by third parties. The damage must be severe enough to cause the asset to functionally fail. In some cases, the party responsible for the damage is unknown. Assets replaced under this program include the following: • Substation buildings • Miscellaneous equipment • Interval meters • Smart meters • Station equipment • SCADA/RTU/Communications equipment • Polymer cable • Underground switchgear/reclosers • Vault switchgear/reclosers • PILC cable • Underground conduits/cable chambers • Overhead/Underground transformers • Overhead insulators/conductors • Poles, towers and fixtures • Services	
Priority	
The renewal projects under this program are always high-priority replacements. They are mandatory replacements, where the assets are replaced as soon as reasonably possible.	
Work Plan	
Hydro Ottawa recovers the cost of the replacement whenever possible. However, this is not always possible. Historically, Hydro Ottawa has spent approximately $1M per year on damage to plant renewal projects. Table 1.83 shows the historical, approved, and forecasted spend per year for damage to plant projects, as well as the number of units replaced. Figure 1.58 below shows the historical spend amount for this program on different types of assets. "Other" category includes the substation buildings, miscellaneous equipment, interval meters, Smart meters, substation equipment, SCADA/RTU/communications equipment, and underground switchgear/reclosers asset categories, and make up less than 1% of the total spending.	

Customer Impact
This program's impact on the customer largely depends on the asset that was damaged. However, without this program in place, customers affected by third parties' negligence would be without power for an extended duration, as Hydro Ottawa would be required to cut funding to other renewal projects and solve all the logistical issues before performing the renewal work to restore power.

Table 1.83 - Historical and Forecast Expenditure

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Expenditure ($'000s)	$1.12	$0.85	$1.13	$1.25	$0.99	$1.04	$1.03	$1.06	$1.03	$1.03
Units	196	207	220	361	246	246	246	246	246	246

Figure 1.58 - Historical Damage to Plant Contribution by Asset Type



1.5 METERING RENEWAL

1.5.1 METERING UPGRADES

1.5.1.1. Metering Standardization

1.5.1.1.1. Program Summary

This material investment plan outlines the cost, drivers and implementation plan to standardize Hydro Ottawa's metering fleet. This program includes the following Projects:

1. C Phase Reversal
2. 1 element to 1.5 element upgrade
3. GREX upgrade
4. ION upgrade
5. Fleet Standardization

1.5.1.1.2. Program Description

Current Issues

Hydro Ottawa currently has specific nonstandard meter installations that are causing inventory and maintenance issues in our service territory. These are non-standard meter installations that require Hydro Ottawa to keep inventory for replacement of rarely used meter types. The elimination of these nonstandard meter installation from Hydro Ottawa's system would reduce inventory overhead costs.

Program Scope

The following Projects are part of the program and there scopes follow:

C Phase Reversal

This project will perform C-Phase reversals on 38 services across the Hydro Ottawa service territory. Of these services, 31 are primary and 7 are secondary services. Primary services require a system office isolation and service shutdown to complete the C-Phase reversal. The secondary services do not require a shutdown and the C-Phase reversal can be done directly. The 7 secondary services will also be upgraded to three element services

1 element to 1.5 element upgrade

This project will upgrade 50 self-contained 1 Element services to self-contained 1.5 Element services at a total cost of $166K.

GREX upgrade

This project will replace 114 GREX meters with a standard residential meter at a total cost of $362K. GREX meters were initially installed because they were more compact than a standard residential meter, and could readily be installed at the smallest indoor service points. The primary driver of this project is infrastructure standardization, as the GREX meters will be replaced with standard residential meters. The GREX meter stock code will subsequently be eliminated to streamline inventory management.

ION upgrade

This project will invest $144K to replace the 8400 and 8600C model ION meters with an updated ION meter. The 8400 and 8600C meters are used as alternate meters at wholesale metering points, as mandated by the IESO, and retail metering points. These models are not Ethernet enabled, which prevents one to one connection with the alt meter. As a result, the 8400 and 8600C alt meters must be wired with the main meter in a daisy chain configuration. When meter technicians call the 8400 and 8600C meters remotely and the connection fails, the meter technician must travel to the site to re-establish connection.

Fleet Standardization

This project will replace 52 non-standard meters with standard meters at a total cost of $196K. The benefits of fleet standardization include a 22% stock code reduction, a one-time $93.6K decrease in inventory overhead and simplified inventory management. Additionally, this project will reduce missed customer appointments due to failure to stock a non-standard meter on technician trucks.

Main and Secondary Drivers

The drivers of this program are system standardization, streamlined inventory management and a permanent one-time reduction in inventory overhead.

Performance Targets and Objectives

The performance targets and objectives include:

1. Eliminate all non-standard meter types described in the projects from the Hydro Ottawa service territory
2. Reduce total number of meter stock codes
4. Increase billing accuracy
5. Permanently reduce working capital
6. Standardize of distribution system assets

1.5.1.1.3. Project Justification

Alternatives Evaluation

Alternatives Considered

The do nothing option was the only alternative considered. In this case, Hydro Ottawa would have to reactively replace non-standard meter installations. Further, Hydro Ottawa would need to continue to carry the non-standard meter inventory further into the future, costing an additional $101K in inventory working capital while still having to invest in upgrading the non-standard meters in the future. In addition failure to execute this program would result in an estimate $10K - 16K of maintenance spending per year.

Evaluation Criteria

The following evaluation criteria were used to compare the design alternatives:

- Availability of resources to complete capital work
- Elimination of future maintenance work
- System standardization (reduced inventory)

Preferred Alternatives

The following preferred Alternatives are listed by project as part of this program:

C Phase Reversal

The Preferred alternative is the C Phase Reversal upgrade. This project will perform C-Phase reversals on 38 services across the Hydro Ottawa service territory. Of these services, 31 are primary and 7 are secondary. Primary services require a system office isolation and service shutdown to complete the C-Phase reversal. The secondary services do not require a shutdown and the C-Phase reversal can be done directly. The 7 secondary services will also be upgraded to three element services.

Services requiring C-Phase reversals often contain outdated wiring configurations and equipment. These antiquated services present safety concerns for technicians performing maintenance. Additionally, modern Hydro Ottawa cross read equipment cannot perform cross reads on these services due to their outdated configurations. As a result, they must be tested with legacy equipment. Elimination of these services will also streamline meter technician training by reducing the number of unique configurations to understand and maintain. In conclusion, this project will standardize the distribution system, improve safety conditions for meter technicians, reduce billing inaccuracies and permanently reduce inventory overhead one-time by $3.8K

1 element to 1.5 element upgrade

The preferred alternative is the 1 element to 1.5 element meter upgrade. This project will ensure that Hydro Ottawa is progressing in its initiative to standardize the distribution system. This alternative will allow better utilisation of labour, and reduce future maintenance costs of having an additional meter type in the system.

GREX upgrade

The preferred alternative is the GREX upgrade. This project will replace 114 GREX meters with a standard residential meter at a total cost of $362K. GREX meters were initially installed because they were more compact than a standard residential meter, and could readily be installed at the smallest indoor service points. The primary driver of this project is infrastructure standardization, as the GREX meters will be replaced with standard residential meters. The GREX meter stock code will subsequently be eliminated to streamline inventory management. Indoor metering points will also be moved outside. Moving the service outside will make it more accessible for meter technicians performing maintenance in the future, reduce the time required to gain building access and reduce customer inconvenience due to Hydro Ottawa work being done indoors. Finally, this project will permanently reduce inventory overhead one-time by $3.6 K.

ION upgrade

The preferred alternative is the ION upgrade. This project will invest $144K to replace the 8400 and 8600C model ION meters with an updated ION meter. The 8400 and 8600C meters are used as alternate meters at wholesale metering points, as mandated by the IESO, and retail metering points. These models are not Ethernet enabled, which prevents one to one connection with the alt meter. As a result, the 8400 and 8600C alt meters must be wired with the main meter in a daisy chain configuration. When meter technicians call the 8400 and 8600C meters remotely and the connection fails, the meter technician must travel to the site to re-establish connection. It is estimated that 10-15 hours of technician time per month are dedicated to ION 8400 and 8600C meter communications troubleshooting, translating to $10K- $16 of maintenance spending per year. Removing these meters and replacing them with an Ethernet enabled meter will increase the reliability of the service and decrease the technician hours required to maintain the ION services.

Fleet Standardization

The preferred alternative is the Fleet Standardization scope. This project will replace 52 non-standard meters with standard meters at a total cost of $196K. The benefits of fleet standardization include a 22% stock code reduction, a one-time $93.6K decrease in inventory overhead and simplified inventory management. Additionally, this project will reduce missed customer appointments due to failure to stock a non-standard meter on technician trucks.

Program Timing & Expenditure

Each project Timeline and Expenditure is detailed separately below:

C Phase Reversal

There is no historical spending on this project. To minimize controllable costs, the services will be changed in 2024 when they will be fully depreciated.

Table 1.84 – Historical and Projected Renewal Spend for C Phase Reversal

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($'000s)	$0	$0	$0	$0	$0	$0	$0	$0	$35	$0
Units	0	0	0	0	0	0	0	0	38	0

1 element to 1.5 element upgrade

There is no historical spending on this project. To minimize controllable project costs, Hydro Ottawa will schedule capital work to coincide with meters coming due. This will eliminate the costs associated with resealing due meters.

Table 1.85 – Historical and Projected Renewal Spend for 1 element to 1.5 element upgrade

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($'000s)	$0	$0	$0	$0	$0	$22	$25	$4	$22	$85
Units	0	0	0	0	0	7	8	1	7	27

GREX upgrade

There is no historical spending on this project. To minimize controllable costs, the services will be changed in 2025 when they will be fully depreciated.

Table 1.86 – Historical and Projected Renewal Spend for GREX Upgrade

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($'000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$360
Units	0	0	0	0	0	0	0	0	0	155

ION upgrade

There is no historical spending on this project.

Table 1.87 – Historical and Projected Renewal Spend for ION upgrade

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($'000s)	$0	$0	$0	$0	$0	$125	$0	$0	$19	$0
Units	0	0	0	0	0	13	0	0	3	0

Fleet Standardization

There is no historical spending on this project.

Table 1.88 – Historical and Projected Renewal Spend for Fleet Standardization

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($'000s)	$0	$0	$0	$0	$0		$0.7	$33	$12	$3
Units	0	0	0	0	0	15	17	42	98	59

Benefits

Table 1.89 – Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Simplify inventory management through reducing stock codes and inventory overhead
Customer	Upgrade the metering service and increase reliability More accurate customer billing
Safety	Standardizing distribution system equipment and subsequently reducing the number of configurations technicians work with will reduce the risk of technician error and injury.
Cyber-Security, Privacy	N/A
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	N/A

1.5.1.1.4. Prioritization

Consequences of Deferral

The work schedule is designed to minimize write off expenses and resealing meter costs. If the project is deferred, there will be an increased cost incurred to reseal meters.

Priority

Medium

1.5.1.1.5. Execution Path

Implementation Plan

The factor which will have the greatest impact on the order of services changes is scheduled resealing of the meters. By changing the services before the meter comes due, it will save costs associated with resealing meters. This is also a benefit to our inventory management the meters will not need to be collected and track for resealing.

Risks to Completion and Risk Mitigation Strategies

The primary risk to completion of this project is a shortage of resources to perform capital work due to retirement or an unprecedented increase in reactive maintenance work. To mitigate this, Hydro Ottawa has planned to hire a contractor to complete the service upgrades if required.

Timing Factors

The availability of resources to complete capital work will be a limiting timing factor of this project. Capital work availability can be impacted by retirement of meter technicians and the amount of reactive maintenance to be completed.

Cost Factors

Changes in vendor pricing, variable installation costs due to delays or inability to access metering points on customer sites, outsourcing the work to contractors and inclement weather can impact the overall cost of the projects.

Other Factors

Inaccessible metering points or inability to perform an outage can impact the ability of Hydro Ottawa to complete this project.

1.5.1.1.6. Renewable Energy Generation (if applicable)

N/A

1.5.1.1.7. Leave-To-Construct

N/A

1.5.1.1.8. Project Details and Justification

Table 1.90 – C-Phase Reversal Elimination Overview

Project Name:	C-Phase Reversal Elimination
Capital Cost:	$36,000.00
O&M:	Enter Project O&M
Start Date:	2024
In-Service Date:	In-Service Date
Investment Category:	System Renewal
Main Driver:	System Standardization, Safety,
Secondary Driver(s):	Billing Error Reduction
Customers	38
Project Scope	
This project will perform C-Phase reversals on 38 services across the Hydro Ottawa service territory. Of these services, 31 are primary services and 7 are secondary services. Primary services require a system office isolation and service shutdown to complete the C-Phase reversal. The secondary services do not require a shutdown and the C-Phase reversal can be done directly. The 7 secondary services will also be upgraded to three element services. Services requiring C-Phase reversals often contain outdated wiring configurations and equipment. These antiquated services present safety concerns for technicians performing maintenance on them. Additionally, modern Hydro Ottawa cross read equipment cannot perform cross reads on these services due to their outdated configurations. As a result, they must be tested with legacy equipment. Elimination of these services will also streamline meter technician training by reducing the number of unique configurations to understand and maintain. In conclusion, this project will standardize distribution system equipment, improve safety conditions for meter technicians, reduce billing inaccuracies and permanently reduce inventory overhead one-time by $3.8K.	
Priority	
Medium	
Work Plan	
The work plan is designed to minimize write off and due meter expenses. For a detailed Work Plan, see Table 1.91 below.	
Customer Impact	
The C-Phase reversal will reduce customer billing inaccuracies caused by C-Phase wiring errors.	

Table 1.91 – C-Phase Reversal Elimination Work Plan

	2021	2022	2023	2024	2025
Number of C-Phase Reversals	0	0	0	38	0
Labour(Hours)	0	0	0	304	0
Capital ($'000s)	$0	$0	$0	$36	$0
Expense	$0	$0	$0	$0	$0

Table 1.92 – 1 EL to 1.5 EL Overview

Project Name:	1 EL to 1.5 EL
Capital Cost:	$160K
O&M:	
Start Date:	2021
In-Service Date:	In-Service Date
Investment Category:	System Renewal
Main Driver:	Distribution Standardization
Secondary Driver(s):	Grid Reliability, Reduced Working Capital
Customer	50
Project Scope	
This project will upgrade 50 self-contained 1 Element services to self-contained 1.5 Element services at a total cost of $160K. The drivers of this project are system standardization, streamlined inventory management and a permanent one-time $6.3 K reduction in inventory overhead.	
Priority	
Medium	
Work Plan	
The work schedule is designed to minimize project expenses.For a detailed Work Plan see Table 1.93 below.	
Customer Impact	
Replacing a 1 element self-contained meter with a 1.5 element self-contained meter will provide the customer with an increased load capacity and a complimentary service upgrade.	

Table 1.93 – 1 EL to 1.5 EL Work Plan

	2021	2022	2023	2024	2025
Number of Installed Meters to be replaced and disposed of	7	8	1	7	27
Number of In Stock Meters to be written off and disposed of	2	2	4	22	2
Labour Time (Hours)	3.5	4	0.5	3.5	13.5
Capital ($'000s)	$22	$25	$4.3	$22	$85
Derecognized Expense ($'000s)	$0.6	$0.48	$0	$0	$0
Write Off Expense ($'000s)	$0.2	$0.2	$3.2	$2.5	$0.2

Table 1.94 – GREX Meter Replacement Overview

Project Name:	GREX Meter Replacement
Capital Cost:	$359K
O&M:	Enter Project O&M
Start Date:	2025
In-Service Date:	
Investment Category:	System Renewal
Main Driver:	System Standardization
Secondary Driver(s):	Reliability, service point accessibility, customer convenience
Customer	114

Project Scope

This project will replace 114 GREX meters with a standard residential meter at a total cost of $364K. GREX meters were initially installed because they were more compact than a standard residential meter, and could readily be installed at the smallest indoor service points. The primary driver of this project is infrastructure standardization, as the GREX meters will be replaced with standard residential meters. The GREX meter stock code will subsequently be eliminated to streamline inventory management. Indoor metering points will also be moved outside. Moving the service outside will make it more accessible for meter technicians performing maintenance in the future, reduce time required to gain building access and reduce customer inconvenience due to Hydro Ottawa work being done indoors. Finally, this project will permanently reduce inventory overhead one-time by $3.6 K.

Work Plan

To reduce project costs, all 114 GREX meters will be replaced when they are fully depreciated in 2025. This ensures that no write-off costs will be incurred at the time of GREX replacement. For a detailed Work Plan see Table 1.95 below.

Customer Impact
Moving the metering points outside will allow technicians to access the metering point independently of the customer. Failure to gain indoor access can cause missed appointments or delays in scheduling. As a result, this initiative will ensure that customer appointments are completed in a timely manner. Additionally, the customer will receive a complimentary service upgrade.

Table 1.95 – GREX Meter Replacement Work Plan

	2021	2022	2023	2024	2025
Number of Installed Meters to be replaced and disposed of	0	0	0	0	114
Number of In Stock Meters to be written off and disposed of	0	0	0	0	41
Labour (Hours)	0	0	0	0	57
Capital ($'000s)	$0	$0	$0	$0	$360
Write-Off ($'000s)	$0	$0	$0	$0	$3.6

Table 1.96 – Ion Upgrade Overview

Project Name:	Ion Upgrade
Capital Cost:	$144K
O&M:	N/A
Start Date:	2021
In-Service Date:	Click here to enter text.
Investment Category:	System Renewal
Main Driver:	Reliability
Secondary Driver(s):	Reduced maintenance
Customers	55 customers
Project Scope	
This project will invest $144K to replace the 8400 and 8600C model ION meters with an updated ION meter. The 8400 and 8600C meters are used as alternate meters at wholesale metering points, as mandated by the IESO, and retail metering points. These models are not Ethernet enabled, which prevents one to one connection with the alt meter. As a result, the 8400 and 8600C alt meters must be wired with the main meter in a daisy chain configuration. When meter technicians call the 8400 and 8600C meters remotely and the connection fails, the meter technician must travel to the site to re-establish connection. It is estimated that 10-15 hours of technician time per month of are dedicated to ION 8400 and 8600C meter communications troubleshooting, translating to $10K- $16 of maintenance spending per year. Removing these meters and replacing them with an Ethernet enabled meter will increase the reliability of the service and decrease the technician hours required to maintain the ION services.	

Priority
Medium
Work Plan
The work plan is designed to minimize write off costs. For a detailed Work Plan see Table 1.97 below.
Customer Impact
This project will reduce the maintenance costs, which will decrease the socialized costs charged to the customer rate base.

Table 1.97 – GREX Meter Replacement Work Plan

	2021	2022	2023	2024	2025
Number of Meters Changed	13	0	0	3	0
Capital ($'000s)	$125	$0	$0	$19	$0
Expense ($'000s)	$0	$0	$0	$0	$0

Table 1.98 - Fleet Standardization Overview

Project Name:	Fleet Standardization
Capital Cost:	$48k
O&M:	$200K
Start Date:	2021
In-Service Date:	In-Service Date
Investment Category:	System Renewal
Main Driver:	System Standardization
Secondary Driver(s):	Reduced Working Capital, lower inventory levels, resource optimization
Customers	52 customers
Project Scope	
This project will replace 52 non-standard meters with standard meters at a total cost of $248K. The benefits of fleet standardization include a 22% stock code reduction, a one-time $93.6K decrease in inventory overhead and simplified inventory management. Additionally, this project will reduce missed customer appointments due to failure to stock a non-standard meter on technician trucks.	
Priority	
Medium	
Work Plan	
The work schedule is designed to minimize write off and due meter expenses from 2021 to 2025.	

Customer Impact
Streamlined inventory management will reduce the number of missed customer appointments due to stocking errors on meter technician trucks. Additionally, when a non-conformance meter is removed and the replacement meter is not in stock, customer bills are estimated while the new meter is on order. Standardizing the metering inventory will increase the probability of having the required replacement meter in stock and reduce the number of billing estimates required. As a result, this project will increase Hydro Ottawa's ability to provide accurate metering to Hydro Ottawa customers.

Table 1.99 - Fleet Standardization Overview

	2021	2022	2023	2024	2025
Number of Installed Meters to be replaced and disposed of	0	5	14	16	17
Number of In Stock Meters to be written off and disposed of	15	12	28	82	42
Labour (Hours)	0	2.5	7	8	8.5
Capital ($'000s)	$0	$0.76	$33	$12	$2.9
Write Off Expense ($'000s)	$15	$8.6	$18	$32	$76

1.5.1.2 2.5EL to 3EL

1.5.1.2.1. Program Summary

This material investment plan outlines the drivers, cost and implementation plan to convert 1611 meters from 2½ element to 3 element services. This program is intended to proactively bring Hydro Ottawa into compliance with industry standards.

1.5.1.2.2. Program Description

Current Issues

According to Measurement Canada Policy E-24, Policy on Approval and Use of 2½ Element Metering, 2½ element meters were designed to reduce costs by using one less instrument transformer in the metrology. However, the potential for error due to zero sequence voltage exists with 2½ element meters. Measurement Canada has the long term expectation that self-contained 2½ element meters will be replaced with self-contained 3 element meters through obsolescence. Transformer-rated 2 ½ element meters should be replaced with transformer-rated 3 element meters, on an opportunity basis, through obsolescence or reconstruction of the metering installation.

Additionally, 2 ½ element metering is non-compliant with Blondel's Theorem. The Independent Electricity System Operator (IESO) mandates in the Wholesale Revenue Metering Standard, Non-Compliant Metering – Existing Installations that all new and reconstructed 3- phase 4- wire wye configured metering installations use metering that is compliant to Blondel's Theorem, such as 3-element metering.

Though the metering services in the Hydro Ottawa service territory are not in violation of these two standards, they are not proactively in compliance. Additionally, 2½ element meters have unique stock codes that complicate inventory management. This inventory management complication is driving additional overhead costs as a result of the increased inventory needed to meet compliance sampling requirements.

Program Scope

Hydro Ottawa will convert 1611 2½ element to 3 element meter services. By removing 2½ elements meters from the service territory, Hydro Ottawa will proactively comply with Measurement Canada Policy E-24, Policy on Approval and Use of 2½ Element Metering, the IESO Wholesale Revenue Metering Standard, Non-Compliant Metering – Existing Installations, reduce inventory overhead by $167K and simplify inventory management moving forward.

Main and Secondary Drivers

The main driver of this project is to proactively comply with Measurement Canada Policy E-24, Use and Approval of 2½ element metering and the IESO Wholesale Revenue Metering Standard, Non-Compliant Metering – Existing Installations. The secondary drivers of this project include streamlining inventory, reducing stock codes and inventory overhead by 9% and 167K, respectively, improving billing accuracy and reducing error due to zero sequence voltage.

Performance Targets and Objectives

The performance targets and objectives include:

1. Eliminate all 2½ element secondary services from the Hydro Ottawa service territory
2. Comply with Measurement Canada Policy E-24, Approval and Use of 2½ to 3 Element Metering and the IESO Wholesale Revenue Metering Standard, Non-Compliant Metering – Existing Installations
3. Reduce total number of meter stock codes by 9%

4. Increase billing accuracy
5. Permanently reduce working capital by $167K
6. Standardize of distribution system assets

1.5.1.1.3. Program Justification

Alternatives Evaluation

Alternatives Considered

The do nothing option was the only alternative considered. In this case, Hydro Ottawa would have to reactively comply with Measurement Canada Policy E-24 through meter obsolesce and installation reconstruction. This alternative would mean Hydro Ottawa would need to continue to carry the 2½ element meter inventory further into the future costing any additional $167K in inventory working capital while still have to invest the funds to upgrade the meter to 3 element in the future.

Evaluation Criteria

The following evaluation criteria were used to compare the design alternatives:

- Rate of return on investment
- Availability of resources to complete capital work
- Elimination of future maintenance work
- System standardization (reduced inventory)

Preferred Alternative

The preferred alternative is the 2.5 element to 3 element meter upgrade. This project will ensure that Hydro Ottawa is proactively compliant with Measurement Canada policy E-24. Additionally, this initiative will standardize the distribution system. This alternative will allow better utilisation of labour, and reduce the future maintenance cost of having an additional meter type in the system.

Program Timing & Expenditure

There is no historical spending on this project. To minimize controllable project costs, Hydro Ottawa will schedule capital work to coincide with meters coming due. This will eliminate the costs associated with resealing due meters.

Table 1.100 - Historical and Forecast Expenditure

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($'000s)	$0	$0	$0	$0	$0	$137	$119	$684	$949	$543
Units	0	0	0	0	0	83	77	483	612	317

Table 1.101 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Comply with Measurement Canada Policy E-24 , Approval and Use of 2½ to 3 Element Metering Simplify inventory management through reducing stock codes by 9% and inventory overhead by 167K Reduce risk of zero sequence voltage error Comply with IESO Wholesale Revenue Metering Standard, Non-Compliant Metering – Existing Installations
Customer	Upgrade the metering service and increase reliability More accurate customer billing
Safety	Standardizing the distribution system and subsequently reducing the number of configurations technicians work with will reduce the risk of technician error and injury.
Cyber-Security, Privacy	N/A
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	N/A

1.5.1.1.4. Prioritization

Consequences of Deferral

The work schedule is designed to minimize write off expenses and resealing meter costs. If the project is deferred, there will be an increased cost incurred to reseal meters.

Priority

If this investment is deferred to the next planning period there will be unnecessary duplicate costs incurred to re-seal the meters as they become due. As it is also an expectation of Measurement Canada that utilities are proactively eliminating these installations, the funding is necessary to remain compliant.

1.5.1.1.5. Execution Path

Implementation Plan

The factor which will have the greatest impact on the order of services changes is the resealing schedule of the meters. By changing the services before the meter comes due, it will save costs associated with resealing meters. This is also a benefit to our inventory management the meters will not need to be collected and track for resealing.

Risks to Completion and Risk Mitigation Strategies

The primary risk to completion of this project is a shortage of resources to perform capital work due to retirement or an unprecedented increase in reactive maintenance work. To mitigate this, Hydro Ottawa has planned to hire a contractor to complete the service upgrades if required.

Timing Factors

The availability of resources to complete capital work will be a limiting timing factor of this project. Capital work availability can be impacted by retirement of meter technicians and the amount of reactive maintenance to be completed.

Cost Factors

Changes in vendor pricing, variable installation costs due to delays or inability to access metering points on customer sites, outsourcing the work to contractors and inclement weather can impact the overall cost of the projects.

Other Factors

Inaccessible metering points or inability to perform an outage can impact the ability of Hydro Ottawa to complete this project.

1.5.1.1.6. Renewable Energy Generation (if applicable)

N/A

1.5.1.1.7. Leave-To-Construct (if applicable)

N/A

1.5.1.1.8. Project Details and Justification

Table 1.102 - 2.5 to 3 Element Service Upgrade Overview

Project Name:	2.5 to 3 Element Service Upgrade
Capital Cost:	2.4 M
O&M:	N/A
Start Date:	2021
In-Service Date:	2021-2025
Investment Category:	System Renewal
Main Driver:	Compliance with Measurement Canada Policy E-24, Policy on Approval and Use of 2.5 Element Metering
Secondary Driver(s):	System Standardization, Reliability
Customer/Load Attachment	1,611 customers
Project Scope	
1611 meters will be upgraded from 2.5 Element to 3 element services at a cost of $2.5 M. The primary driver of this project is proactive compliance with Measurement Canada Policy E-24, Policy on Approval and Use of 2.5 Element Metering and with the ISEO Wholesale Revenue Metering Standard, Non-Compliant Metering – Existing Installations. This project will also streamline inventory management, permanently reduce the inventory overhead by $167K and increase the accuracy of customer billing.	
Priority	
High	
Work Plan	
The work schedule was designed to minimize the write off and resealing costs associated with the service upgrades. For a detailed Work Plan see Table 1.103 below.	
Customer Impact	
The primary customer benefit is a more accurate bill as a result of this service upgrade.	

Table 1.103 - 2.5 to 3 Element Service Work Plan

	2021	2022	2023	2024	2025
Number of Installed meters to be disposed of and replaced	83	77	438	612	317
Number of in stock meters to be disposed of	13	10	25	234	82
Labour Hours	41.5	38.5	216	306	158.5
Capital	$137,029	$119,462	$683,908	$948,527	$543,089
Derecognized Assets	$2,881	$64	$1,024	$1,537	$2,295
Write Off	$2,868	$0	$2,196	$9,582	$48,805

1.5.1.3. Self-Contained Phone Line Communication Upgrade

1.5.1.3.1. Program Summary

This material investment plan outlines the cost, drivers and implementation details of removing the phone lines from 413 self-contained gatekeepers. These meters will be converted to nodes and 350 upgraded gatekeepers will be installed throughout the service territory in their place.

1.5.1.3.2. Program Description

Current Issues

Using phone lines as a means of meter communication presents several challenges to Hydro Ottawa. Firstly, phone lines are unreliable; they have relatively low communication success rates with Meter Data Services. Additionally, phone lines regularly require maintenance, and Hydro Ottawa inconveniences customers by accessing these meters for repair on residential sites. Frequent site visits for phone line trouble shooting also incur high maintenance costs and limit available resources for capital and proactive maintenance work. Currently, these meters have limited outage management and data analytics capabilities. Finally, Hydro Ottawa is responsible for a $22K monthly bill to operate the phone lines. In summary, self-contained phone line gatekeepers are resource intensive to maintain, unreliable and create inconveniences for customers.

Program Scope

Self-contained phone line meters currently serve as gatekeepers, collecting residential meter data for billing purposes. It was determined that 350 new gatekeepers can collect an equivalent amount of billing data as the 413 phone line gatekeepers currently in service. After installing 350 new gate keepers, the 413 self-contained phone line meters will be converted to nodes by removing the phone lines. Additionally, the upgraded gatekeepers will be moved from customer premises and installed on Hydro Ottawa poles to optimize coverage, improve the communication success rates and eliminate the need for technicians to access customer premises to perform maintenance work. These new gate keepers will also have battery backup and increased reporting capabilities for improved outage management.

Main and Secondary Drivers

The main driver of this project is the financial and operational benefits to Hydro Ottawa. This project will eliminate the $272K yearly bill Hydro Ottawa pays to operate 413 phone line gatekeepers. Instead, Hydro Ottawa will pay $29K in cell modem operation fees, resulting in an annual savings of $243K. Eliminating phone line meters will optimize workforce management by reallocating 25% of a full time meter technician time and salary to capital projects. Additionally, this project will improve the outage management and data analytics capabilities of the meter.

The secondary drivers of this project include a reduction in customer inconvenience caused by site visits for phone line maintenance and improved meter communication success rates.

Performance Targets and Objectives

The performance targets for this project include:

- Eliminate the phone line bills after the telecommunication contract is terminated in 2021 to save $243K yearly
- Increase gatekeeper communication success rates with Meter Data Services
- Reduce the number of residential gate keepers in the service territory from 413 to 350
- Redistribute 25% of a meter technician salary from reactive maintenance to proactive maintenance and capital work
- Increase outage management functionality of residential gatekeepers
- Reduce inventory overhead by $196K

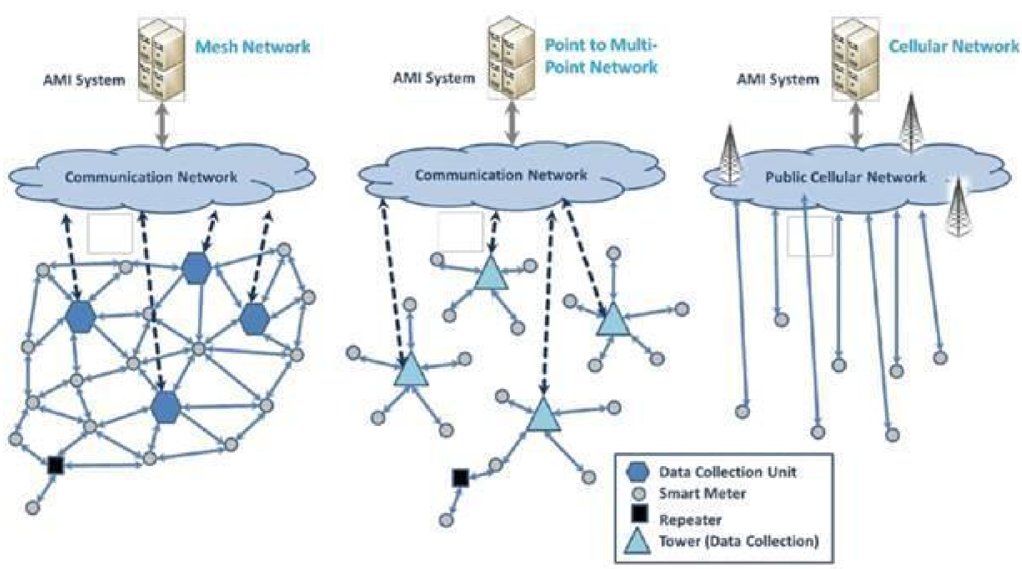
1.5.1.3.3. Program Justification

Alternatives Evaluation

Alternatives Considered

The first alternative considered was the do nothing option. In this case, the phone lines would be kept and the Bell contract will be renewed on a shorter term basis in 2021. In this case, Hydro Ottawa would continue to dedicate meter technician labour to phone line maintenance, and pay a monthly bill of $22K. If this option was selected, there would be no improvements in data analytics or outage management capabilities. The second alternative considered was a complete fleet replacement of all meters in the service territory. Referring to Figure 1.59, Hydro Ottawa currently operates on a mesh network. In the case of a complete fleet replacement, the communication style would be converted to point to multi-point network or cellular network. This would cost upwards of 80M.

Figure 1.59- Meter AMI Network Structures



Evaluation Criteria

The evaluation criteria of the project include:

- Rate of return on investment
- Availability of resources to complete capital work

- Elimination of future maintenance work by implementing the project
- Standardization of the distribution system
- Environmental impact

Preferred Alternative

The preferred alternative is the phone line communication upgrade at a cost of $2.3M. This project eliminates maintenance costs and technician time associated with the phone line infrastructure. This option also enables outage management and data analytics functionality, decreases the number of field visits required for maintenance and standardizes installations, and has a payback interval of 8 years. Conversely, the do nothing option would cost $324,490 per year in maintenance costs and continue to tie up technician time in meter maintenance. The fleet replacement would be an enormous draw on both labour and financial resources. A full fleet replacement would be 26 times more expensive than the phone line elimination, and would require 173,000 labour hours, which is the equivalent of 21 full time technicians for 5 years. The metering department currently staffs 17 meter technicians, and their availability to complete capital work is already limited by obligatory maintenance work. As a result, investing in this project would require contracting or new hires, which would further increase project cost and limit Hydro Ottawa's ability to complete maintenance work of other capital projects. Additionally, the communication infrastructure is likely to become obsolete before the fleet is depreciated and result in a low return on the investment.

Program Timing & Expenditure

This upgrade will be completed in 2021 and 2022 to maximize the rate of return on the investment and eliminate due meter and sample group resealing costs. Completing the project in 2021 and 2022 will eliminate the need to renew the telecommunications contract. In terms of historical spending, a $10K study was conducted in 2019 to determine the number of new gatekeepers required to replace the functionality of the 413 phone line gatekeepers currently in service.

Table 1.104 - Historical and Forecast spending

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($'000s)	$0	$0	$0	$0	$0	$1.81	$0.16	$0	$0	$0
Units	0	0	0	0	0	582	429	0	0	0

Table 1.105 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	**Communication** ● improve communication success rate with Meter Data Services ● leverage the existing Hydro Ottawa fiber network ● improve identification of lost and orphaned meters ● improved AMI alert and exception management **Operations** ● reallocate meter technician time from reactive phone line maintenance to capital work ● eliminate 15% of the stock codes to simplify inventory management **Financial** ● reduce accounts in arrears and inactive account consumption ● eliminate $264K in annual Hydro Ottawa phone line bills ● reduce loss due to defective meters ● faster detection and collection of power theft ● reduce inventory overhead by $196 K **Outage Management** ● outage battery backup ● improve outage identification and reliability index reporting ● improve system reliability planning from post outage analysis

Benefits (Cont'd)	Description (Cont'd)
Customer	• reduce the inconvenience of having meter technicians perform customer site visits for phone line maintenance • improve reliability of meter services • improve customer outage communications • near real time data usage for the customer, enabling peak usage reduction and conservation to reduce billing • AMI enabled load control
Safety	• By standardizing the distribution system, the number of configurations a meter technician has to work with decreases. This reduces the chances of error, streamlines future technician training and increases the safety of Hydro Ottawa employees.
Cyber-Security, Privacy	• The cell modem communication process was designed by internal IT and reviewed by network security to ensure that it conforms to all Hydro Ottawa standards.
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	• This project will reduce the number of site visits and associated emissions required for maintenance work.

1.5.1.3.4. Prioritization

Consequences of Deferral

If the project is deferred, there will be several financial and operational consequences to Hydro Ottawa. The current phone line contract terminates in 2021. If the project is deferred past 2021, the contract will have to be renewed. Depending on the length of the project delay, a financial penalty may be incurred to cancel the renewed contract at a later time.

Retirement and the subsequent shortage of labour have been identified as key departmental risks. Deferring this upgrade will require that meter technician resources continue to be dedicated to phone line maintenance, creating a potential shortage of labour for capital work.

Additionally, self-contained phone line meters account for 15% of the meter stock codes. By deferring the project, these stock codes cannot be eliminated and, as a result, there will continue to be increased inventory overhead and less efficient inventory management. Additionally, Hydro Ottawa will continue to pay $264K per year to operate the phone lines, have meters with limited outage management capabilities and customer functions.

Priority

High

1.5.1.3.5. Execution Path

Implementation Plan

The priority of the phone line elimination will be determined based on the communication success rate of the meter with Meter Data Services. The meters with the lowest communication success rates will be prioritized and changed first as they require the most maintenance work and incur the highest costs. This will minimize the maintenance costs accumulated throughout the length of the project.

Risks to Completion and Risk Mitigation Strategies

The primary risk to project completion is a shortage of labour due to the prioritization of maintenance work or other capital work. To mitigate this risk, Hydro Ottawa has developed a contingency plan to distribute the work to an independent contractor.

Timing Factors

The timing of the project can be affected by the availability of meter technician labour hours, the ability to access customer premises, and unforeseen emergency maintenance that would create a labour shortage for capital work.

Cost Factors

Changes in vendor pricing, variable installation costs due to delays or inability to access metering points on customer sites, outsourcing the work to contractors and inability to complete work due to inclement weather can impact the overall cost of the project.

Other Factors

Premise inaccessibility or inability to perform an outage to occur can impact the ability of Hydro Ottawa to complete this project on time and on budget.

1.5.1.3.6. Renewable Energy Generation (if applicable)

N/A

1.5.1.3.7. Leave-To-Construct (if applicable)

N/A

1.5.1.3.8. Project Details and Justification

Table 1.106 - Self-Contained Meter Phone Line Elimination Overview

Project Name:	Self-Contained Meter Phone Line Elimination
Capital Cost:	$1.98 M
O&M:	N/A
Start Date:	2021
In-Service Date:	2021-2025
Investment Category:	System Renewal
Main Driver:	Economic Benefits for Hydro Ottawa and Hydro Ottawa customers
Secondary Driver(s):	Reliability, Resource Optimization
Customers	413 customers
Project Scope	
This project will remove the phone lines from 413 self-contained meters, currently serving as residential gatekeepers, at a total cost of $1.98 M. The 413 self-contained meters will be converted to nodes and 350 new gatekeepers will be installed on Hydro Ottawa poles throughout the service territory. The higher elevation of the poles will provide the gatekeepers with better coverage improve their communication success rates with Meter Data Services and make them more accessible to Hydro Ottawa workers performing meter maintenance. The 350 upgraded gatekeepers will also have battery backup, use AMI data to enhance outage management capabilities and leverage the existing Hydro Ottawa fiber network. Finally, this initiative will eliminate the $22K monthly bill paid by Hydro Ottawa to operate the phone lines and reduce inventory overhead by $196 K.	
Priority	
High	
Work Plan	
All work will be done 2021 and 2022 in order to minimize the costs associated with the maintenance of the phone lines. For a detailed Work Plan see Table 1.107 below.	
Customer Impact	
This project will increase the communication success rate of Hydro Ottawa meters with Meter Data Services and therefore provide the customer with a more reliable service. Additionally, moving gatekeepers from residential premises to poles will reduce the inconvenience for customers associated with technicians accessing phone lines on their property. This project will also create customer portals and enable in-home data device functionality.	

Table 1.107 - Self-Contained Meter Phone Line Elimination Work Plan

	2021	2022	2023	2024	2025
Number of Installed Meters to be replaced and disposed of	134	279	0	0	0
Number of In Stock Meters to be written off and disposed of	98	150	0	0	0
Number of Gatekeepers Installed	350	0	0	0	0
Capital	$1,816,516	$163,066	$0	$0	$0
Derecognized Asset	$ 13,291.41	$23,516.93	$0	$0	$0
Write Off	$80,799.63	$115,132.50	$0	$0	$0

1.5.1.4. Transformer-Rated Communication Upgrade

1.5.1.4.1. Project Summary

This material investment plan outlines the project drivers, costing and implementation plan to convert meter phone lines to cell modems in 945 internal modem and 382 external modem transformer-rated meters.

1.5.1.4.2. Project Description

Current Issues

Phone lines used for meter communication present several challenges to Hydro Ottawa. First, customers with transformer-rated phone line meters are financially responsible for phone line maintenance and a monthly bill of $55. Phone line meters are also unreliable and have relatively low communication success rates with Meter Data Services. Consequently, 75% of a meter technician time must be dedicated to phone line maintenance and troubleshooting. In summary, phone line meters are resource intensive to maintain, unreliable and burden the customer financially.

Project Scope

Transformer-rated phone line meters currently serve as gatekeepers, collecting commercial and industrial meter data for billing purposes. The meter phone lines will be replaced with cell modems. Cell modems are projected to improve the communication reliability of the meter and subsequently reduce the maintenance costs required to maintain the phone lines.

Main and Secondary Drivers

The main driver of this project is the financial and operational benefits to Hydro Ottawa and its customers. Eliminating phone line meters will permit the reallocation of 75% of a meter technician position from maintenance to capital work. This project will also eliminate the customer phone line bill, resulting in an average annual savings of $660.00 per customer.

The secondary drivers of this project include reduced customer inconvenience caused by Hydro Ottawa site visits for phone line maintenance, increased meter communication reliability and decreased socialized costs to the rate base due to the savings the project will create in the long term. Another secondary driver is streamlined inventory management due to a 27% reduction in meter stock codes and a $263K inventory overhead reduction.

Performance Targets and Objectives

The performance targets for this project include:

- Eliminate the $660.00 annual customer phone line bill and inconvenience associated with site visits required for phone line maintenance
- Reallocate 75% of a meter technician position from reactive maintenance to proactive maintenance and capital work
- Reduce the number of meter stock codes by 27%
- Streamline inventory management and reduce working capital by $263K

1.5.1.4.3. Project Justification

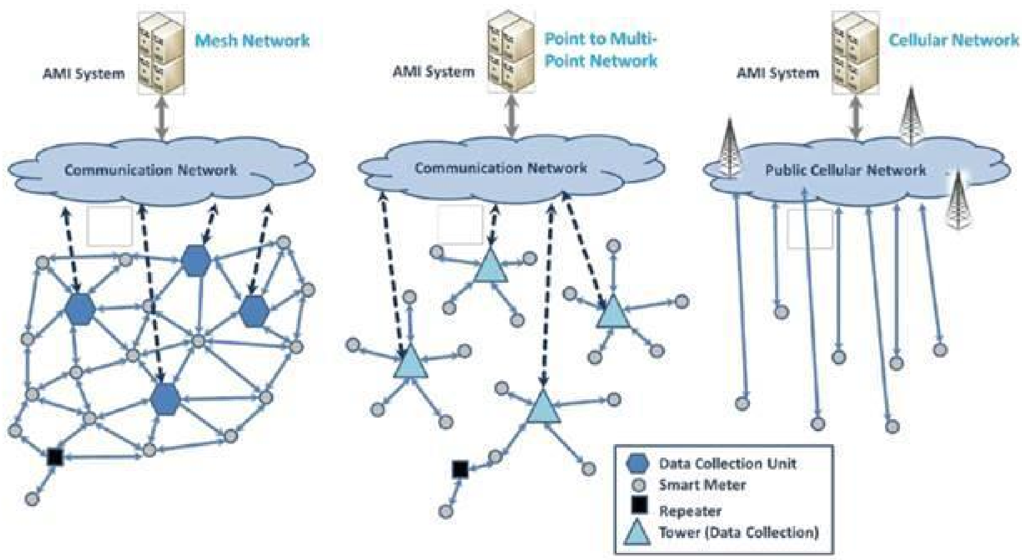
Alternatives Evaluation

Alternatives Considered

The first alternative considered was the do nothing option, which would entail keeping the current phone line infrastructure and renewing the phone line contract in 2020. Additionally, Hydro Ottawa would have to continue to dedicate meter technician maintenance hours to phone line troubleshooting, and customers will continue paying a $660 annual phone line bill. The do nothing option could also threaten to tie up retirement dollars in maintenance and prevent work force reallocation from maintenance to capital projects.

The second project alternative was a complete fleet replacement of all meters in the service territory. Referring to Figure 5.2, Hydro Ottawa currently operates on a mesh network. In the case of a complete fleet replacement, the communication style would be converted to either a point to multi-point network or a cellular network. This would cost upwards of $80M.

Figure 1.60 – Meter AMI Network Structures



Evaluation Criteria

The evaluation criteria used to determine the preferred alternative were:

- Total project cost
- Rate of return on investment
- Availability of resources to complete capital work
- Elimination of future maintenance work by implementing the project

Preferred Alternative

The preferred alternative is the $2.9M phone line communication upgrade. This option eliminates maintenance costs and the technician hours required to operate the phone lines. In contrast, the do nothing option would require that meter technician hours continue to be allocated to maintenance work, reducing the resources available for capital and proactive maintenance work in the future. The do nothing option costs Hydro Ottawa $1,003,021 per year. As a result, the rate of return on the phone line meter option is 3 years. The full fleet replacement would not be feasible from either a financial or a workforce management perspective. A full fleet replacement would be 26 times more expensive than the phone line elimination, and would require 173,000 labour hours, which is the equivalent of 21 full time technicians per year for 5 years. The metering department currently staffs 17 meter technicians, and their availability to complete capital work is already limited by obligatory maintenance work. As a result, investing in this project would require contracting or new hires, which would further increase project cost and limit Hydro Ottawa's ability to complete maintenance work or other capital projects. Additionally, the communication infrastructure is likely to become obsolete before the fleet is fully depreciated, and is thus projected to provide an insufficient rate of return on investment.

Project Timing & Expenditure

Historically, $250 K has been invested in this project in both 2018 and 2019.

To minimize the controllable costs, this project will be completed in 2021 and 2022 in order to maximize the rate of return on investment, reduce the maintenance investment in the phone line bill and eliminate due meter and sample group resealing costs.

Table 1.108 - Project Timing & Expenditure

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($'000s)	$0	$0	$0	$0.25	$0.25	$1.13	$1.02	$0	$0	$0
Units	0	0	0	100	100	736	591	0	0	0

Table 1.109 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	**Communication** ● Improve communication success rate with Meter Data Services ● Improve identification of lost and orphaned meters ● Improved AMI alert and exception management **Operations** ● Reallocate meter technician labour from reactive phone line maintenance to capital work ● Eliminate 26% of the stock codes to simplify inventory management **Financial** ● Reduce accounts in arrears and inactive account consumption ● Reduction in loss due to defective meters ● Eliminate $660 annual customer bill ● Improve the detection and collection of power theft ● Reduce inventory overhead one-time by $263K **Outage Management** ● Outage battery backup ● Improve outage and reliability index reporting ● Improve system reliability planning from post outage analysis
Customer	● Net annual savings of approximately $660.00 due to elimination of the phone line bill ● Reduced inconvenience of having meter technicians perform site visits for phone line maintenance ● Improve meter service reliability ● Eliminate customer responsibility to maintain the phone line
Safety	● By standardizing the distribution system, the number of configurations a meter technician has to work with decreases. This reduces the chances of error, streamlines future technician training and increases the safety of Hydro Ottawa employees.
Cyber-Security, Privacy	● The cell modem communication process was designed by internal IT and reviewed by network security to ensure that it conforms to all Hydro Ottawa standards.
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	● This project will reduce the number of site visits and associated emissions required for maintenance work.

1.5.1.4.4. Prioritization

Consequences of Deferral

If the project is deferred, there will be several financial and operational consequences to Hydro Ottawa. The phone line contract terminates in 2021. Deferring this project will require the continued allocation of technician resources to phone line maintenance. Retirement and the subsequent shortage of labour have been identified as key departmental risks. Deferring this upgrade will require that meter technician resources continue to be dedicated to phone line maintenance, creating a potential shortage of labour for capital work.

For every year that the project is deferred, the customer will have to pay $660 to operate the phone line and be inconvenienced by Hydro Ottawa phone line maintenance on their premises. The transformer-rated meters that operate with the phone lines account for 26% of the total meter stock codes. By deferring the project, Hydro Ottawa will continue operating with increased inventory overhead and less agile inventory management caused by carrying unnecessary meter stock codes.

Priority

This project is categorized as high priority because of the high maintenance cost, customer inconvenience and economic benefits associated with phone line replacement.

1.5.1.4.5. Execution Path

Implementation Plan

The phone line replacements will be completed based on the communication success rate of the meter. The meters with the lowest meter success rates will be changed first as they require the most maintenance work and incur the highest costs. This will reduce the maintenance costs incurred throughout the duration of the project.

Risks to Completion and Risk Mitigation Strategies

The primary risk to completion is a shortage of labour due to the prioritization of reactive maintenance work or capital work. To mitigate this risk, Hydro Ottawa has developed a contingency plan to distribute the work to an independent contractor if required.

Timing Factors

The timing of the project can be affected by the availability of meter technician labour, the ability to access premises and unforeseen emergency maintenance taking precedence over the project.

Cost Factors

Changes in vendor pricing, variable installation costs due to delays or inability to access metering points on customer sites, outsourcing the work to contractors and inability to complete work due to inclement weather can impact the overall cost of the projects.

Other Factors

Customers refusing to grant site access or allow for an outage to occur can impact the ability of Hydro Ottawa to complete this project.

1.5.1.4.6. Renewable Energy Generation (if applicable)

N/A

1.5.1.4.7. Leave-To-Construct (if applicable)

N/A

1.5.1.4.8. Project Details and Justification

Table 1.110 - Transformer-Related Meter Phone Line Elimination

Project Name:	Transformer-Rated Meter Phone Line Elimination
Capital Cost:	$2.15M
O&M:	N/A
Start Date:	2021
In-Service Date:	2021-2022
Investment Category:	System Renewal
Main Driver:	Economic Benefits for Hydro Ottawa & customers
Secondary Driver(s):	Reliability, Resource Optimization
Customers	1,327 customers
Project Scope	
This project will replace the phone lines of 945 internal modem and 382 external modem transformer-rated meters with cell modems at a cost of $2.55 M. Removing phone lines will eliminate the $55 monthly customer phone line bill and permit the reallocation of technician resources from phone line maintenance work to capital work. This project will also enhance operational processes, enable outage management functions and enhanced data analytics. Finally, this project will permanently reduce inventory overhead one-time by $ 263K.	
Priority	
High	
Work Plan	
All work will be done 2021 to maximize the rate of return on the investment. For a detailed Work Plan see Table 1.111 below.	
Customer Impact	
This project will eliminate the maintenance and monthly bill associated with meter phone devices. lines, amounting to $660 of annual savings for the customer. The phone line removal will also improve the reliability of the meter; enable customer portals and data access.	

Table 1.111 - Transformer-Related Meter Phone Line Elimination Work Plan

	2021	2022	2023	2024	2025
Capital ($'000,000s)	$1.12	$1.02	$0	$0	$0
Write Off ($'000s)	$126	$136	$0	$0	$0
Derecognized Assets ($'000s)	$62.4	$61.8	$0	$0	$0
Number of Meters to Change	736	591	0	0	0
Number of Meters to Scrap	157	163	0	0	0
Labour (Hours)	736	591	0	0	0

1.5.1.5. REX 1 Meter Upgrade

1.5.1.5.1. Project Summary

This project will invest $5M over 5 years to replace 33,300 Rex 1 meters with an upgraded model to improve outage visibility in the service territory.

1.5.1.5.2. Project Description

Current Issues

Currently, the Hydro Ottawa SCADA system has limited visibility in the distribution system beyond secondary transformers, including many residential customer points. As a result, customer outages are often not visible via the SCADA control system; Hydro Ottawa relies on customer reporting to identify and manage these outages. This delays power restoration and places the burden of outage reporting entirely on the customer.

Project Scope

This project will invest $5M annually to replace 33,330 Rex 1 meters with an updated Rex model. These meters will be strategically placed to enable last gasp signals at service points where SCADA has little to no visibility.

Main and Secondary Drivers

The primary driver of this project is increased outage management capabilities via meter last gasp signaling.

The secondary driver of this project is more efficient customer power restoration and removing the burden of outage reporting from the customer to Hydro Ottawa infrastructure.

Performance Targets and Objectives

The performance objectives for this project include:

1. Improve outage visibility
2. Improve outage response time
3. Decrease instances of customer reported outages from 100% to 60%

1.5.1.5.3. Project Justification

Alternatives Evaluation

Alternatives Considered

The only alternative considered to this project is the do nothing option. In this case, Hydro Ottawa would continue to have limited visibility and insight into customer outages. If Hydro Ottawa were to proceed with the do nothing option, the burden of outage reporting will continue to be placed entirely on the customer.

Evaluation Criteria

The evaluation criteria for the project include:

1. Project cost
2. Projected improvement to outage restoration response time
3. Projected increase in customer service and satisfaction

Preferred Alternative

The preferred alternative is to replace select Rex 1 meters with an updated meter with last gasp functionality. This investment of $ 5M over 5 years will increase outage visibility at service points where SCADA data is limited. This project is projected to improve the power restoration response time and reduce the dependency on customer reporting for outage management. This will ultimately result in an increase in customer satisfaction.

Project Timing & Expenditure

There is no historical spending on this project.

Table 1.112 - Project Timing & Expenditure

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($'000s)	$0	$0	$0	$0	$0	$1.0	$1.0	$1.0	$1.0	$1.0
Units	0	0	0	0	0	6600	6600	6600	6600	6600

Table 1.113 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	• Enable precise outage visibility • Reduce the outage reporting burden on customers • Increase the efficiency of outage response time • Reduce organizational resources required to locate and repair the outage
Customer Restoration	• Faster power restoration • Outage management no longer dependent on customer reporting
	N/A
Cyber-Security, Privacy	N/A
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	• Increased outage visibility will reduce the emissions from excess travel currently required to pinpoint outage sources when SCADA visibility is limited.

1.5.1.5.4. Prioritization

Consequences of Deferral

If this project is deferred, there will be several operational and financial consequences to Hydro Ottawa. Firstly, Hydro Ottawa will continue to have limited outage visibility in the distribution system beyond secondary transformers. Consequently, Hydro Ottawa will continue to rely on customer reporting for outage identification, which ultimately delays power restoration. Without meters distributed across the service territory that have last gasp signaling, technicians must rely on limited customer information to pinpoint outage locations. This ultimately delays power restoration and creates unnecessary maintenance expenses.

Priority

High

1.5.1.5.5. Execution Path

Implementation Plan

The updated REX meters will be dispersed to provide last gasp signaling for a cluster of meters fed by the same secondary transformer. By distributing the upgraded REX meters across the service territory, it will enable widespread outage visibility and expedite the power restoration process.

Risks to Completion and Risk Mitigation Strategies

The primary risk to project completion is a shortage of labour due to the prioritization of reactive maintenance work or other capital work. To mitigate this risk, Hydro Ottawa can distribute the work to an independent contractor.

Timing Factors

The timing of the project can be affected by the availability of meter technician labour hours, ability to outsource work to contractors, accessibility of customer premises, and unforeseen emergency maintenance taking precedence over capital work.

Cost Factors

Changes in vendor pricing, variable installation costs due to delays or inability to access metering points on customer sites, outsourcing the work to contractors and inability to complete work due to inclement weather can impact the overall cost of the project.

Other Factors

N/A

1.5.1.5.6. Renewable Energy Generation (if applicable)

N/A

1.5.1.5.7. Leave-To-Construct (if applicable)

N/A

1.5.1.5.8. Project Details and Justification

Table 1.114 Rex 1 Upgrade

Project Name:	Rex 1 Upgrade
Capital Cost:	$5 M
O&M:	N/A
Start Date:	2021
In-Service Date:	
Investment Category:	System Renewal
Main Driver:	Outage management
Secondary Driver(s):	Customer Satisfaction
Customers	33,000 customers
Project Scope	
This project will replace 6600 Rex 1 meters per year from 2021 to 2025 with upgraded REX meters. The upgraded meters will enable precise outage visibility within the service territory, enable last gasp signals, provide outage data to Hydro Ottawa and enable more efficient outage management.	
Priority	
High	
Work Plan	
The work schedule is designed to distribute financial and labour investment evenly across the 5 year rate application period. For a detailed Work Plan see Table 1.115 below.	
Customer Impact	
The last gasp functionality of the upgraded meters will enable Hydro Ottawa to identify outages efficiently and independently of the customer. This will ultimately result in more effective and timely power restoration at customer points.	

Table 1.115 Rex 1 Upgrade Work Plan

	2021	2022	2023	2024	2025
Number of Meters Changed	6600	6600	6600	6600	6600
Capital ($'000,000s)	$1	$1	$1	$1	$1
Expense	0	0	0	0	0

1.5.1.6. Transformer-Rated to Self-Contained 200A Services

1.5.1.6.1. Project Summary

This material investment plan outlines the cost, drivers and implementation plan to convert 225 transformer-rated services to 200A self-contained services.

1.5.1.6.2. Project Description

Current Issues

Transformer-rated services present several challenges to Hydro Ottawa. First, these installations are non-standard and subsequently complicate the meter technician training process. Transformer-rated services also require instrument transformers, which must be cross read once every three years. This incurs extraneous maintenance costs compared with other metering means.

Project Scope

This project will convert 225 transformer-rated services to 200A self-contained services at a cost of $1.13 M. These service configurations are relatively uncommon. Removing them from operation will standardize the distribution system and simplify meter technician training. Installing self-contained services also eliminates the yearly $6.7K cost associated with maintaining instrument transformers used in transformer-rated services.

Main and Secondary Drivers

The main driver of this project is reduced maintenance costs. Cross reads must be performed once every three years on instrument transformers required for transformer-rated services, and each cross read requires on average one hour of technician time. Eliminating instrument transformers from operation eliminates 75 technician hours and reduces maintenance costs by $6.7K yearly.

The secondary driver of this project is the standardization of metering infrastructure. Retirement and subsequent loss of institutional knowledge have been identified as high priority risks for the Hydro Ottawa metering department. By standardizing the distribution system and removing uncommon installations, it mitigates the loss of institutional knowledge and streamlines the training process for future meter technicians.

Performance Targets and Objectives

The performance objectives for this project include:

- Eliminate the instrument transformers on 225 200A services
- Reduce instrument transformer maintenance time by 225 hours every three years
- Reallocate 75 hours of meter technician time and resources from reactive maintenance to proactive maintenance and capital work every year
- Standardize the metering installations in the service territory
- Simplify future meter technician training

1.5.1.6.3. Project Justification

Alternatives Evaluation

Alternatives Considered

The only alternative considered was the do nothing option, where the 1000 services considered will remain transformer-rated. The consequences of the do nothing option would include operating with high maintenance costs and an unstandardized distribution system.

Evaluation Criteria

The evaluation criteria of the project include:

1. Total project cost
2. Availability of resources to complete capital work
3. Elimination of future maintenance work by implementing the project
4. Standardization of the distribution system
5. Environmental impact

Preferred Alternative

The transformer-rated to self-contained service conversion is the preferred project alternative. This project will eliminate 75 hours of technician time and $6.7 K per year required for transformer-rated meter maintenance. This project will also remove the low voltage transformer-rated configurations from the service territory and standardize the distribution system. Loss of institutional knowledge and labour shortages are two identified departmental risks for revenue metering. This project will standardize the configurations meter technicians work with and reduce labour demands to mitigate both of these risks. Finally, the elimination of cross read maintenance will reduce emissions released through travel to sites for maintenance.

Project Timing & Expenditure

There is no historical spending on this project. To minimize controllable costs, the services will be changed in 2024 when they will be fully depreciated.

Table 1.116 - Project Timing & Expenditure

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure ($000)	$0	$0	$0	$0	$0	$226	$226	$226	$226	$226
Units	0	0	0	0	0	75	75	75	75	75

Table 1.117 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	• Eliminate $20K in maintenance costs for cross reads every 3 years • Reallocate 225 meter technician resources from maintenance to capital work in a three year period • Standardize the metering installations in the service territory • Simplify future meter technician training • Reduce maintenance costs associated with changing and resealing meters
Customer	• Optimize workforce management to ensure that customer appointments can completed efficiently • Create more space in the customer's electrical room by removing instrument transformers • Reduce customer inconvenience due to instrument transformer maintenance work being done on customer properties
Safety	Standardization of the distribution system simplifies meter technician training and reduces the chance of error when performing maintenance, which can result in injury and lost time.
Cyber-Security, Privacy	N/A
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	This project will reduce the number of site visits and associated emissions required for transformer-rated meter maintenance.

1.5.1.6.4. Prioritization

Consequences of Deferral

If the contract is deferred, Hydro Ottawa must continue dedicating 225 technician hours and $20K every three years towards cross reads for instrument transformer maintenance. Additionally, the non-standard services will continue to complicate meter technician training and increase the potential for technician error.

Priority

Medium

1.5.1.6.5. Execution Path

Implementation Plan

The factors that will affect the order of services changes are the ease of access to the service point and the resealing schedule of the meters. By changing the services before the meter comes due, it will save costs associated with testing due meters.

Risk to Completion and Risk Mitigation Strategies

The primary risk to completion is the shortage of technician time to allocate towards capital work due to retirement of technicians or the prioritization of reactive maintenance work. Hydro Ottawa has developed a plan to hire a contractor to complete capital work in the case of resource shortage.

Timing Factors

The availability of resources to complete capital work will be a limiting timing factor. Timing can be impacted by the retirement of meter technicians and the amount of other reactive maintenance that must be completed. Additionally, the ability to access the meters on customer premises will impact the timing of this project.

Cost Factors

Changes in vendor pricing, variable installation costs due to delays, inability to access metering points on customer sites, contractor outsourcing and inclement weather can impact the overall cost of the projects.

Other Factors

Difficulty accessing customer sites or inability to perform a service outage can influence the ability of Hydro Ottawa to complete this project.

1.5.1.6.6. Renewable Energy Generation (if applicable)

N/A

1.5.1.6.7. Leave-To-Construct (if applicable)

N/A

1.5.1.6.8. Project Details and Justification

Table 1.118 - TX 200A to SC Upgrade Overview

Project Name:	TX 200A to SC Upgrade
Capital Cost:	$1.13 M
O&M:	Enter Project O&M
Start Date:	2021
In-Service Date:	In-Service Date
Investment Category:	System Renewal
Main Driver:	System Standardization
Secondary Driver(s):	Reducing Equipment Maintenance
Customer	225 customers
Project Scope	
This project will convert 225 transformer-rated services to 200A self-contained services at a cost of $1.13 M. These services are uncommon, and removing them will standardize the distribution system and simplify future meter technician training. Installing self-contained services also eliminates 225 technician hours and $20K required every three years for instrument transformer maintenance.	
Priority	
High	
Work Plan	
The work schedule is designed to minimize the costs associated with asset write off. For detailed Work Plan see Table 1.119 below.	
Customer Impact	
Removing cross reads for transformer-rated services will eliminate customer inconvenience associated with accessing customer properties for maintenance. The removal of the instrument transformers will also create more space in the customer's electrical room	

Table 1.119 - TX 200A to SC Upgrade Work Plan

	2021	2022	2023	2024	2025
Number of Installed Meters to be replaced and disposed of	45	45	45	45	45
Number of In Stock Meters to be written off and disposed of	0	0	0	0	0
Capital ($'000s)	$226	$226	$226	$226	$226
Derecognized Assets	0	0	0	0	0
Expense	0	0	0	0	0

SYSTEM SERVICE

2.1 CAPACITY UPGRADES

2.1.1 STATION CAPACITY UPGRADES

The prioritized projects under the Station Capacity Upgrades Program alleviate short to long-term capacity constraints within Hydro Ottawa's distribution system. They are primarily focused on new station capacity at Cambrian MTS (previously named South Nepean MTS) in Nepean South and the New East Station in Leitrim as well as additional station capacity at existing stations such as Limebank MTS, Uplands MTS and Riverdale TS. The need for these additions or upgrades is identified through the System Capacity Assessment and IRRP.

In total, Hydro Ottawa plans to invest an estimated $55.1M in station capacity upgrades in the 2021-2025 rate period compared to a historical spending of $43.1M in the 2016-2020 period. Hydro Ottawa expects to add over 220MVA in station capacity to Hydro Ottawa's distribution system as a result of these projects.

2.1.1.1. Limebank MTS T4 Capacity Upgrade

2.1.1.1.1. Project Summary

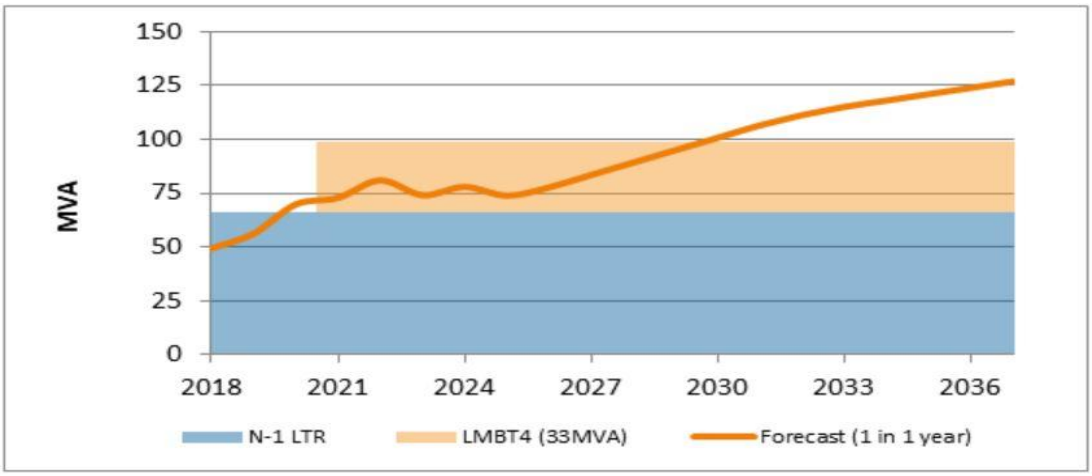
Limebank MTS is a 115kV to 28kV station which supplies the Riverside South and Barrhaven communities in the City of Ottawa. The station currently has three 33MVA transformers and has 28kV infrastructure installed to accommodate a fourth transformer. The planning process to add a fourth 33MVA transformer, the LMBT4, is scheduled to begin in 2019 with energization anticipated in 2021. This fourth transformer will be relocated from Uplands MTS station. The project is estimated at $2.98M and will increase the overall station planning capacity from 66MVA to 99MVA. This capacity upgrade addresses forecasted needs to accommodate load transfers from the Barrhaven and Leitrim regions scheduled for 2020 and forecasted growth within the developing Riverside South community. Considered alternatives include load transfers to other stations and a Do Nothing option.

2.1.1.1.2. Project Description

Current Issues

Limebank MTS is currently limited by its transformer capacity. There are currently three 33MVA transformers which limit the station to a 66MVA planning capacity. In order to minimize risk of stranded load at nearby stations Longfields DS, Fallowfield MTS and Leitrim DS, large load transfers to Limebank MTS are scheduled between 2020 and 2022. With the addition of growth from the Riverside South community, the demand forecast anticipates station loading to exceed planning capacity in 2020 at 71MVA and to reach 99MVA by 2030, as shown in Figure 2.1.

Figure 2.1- Limebank MTS Demand Forecast in MVA



Main and Secondary Drivers

The main driver for this project is an N-1 capacity constraint, where the loss of a transformer results in an overload on the remaining transformer. Additional capacity is required in the Limebank supply area in order to meet the growing demand in the Riverside South community as well to provide short term capacity relief in the Nepean South area until the new Cambrian MTS is energized.

Reliability is a secondary driver for this project. Currently, feeder capacity exceeds transformer capacity at the station. As a result, multiple switching operations are required to sectionalize feeders prior to restoring load with multiple backup supplies. Sectionalizing is necessary in order to not exceed the backup supply's transformer limited time rating (LTR).

Performance Targets and Objectives

The objectives of the project are as follows:

- Increase station planning capacity from 66MVA to 99MVA to accommodate short-term load transfers and long-term growth.

- Increase the amount of available feeder capacity by increasing the amount of transformer capacity.
- Reduce outage duration and number of switching operations by reducing the average load supplied by each transformer. Currently, highly loaded feeders must first be segmented before being restored by multiple feeders in order to not exceed transformer ratings at the station.
- Reduce operational costs as a result of fewer switching operations.

Performance targets and objectives addressed by the Limebank MTS T4 Capacity Upgrade project are summarized below in Table 2.1.

Table 2.1 - Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Improve SAIFI/SAIDI
Cost Efficiency & Effectiveness	Resource Efficiency	Labour Utilization	Reduce Labor Allocation to Outage Restoration
System Operations Performance	Levels of Service	Stations Capacity	Reduce Station Transformer Loading Below Planning Capacity
		Feeder Capacity	Increase Usable Feeder Capacity and Reduce Switching Operations

These objectives are aligned with customer expectations to prioritize reliability by ensuring sufficient capacity is available to serve a growing city. Through public consultation, customers indicated that they are in support of Hydro Ottawa proactively investing in system capacity in order to ensure that customers in high growth areas do not experience a decrease in reliability.

2.1.1.1.3. Project Justification

Alternatives Evaluation

Alternatives Considered

Do Nothing

Large load transfers between 2020 and 2022 from Longfields DS, Fallowfield MTS and Leitrim DS are required to minimize overload risk between these stations and to prevent the Limebank station from exceeding N-1 planning limits in 2020. In the event of a transformer loss due to failure or for maintenance, there would be approximately 3 MVA of stranded load in 2020, 8 MVA by 2025 and 34 MVA of stranded load by 2030 during peak loading conditions.

Additional investments will be required to create multiple ties between feeders and segment load within each feeder. Due to the limited size of the existing transformers, feeders will need to be backed up from multiple sources originating from different transformers to remain below the current maximum transformer rating of 33 MVA during N-1 contingencies.

The do nothing option is not considered an acceptable solution, since it would overload existing transformers during contingencies with attendant stranded load, which would not be responsive to customer expectations for reliability, accessibility and overall system resilience.

Load Transfers to Connected Stations

Limebank MTS has distribution ties with Longfields DS, Fallowfield MTS, Leitrim DS and Uplands MTS. Load transfers to adjacent stations were evaluated as an option to meet the growing capacity needs in the Limebank supply area.

- Longfields DS and Fallowfield MTS:
  Both stations are exceeding their planning rating; therefore, load transfers from Limebank are not feasible without investment in additional station capacity at Longfields DS and Fallowfield MTS. Both stations are not scheduled for capacity upgrades, as capacity constraints at these stations will be addressed with the addition of the new Cambrian MTS station in 2022.

- Leitrim DS:
  Leitrim is forecasted to exceed its planning rating in 2019. As such, permanent load transfers to Leitrim MS are not feasible.

- Uplands MTS:

  Uplands MTS is currently a single transformer station (33 MVA) with approximately 7 MVA of remaining capacity. The remaining capacity is not sufficient to significantly defer the need of additional transformation at Limebank. Additionally, load would need to be retransferred to Limebank in the event of transformer failure or station maintenance at Uplands.

  Uplands MTS is in the process of being upgraded to a two 60MVA transformer station, effectively increasing the planning rating to 60 MVA, planned to be commissioned in 2021. Transferring load from Limebank to Uplands would require $9.3M in distribution feeder extensions to create new ties between these stations. However, Uplands station would be above its planning rating by the end of the 20-year demand forecast.

Relocate 33 MVA Transformer from Uplands MTS to Limebank MTS

In 2015, a third transformer was added to Limebank station along with new secondary (27.6 kV) breakers. The project included the installation of secondary breakers to accommodate the addition of a future fourth transformer. The existing transformer at Uplands MTS was manufactured in 2000 and is in good condition. It can be relocated from Uplands MTS to Limebank MTS since it is of equivalent size to the existing transformers at Limebank and will no longer be needed at Uplands once the station is upgraded. Utilizing the relocated transformer mitigates de-recognition cost of the asset ($153,180). Low voltage switchgear at Limebank is already in place, limiting the investment cost associated with this alternative. The cost of adding a fourth transformer is limited to the installation of a high-voltage breaker, transmission connection costs, transformer P&C, oil containment and the relocation costs of the transformer from Uplands MTS.

The addition of a fourth transformer will increase the station’s planning rating in order to accommodate short-term load transfers from the Barrhaven community and remain below planning rating until 2030. If forecasted load at connecting stations do not materialize up to 2030, load transfers to the new Cambrian MTS, Uplands MTS or Leitrim DS will address the capacity need at Limebank. On the other hand, if all load materializes, the capacity need beyond 2030 will be addressed through the renewal of the T1 and T2 transformers at Limebank MTS which will be approaching end of life by 2031.

Evaluation Criteria

As per DSP Section 5.2.2, the evaluation criteria used to review the alternatives included the following:

- Risk Mitigation (Capacity): Satisfy N-1 capacity requirements for immediate load transfers and future load growth
- Cost (Investment Cost): Upgrades must make use of existing infrastructure if possible to minimize investment cost
- Key Performance Indicator Impacts (Reliability): Reliability improvements at Limebank MTS and neighboring stations

Preferred Alternative

The preferred alternative for resolving capacity constraints at Limebank MTS is adding a fourth transformer. This alternative makes best use of the existing infrastructure at Limebank MTS and the existing transformer from Uplands MTS to minimize investment costs.

The ‘Do Nothing’ option is not viable. If no action is taken to address the capacity constraint at Limebank, additional cost and risks related to additional switching operations and large stranded load materialize. In the case of a transformer or bus failure there will be stranded load. The amount and duration of stranded load will continue to increase as forecasted growth is materialized.

A load transfer to connected stations is also not a viable option since the connected stations are currently or forecasted in the near term to exceed their planning rating. In the case of transfers to Uplands MTS station, additional investments would be required in station switchgear and to create feeder ties capable of deferring capacity increases at Limebank.

Relocating the existing 33 MVA transformer from Uplands MTS to Limebank MTS is the preferred alternative since it utilizes existing infrastructure to minimize cost and meets the region’s forecasted demand until 2030. Although the 33 MVA increase does not meet forecasted growth beyond 2030, the upgrade will defer additional investment and allow planning to evaluate if the forecasted growth will be realized over the forecasting study horizon.

Additionally, ties to the new Cambrian MTS will be available by 2030 permitting load transfers which will help defer further capacity investment at Limebank MTS.

Using the evaluation criteria described in Section 1.1.1.3.1.2, the addition of a new transformer at Limebank provides a larger value per dollar when compared to the option to transfer load to Uplands.

Project Scope

The scope of the project includes the following:

- Relocation of the 33 MVA transformer from Uplands MTS to the LMBT4 transformer bay at Limebank MTS. There is no existing oil containment infrastructure for the fourth transformer; therefore, a new installation is required to meet current standards.
- Installation of a new high-voltage breaker and connection to the L2M 115kV transmission supply is required.
- Transformer overcurrent and differential protection is required for the new LMBT4 transformer. Low-voltage bus breakers and associated protection devices were previously installed along with the LMBT3 transformer installation, completed in 2015.

Project Timing & Expenditure

Historical spending for a similar project, the ‘TFX NEW – Leitrim T1 (Island)’, was approximately $6.5M from 2015 to 2018. Although the project also consisted of the addition of a transformer, the Leitrim transformer was newly purchased rather than the relocation of an existing transformer. Additionally, new secondary side 28kV breakers were required for the Leitrim project, whereas there is existing 28kV switchgear at Limebank. Using these adjustments, the total cost of the transformer relocation to Limebank is forecasted at $3.04M.

Table 2.3 - Project Scope Comparison

TFX NEW – Leitrim T1 (Island)	Limebank MTS T4 Cap. Upgrade
Purchase 25 MVA transformer	Relocate 33 MVA transformer
Install two high-voltage air-break switch	Install one high-voltage air-break switch
Install two high-voltage breakers	Install one high-voltage breaker
Construct new transformer oil containment pit	Construct new transformer oil containment pit
Install low-voltage bus tie breaker	
Install two low-voltage bus breakers	
New ground grid, station fence and access route	

The cost of the 'Limebank MTS T4 Cap Upgrade' project is lower due to the reduced scope compared to the Leitrim transformer addition. The majority of the additional cost can be attributed to the cost of purchasing a new transformer and additional bus and transformer breakers.

Table 2.4 - Project Cost Comparison ($'000,000s)

	TFX NEW – Leitrim T1				Limebank MTS T4 Cap. Upgrade				
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total Expenditure	$0.96	$2.94	$2.20	$0.41	$0.03	$0.33	$2.65	$0.03	$0

Benefits

The benefits of the project are described in Table 2.5 below.

Table 2.5 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The upgrade in capacity will reduce the number of required switching operations to restore power or offload feeders, thus reducing switching operation costs. The additional capacity will avoid cycling power outages and associated switching operations due to stranded load during transformer or bus related outages.
Customer	The project provides a short term solution to meet the growing capacity demand in Barrhaven and Riverside South communities and improve reliability. This project aligns with customer expectations to prioritize reliability while servicing a growing city.
Safety	The installation of the LMBT4 will be completed as per Hydro Ottawa standards, and include protection and control upgrades and transformer oil containment.
Cyber-Security, Privacy	N/A
Coordination, Interoperability	Microprocessor protection and control equipment will permit proper device coordination, detailed event analysis and quicker fault detection to minimize equipment damage.
Economic Development	The project enables load transfers from the Barrhaven community and permits forecasted growth within the Riverside community to be serviced without exceeding the Limebank MTS planning rating until 2030.
Environment	A transformer oil containment pit will be installed to avoid adverse environmental impacts of a potential transformer leak.

2.1.1.1.4 Prioritization

Consequences of Deferral

Deferral of the project would not satisfy customer expectations to maintain reliability while finding efficiencies to reduce operating costs. Outage duration, number of switching operations, equipment de-recognition costs and economic growth would be impacted by the deferral of this project. Without additional capacity, load transfers from the South 28kV system will result in stranded load at Limebank MTS in the event of a transformer or bus loss. Outage duration and number of switching operations will increase in order to restore load without exceeding thermal limitations of an individual station transformer. Economic growth may be impacted as a result of constrained capacity.

Priority

The 'Limebank MTS T4 Cap Upgrade' project has a 'High' priority with respect to other initiatives currently being considered or implemented by Hydro Ottawa.

The project is 'High' priority due to the large amount of existing and future customers impacted by the capacity limitations and to the short-term capacity needs to accommodate load transfers from the South Nepean region. The amount of stranded load will increase as part of scheduled load transfers from Barrhaven and growth in the Riverside South community driven by the introduction of light rail transit (LRT).

2.1.1.1.5. Execution Path

Implementation Plan

The plan is to construct and commission the new transformer and high-voltage equipment as per the implementation schedule in Table 2.6.

Table 2.6 - Implementation Schedule Summary

Year	Scope
2019	• Submit Hydro One Connection Impact Assessment CIA) • Submit IESO System Impact Assessment (SIA) • Complete 33% Drawings
2020	• Complete Final Drawings • Begin Electrical and Civil Construction
2021	• Complete Electrical and Civil Construction • Relocate Transformer from Uplands to Limebank • Energization of LMBT4
2022	• Project Closeout (Site Cleanup and As-Builts)

Risks to Completion and Risk Mitigation Strategies

The outcome of Hydro One's Connection Impact Assessment (CIA) and the IESO's System Impact Assessment (SIA) will determine if the project is feasible and if transmission supply upgrades are also required. Unforeseen transmission costs and lead-times are a risk to project completion.

Timing Factors

The time required to obtain approval from Hydro One and the IESO may impact project timing. Additionally, delays in the Uplands MTS station project will consequently delay the Limebank T4 project. One of the two transformers at Upland MTS must be installed prior to removing and relocating the existing 33MVA transformer to Limebank MTS.

Cost Factors

Equipment procurement costs could potentially impact the forecasted budget. The final costs will not be known until the second or third year of the project. Transmission system upgrades identified through the CIA and SIA process may also increase the cost of the project.

Other Factors

N/A

2.1.1.1.6 Renewable Energy Generation (if applicable)

N/A

2.1.1.1.7 Leave-To-Construct (if applicable)

N/A

2.1.1.1.8. Project Details and Justification

Table 2.7 - Limebank MTS T4 Cap. Upgrade Overview

Project Name:	Limebank MTS T4 Cap. Upgrade
Capital Cost:	$3,044,356
O&M:	N/A
Start Date:	2019
In-Service Date:	2022
Investment Category:	Station Capacity Upgrades
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Planning Rating Increase	13,239 customers / 33 MVA
Project Scope	
Add a 4th transformer, transformer protection and one 115kV high-voltage breaker at Limebank station. The transformer will be a 33MVA transformer relocated from Uplands MTS station.	
Work Plan	
The project will begin in 2019, with expected completion in 2022. 2019: SIA and CIA Studies 2020: Engineering, Tenders and Purchase Orders 2021: Construction 2022: Project Closeout	
Customer Impact	
The increase in capacity allows additional customer connections while maintaining a high level of system reliability to existing customers. The increase in station capacity results in improvements in SAIFI by distributing the load among the four transformers thus decreasing customer exposure and SAIDI since less switching operations are required to restore power.	

2.1.1.2. Cambrian MTS

2.1.1.2.1. Project Summary

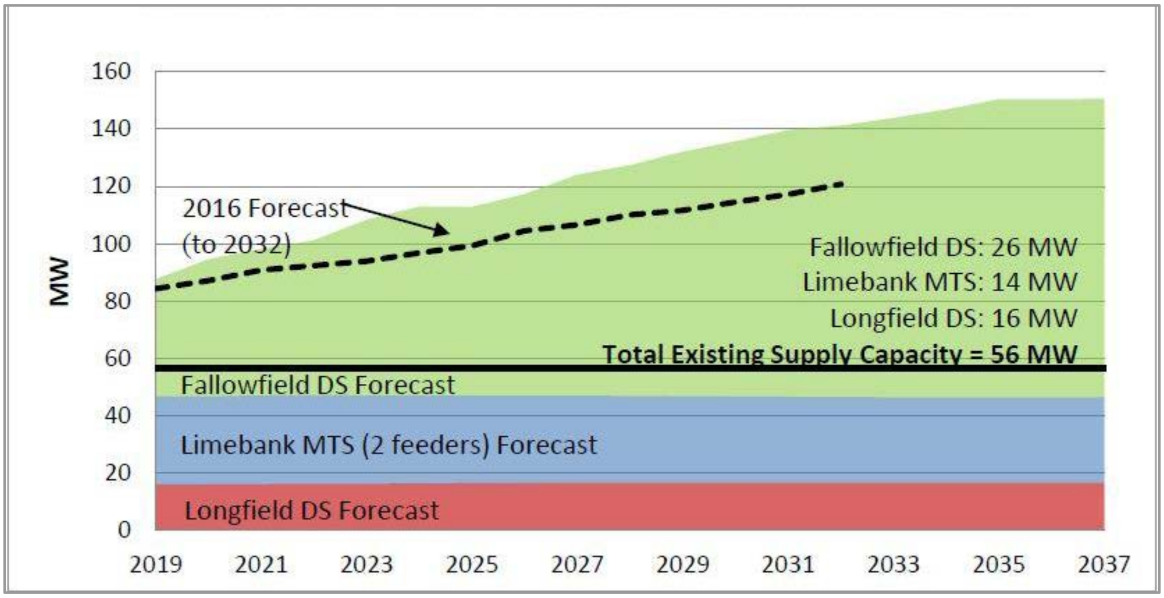
With the south of Ottawa expanding rapidly, there is a need in the short term for additional distribution station capacity. The purpose of this project is to supply upcoming demand increases with the construction of a new 28kV station equipped with two 100MVA transformers. Hydro Ottawa, in conjunction with the Integrated Regional Resource Planning (IRRP) in 2015, identified the need for an additional station in the South Nepean Region to address future capacity deficiencies. The new station will also contribute to improving area reliability by initiating a series of asset replacements and upgrades, and by enabling the creation of feeder ties between the station feeders and existing feeders from adjacent stations. The total cost of this project is divided into stages starting in 2017, with an anticipated commissioning date of Q2 2022. Hydro One is involved in this project due to required transmission upgrades.

2.1.1.2.2. Project Description

Current Issues

The capacity need in the Nepean South area was first established in the 2015 IRRP. Electricity demand has been steadily increasing in the South Nepean area over the last 15 years as a result of regional growth. This strong growth trend is expected to continue going forward, with demand expected to more than double over the next 20 years due to planned residential and commercial development. Based on the South Nepean Planning forecast shown in Figure 1.2, the transformation capacity for the area has already been exceeded.

Figure 2.2 - Forecasted Growth in South Nepean (Demand Net of Conservation and Distributed Generation)



In 2018, the peak demand from Fallowfield station was 47.9 MW, which significantly exceeds the station planning rating decreasing the ability to transfer load during contingency events.

Main and Secondary Drivers

The main driver of this project is a capacity constraint to meet expected increases in area load. The system is currently constrained in the area, and without this project, the ability of the system to provide continuous service delivery could be compromised. Distribution projects are underway to temporarily increase capacity until the New South station is energized to supply the expected growth in this area for the next 20 years.

As a secondary driver for this project, reliability will be improved by creating feeder ties to other 28kV stations, specifically Fallowfield MTS, Longfields DS, Limebank MTS and the new 28kV Richmond South MTS.

Performance Targets and Objectives

The objectives of the project are as follows:

- Increase area station capacity to approximately 180 MW

- Decrease feeder loading by introducing new feeders in the area
- Reduce outage frequency and duration during contingencies by reducing the average load supplied from existing stations and feeders. Currently, highly loaded feeders must be segmented before being restored by multiple feeders in order to not exceed transformer ratings at the station.

Performance targets and objectives addressed by the Limebank MTS T4 Capacity Upgrade project are summarized below in Table 2.8.

Table 2.8 - Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Improve SAIDI and SAIFI
Cost Efficiency & Effectiveness	Resource Efficiency	Labour Utilization	Reduce labor allocation to outage restoration
System Operations Performance	Levels of Service	Stations Capacity	Reduce station loading below planning capacity
		Feeder Capacity	Reduce feeder loading below planning capacity

These objectives are aligned with customer expectations to prioritize reliability by increasing station capacity to service a growing city. Through public consultation, customers indicated that they are in support of Hydro Ottawa proactively investing in system capacity in order to ensure that customers in high growth areas do not experience a decrease in reliability.

2.1.1.2.3. Project Justification

The April 2015 IRRP and the Dec 2015 Regional Infrastructure Plan (RIP) identify the need for new electricity transmission (and distribution) facilities to meet the growing electricity demand in the South Nepean area. In 2016, The Independent Electricity System Operator (IESO) asked Hydro One and Hydro Ottawa to jointly initiate work on a new line and station to meet the near-term and medium-term capacity needs in the South Nepean area of southwest Ottawa. The OEB approved the project in October 2019, through the approval of a joint Leave to Construct application submitted by Hydro Ottawa and Hydro One pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (Decision and Order EB-2019-0077).

Project Scope

The project will involve the following transmission line work by Hydro One:

- Rebuild the existing 115kV single circuit line S7M, an approximate distance of 10.9 km, as a double circuit 230kV line. This section will span between a point along West Hunt Club Road at the current S7M connection point, known as S7M STR 673N JCT, along the current S7M Right of Way to the intersection of Trail Road and Cambrian Road (to be known as “Cambrian Road JCT”).
- Construct a new double circuit line section, an approximate distance of 1.3 km, from Cambrian Road JCT in an easterly direction, to the new proposed MTS. Both circuits on the double circuit line will be connected to the new Cambrian MTS (formerly named South Nepean MTS).
- Connect one circuit on the new line to the 115kV circuit S7M. This circuit will continue to operate at 115kV and supply the three existing 115kV stations of the area. This line’s circuit nomenclature will remain as S7M.
- Connect the other circuit to the 230 kV circuit E34M and operate it at 230 kV.This line’s circuit nomenclature will be E34M.
- Perform necessary protection and control work on circuit S7M and E34M to incorporate the connection of the new MTS.

The Project will involve the following station work by Hydro Ottawa:

- Construct the new Cambrian MTS to be owned and operated by Hydro Ottawa. The new MTS will be connected to both the E34M and S7M circuits and will consist of one 100MVA 230/28kV transformer and one 100MVA 115/28kV transformer. These will supply two 28kV switchgear line-ups with three feeder breakers each. Both transformers will be designed and capable of supplying the entire Cambrian MTS load in the event that one of the circuits is unavailable. Under normal operating conditions, the Cambrian MTS will be supplied via the 230kV circuit. Hydro Ottawa will be the only customer supplied by the new Cambrian MTS.

Project Timing & Expenditure

The proposed in-service date for the project is Q2 2022. Hydro Ottawa started construction the week of November 25, 2019. The total cost of the new Cambrian MTS is expected to be $26.9M. This investment is captured under the Station Capacity Upgrade Program. The transmission cost contributed by Hydro Ottawa for this project is expected to be $50.2M (total transmission cost is $58.8M). Transmission cost is captured under the General Plant Investment Category.

Table 2.9 - Expenditure for Cambrian MTS project

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cambrian MTS	$0	$0.21	$0.19	$2.15	$10.22	$11.91	$2.24	$0	$0	$0
Transmission (CCRA)	$0	$1.49	$0.37	$3.25	$29.08	$16.03	$0	$0	$0	$0

Figure 2.3 - Construction Starting at Cambrian MTS Site

Benefits

The benefits from this project are listed in Table 2.10.

Table 2.10 - Project Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	This project is required to satisfy the upcoming load growth in the South Nepean area. It is an essential system service project to supply area capacity deficiencies. System operation efficiency will be improved by the new station feeders' ability to connect with other existing 28kV feeders in the area. The backup ties will ensure faster restoration times in the event of an outage, as well as the capability to maintain adequate supply in a station contingency scenario. This will contribute to reducing SAIDI, which is important in an area where the overhead distribution system is subject to weather-related outages. Constructing a new station is the most cost-effective solution to provide the required demand.
Customer	This project will achieve two objectives: one supply future demand and second improve reliability in the south of the city. Not only will development projects be given adequate electrical supply, but the new station presents several opportunities to improve the system. This project will contribute to a larger system plan to convert the entire south to a 28kV system, in order to keep up with city development. This larger system plan will provide enhanced capacity and improved reliability to customers in several communities: Barrhaven, Manotick, Riverside South, Richmond and Kanata. The additional feeder ties between stations servicing this region will reduce outage durations and eliminate several radial segments that exist in the current distribution system.
Safety	Building a new station will address the predicted thermal overload of existing feeders and station transformers that will occur in the near future. Overloading the system can lead to equipment damage and safety hazards. This project will mitigate that risk.
Cyber-Security, Privacy	This project does not affect customer privacy or cyber-security. Grid protection will be achieved by designing the new station according to Hydro Ottawa's current standards. This involves providing differential protection to the station transformers, installing a ground grid and breakers. All of these components contribute to protecting both the station and its feeders, in the event of fault currents or other equipment failures.

Benefits (Cont'd)	Description (Cont'd)
Coordination, Interoperability	The new station will be supplied on the high side by Hydro One's 230kV and 115kV transmission systems. The provincial utility has been heavily involved in the development of this project from the beginning, as it requires a new transmission line. Hydro One has completed a Connection Impact Assessment, the results show that the project will improve reliability to area customers and that there will be no adverse impacts on short-circuit levels and voltage performance as a result of the project. The IESO has conducted a System Impact Assessment concluding that the project is expected to have no inverse impact on the reliability of the integrated power system. The project contributes to a longer term plan to address the broader needs across the West Ottawa area.
Economic Development	The additional capacity from the new Cambrian MTS will allow further expansion of residential and commercial developments in the South Nepean area.
Environment	A transformer oil containment pit will be installed to avoid adverse environmental impacts of a potential transformer leak.

2.1.1.2.4 Prioritization

Consequences of Deferral

Deferral of the project would not meet Hydro Ottawa's customer expectations to invest in system capacity in order to ensure that customers in high growth areas do not experience a decrease in reliability. Without additional capacity, stations and feeders in the South Nepean area will exceed their design ratings. Economic growth may be impacted as a result of constrained capacity since new residential and commercial customers will not be able to connect to Hydro Ottawa's distribution system. Outage duration in this area will increase due to the number of switching operations in order to restore load without exceeding thermal limitations of feeders and station equipment.

Priority

The 'Cambrian MTS' project has a 'High' priority with respect to other initiatives currently being considered or implemented by Hydro Ottawa.

The project is 'High' priority due to the large amount of existing and future customers impacted by the capacity limitations. The amount of stranded load during contingencies will increase as forecast demand growth materializes.

2.1.1.2.5. Execution Path

Implementation Plan

To date, the project schedule has proceeded as follows: The HONI study agreement has been completed, as has the Environmental Assessment (EA). The project EA has been approved by the City of Ottawa. Hydro Ottawa's current station design standards were used which minimizes environmental risks with features such as oil containment. The draft Environmental Study Report (ESR) was made available for 45 days for public review and comments between March 12, 2019 and April 26, 2019. The ESR describes the class EA activities that have to be undertaken for the Power South Nepean Project, including a description of the project environmental factors, potential environmental effects and mitigation measures. On October 17, 2019, the OEB granted leave to construct the transmission upgrade required to provide supply to the new Cambrian MTS.

Hydro Ottawa started construction in November 2019 with an expected in-service date of Q2 2022.

This project is being coordinated with other asset replacement and upgrade projects to prepare the entire area for a 28kV voltage conversion. These projects are all interrelated and will involve making connections between feeders to achieve a more reliable system.

The project key milestones are outlined as follows:

- Class Environmental Assessment complete: April 26, 2019
- Federal Section 67 Application Approval: August 30, 2019
- OEB Section 92 Application submission: May 28, 2019
- OEB Section 92 Application Approval: October 17, 2019
- Project construction start date: November 2019
- Project commissioning date: Q2 2022

Risks to Completion and Risk Mitigation Strategies

The construction of Hydro Ottawa's new station is dependent upon the availability of Hydro One's new transmission supply line. Timely completion of the new 230kV transmission line is required in order to energize the new station by Q2 2022.

Risks to Completion and Risk Mitigation Strategies

The construction of the new MTS was expected to start in September 2019; however, due to delays in approval of the Section 92 application the start of construction was delayed until November 2019.

The station is required to be energized before the 2022 summer peak based on capacity limitations to supply forecasted growth.

Cost Factors

The following are the factors that could affect the estimated cost of the project.

Equipment Cost

The equipment cost has been estimated but yet to be purchased, equipment vendors may increase the equipment cost before the final agreements are signed.

Multi- year Project

Like any multi-year project, this project will be subject to inflationary increases in labor costs.

Transmission Cost

Due to the transmission upgrade requirement for the Cambrian MTS project, Hydro Ottawa and Hydro One need to have a Connection Cost Recovery Agreement (CCRA) in place. While the agreement is being finalized, there is a Connection Cost Estimate (CCE) in place of approximately $50.2M. The total cost of the transmission line upgrade for this project is $58.8M.

Other Factors

N/A

2.1.1.2.6. Renewable Energy Generation (if applicable)

Energy Resource Facility (ERF) projects currently have limited distribution feeders to connect to as well as limited feeder capacity available on existing feeders. This is due to Hydro Ottawa's having confirmation of only select station transformers being capable of handling reverse flow. The new station will have reverse flow capability on both transformers, thus increasing the number and capacity of renewable energy generation projects that can be interconnected.

2.1.1.2.7. Leave-To-Construct (if applicable)

The leave to construct application was submitted to OEB on May 28, 2019. The application received OEB's approval on October 17, 2019.

2.1.1.2.8. Project Details and Justification

Table 2.11 - New South 28kV Substation (Cambrian MTS) Overview

Project Name:	New South 28kV Substation (Cambrian MTS)
Capital Cost:	$26,922,469 (plus $50M in CCRA)
O&M:	N/A
Start Date:	2017
In-Service Date:	Q2 2022
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Load Attachment	100 MVA
Project Scope	
Land acquisition and approvals required Complete design and construction of a new 230/115kV to 28kV distribution substation 2 x 100 MVA transformers, protection, oil containment New 230kV transmission supply	
Work Plan	
Land procurement, Detailed Design, Tender of major equipment Station construction – Foundations, oil containment, transformer installation, switches, breakers, switchgear, relays, Protection & Control equipment Commissioning target date - Q2 2022	
Customer Impact	
Available distribution capacity to supply new loads for upcoming developments Reliability improvement associated with replacement of aging assets and equipment upgrades Reduced outage durations with eventual backup supply	

2.1.1.3. Uplands MTS Capacity Upgrade

2.1.1.3.1. Project Summary

The ‘Uplands MTS Capacity Upgrade’ project addresses area station capacity and reliability needs. Uplands MTS is a 115kV to 27.6kV station consisting of a single 33MVA transformer and two distribution feeders. The station currently depends on ties to adjacent stations during station contingency scenarios for planned and unplanned activities. Forecasted growth in the region is expected to reduce transfer capability between stations and exceed the transformer equipment rating, further driving the need for redundancy and capacity within the station. Two new transformers will be installed at Uplands, thereby increasing station capacity and enabling the addition of two new feeders. The existing 33MVA transformer will be relocated to Limebank MTS to address capacity needs at the station transformer level (Limebank MTS T4 Capacity Upgrade Project).

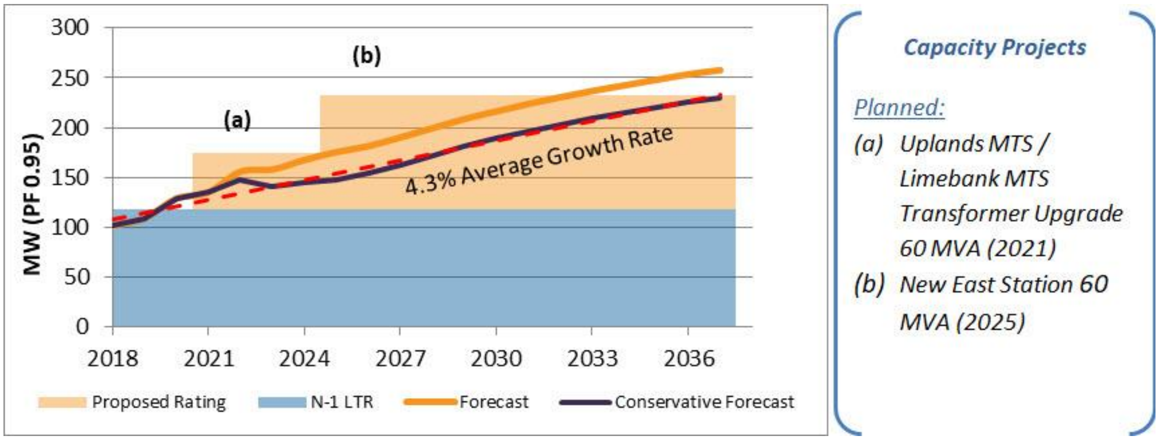
Project cost is estimated at $11.38M with an increase in overall station planning capacity from 33MVA to 60MVA. This capacity upgrade is needed to supply growing demand in this region mainly driven by transit oriented development related to the extension of the LRT Trillium line to the airport. In the near-term, this additional capacity will also relieve capacity constraints at other stations supplying the South East 28kV region such as Leitrim DS and Limebank MTS.

2.1.1.3.2. Project Description

Current Issues

The Uplands MTS is forecasted to exceed its planning rating by 2023. Uplands MTS has a single transformer;therefore, the station's capacity is limited to the remaining capacity on distribution ties to the adjacent Limebank MTS and Leitrim DS stations, each of which are at or above planning limitations. The South East 28kV region is expected to exceed its planning rating by 2020 as shown in Figure 2.4. Significant forecasted growth in the region is expected to increase loading in the South East 28kV region and limit transfer capability between stations in the near-term and long-term.

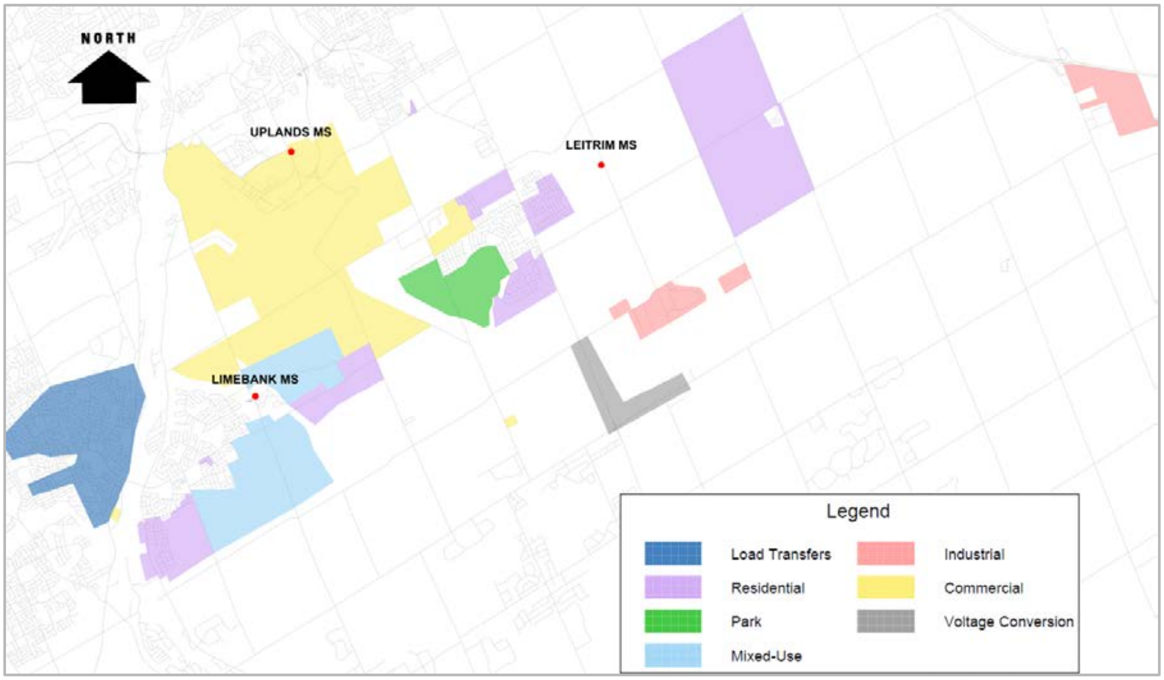
Figure 2.4 - South East 28kV Forecast (Limebank, Uplands, Leitrim)



Load increases impacting Uplands MTS and connected stations are forecasted from a variety of developments, including Light-Rail Transit (LRT) related growth, airport lands redevelopment and several heavy commercial or light industrial customers. The main driver is transit-oriented development related to the extension of the LRT Trillium line to the airport and the Riverside South and Leitrim communities.

Forecasted demand in the near-term will drive new feeder extensions from Uplands MTS to reduce feeder loading below planning limits and to alleviate capacity constraints at Limebank MTS and Leitrim DS. Figure 2.5 shows the forecasted growth pockets in the South East 28kV area.

Figure 2.5 - South East 28kV Growth Pockets



Main and Secondary Drivers

The main driver is capacity constraints, at both the station and distribution level. The station is forecasted to exceed its planning rating by 2023. Forecasted demand for Uplands MTS, Limebank MTS and Leitrim DS will result in distribution feeders exceeding planning capacity and limiting load transferring capability from Uplands MTS in contingency scenarios.

Reliability and future proofing are the secondary drivers for the project. The addition of two feeders permit new distribution extensions to supply forecasted growth while maintaining reliability to customers. The additional breakers will support loading from adjacent stations during contingencies further reducing outage durations.

Performance Targets and Objectives

The objectives of the project are as follows:

- Increase station capacity to accommodate forecasted growth while operating below the planning criteria.

- Increase planning capacity within the South East 28kV region by increasing distribution tie transfer capability between interconnected stations.
- Improve reliability by adding feeder breaker positions. The additional feeder positions will permit feeders to operate below planning limits. As a result, fewer switching operations are required to restore load and outage durations are reduced. Fewer switching operations results in lower operations costs.
- Mitigate potential oil remediation cost by installing transformers within oil containment pits designed to prevent soil contamination.

Table 2.12 - Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Improve SAIFI & SAIDI
Cost Efficiency & Effectiveness	Compliance	Cost Efficiency	Minimize Cost of Project through Labor Efficiencies
	Resource Efficiency	Labour Utilization	Reduce Labor Allocation to Outage Restoration
Asset Performance	Health, Safety & Environment	Oil Spilled	Reduce Oil Remediation Cost
System Operations Performance	Levels of Service	Stations Capacity	Reduce Station Loading Below Planning Capacity
		Feeder Capacity	Reduce Feeder Loading Below Planning Capacity

Project objectives include improving reliability by proactively investing in system capacity that align with customer expectations. Through public consultation, customers identified “ensuring reliable electrical service" as their most important priority. The majority of residential and small commercial customers are in favor of Hydro Ottawa proactively investing in system capacity in order to ensure that customers in high growth areas do not experience a decrease in reliability.

2.1.1.3.3. Project Justification

Alternatives Evaluation

Alternatives Considered

Do Nothing

In the case of the Do Nothing alternative:

- The connection of forecasted developments will result in the Uplands MTS single transformer exceeding rating or will require transfers to Limebank MTS and/or Leitrim DS resulting in those stations operating above N-1 loading limits.
- Distribution feeders will operate above planning limits which will result in additional switching time and cost to sectionalize and restore load during contingencies. Additional load sectionalizing will be required in the short-term and risk of stranded load occurs in the medium-term.
- Forecasted loading is expected to increase station loading and reduce load transfer capabilities. As a result, the ability to perform station maintenance or construction activities will be restricted.

Install two new transformers at Uplands MTS

In the case of adding two new transformers:

- Station loading is independent of distribution tie capacity since additional capacity and redundancy within the station can support full load during contingency scenarios or during station maintenance and construction activities.
- Additional feeder breaker positions permit feeder extensions to supply forecasted demand while remaining below feeder planning limits. Future extensions increase load transfer capabilities between Uplands MTS and adjacent stations.
- The existing 33MVA transformer can be repurposed for the 'Limebank MTS T4 Capacity Upgrade' project, effectively reducing project cost and avoiding asset derecognition.

- Uplands MTS planning rating would increase to 60MVA (10-day limited time rating) rather than be limited to a decreasing distribution tie transfer capability. The increased planning rating is sufficient to supply demand over the 20-year forecasting horizon and accommodate load transfers from connected stations.

Install one additional transformer at Uplands and maintain existing transformer

In the case of adding a single transformer and maintaining the existing 33MVA transformer:

- Additional redundancy within the station results in less distribution tie capacity required to restore station load during contingency scenarios or during station maintenance and construction activities.
- Additional feeder breaker positions permit feeder extensions to supply forecasted demand while remaining below feeder planning limits. Future extensions increase load transfer capabilities between Uplands MTS and adjacent stations.
- Uplands MTS planning rating would be limited to the capacity of the smaller 33MVA transformer rather than the larger transformer unit. The reduced planning rating is insufficient to supply demand over the medium-term and long-term forecasting horizon or accommodate load transfers from connected stations.

Evaluation Criteria

The evaluation criteria included the following:

- Cost (Investment Cost): Capital cost required to meet future demand requirements
- Risk Mitigation (Financial): Deferral of need to a later date with lower capital costs and ability to accommodate economic growth
- Risk Mitigation (Capacity): Capacity or stranded load risks during contingencies
- Key Performance Indicator Impacts (Reliability): Reliability improvements

Preferred Alternative

The preferred alternative for resolving capacity constraints at Uplands MTS is to install two 60MVA transformers and repurpose the existing 33MVA transformer at Limebank MTS.

‘Doing nothing’ does not require any current capital cost, but will result in reliability issues as demand increases beyond the single transformer rating. In the short-term, outage durations and operating costs will increase since feeders will need to be sectionalized in order to complete a staged restoration.

Adding a single 60MVA unit reduces the dependency on distribution ties to provide backup capacity in the short-term since redundancy is added within the station. In the medium-term, as forecasted demand continues to materialize, station loading will exceed planning limitations. Permanent load transfers using distribution ties would increase capacity needs at adjacent stations. To add, the purchase of an additional transformer would be required to address the capacity need at Limebank MTS. In brief, this alternative does not address the medium to long-term needs at Uplands MTS.

Finally, adding two 60MVA transformers and two feeder breaker positions addresses capacity requirements over the 20-year demand forecast. The additional feeder positions increase distribution capacity. As a result, feeders operate within planning limits and eliminate the need for staged restoration with additional feeder sectionalizing operations. Lastly, efficiencies in installing both units simultaneously provide a source of cost savings compared to adding a second matching unit in the future.

Project Scope

The scope of the selected alternative includes the following:

- Completion of an IESO System Impact Assessment (SIA) and a Hydro One Connection Impact Assessment (CIA) to determine the feasibility of increasing station capacity connecting to the 115kV A3RM transmission supply.
- Reinforcement of the high-voltage tapping structure.
- Installation of a new switchgear and P&C building, including the relocation of the existing switchgear and the addition of a new switchgear lineup, to add two feeder breaker positions.
- Installation of new high-voltage switching equipment.

- Installation of two 60MVA (10-day LTR) transformers and transformer oil containment pits.

2.1.3.3.4. Project Timing & Expenditure

The total cost of the Uplands MTS Capacity Upgrade project is $11.38M starting in 2017 and expected to be energized in 2021. Historical spending for a similar project, the "Limebank MTS 3rd Transformer Upgrade" project, was $8.65M from 2012 to 2016. As indicated below, there are several similarities between the "Limebank MTS 3rd Transformer Upgrade" project and the proposed "Uplands MTS Capacity Upgrade" project.

Table 2.13 - Project Scope Comparison

Uplands MTS Capacity Upgrade	Limebank MTS 3rd Transformer Upgrade
• Install Two 115kV Breakers & Disconnects • Install Two 30/40/50/60MVA Transformers • Install New Switchgear & P&C Building • Install Half of Switchgear and Relocate Existing Switchgear lineup	• Install One 115kV Breakers & Disconnect • Install One 20/26/33MVA transformer • Install New Switchgear Building & Separate P&C Building • Install Full Switchgear

The cost of the Uplands MTS project is higher since the transformer is a larger, more costly unit and the scope includes an additional transformer, high-voltage breaker and disconnect switch. Inflated labor and material costs are also contributing factors to the increased budget.

There are efficiencies in installing a second transformer in conjunction with the first unit which makes it more cost effective to install the units under the same project. Additionally, purchasing a second unit for Uplands MTS rather than a new 33MVA unit for the proposed Limebank MTS project provided higher value since the units will be matching in size with other transformers within the station. Matching transformer sizes maximizes the planning capacity of the station.

Table 2.14 - Project Cost Comparison ($'000,000s)

	Limebank MTS					Uplands MTS				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total Expenditure	$1.04	$5.53	$1.68	$0.36	$0.01	$0.09	$1.20	$3.27	$4.96	$1.86

Benefits

The benefits of the project are described in the table below.

Table 2.15 - Project Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The increased capacity allows Uplands MTS to operate below its N-1 planning rating and permits transfers from adjacent stations to alleviate loading constraints. Operating below the planning rating eliminates the additional switching orders required to sectionalize and restore load.
Customer	This project will positively impact customer reliability. The introduction of new feeder breaker positions facilitates an increase in distribution capacity which will be used to reduce feeder loading below planning limits and provide backup capacity to adjacent stations. The increase in station and distribution capacity facilitates new customer connections without adversely impacting current levels of reliability.
Safety	The new station will be built to current design standards for safe working clearances, use modern arc-proof equipment, and introduce remote-operable equipment to improve safety during planned or emergency work.
Cyber-Security, Privacy	This project does not affect customer privacy or cyber-security. Grid protection will be achieved by designing the upgraded station according to Hydro Ottawa current standards. This involves providing differential protection to the station transformers, installing a ground grid and breakers. All of these components contribute to protecting both the station and its feeders, in the event of fault currents or other equipment failures.
Coordination, Interoperability	N/A
Economic Development	This project takes into account existing forecasted growth for the area and provides sufficient capacity to connect future demand.
Environment	Transformers to be installed within oil containment pits to prevent soil contamination in the case of transformer failure.

2.1.1.3.5. Prioritization

Consequences of Deferral

Deferral of this project would negatively impact customer reliability. Forecasted growth is expected to result in Upland MTS and the South East 28kV region exceeding planning ratings. As forecasted growth materializes and planning ratings are exceeded, additional switching orders will be required to sectionalize load prior to restoring power. Outage duration and cost would increase as a result of the staged restoration approach. Distribution investments would also be required to create additional feeder ties to enable staged restorations. Finally, forecasted loading would restrict the ability to perform equipment maintenance activities due to insufficient redundancy within the station and limited distribution tie capacity.

Priority

The “Uplands MTS Capacity Upgrade” project has a high priority with respect to other initiatives currently being considered or implemented by Hydro Ottawa.

The Uplands MTS project priority is driven by the rate of growth anticipated to exceed equipment ratings and reduce transfer capability to adjacent stations, thereby restricting our ability to perform proper station maintenance or restore load during N-1 contingency scenarios.

2.1.1.3.6. Execution Path

Implementation Plan

Implementing this project according to the below key milestones and timeline will be necessary to ensure that sufficient capacity will be available in this area when needed.

Table 2.16 - Implementation Schedule Summary

Year	Milestones
2017	• Engage Electrical/Civil Consultants
2018	• Submit Initial CIA and SIA Applications • Site Preparation
2019	• Equipment Procurement • Civil Construction
2020	• Civil Construction Completion • High-Voltage Side Electrical Completion • Energization of T1 and Switchgear
2021	• Delivery and Energization of T2 and Switchgear
2022	• Project Closeout (Site Cleanup, As-Builts)

Risks to Completion and Risk Mitigation Strategies

No abnormal risks are known at this time.

Timing Factors

Load growth is driving the need for this project. The timing and priority of this project is unlikely to change unless economic development is reduced as a result of a declining housing market or LRT implementation schedule. Given the City of Ottawa's investment into the LRT and the impact of the LRT on residential growth, it is unlikely that the timing or priority level of this project will change.

Cost Factors

The following are the factors that could affect the estimated cost of the project:

Equipment Cost

All major equipment has been purchased or a purchasing agreement has been signed. The cost of all minor equipment that has not yet been purchased is subject to inflation and cost increases due to increases in raw material value.

Multi- Year Project

Multi-year projects are susceptible to increases in labor cost from year to year due to inflation.

Cost Recovery Agreement (CCRA)

Capital contributions to be made to the transmitter for connection costs have not yet been finalized. Connection costs are limited to the cost of implementing protection changes on the transmission system.

Other Factors

N/A

2.1.1.3.7. Renewable Energy Generation

Stations must have reverse flow capability as well as short-circuit and thermal capacity to accommodate large amounts of renewable generation. The new station transformers will be designed with reverse flow capability and with sufficient short-circuit and thermal capacity to accommodate greater amounts of renewable energy generation.

2.1.1.3.8. Leave-To-Construct

N/A

2.1.1.3.9. Project Details and Justification

Table 2.17 - Uplands MTS Capacity Upgrade Overview

Project Name:	9202011956 – Uplands MTS Capacity Upgrade
Capital Cost:	$11,381,382 (2017-2021)
O&M:	N/A
Start Date:	2017
In-Service Date:	2021
Investment Category:	System Service
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Planning Rating Increase	6000 customers/27MVA
Project Scope	
Replace the existing 33MVA transformer with two 60MVA transformers and additional switchgear at Uplands to permit two new feeder breaker positions. The existing 33MVA transformer will be relocated to Limebank MTS.	
Work Plan	
2017: Engage Electrical/Civil Consultants 2018: Submit Initial CIA and SIA, Site Preparation 2019: Equipment Procurement for T1, T2, High-Voltage Disconnects and Switchgear, Civil Construction 2020: Civil Construction Completion, T1 and Switchgear Energization 2021: Equipment Delivery for T2, T2 Energization 2022: Project Closure (Site Cleanup, As-Builts)	
Customer Impact	
Increase in planning capacity permits the connection of new customers. The addition of a transformer permits regular station maintenance, further reducing the probability of failure. The addition of new switchgear permits the use of two new feeders to address customer distribution capacity and reliability needs.	

2.1.1.4. New East Station

2.1.1.4.1. Project Summary

The ‘New East Station Capacity Upgrade’ project addresses area capacity deficiencies and reliability needs in the Gloucester region. Leitrim station’s planning capacity is forecasted to be exceeded due to large industrial and residential growth. Additionally, reliability issues exist as a result of long distribution feeders supplying the edges of Hydro Ottawa’s service territory. The preferred alternative identified through the 2019 IRRP process was to construct a new 230/28kV station. The New East Station addresses the capacity needs over the forecasting period and improves distribution and transmission level reliability in the region. The proposed station will have a 60 MVA planning rating and will be located in proximity to the lie-along L24A 230kV transmission supply.

Project cost is estimated at $24.58M and will increase station capacity in the South East 28kV by 60MVA. This capacity upgrade will supply growing demand in this region, mainly driven by residential and commercial expansion in former rural areas.

2.1.1.4.2. Project Description

Current Issues

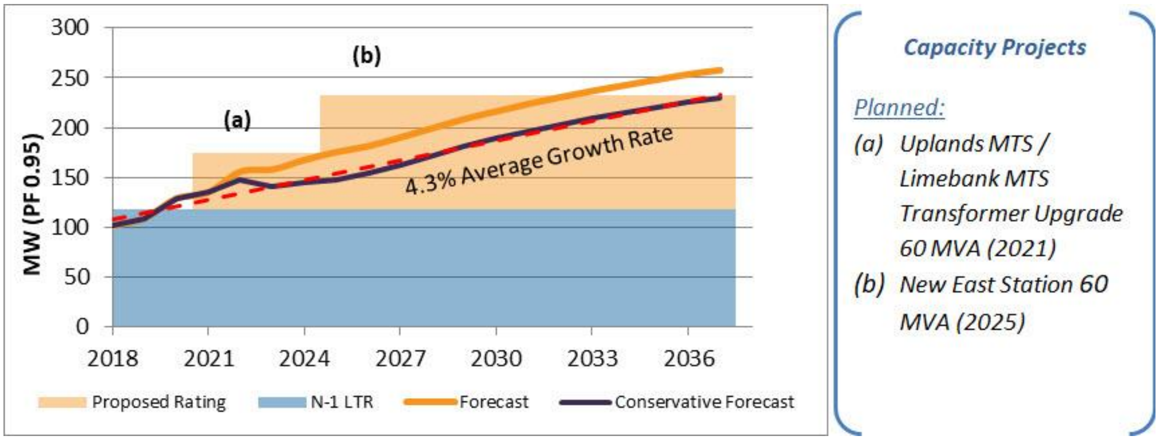
Leitrim DS is a 28kV distribution station supplied by a 44kV feeder from Hawthorne TS. Large forecasted industrial and residential growth in the Leitrim station supply area will result in the station exceeding its planning capacity in 2022 as shown in Table 2.18. Capacity at Leitrim station is limited by two major factors: transformer rating (25MVA) and 44kV supply capacity (39MVA).

Table 2.18 - Leitrim Station Capacity Forecast

	Year	2017	2018	2019	2020	2021	2022	2026	2027	2028	2033	2037
Leitrim DS	Load	18.7	18.7	16.2	20.5	22.3	28.2	35.4	38.1	40.7	50.1	57.8
	N-1 Rating	25	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
	Capacity	39	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
	N-1 %	75%	75%	65%	82%	89%	113%	142%	152%	163%	200%	231%
	Capacity %	48%	48%	42%	53%	57%	72%	91%	98%	104%	128%	148%

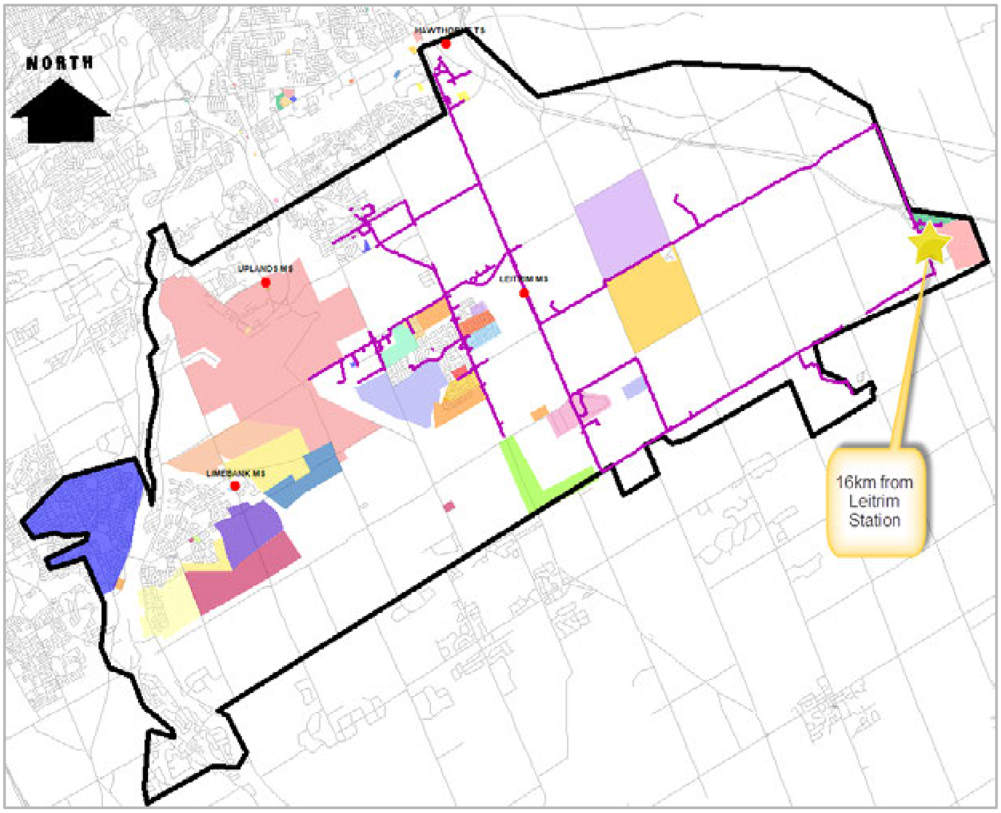
In addition to near-term capacity issues at Leitrim DS, there are medium-term capacity needs in the South East 28kV region. Figure 2.6 shows that the planned upgrades at Uplands MTS and Limebank MTS will provide additional capacity to this region in excess to their forecasted growth until 2026; however, significant investment at the distribution level would be required to deliver available capacity from adjacent stations to the Leitrim supply area. Beyond 2026, further station capacity upgrades will be required in this region to meet planning requirements in the medium to long-term.

Figure 2.6 - South East 28kV Region Forecast (Limebank, Uplands, Leitrim)



In addition to capacity needs, reliability in the Leitrim supply area is also of concern. The distribution feeders extending towards the eastern boundary of Hydro Ottawa's service territory cover a large area which was previously mostly rural with minimal load on these feeders. In recent years, this area has seen an uptake of new commercial and industrial customers driving further expansion of suburban development in former rural areas. The addition of these large loads decrease the tie transfer capacity of the system during contingency scenarios. To add, Leitrim DS is fed from a single 44kV supply and must rely on adjacent stations to resupply load in case of a loss of station supply. Loads east of Leitrim DS cannot be fully restored with ties from Limebank MTS or Uplands MTS due to the distance between the loads and the station breakers. The lack of an alternate source, more local to the load pocket, leads to longer lasting outages.

Figure 2.7- South East 28kV System Growth Pockets



Main and Secondary Drivers

The main driver of this project is capacity constraints; specifically, additional capacity is needed to ensure both regional and station capacity can be served. Leitrim station is forecasted to exceed planning capacity in 2022 after transfers to other stations are exhausted. Capacity in the South East 28kV region is forecasted to be exceeded starting in 2026 when scheduled upgrades at Uplands and Limebank stations are included.

System reliability is a secondary driver. Introducing a new transmission supply voltage (230kV) within the region would increase bulk supply diversity which positively impacts area reliability. The addition of a new source located in the south east corner of Hydro Ottawa's service territory would shorten the length of feeders and increase system flexibility during contingency scenarios.

Performance Targets and Objectives

The objectives of the project are as follows:

- Increase capacity in the region to reduce Leitrim station below its planning rating and accommodate forecasted growth in the Gloucester region over the 20-year forecasting horizon.
- Increase distribution capacity to maintain feeder loading below planning limits. Operating below planning limits prevents the need to perform additional switching operations to restore power in a staged approach and reduces both outage duration and operations costs.
- Prevent forecasted growth from connecting to the 115kV system in order to reserve capacity for growth with Ottawa’s downtown core and defer future transmission capacity investments.
- Reduce SAIFI, SAIDI and CAIDI by introducing a more reliable transmission supply voltage to the region and adding feeder supply diversity.
- Reduce FEMI as a result of reducing feeder length and limiting the fault exposure of individual feeders.

Table 2.19 - Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Improve FEMI, SAIFI, SAIDI and CAIDI
Cost Efficiency & Effectiveness	Compliance	Cost Efficiency	Minimize Investment Cost and Mitigate Against Future Investment Cost
	Resource Efficiency	Labour Utilization	Prevent Labor Allocation Increases to Outage Restoration Effort
System Operations Performance	Levels of Service	Stations Capacity	Reduce Station Loading Below Planning Capacity
		Feeder Capacity	Increase Feeder Capacity

Through public consultation, customers indicated that their most important priority is reliability and the majority of customers support Hydro Ottawa's proactive investment in system capacity upgrades. The objectives of this project thus aligned with customer expectations.

2.1.1.4.3. Project Justification

Preliminary results from the 2019 IRRP identified the need for a new station to meet the growing electricity demand in the Leitrim supply area. A variety of options were evaluated to address the identified capacity need:

- Transmission expansion (e.g. a new or modified transformer station and transmission line)
- Distribution solutions (e.g. transferring demand between transformer stations)
- Distributed energy resources (e.g. distribution connected generation or storage)
- Other demand side options (e.g. energy efficiency measures, demand response, etc.)

Assessment of the options concluded that a new supply station cannot be avoided or delayed by alternate supply means due to the timing and magnitude of growth. Therefore, the IESO will be recommending that Hydro Ottawa proceeds with a plan to build a new 230kV connected supply in the south east part of the City.

The preferred option for resolving capacity constraints at Leitrim DS and in its supply region is building a new 230kV connected station supplied by Hydro One's L24A transmission line. Preliminary connection assessment to the L24A did not identify any reliability or capacity constraints with the proposed connection.

The increase in capacity addresses the forecasted demand over the study period and permits future transfers from adjacent stations to Leitrim to alleviate increased demand on the 115kV system. The level of reliability in the region is improved by adding the 230kV supply. The 230kV system is more reliable than the 44kV system and adding a new voltage level eliminates stranded load in the event the 44kV supply to Leitrim DS is lost or isolated for construction purposes. Reliability due to the existing length of distribution lines and forecasted end of line loads will also be eliminated.

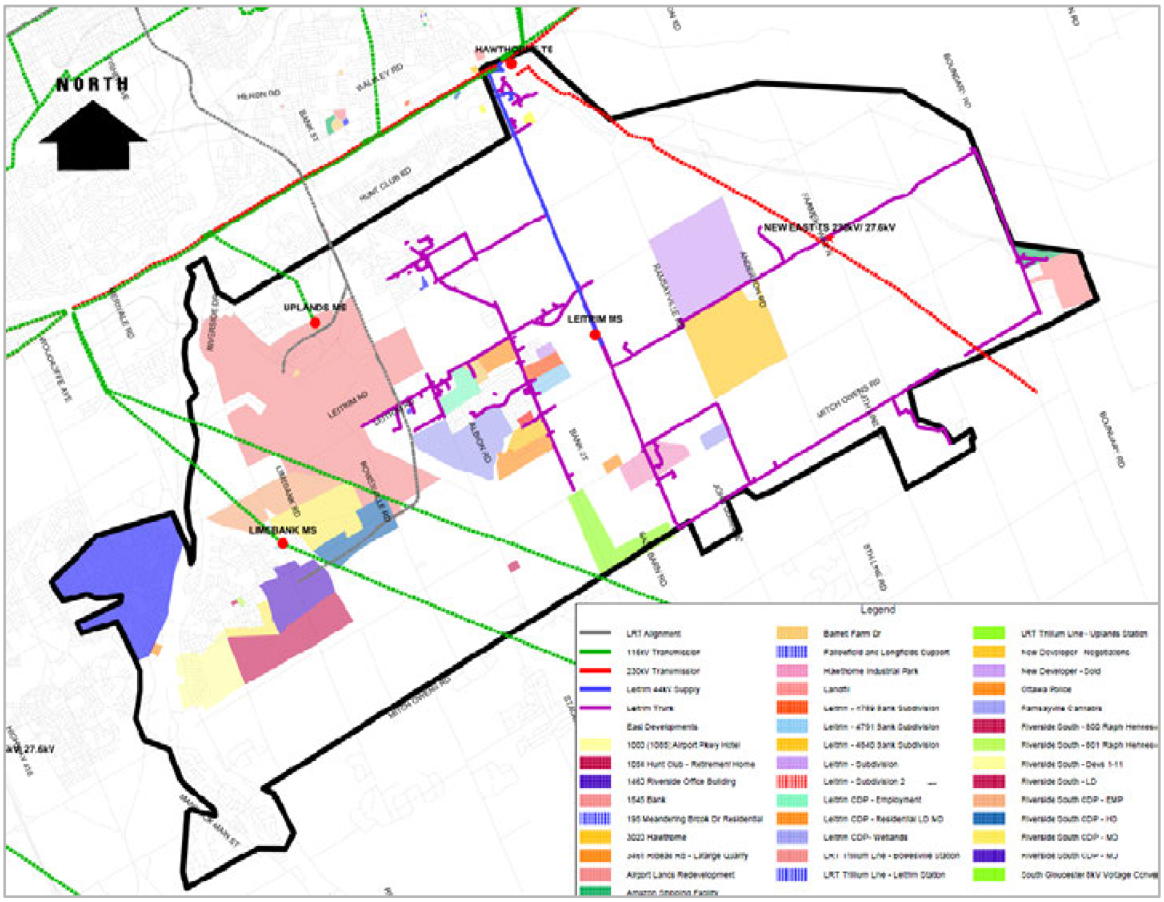
Project Scope

The scope of the project includes the following:

- Completion of an IESO System Impact Assessment (SIA) and a Hydro One Connection Impact Assessment (CIA) to determine the feasibility of connecting a new station to the lie-along L24A 230kV transmission supply and identify any required contribution towards transmission system enhancements.
- Acquisition of property and completion of an environmental assessment.
- Construction and installation of the station transmission supply structures, high voltage switchgear, two 230kV/27.6kV transformers, and low voltage switchgear with 4 feeder positions.

The proposed location of the "New East" station is shown in Figure 1.7 and was based on limiting transmission line extensions while integrating within the existing distribution system. The proposed location minimizes distribution investment by utilizing existing infrastructure and reducing distribution feeder length.

Figure 2.8 - New East 230kV/27.6kV Proposed Location



Project Timing & Expenditure

Historical spending for a similar project, the Terry Fox MTS station, was $23.9M from 2009 to 2016. The cost required to build the New East Station is forecasted to be $24.6M starting in 2021 with a planned station commissioning in May 2025. As shown in Table 2.20, there are several similarities between the Terry Fox station project and the proposed New East Station project. For both stations, cost was minimized by selecting a location with a lie-along transmission supply avoiding extensive transmission line extensions. Connecting to a high capacity transmission supply voltage limits future capacity increases to upgrades within the station fence.

Table 2.20 – Project Scope Comparison

Project	Terry Fox MTS New Station Build	New East Station Build
Technical	230/27.6kV - 2 Transformers 6 Feeders -2 Capacitor Banks P&C Building	230/27.6kV - 2 Transformers 6 Feeders -2 Capacitor Banks P&C Building
Transmission Extension Length	N/A	N/A
Project Surroundings	Mostly Commercial	Rural Residential & Agricultural
Environmental Issues	None	Unknown
In-Service Date	April 2014	May 2025
Total Project Cost	$23,869k	$24,582k

Table 2.21 shows the annual investments required for the New East Station from 2021 to 2025. In addition, $6.1M has been forecasted for transmission cost contributions.

Table 2.21 - Project Cost ($'000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0	$0	$0	$0	$0	$0.51	$2.61	$7.22	$7.46	$6.79
CCRA						$0	$0	$0.10	$3.00	$3.00

Benefits

The benefits of this project are outlined in Table 2.22.

Table 2.22 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The increased capacity allows stations within the South East 28kV region to operate below their planning rating while accommodating forecasted growth. Operating below the planning rating eliminates the additional switching orders required to sectionalize and restore load. Introducing capacity connecting to a lie-along transmission line is estimated to be a more cost effective approach compared to extending multiple 44kV sub-transmission supplies from Hawthorne TS.
Customer	Existing customers will see an increase in reliability due to the increase in capacity, the introduction of a new transmission supply voltage in the region and from the reduction in length of the existing distribution lines. The increase in capacity allows Leitrim DS to operate below planning capacity while accepting transfers from Limebank MTS and Upland MTS. Operating below the planning rating reduces the outage duration by reducing the amount of switching operations required to restore load. The introduction of the 230kV transmission supply increases supply diversity and therefore reliability as well.
Safety	The new station will be built to current standards for safe working clearances, use modern arc-proof equipment, and introduce remote-operable equipment to improve safety during planned or emergency work.
Cyber-Security, Privacy	This project does not affect customer privacy or cyber-security. Grid protection will be achieved by designing the new station according to Hydro Ottawa's current standards. This involves providing differential protection to the station transformers, installing a ground grid and breakers. All of these components contribute to protecting both the station and its feeders, in the event of fault currents or other equipment failures.
Coordination, Interoperability	
Economic Development	This project takes into account forecasted growth for the area and provides sufficient capacity to connect future demand.
Environment	Transformers to be installed within oil containment pits to prevent soil contamination in the case of transformer failure.

2.1.1.4.4. Prioritization

Consequences of Deferral

Deferral of this project would negatively impact reliability. Forecasted growth is expected to result in Leitrim DS and the South East 28kV region exceeding planning ratings. As forecasted growth materializes and planning ratings are exceeded, additional switching orders will be required to sectionalize load prior to restoring power. Outage duration and cost would increase as a result of the staged restoration approach. Distribution investments would also be required to create additional feeder ties to enable staged restorations.

Priority

New South Station has a higher priority as planning ratings are currently being exceeded and are affecting reliability during peak periods. The New East Station project is of lower priority since the planning rating is not currently exceeded. However, planning ratings are forecasted to be exceeded at Leitrim DS is the short-term and in the South East 28kV region in the medium-term.

The New East Station project's priority is driven by the number of customers and load impacted, including large developments forecasted for the area, and reliability impacts placed upon existing customers through new connections due to the planning ratings being exceeded.

2.1.1.4.5. Execution Path

Implementation Plan

Implementing this project according to the below key milestones and timeline will be necessary to ensure that sufficient capacity will be available in this area when needed.

Table 2.23 - Implementation Schedule Summary

Year	Milestones
2021	• IESO SIA • HONI CIA • Conditional Land Procurement • Class Environmental Assessment
2022	• Consultation and Engineering
2023	• Equipment Procurement • Construction – Phase 1 (Civil)
2024	• Construction – Phase 2 (Electric)
2025	• Construction – Completion • Station Commissioning • Project Closeout

Risks to Completion and Risk Mitigation Strategies

The construction of Hydro Ottawa's new station is dependent on the feasibility of connection to Hydro One's L24A 230kV transmission line. Feasibility of the connection and any required conditions to be met prior to connection will be stated in the IESO's SIA and HONI's CIA reports. General feasibility was discussed as part of the IRRP study group and no major risks were identified.

Risks related to land procurement include whether the land can be purchased at an acceptable price and that land use for the property is approved through a Class Environmental Assessment. Multiple properties will be evaluated to create competitive purchasing costs and have a backup location in case the preferred site fails the Class EA.

Timing Factors

Load growth is the primary driver for this project. The timing and priority of this project is unlikely to change unless economic development is reduced as a result of a declining housing market or LRT implementation schedule. Given the City of Ottawa's investment into the LRT and the impact of the LRT on residential growth, it is unlikely that the timing or priority level of this project will change.

Another factor affecting timing would be delays in land acquisition since the property owners have not yet been engaged.

Cost Factors

Land cost

Although the preferred location to build the New East Station has been identified, the property owners have not yet been engaged. The cost of the property will be determined in year 1 of the project.

Equipment Cost

The equipment cost has been estimated but yet sent for RFQ, equipment vendors may increase the equipment cost before the final agreement is signed. Vendors may increase the cost as a result of inflation and increased material value.

Multi- year project

Multi-year projects are susceptible to increases in labor cost from year to year due to inflation.

Cost Recovery Agreement (CCRA)

Capital contributions to be made to the transmitter for connection costs have not yet been finalized; however, it has been estimated to be $6.1M based on similar historical projects. Connection costs are typically determined after the completion of system impact assessments to ensure project feasibility before connection.

Other Factors

N/A

2.1.1.4.6. Renewable Energy Generation (if applicable)

Stations must have reverse flow capability as well as short-circuit and thermal capacity to accommodate large amounts of renewable generation. The new station transformers will be designed with reverse flow capability and with sufficient short-circuit and thermal capacity to accommodate the connection of large amounts of renewable energy generation. Transformer impedance and grounding reactors will be evaluated during the station design phase.

2.1.1.4.7. Leave-To-Construct (if applicable)

N/A

2.1.1.4.8. Project Details and Justification

Table 2.24 - New East Station Capacity Upgrade Overview

Project Name:	9202014282 - New East Station Capacity Upgrade
Capital Cost:	$24,581,996 (plus $6.1M estimated for CCRA)
O&M:	N/A
Start Date:	2021
In-Service Date:	2025
Investment Category:	System Service- Capacity Upgrades
Main Driver:	Capacity
Secondary Driver(s):	Reliability
Customer/Planning Rating Increase	7462 customers/60 MVA
Project Scope	
New 230kV/27.6kV 2x30/40/50 (LTR-60MVA) station to address load growth in the south east corner of Hydro Ottawa's service territory.	
Work Plan	
2021: Complete environmental assessment and System Impact Assessment 2022: Engage consultants and begin procurement 2023: Complete procurement and begin construction 2024: Complete construction 2025: Project closeout (Site Cleanup, As-Builts)	
Customer Impact	
Capacity will increase by 60MVA in the area. The capacity increase allows Leitrim station to remain below planning capacity allowing full load restoration without stranded customers. Customers will experience fewer outages due to the reduction in feeder length. Spare capacity permits new customer connections.	

2.1.1.5. Riverdale TS Switchgear Capacity Upgrade

2.1.1.5.1. Project Summary

The 13kV switchgear at Riverdale TS is planned to be upgraded over the period of 2022 to 2026 at an estimated cost of $12.11M. This project is required to increase feeder and bus capacity to 137MVA and meet forecasted growth. The Riverdale TS 13kV switchgear upgrades align with other known future needs and will take into account opportunities for capacity upgrades from Hydro One owned equipment.

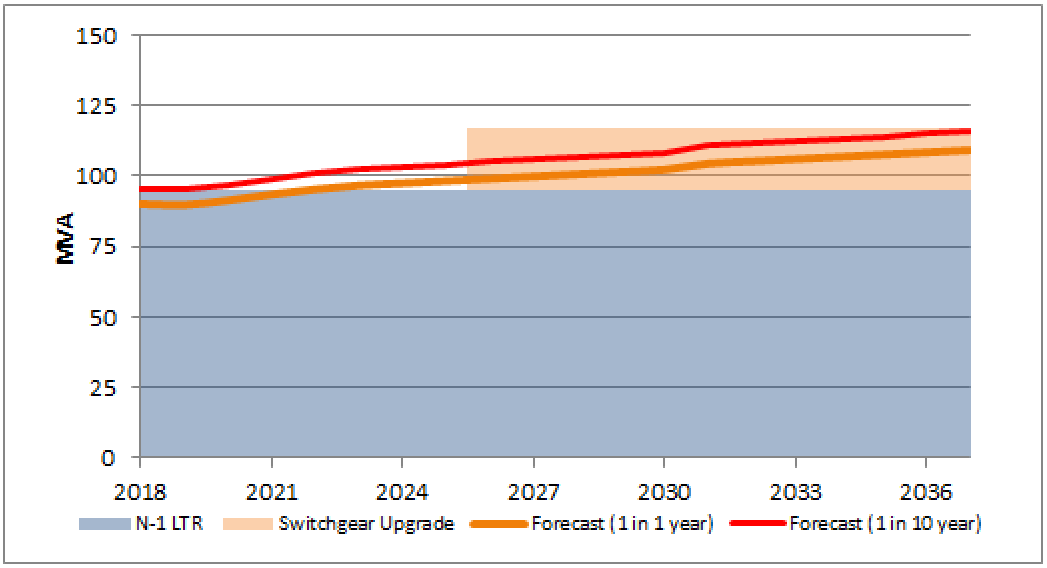
2.1.1.5.2. Project Description

Current Issues

Capacity at Riverdale TS is limited by two main factors: the 13kV switchgear bus rating (2000A) and insufficient availability of spare feeder breakers to supply future developments or new system ties. There are currently 22 feeder breakers at Riverdale TS, all of which are currently in use. Additionally, feeders at Riverdale TS station are approaching their feeder planning rating due to the absence of spare feeder breakers from which to supply new growth. There is only approximately 2.7MVA of unassigned planning capacity remaining at the feeder level using existing configurations. Taking into account hairpinned breakers supplying dual-load feeders, the feeders at this station exceed their planning rating by approximately 3MVA.

Demand growth is driven from a variety of developments, including Light-Rail Transit (LRT) related growth. These developments include high-density mixed-use buildings adjacent to the Hurdman and Lee’s LRT stations, urban intensification around TD Place and Greystone Village high-density residential load.

Figure 2.9 - Riverdale TS Demand Forecast (MVA)



As shown in Figure 2.9, transformer capacity is sufficient to meet forecasted demand; however, the switchgear is limiting as there are no spare breakers from which to extend new load circuits.

Forecasted demand increases in the near-future will require multiple new feeder extensions from the Riverdale TS switchgear breakers that currently supply existing customers. The majority of the existing feeders with remaining ampacity below their planning rating are either backing up the demand of another feeder or system of feeders, or have load allocated from known developments. The remaining feeders with available capacity are not located within the expected load growth areas. This will result in some feeders requiring to be hairpinned feeders (two feeders supplied from one breaker). Two hairpinned feeders supplying load is not a standard practice, the typical configuration is one backup and one load circuit connected to the same breaker. In the case of two feeders supplying load, faults on one feeder would cause outages on both, resulting in a larger number of customers impacted by outages. This decreases reliability for existing and future customers and introduces additional constraints for system operators.

Main and Secondary Drivers

The main driver for upgrading the Riverdale TS 13kV switchgear is capacity constraints at both the station and distribution level. At this time, the station has no available breakers from which to extend new supply feeders - existing distribution capacity is either committed or forecasted to be used in the short to medium term. Hydro Ottawa has determined that the upgrades to the bus ampacity and number of feeder breakers will allow the station to support future upgraded transformers when replaced.

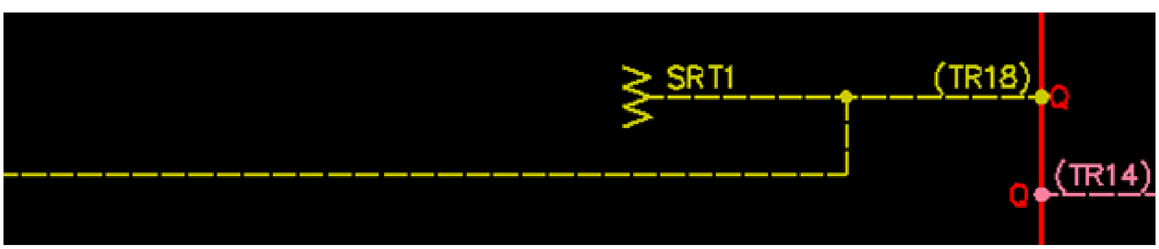
A secondary driver for upgrading the Riverdale TS 13kV switchgear is improving reliability. Several existing breakers are hair pinned to supply load on two connected feeders, which does not align with Hydro Ottawa's typical configuration. The addition of new breakers will allow these configurations to be removed.

Performance Targets and Objectives

Hydro Ottawa employs key performance indicators for measuring and monitoring its performance. With the implementation of the Riverdale TS 13kV switchgear, improvements are expected in the following measurements :

- Feeders exceeding planning rating by Increase distribution and station breaker capacity to accommodate forecasted growth
- Defective Equipment SAIFI, SAIDI CAIDI through elimination of dual-load circuit hairpins. Increase reliability by eliminating existing hairpin breaker configurations; for example: Riverdale DS (13/4kV) transformer ingresses (see Figure 2.10). The existing 13kV feeder breakers must balance overcurrent protection for the 4kV transformers and feeder overcurrent protection. This compromises protection for both scenarios, and decreases the coordination ability to sectionalize faults. Removing these configurations allows for protection to align with internal guidelines and optimal configurations, thereby improving customer reliability.

Figure 2.10- TR18 Breaker Supplying SRT1 13/4kV Transformer and Supply Feeder



- Account for future transformation upgrades by increasing the bus and feeder breaker capacity to match a planning rating of 137MVA. This planning rating is based on typical Hydro One transformer limited time ratings (LTR) for recent or upcoming installations in the Ottawa region (e.g. King Edward T3 is rated at approximately 135MVA LTR). This allows for additional transfer capability from other stations during N-1 contingencies or planned maintenance.

2.1.1.5.3 Project Justification

Alternatives Evaluation

Alternatives Considered

The alternatives considered for increasing capacity at Riverdale TS are detailed below:

Do Nothing

In the case of the Do Nothing alternative:

- Connecting new developments beyond existing forecast will require hairpin feeder extensions from breakers supplying existing load
    - Limited options are available on existing feeders as those with available capacity are not located adjacent to projected growth areas
    - This will result in a reduction in reliability due to a system fault resulting in additional customer outages
- There will be an increased risk of stranded load during bus-outages due to mismatched capacity between bus-pairs; J-bus has six (6) feeder-breakers and an emergency-bus tie to Y- bus, which only has five (5) feeder-breakers.
- There will be an increased fault exposure at six (6) existing hairpin breakers, two supplying 13/4kV transformers and a sub-transmission feeder; protection settings cannot be optimized for both operational scenarios. Details on costs and benefits can be seen in Table 1.22 below.

Load Transfers to Connected Stations through Existing Feeder Ties

Riverdale TS has feeder ties to the following stations: Albion TS, Ellwood MTS, Carling TS, King Edward TS, Lisgar TS, Overbrook TS, Russel TS, and Slater TS.

One tie to Slater TS (TR2TS) is capable of transferring load reliably for long periods at a time; however, it also provides backup through a hairpin to Lisgar TS through feeder TL7TS. All other ties are only capable of load transfers during emergencies or contingency scenarios. This is due to the feeder ties being either dedicated backups for several feeders, or the backup supply is connected to a hairpin already supplying permanent load.

New Feeder Ties

New feeder ties from surrounding stations to existing Riverdale TS loops would free up existing breakers for new load feeder extensions. However, the new feeder extensions would also require backup, potentially from another station due to the lack of available breakers at Riverdale TS. This alternative would require three new feeder extensions to improve distribution capacity. The location of Riverdale TS on Main Street between the Rideau Canal and the Rideau River, relative to other nearby stations such as Overbrook TS and Slater TS, still requires large extensions to make inter-station ties.

One new tie between Riverdale TS and Slater TS is currently planned, with the primary driver being reliability. A secondary benefit is new transfer capabilities at Riverdale, but the breaker availability issues remain.

Upgrade Secondary Switchgear (Riverdale TS Switchgear Capacity Upgrade)

Upgrade the existing secondary switchgear lineup to increase capacity, improve reliability and allow future transformer capacity upgrades.

- Upgrade J, Y, Q & Z buses to 3000A
- Install eight (8) feeder breakers per bus (32 total)
- Install protection and control equipment that meets existing standards, with updated settings consistent with new internal guidelines.

This alternative would allow for all existing dual-load circuit hairpin configurations to be eliminated, allowing all existing load and backup circuits to be supplied from a dedicated breaker, with the exception of two (2) existing load and backup hairpinned breakers at Riverdale TS, which aligns with the typical configuration. This would permit the extension of new load circuits from breaker supplying backup circuits, and provide two (2) unused breakers for to supply future demand, adding approximately 18MVA of feeder planning capacity to the station.

The additional breakers also provide options for long-term load transfers or intra-station ties, specifically to Overbrook TS, which can be used to diversify supply in the northern region of the East 13kV system, which relies exclusively on Overbrook TS at this time.

Evaluation Criteria

Evaluation criteria for the preferred alternative included the following:

- Capital cost required to meet future demand requirements
- Does a lower-cost alternative solve short-term need and allow deferral of higher-cost alternatives?
- Capacity or stranded load risks during contingencies
- Reliability improvements

Preferred Alternative

The preferred alternative for resolving capacity constraints at Riverdale TS is upgrading the secondary switchgear with additional breakers and higher ampacity buses. While ranking the lowest of all alternatives with respect to total cost, the other alternatives do not provide a long-term solution to the existing and future capacity, breaker availability, and reliability issues. Upgrading the secondary switchgear has the highest value to cost ratio among the alternatives.

'Doing nothing' does not require any capital cost, but will result in customer connection and reliability issues as demand increases beyond the breaker planning ratings when taking into account existing system limitations and ties. Additional hairpin breakers where both feeders supply load customers will adversely impact reliability.

A long-term load transfer through the TR2TS tie to Slater TS is feasible; however, it does not address the underlying issue of breaker availability for new feeder extensions. This would also prevent using the Slater breaker, TS54, to transfer load from Lisgar TS. This breaker is expected to require load transfers during the existing forecast period as growth exceeds the Lisgar TS station planning rating. Since this alternative is only possible for one existing tie, the load transfer option is not a viable solution.

Finally, the secondary switchgear upgrade alternative will remove all existing issues with respect to breaker availability, allow for bus loading to be rebalanced, and upgrade the protection and control equipment to current standards. As well, Hydro Ottawa-owned assets at the station would be future-proofed with respect to potential Hydro One-owned equipment upgrades.

Project Scope

The scope of the preferred alternative includes the following:

- Replacement of the existing 13kV buses (J, Y, Q & Z) at Riverdale TS with 3000A rated bus, including emergency-buses consistent with the existing switchgear configuration. The existing station building has insufficient space for four new metalclad switchgear lineups, both in terms of physical limitations and complying with existing standards for clearances and safe working areas. Outdoor switchgears, similar to those used in the recently completed Woodroffe TS project (completed 2018), are proposed in the Riverdale TS station yard.
    - Additional work includes new cable connections between the station transformers and the upgraded switchgear. New underground civil structures as necessary for cable routing, and outdoor switchgear foundations. New fencing will also be introduced at the site, requiring an expansion of the grounding grid.
- Installation of eight (8) feeder-breakers per bus, 32 in total, each rated to 1200A. This represents an increase of six (6) breaker positions. One breaker from each bus will be used as a tie to the emergency-bus of the paired switchgear lineup (JY & QZ in the current configuration) as exists today.
- Upgrade the existing protection at Riverdale TS station to current standards, including electronic relays, RTUs, and battery upgrades.

Project timing & Expenditure

Historical spending for a similar project, the “Woodroffe TS 13kV SWG Replacement”, was approximately $11.80M from 2015 to 2019. While the main driver for the Woodroffe TS project was asset renewal rather than capacity, the scope is similar:

- Replacement of four (4) 13kV bus lineups
  - 2000A at Woodroffe TS (to align with load growth forecasts)
  - 3000A at Riverdale TS
- New 1200A feeder breakers
  - Seven (7) per bus at Woodroffe TS, 28 total
  - Eight (8) per bus at Riverdale TS, 32 total
- Upgrade protection and control equipment to current standard

The existing electronic relays at Riverdale TS have not reached end-of-life; however, retro-fitting and relocating the units in the new switchgear lineups was determined to have a higher cost, both financially and from an outage scheduling and isolation perspective. New relays could be installed and commissioned before transferring existing load feeders over to the new lineup, reducing isolation times and coordination requirements; this is not possible when reusing existing relays.

After internal consultations with stakeholders, it was determined that the best course of action would be to install new relays at Riverdale TS, while keeping the existing relays as spares for failed or end-of-life relays at stations within the service territory.

As shown below in Table 2.25, the Riverdale Switchgear Upgrade is planned to commence in 2022 with expected energization in 2025. This is in line with the existing forecast for TOD developments around the Lees and Hurdman LRT stations, as well as continued growth in Greystone Village. The total cost of the Riverdale TS Switchgear is estimated to be $12.11M for 2022-2026.

Table 2.25 – Riverdale TS Switchgear Cost Estimate ($'000,000s)

	Historical: Woodroffe TS			Bridge: Woodroffe TS		Test: Riverdale TS				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$4.68	$3.41	$2.50	$0.06	$0	$0	$1.24	$3.10	$5.33	$2.16

Benefits

Key benefits that will be achieved by implementing the Riverdale TS switchgear capacity upgrade project are summarized in Table 2.26.

Table 2.26 – Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	This project removes all hairpins where both feeders carry load, and reduces the overall number of hairpinned breakers from six to two, by adding six (6) additional feeder breakers at Riverdale TS. This will reduce operating restrictions during outages with fewer instances requiring complicated or abnormal switching orders.
Customer	This project will have a positive impact on customer reliability. All customers supplied by Riverdale TS will benefit from new station equipment, as well as updated protection settings. Customers supplied from hairpinned breakers with load on both feeders will have reduced feeder exposure to system faults, and protection settings can be optimized for specific loading scenarios (i.e. normal sub-transmission feeder vs. 13/4kV station supply).
Safety	The new station switchgear will be built with current standards for safe working clearances, use modern arc-proof equipment, and introduce remote-operable equipment to improve safety during planned or emergency work.
Cyber-Security, Privacy	N/A
Coordination, Interoperability	N/A
Economic Development	This project takes into account existing forecasted growth for the area, and provides a reasonable margin, equivalent to 20% of existing transformation capacity, for undetermined future developments or HONI upgrades. The additional breakers at the station will allow for system expansions into new developments and additional ties to adjacent 13kV stations, such as Overbrook TS.
Environment	N/A

2.1.1.5.4. Prioritization

Consequence of Deferral

Existing and future customer reliability would be impacted by deferral of this project. Capacity using typical configurations (one load feeder per hairpinned breaker), which result in improved reliability, has almost been reached at Riverdale station, with approximately 2MVA remaining; however, new customers can be connected from a bus and transformer capacity basis. Feeder load rebalancing is not possible at this time as most feeders below the planning rating have reserved capacity for backup of other 13kV feeders or 13/4kV substations, or are isolated from new growth areas. Switching and operations for transferring or restoring load will become more complex and regular bus or breaker maintenance will put larger loads and customers into abnormal system configurations than under typical circumstances. O&M costs, safety and economic development are not expected to be impacted by deferral.

Priority

The Riverdale TS switchgear capacity upgrade project has a medium priority with respect to other initiatives currently being considered or implemented by Hydro Ottawa.

Capacity projects, such as the King Edward TS transformer upgrade or the New South station, have a higher priority as planning ratings in the respective areas are currently being exceeded and are affecting reliability during peak periods. The Riverdale TS project is not as high a priority as capacity is still available at the transformer and breaker level; however, the use of this capacity will result in a reduction of customer reliability.

Major station asset renewal projects, such as switchgear or transformer upgrades, are of similar priority with respect to Riverdale, depending on asset condition.

The Riverdale project’s priority is driven by the number of customers and load impacted, large developments forecasted for the area, and reliability impacts placed upon existing customers through breaker availability for new connections. With the existing switchgear configuration, all new feeders required to connect customers will use a hair pinned breaker supplying two load feeders.

2.1.1.5.5. Execution Path

Implementation Path

The current plan is to construct and commission the new switchgear lineups while maintaining the existing configuration in service. Each bus will then be transferred over to the new line-up one feeder at a time.

Hydro Ottawa best practices dictate that primary and back-up supply feeders should not be connected to the same station bus, as this eliminates N-1 redundancy for a bus outage. By transitioning the station one bus and feeder at a time, keeping recall times low, additional outage risk will be minimized to customers while each circuit or breaker is out of service.

Risks to Completion and Risk Mitigation Strategies

Coordination with Hydro One is required for re-connecting supply feeders at the Hydro One/Hydro Ottawa ownership demarcation. There are also timing and cost risks associated with doing civil construction in the winter. Both risks can be mitigated through project scheduling and early consultations with identified stakeholders.

Timing Factors

Several critical customers are supplied from Riverdale TS, including Carleton University, the Ottawa Hospital Riverside Campus, and the Ottawa Hospital General Campus. Each of these customers are supplied from multiple feeders and station buses. Coordinating circuit outages with these customers will be a key factor for project scheduling and timelines. Load growth, as monitored through development progress and forecasting, must also be taken into account.

Cost Factors

Equipment procurement costs have the largest potential impact to the forecast budget; these will not be known until the end of the first year of the project due to timelines for procurement bids to be submitted.

Other Factors

As Riverdale TS is a shared-site with Hydro One, their input will be required during the project for access, coordination of existing and future work or expansions, and isolations or outage coordination.

2.1.1.5.6. Renewable Energy Generation (if applicable)

N/A

2.1.1.5.7. Leave-To-Construct (if applicable)

N/A

2.1.1.5.8. Projects Details and Justification

Table 2.27 – Riverdale TS Switchgear Capacity Upgrade Overview

Project Name:	9202013598 - Riverdale TS Switchgear Capacity Upgrade
Capital Cost:	$12,111,833 (2022-2026)
O&M:	N/A
Start Date:	January 2022
In-Service Date:	December 2025
Investment Category:	System Service - Capacity Upgrades
Main Driver:	Capacity Constraint
Secondary Driver(s):	Reliability
Customer/Planning Rating Increase	9,395/26MVA
Project Scope	
Replace 13kV switchgear lineup at Riverdale TS station with new outdoor 13kV switchgear lineup rated at 3000A. New switchgear lineup will require 7 breakers for feeders on each bus as well a breaker for a bus tie. Includes cable extensions to reconnect Hydro One supply feeders to the upgraded switchgear, additional civil as required for new cable routing, updated fencing for the site and an expanded ground grid. Protection and control equipment will be upgraded, and will be commissioned with new settings aligned with updated protection guideline.	
Work Plan	
The project will begin in 2022, with expected completion in 2026. 2022: Procurement process begins for switchgear, 33% completion milestone for civil and electrical design 2023: Procurement process begins for remaining minor equipment, 66% and Complete Design milestones, Begin Civil construction, Final payments for switchgear 2024-2025: Complete Civil and begin Electrical construction 2026: Final stages of construction and closeout	
Customer Impact	
Customers should see no impacts to reliability during the project, as the existing switchgear lineups will be decommissioned in phases to minimize time with reduced redundancy. When completed, the project will increase capacity for the area to accommodate future growth and maintain or improve reliability through improved protection equipment and settings.	

2.1.2. DISTRIBUTION CAPACITY UPGRADES

2.1.2.1. Program Summary

The prioritized projects under the ‘Distribution Capacity Upgrades’ program alleviate short- to long-term feeder capacity constraints within the Hydro Ottawa distribution system. They are primarily focused on supporting the addition of new station capacity through new or upgraded infrastructure and/or reconfiguration of the existing system.

The planned distribution capacity upgrades align with the station capacity upgrade recommendations in the 2015 IRRP and the on-going 2019 IRRP. Additional distribution capacity is required to compliment proposed station capacity increases in the South Nepean, Leitrim and Bilberry regions, and to reduce system constraints in the Kanata North region.

In total, Hydro Ottawa plans to invest an estimated $20.7M in distribution capacity upgrades in the 2021-2025 rate period compared to a historical spending of $19.9M in the 2016-2020 period. Hydro Ottawa expects to add over 180MVA in feeder planning capacity to the distribution system as a result of these projects.

2.1.2.2. Program Description

2.1.2.2.1. Current Issues

The planned projects under the ‘Distribution Capacity Upgrades’ program from 2021-2025 address several issues: adding distribution capacity to match new station capacity, reducing demand on existing feeders to below planning ratings, enabling forecasted growth with reduced system expansion requirements for customers, and deferring more expensive alternatives, such as new station builds.

The needs for the major areas, as identified through the 2015 and 2019 IRRPs, requiring distribution capacity upgrades are summarized below.

South Nepean – New Station

The South Nepean 28kV supply region has seen steady growth over the past decade, with demand doubling over that period. A new station (Cambrian MTS) in the area, as recommended in the 2015 IRRP, is planned for energization in 2022. This will add 100MVA of station capacity for the region, relieving existing stations and feeders which are above planning ratings and enabling forecasted commercial, high-density residential and suburban developments over the next 20 years.

The intended location of the new station requires distribution upgrades to connect six (6) new 28kV feeders to the existing system. These new feeders are needed to add distribution capacity equal to the new station capacity, which the existing system cannot accommodate.

Leitrim - New Station Egress and Conductor Upgrades

The South East 28kV supply region has seen an increase in demand due to large residential growth and mixed commercial and industrial developments. A new station in the area, as recommended in the 2019 IRRP, is planned for energization in 2025. This will add 60MVA of station capacity for the region, relieving existing stations and feeders which are forecasted to exceed planning ratings in the short-term and increase transmission level reliability to customers located in the south east corner of Hydro Ottawa's service territory. Additionally, the increase in capacity enables the connection of forecasted commercial, industrial and suburban developments over the next 20 years.

The intended location of the new station requires distribution upgrades to integrate two (2) new 28kV feeders within the existing distribution system in 2025. Two additional feeders are expected to be extended from the new station beyond 2025 and will be driven by forecasted developments.

In addition to the new station feeder extensions, conductor upgrades along Rideau Rd and Bank St are required to increase feeder capacity. The increase in conductor size will allow the feeder to support forecasted growth while providing backup capacity during contingencies without exceeding its thermal rating.

Kanata North - Distribution Capacity

The Kanata North 28kV supply region, consisting of the supply areas for Kanata MTS (230/28kV) and Marchwood MTS (115/28kV), has experienced steady growth over the last several years. The Kanata North 'Tech Loop', made up of high-tech businesses and large commercial customers, has seen large additions and upgrades to existing buildings in the past five years. New residential developments, as planned in the Kanata North Community Design Plan (CDP), are under construction or forecasted from 2020-2030.

With Marchwood MTS and Kanata MTS above their respective planning ratings, and several feeders at or above planning ratings, a long-term capacity solution is required. As determined through on-going discussions in the 2019 IRRP, a new station in the area is needed in the medium-term. Feeder extensions relieving capacity constraints in the Kanata North area or providing additional capacity will be required to allow for deferral of the new station timeline beyond 2025.

Bilberry MTS - Station Renewal

Renewal of Bilberry MTS, as recommended from the on-going 2019 IRRP, will require the addition of two feeder breakers to the station lineup. Feeders from these breakers will supply forecasted residential growth, future LRT stations from the Stage 2 Confederation Line expansion and high-density, mixed-use Transit Oriented Developments (TODs).

The extension of two new feeders from Bilberry MTS into these growth areas will bring existing feeder demand below planning ratings, and reduce station loading at Orleans TS to below planning ratings. This will maintain or improve reliability for existing customers, specifically outage duration through reducing switching operations necessary to restore load.

2.1.2.2.2. Main and Secondary Drivers

The main driver for projects under this program is a capacity constraint at either the feeder or station level. Extensions of existing or new feeders can be used to (1) transfer load from one station to another, alleviating both feeder and station limitations, (2) add new capacity into an area with committed growth, or (3) add back-up capacity to allow additional growth on existing load feeders.

Areas identified through the IRRP working group that are above planning ratings and associated feeders are listed below:

- South Nepean: FAL02, FAL03, 7F1, LMBF7
- Kanata North: MWDF1, MWDF2, MWDF3, MWDF4, 6241F1, 624F2, 624F5, 624F6
- Leitrim: LTM02 (forecasted)
- Bilberry MTS: 77M6, 325M8

Needs identified in the IRRP include short-term station capacity constraints in South Nepean, Leitrim and Kanata North, and medium-term capacity needs in the Bilberry supply region.

The secondary driver for projects under this program is Reliability. Bringing feeders and stations below planning ratings reduces system constraints and provides additional options to System Operators when isolating outages and restoring load.

2.1.2.2.3. Performance Targets and Objectives

The objectives of the project are as follows:

- Increase distribution feeder capacity across Hydro Ottawa service territory by approximately 180MVA from 2021-2025 to reduce the number of existing feeders above planning rating and provide additional capacity in regions with significant forecasted growth
- Reduce outage duration and number of switching operations by reducing the average load supplied by feeders to below planning ratings. Currently, highly loaded feeders must be segmented before being restored by multiple feeders in order to not exceed asset equipment ratings

Table 2.28 - Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Improve SAIDI and CAIDI
Cost Efficiency & Effectiveness	Resource Efficiency	Labour Utilization	Reduce Labor Allocation to Outage Restoration
System Operations Performance	Levels of Service	Stations Capacity	Reduce Station Loading Below Planning Capacity
		Feeder Capacity	Reduce feeder load below Planning Capacity
		Feeder Capacity	Increase Usable Feeder Capacity

All proposed projects under the program address one or more Key Performance Indicators (KPI) used by Hydro Ottawa to measure system performance and efficiency, including increasing feeder capacity.

2.1.2.3. Program Justification

2.1.2.3.1. Alternatives Evaluation

Alternatives Considered

Kanata North:

Do Nothing

The 'Do Nothing' alternative will result in several feeders within the Kanata North region being unable to accommodate new customer connections in the short- and medium-term forecast period. Station-level demand may also prevent future customer additions to Marchwood MTS in the short-term as shown in Table 2.29 .

Table 2.29 - Kanata North Stations forecasted Loading Levels (Do Nothing Option)

Transformer	Load (MVA)	Station Load (MVA)	Station Planning Cap (MVA)	Station Planning Cap Load %	Station Rating (MVA)	Station Rating Load %
TFXT1	36.3	88.6	90	98%	180	49%
TFXT2	52.4					
MWDT1	42.1	76.4	33	232%	66	116%
MWDT2	34.3					
624T1	43.0	76.8	54.2	142%	108.4	71%
624T2	33.8					

Existing customer reliability will decrease as the majority of feeders within the region will be above planning rating. This will make restoration more difficult and longer due to additional switching operations required to reconfigure the overall system to accommodate isolation and redistributed load.

New Kanata North Station and Associated Distribution Feeder Upgrades

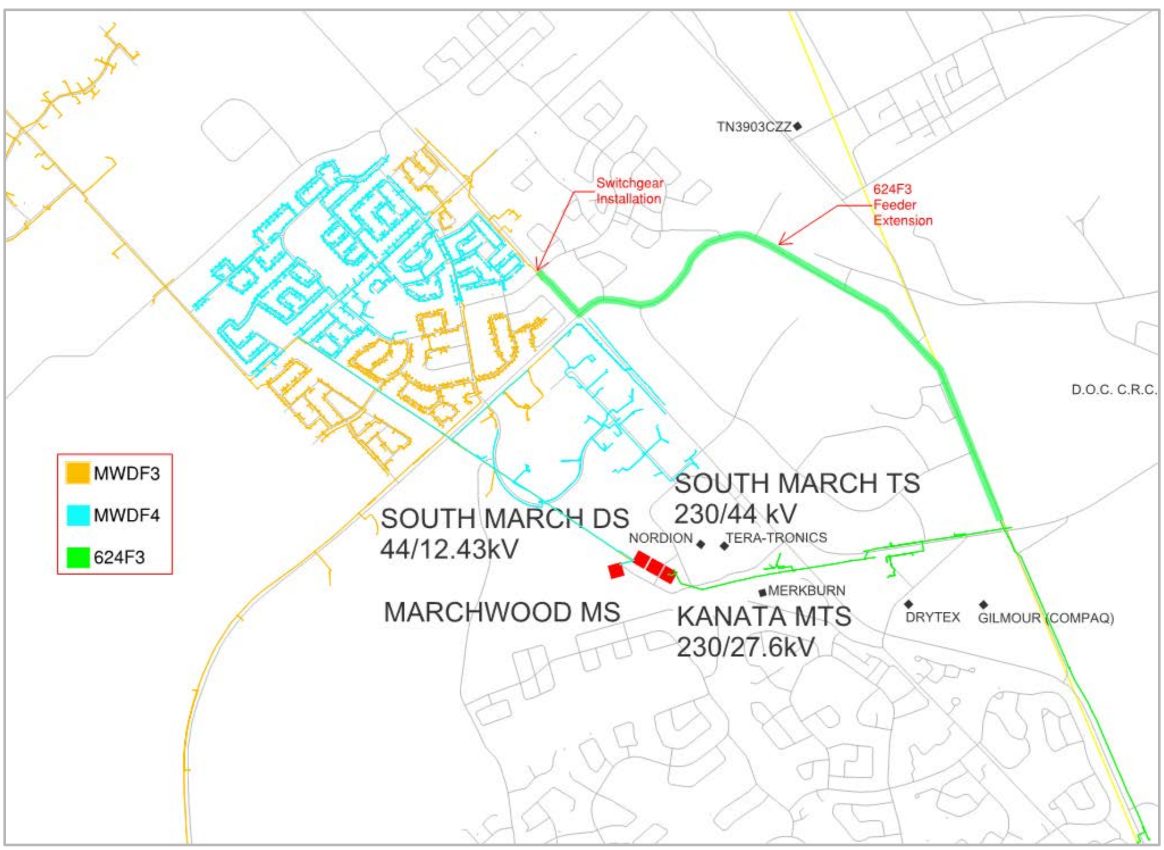
This alternative addresses capacity constraints at both the feeder and station levels. A 60MVA (LTR) station would be added in the Kanata North area, located near the planned Kanata North Community Design Plan (CDP) residential development. Four new 28kV feeders would be extended from the station to connect with the existing 28kV system consisting of feeders from Kanata MTS and Marchwood MTS. The new feeders would (1) supply the forecasted demand from the new Kanata North community, (2) reduce loading on existing feeders within the Kanata North supply region and (3) add new capacity for intensification within the Kanata 'Tech Loop' and new customer connections.

Preliminary results from the IRRP indicate that a new station is required to address the capacity requirements by the end of the study period. Transmission assessments for connecting the new station in the Kanata North region resulted in reliability and voltage issues in connecting to the existing transmission grid. Potential transmission upgrades were evaluated requiring significant investments on the transmission system; however, the evaluation was put on hold since the IESO is currently conducting a network assessment of the 230kV system in western Ottawa to be completed in 2020. Results from that assessment will affect the connection requirements for the new station; thus, this will be evaluated in the next IRRP cycle and short term solutions will be put in place to minimize reliability risks and capacity constraints as described in Option 3. Hydro Ottawa will continue to monitor demand growth in the Kanata North area and request to initiate the next regional planning cycle earlier if deemed necessary.

Deferral of New Station and Distribution Upgrades to Mitigate Capacity Needs

This alternative proposes extending existing feeders with available capacity from Kanata MTS to the supply areas of feeders currently above planning ratings. Load would be transferred to reduce or eliminate load above planning limitations and provide additional capacity within those areas. The proposed extension is shown below in Figure 1.9.

Figure 2.11 – Proposed Kanata North Distribution Upgrades



Transfers through reconfiguration of the existing system connections would be leveraged to transfer demand from Kanata North to Terry Fox MTS, which has capacity available in the short- to medium-term while developments in its supply area of Kanata South continue to develop. This leverages existing station capacity to defer the need for the New Kanata North station. Table 2.30 shows forecasted loading levels for Terry Fox MTS, Kanata MTS and Marchwood MTS. All stations will be above the planning rating but maintained below station design rating as a temporary measure until the new station is built. Under station contingency scenarios, there will be available back-up feeders capable of carrying the excess load from any of the stations.

Table 2.30 - Kanata North Stations forecasted Loading Levels (Distribution Upgrades Option)

Feeder	MVA	Station Load (MVA)	Station Planning Capacity (MVA)	Station Planning Capacity Load %	Station Rating (MVA)	Station Rating Load %
TFXT1	46.3	101.8	90	113%	180	57%
TFXT2	55.5					
MWDT1	21.9	50.3	33	152%	66	76%
MWDT2	28.4					
624T1	51.0	87.1	54.2	161%	108.4	80%
624T2	36.1					

This alternative requires typical costs expected for distribution feeder capacity upgrades, and takes advantage of ties within the existing system, which are very low cost (O&M) with respect to upgraded infrastructure.

Leitrim

Do nothing

As identified through the 2019 IRRP, the proposed site for the new station will have two (2) existing lie-along 28kV feeders once open points are reconfigured. These will be resupplied from the new station upon energization. Two future feeders will be extended once forecasted load is realized.

While this option meets the objectives to increase capacity and reliability in the region, conductor limitations restrict the transfer capability to and from adjacent stations during contingency scenarios.

Feeder Capacity Upgrades

This alternative includes integrating the new station within the existing distribution system but also includes upgrading conductor along Rideau Rd and Bank St. The conductor upgrades will replace existing overhead 3/0 aluminum conductor with 556 MCM aluminum conductor to increase the nominal feeder capacity by 10 MVA and emergency feeder capacity by 18 MVA. The increase in feeder capacity permits the connection of forecasted load while enabling load transfers during contingencies. Poles will be replaced in conjunction with the conductor upgrades to renew end of life poles while framing new poles to accommodate future feeder extensions from the new station.

South Nepean

Do Nothing

The proposed site for the new station, located on Cambrian Road, west of Highway 416, has two (2) existing lie-along 28kV feeders from Fallowfield MTS. These will be resupplied from the new station upon energization.

While this option, involving no capital expenditures, would provide additional distribution capacity into two of the growth areas within South Nepean (CitiGate Business Park and Barrhaven South CDP), it would be insufficient beyond the short-term.

Total distribution planning capacity would include two feeders from Fallowfield MTS, limited to 25MVA by the station transformer ratings, and two feeders from the new station loaded to the planning rating of approximately 16MVA each, for a total of 57MVA of distribution capacity. This will be insufficient within 1 or 2 years after energization, and prevents full use of the planned capacity at the new station (100MVA), reducing the value to customers of a significant capital investment.

Feeder Capacity Upgrades

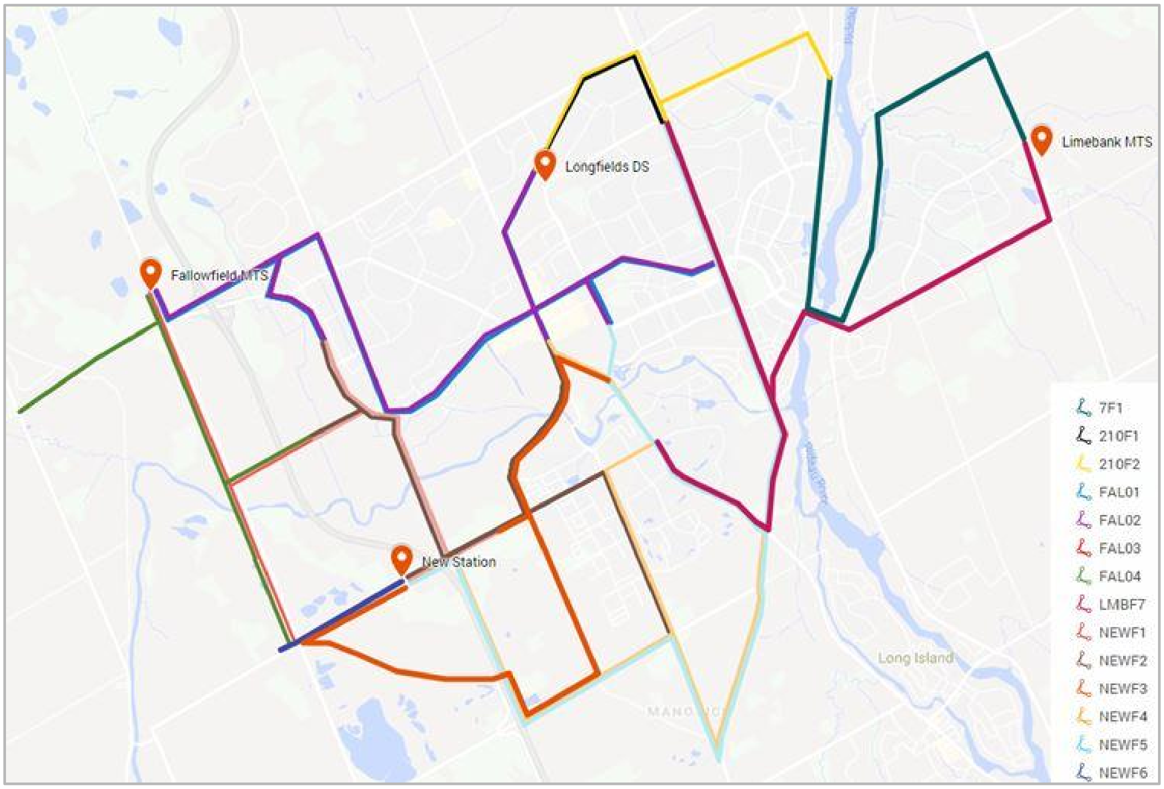
Several projects, including upgrades to existing underground crossings of Highway 416, new overhead lines along Borrisokane and Barnsdale Road, and upgrading existing overhead lines on Cambrian Road and Trail Road, will create distribution infrastructure for six (6) new feeders from the new station.

The routing adds feeder capacity from the new station to all three major developments, creates ties to Fallowfield MTS and Limebank MTS for initial and future load transfers, and will bring four (4) feeders within the supply region below planning ratings.

Feeder Capacity Upgrades and Ties to Adjacent Stations

This alternative includes the feeder upgrades mentioned above, and adds two interstation ties between the New South Station (230/28kV) and the upgraded Richmond MTS (115/28kV). The Richmond Village supply territory, which has historically been 8kV, is isolated from the surrounding 28kV systems in Kanata South and South Nepean. A distribution tie between Kanata South and Richmond is under construction to provide redundancy for the single-transformer Richmond MTS during N-1 contingencies, specifically a loss of the transformer or secondary buss. Figure 1.10 shows the planned configuration for the new feeders from the new Cambrian MTS station and feeders from Longfields DS and Fallowfield MTS.

Figure 2.12– Proposed Cambrian MTS Feeder Configuration



Additional ties to the New South station will provide redundancy for the full planning rating of Richmond MTS (50MVA), add redundancy for the New South station during maintenance or contingencies, and enable long-term 8kV to 28kV conversion plans within the Moodie Road-Old Richmond Road region between South Nepean and Richmond Village.

Bilberry

Do Nothing

As determined through the 2019 IRRP, Bilberry MTS (Hydro One owned station) will be refurbished by 2023 and included in the scope is the addition of two extra breakers to accommodate forecasted growth in the Bilberry supplied area. With no distribution capacity upgrades for the 30MVA of growth forecasted over the next 20 years in South Orleans, as well as future LRT stations and TOD-related growth, forecast demand would be placed on existing feeders. At least 60% of the forecasted growth is expected to materialize by the end of 2025. Forecasted demand would place feeders currently below planning ratings above these limits, and exacerbate feeders currently exceeding planning rating (352M8, 77M6).

Orleans MTS Distribution Capacity Upgrades

Distribution capacity for forecast growth, if not available from Bilberry MTS, would be required from Orleans MTS, the closest alternative supply. Station planning ratings would be exceeded if the forecast growth for the Bilberry supply area were added to Orleans MTS. In order to support two additional feeder breakers, expected growth in the South Orleans area the following station upgrades would be required, as determined by the IRRP:

- Upgrade incoming transmissions feeds to Orleans MTS, currently 115kV & 230kV, to dual-230kV
- Upgrade existing 115kV lineup to 230KV (transformers, primary switchgear, etc.)
    - Equipment was recently installed, significant depreciation costs would be incurred

Feeder egress upgrades would also be required to accommodate the two new feeders.

Bilberry MTS Distribution Capacity Upgrades

Extend two new 28kV feeders from additional breakers at the upgraded Bilberry MTS. This will address capacity needs forecasted in the medium-term to exceed feeder planning ratings. Residential demand forecasted for Orleans MTS will be transferred to Bilberry MTS, preventing the Orleans MTS from exceeding planning ratings. LRT and related growth along the transit corridor will also be accommodated without exceeding planning ratings.

Minor Feeder Capacity Upgrades

Minor feeder capacity issues are found during annual system reviews, where the previous year’s peak demand is evaluated for individual feeders and station-class transformers. The majority of feeders above planning ratings are located in the regions experiencing station capacity-related constraints, and are being addressed through the projects discussed above.

Most feeders experiencing capacity issues outside of these areas are either approaching or slightly above planning ratings. Under this proposed spending alternative, Hydro Ottawa would proactively address capacity constraints in these areas for forecasted developments. During the first year investment would be focused on upgrades to Albion feeder (2206), Nepean feeder (AB02) and Limebank feeder (LMBF3).

Intensification impacting the capacity and reliability of a given subsystem, such as increased infiltration of electric vehicles, heat pump installation, and larger home service sizes, would be addressed through this program. At present, these forms of intensification within established areas do not pose risks; however, as they become more common they will need to be addressed.

Evaluation Criteria

The spending alternatives were compared based on whether they address the following requirements:

- Does the alternative meet the needs as determined by the 2015 IRRP and the on-going 2019 IRRP?
- Does the alternative address feeders above planning rating, and other related KPIs?
- Does the alternative proactively upgrade distribution capacity in areas approaching planning ratings with forecasted growth?

Preferred Alternative

The preferred alternatives for each identified need are listed in Table 2.31 along the investment requirements for both major and minor distribution capacity projects.

Table 2.31 - Distribution Capacity Upgrades Selected Alternatives ($'000,000s)

Need	Selected Alternative	Investment level 2021-2025
Kanata North	Temporary deferral of new Station and distribution upgrades to mitigate capacity needs	$3.79
Leitrim	Feeder capacity upgrades and ties to adjacent stations	$5.14
South Nepean	Feeder capacity upgrades and ties to adjacent stations	$4.83
Bilberry	Bilberry MTS Distribution Capacity Upgrades	$3.30 (+$TBD in Hydro One contributions)
Minor Feeder Capacity Upgrades	Minor Capacity upgrades in targeted areas	$3.67

The selected alternatives complement planned station capacity upgrades, accommodate temporary deferral of larger capital investments and address the capacity limitations across targeted areas in Hydro Ottawa's service territory.

Program Scope

The four major needs summarized in Section 2.1.2.2.1, which were identified through the 2015 IRRP and the on-going 2019 IRRP, are the main drivers for projects under the Distribution Capacity Upgrades Program. Specific feeders exceeding planning ratings identified through annual system reviews will also be addressed through the Minor feeder Capacity Upgrades program.

The overall scope of the program consists primarily of distribution upgrades that (1) complement station capacity upgrades, (2) eliminate or reduce the number of feeders exceeding planning ratings or approaching equipment ratings and (3) defer more costly capital projects.

Capacity constraints introduced by existing customers requiring service upgrades or new customer developments are considered out-of-scope. System Access projects, as deemed financially and operationally expedient, will be developed on a case-by-case basis to address these needs.

2.1.2.3.2. Program Timing & Expenditure

Historical spending for Distribution Capacity Upgrades (including the Line Extension Program which was previously under Distribution Enhancements Program) was $19.9M from 2016 to 2020. The forecast expenditure for 2021-2025 is $20.7M which is in alignment with historical spending.

Table 2.32 - Distribution Capacity Upgrades Program Historical and Forecast Expenditure ($'000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$1.50	$3.70	$2.91	$5.22	$6.61	$2.86	$3.61	$4.25	$5.01	$5.01

2.1.2.3.3. Benefits

The benefits obtained through the Distribution Capacity Program are listed in Table 2.33.

Table 2.33 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Eliminate or significantly reduce the number of feeders and stations operating above planning rating. This simplifies switching operations to restore outages as equipment emergency ratings allow two circuits under the planning rating to be supplied by a single circuit for contingencies during peak demand.
Customer	Customers should see similar or improved performance for reliability, specifically outage duration (SAIDI), due to reduced switching requirements to restore load.
Safety	N/A
Cyber-Security, Privacy	N/A
Coordination, Interoperability	Projects under this program support station capacity upgrades identified through the 2015 IRRP and the on-going 2019 IRRP.
Economic Development	The extension of new circuits enabled by these projects will support forecast growth for the short- and medium-term in most cases. Additional circuits extended into the existing systems will make service connections more accessible and lower costs for development in lie-along areas that previously lacked trunk distribution infrastructure.
Environment	N/A

2.1.2.4. Prioritization

2.1.2.4.1. Consequences of Deferral

As all of the projects under the program address system capacity constraints, the main consequences for deferral are reliability, specifically outage duration, and growth constraints for new development.

In cases where feeder planning ratings continue to be exceeded, additional time is required to sectionalize the feeder to permit transfers to backup feeders, thereby increasing outage duration. Exceeding station planning ratings increases the risk of stranded loads during contingency scenarios where a transformer or bus is out of service.

Finally, when demand exceeds the planning ratings of either feeders or stations to the extent that reliability risks are exacerbated beyond acceptable limits, additional developments may need to be delayed until existing demand is reduced, either through transfers or asset upgrades.

2.1.2.4.2. Priority

South Nepean

The distribution capacity upgrade projects required to connect the New South station with the existing 28kV system have a 'High' priority with respect to other initiatives currently being considered or implemented in Hydro Ottawa's expenditure plan.

As these projects are required to enable the full value of the new Cambrian MTS, which is a critical capital investment with deadlines for meeting forecast demand, they should be completed ahead of most planned and non-emergency work. The Cambrian MTS is planned to be energized by Q2 2022.

Kanata North

Planning ratings for feeders and stations in the supply region are currently being exceeded and are affecting reliability during peak periods. Feeder loading also complicates servicing new customers by requiring additional load transfers to balance demand in order to avoid increasing connection costs excessively through unnecessary system expansions.

Leitrim

The distribution capacity upgrade projects required to connect the New East station with the existing 28kV system have a 'High' priority with respect to other initiatives currently being considered or implemented by Hydro Ottawa. Conductor upgrades along Rideau Road and Bank Street are required to support forecasted load while enabling load transfer during contingencies. The conductor upgrades are of 'Medium' priority compared to other considered or implemented by Hydro Ottawa since the project addresses a short-term need rather than an immediate concern.

As these projects are required to enable the full value of the New East Station, which is a critical capital investment with deadlines for meeting forecast demand, they should be completed ahead of most planned and non-emergency work. The New East Station is planned to be energized by Q4 2025.

Bilberry

Distribution capacity investment in the Orleans community is of ‘Medium’ priority compared to other projects considered by Hydro Ottawa as feeder planning ratings in the Orleans community are forecasted to be exceeded in the medium-term as a result of large residential growth, Light-Rail Transit systems and transit-oriented growth.

The project is to be completed in coordination with the Hydro One renewal of Bilberry TS station which is expected to reach end-of-life in 2023 as identified through the 2019 IRRP.

2.1.2.5. Execution Path

2.1.2.5.1. Implementation Plan

Preliminary timelines for the needs addressed through this program are as follows:

South Nepean

- 2021 – Upgrade existing, and construct new, overhead lines on Trail Road, Borrisokane Road and Barnsdale Road.
- 2022-2023 – Create ties to Richmond South MTS

Kanata North

- 2021-2022 - Transfer loads through available feeder ties as required based on forecasted projects materializing
- 2023-2025 – Complete distribution expansions to upgrade Kanata North capacity including,
    - Complementing load transfers through existing system that will be performed earlier
    - Feeder egress cable upgrades to support transfers during contingency scenarios
    - Installation of remote controllable switches to minimize outage duration

Leitrim

- 2021 – Complete distribution capacity upgrades for radial 28kV feeder in South-East Leitrim pocket as temporary capacity relief measures
- 2023-2025 – Complete distribution upgrades for integration of New East Station into existing 28kV system

Bilberry MTS

- 2023-2025 – Complete distribution upgrades will be aligned with the timing of the station rebuild, allowing load transfers from Orleans MTS and feeders exceeding planning ratings upon energization

Minor Feeder Capacity Upgrades

- 2021-2022 – Upgrade the Albion feeder (2206), Nepean AB feeder (AB02), and Limebank feeder (LMBF3)
- 2023-2025 – Complete distribution upgrades identified through annual feeder and station level assessments.

2.1.2.5.2. Risks to Completion and Risk Mitigation Strategies

South Nepean

The proximity of proposed routing for several feeders from Cambrian MTS to the Ministry of Transportation (MTO) Right-of-Way for Highway 416 requires early consultations and consultations for work approval and permits. Discussions were initiated by Hydro Ottawa, with no risks to completion anticipated from MTO-related restrictions or work.

2.1.2.5.3. Timing Factors

Two projects, the New South and New East stations, require upgraded distribution infrastructure to be fully constructed and ready for energization ahead of the station being completed. Delaying station energization in these areas could prevent developments from proceeding, incur additional costs and prevent availability during peak summer demand.

Timing factors for Bilberry distribution capacity upgrades are tied to Hydro One project to refurbish Bilberry MTS. Delays on this project by Hydro One could bring feeders in the growth area above planning limitations.

2.1.2.5.4. Cost Factors

Bilberry station is owned by Hydro One; therefore, the station refurbishment project will be done by the station owner. Contributions by Hydro Ottawa will be required for the two additional breakers; contribution amount will be confirmed once Hydro One completes the evaluation of projects and a contract is signed.

2.1.2.5.4. Other Factors

Proximity of the South Nepean projects to Highway 416 and Ministry of Transportation Right-of-Ways has resulted in extensive and on-going consultations with the Ministry. No delays or scope changes are expected at this time, however acceleration of a proposed interchange at Barnsdale Road and Highway 416 has resulted in adjustments to the overhead greenfield project.

2.1.2.6. Renewable Energy Generation (if applicable)

N/A

2.1.2.7. Leave-To-Construct (if applicable)

N/A

2.2. STATION ENHANCEMENTS

2.2.1. STATION ENHANCEMENTS

The prioritized projects under the Station Enhancements Program includes modification to existing stations that are made to improve system operating characteristics.

In total, Hydro Ottawa plans to invest $2.74M in station enhancement upgrades in the 2021-2025 rate period compared to a historical spending of $275K in the 2016-2020 period. Investments for the 2021-2025 period are focused on installation of transformer monitoring equipment to support transformer renewal projects and cybersecurity at Hydro Ottawa stations.

2.2.1.1. Station Temperature Sensors

2.2.1.1.1. Project Summary

Hydro Ottawa stations consist of various high-risk assets. Station assets include power transformers, station-class switchgear assemblies, DC power systems, protection and control systems, and communication systems. The goal of this program is to modernize existing stations using updated technologies for equipment health monitoring. This new technology will allow Hydro Ottawa to monitor and make more informed asset management decisions in the future.

2.2.1.1.2. Project Description

Current Issues

Hydro Ottawa currently owns seven station transformers that are over 55 years old, and that will grow to 62 by the year 2025. This accounts for four projected transformer failures before 2025, which would be replaced. With no failures, there would be 66 transformers operating at or beyond their expected life by 2025. In order to better manage and prioritize transformer renewal programs, Hydro Ottawa needs to modernize its transformer monitoring technologies.

For station transformers, temperature data should be available in order to determine if any accelerated ageing factors should be applied when evaluating their health. However, there is currently a lack of historical monitoring data at many stations. At several of these stations, transformers can be retrofitted with magnetic-mount Resistance Temperature Detectors (RTDs) and temperature monitoring units to capture, store, and communicate thermal data.

There are 68 transformers with no historical temperature data that are expected to continue operating for the foreseeable future. In addition, another four transformers with temperature monitoring capabilities were selected to validate the reliability and accuracy of the magnetic-mount RTDs in Hydro Ottawa's environment. These four transformers have internal RTDs that directly measure the internal oil temperature, but are not currently fitted with magnetic-mount RTDs. This brings the total number of transformers to be fitted with temperature monitoring systems to 72.

Transformers can also benefit from the use of Online Dissolved Gas Analyzers (ODGAs). ODGAs periodically draw samples of oil from the transformer's tank and determine the concentration of various fault gases within the oil. This data is useful for identifying potential faults as condition worsens, but before the fault occurs. This allows Hydro Ottawa to remove the transformer from service and plan maintenance strategies accordingly. Existing transformers can be retrofitted with ODGAs to monitor the concentration of fault gases.

The price of ODGA units cannot be justified for smaller transformers. As such, only transformers connected to transmission or sub-transmission systems (44kV and higher) will be fitted with ODGA units. There are 23 transformers that meet the requirements to have ODGA units installed.

Project Scope

Hydro Ottawa has budgeted funds for this project every year from 2021 to 2025. The scope of this program encompasses two activities:

- Retrofitting 72 transformers with temperature monitoring systems
- Retrofitting 23 transformers with ODGA units

Main and Secondary Drivers

The project drivers are listed in Table 2.34.

Table 2.34 – Main and Secondary Drivers

Driver		Explanation
Primary	System Efficiency	Online monitoring solutions are vital in proactively identifying transformers with developing faults. Once a transformer is identified as having a developing fault, it can be planned to be removed from service for maintenance, and corrective actions can be implemented.
Secondary	System Operability	System operability is met by implementing monitoring systems. This program is a control upgrade and automation implementation.
	Reliability	Station transformers have a direct impact on system reliability, as all customers connected would experience a power outage in the event of a failure. Monitoring solutions will decrease the likelihood of an unexpected transformer failure.

Performance Targets and Objectives

Hydro Ottawa's objective for this project is to implement monitoring solutions on all of its transformers. All Hydro Ottawa transformers should have temperature monitoring, and all critical transformers in the system should have ODGA monitoring. As Hydro Ottawa's transformer fleet ages, it becomes increasingly important to implement strategic monitoring solutions to determine transformers whose condition is degrading and that should be prioritized for future renewal.

Implementing the project will accomplish the objectives aligned with the Stations Asset Renewal Program objectives, including improved reliability and efficiency. It will increase value to the customer by increasing the accuracy of end-of-life predictions using monitoring data, which will allow Hydro Ottawa to more effectively schedule renewal projects. Alignment to Hydro Ottawa objectives is shown in Table 2.35.

Table 2.35 – Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Maintain SAIFI & SADI
Cost Efficiency & Effectiveness	Compliance	Cost Efficiency	Optimize spending in transformer replacement
Asset Performance	Asset Value	Defective Equipment Contribution to SAIFI	Maintain contribution due to defective equipment at current levels or better

2.2.1.1.3. Project Justification

Alternatives Evaluation

Alternatives Considered

To address the drivers and achieve the performance objectives of the program, Hydro Ottawa considered three alternatives:

Do Nothing

Hydro Ottawa would not install any monitoring solutions. This alternative would not allow Hydro Ottawa to meet its objective for the project.

Implement Temperature Monitoring

Hydro Ottawa would install temperature monitoring systems on all of its station transformers that currently do not have the ability to monitor temperature.

Implement ODGA Monitoring

Hydro Ottawa would install ODGA units on all of its critical transformers. These are defined as all transformers connected to a transmission or sub transmission system (44kV and over).

Evaluation Criteria

As per DSP Section 5.2.2, Hydro Ottawa evaluates all alternatives with consideration of the following criteria:

Key Performance Indicator- Reliability

The increased risk of failure posed by ageing assets will impact Hydro Ottawa's ability to deliver power reliably. The selected alternative shall maintain or improve the reliability performance of the system.

Risk Mitigation- Safety

Hydro Ottawa puts the safety of its employees and the public at the center of its decision-making process. The preferred alternative must mitigate any present risks to Hydro Ottawa's employees and the public safety.

Risk Mitigation-Financial

Unplanned replacements are usually carried out by Hydro Ottawa's crews, whereas planned replacements typically utilize both internal and external resources. The preferred alternative is one that leads to more planned renewal projects, where appropriate staffing resources can be allocated, rather than unplanned renewal projects that would take resources away from other work.

Financial Benefits

Financial costs and benefits shall include all direct and indirect impact on the utility's performance and rates. The preferred alternative is the one that reduces the total lifecycle cost of an asset for the long-term benefit of stakeholder and customers.

Preferred Alternative

The preferred alternative is to implement both temperature and ODGA monitoring. This will allow for the objectives of the program to be met, and will address all the identified issues.

Project Timing & Expenditure

Table 2.36 below shows Hydro Ottawa's historical spending on similar projects, as well as the forecasted spending for this program.

The historical expenditures for similar projects only include an online dissolved gas analyzer trial. In this project, Morgan Schaffer Calisto 9 gas analyzers were installed on two transformers, with the goal of monitoring internal gassing on these transformers successfully achieved. The scope of the project was much smaller, as only two units were installed.

Forecasted expenditures in Table 2.36 show the allocated budget for the project, as well as the number of transformers to be outfitted each year from the year 2021 to 2025. These expenditures include the cost of the equipment and labour for installation and commissioning. The total cost of the Station Temperature Sensors project is $1.55M.

Table 2.36 – Expenditure History of Comparable Projects ($'000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Expenditure	$111	$0.5	$0	$0	$0	$310	$310	$310	$310	$310
ODGA Units	2	0	0	0	0	5	5	5	4	4
Temp. Units	0	0	0	0	0	14	15	14	15	14

Benefits

The benefits of the project are described in the table below.

Table 2.37 – Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	This project will increase Hydro Ottawa's system operational efficiency by providing live monitoring data. It will increase cost effectiveness by providing new data for condition assessments. KPIs to be improved are listed below: ● Increasing percent of transformers with temperature monitors ● Increasing percent of transformers with ODGA units
Customer	Customers will have improved reliability due to decreased transformer failures from over-temperature faults, and better lifecycle management.
Safety	Installing temperature monitoring systems reduces the risk of thermal related failure, as well as hot oil being expelled from the pressure release valve. Installing ODGA units reduces the risk of internal faults, as they can be detected as they develop, before a fault occurs.
Cyber-Security, Privacy	Refer to the business case 9202014316 – Station Cyber Security for more details on the cyber-security impacts of this program.
Coordination, Interoperability	(Not applicable)
Economic Development	(Not applicable)
Environment	Implementing monitoring systems will reduce the risk of environmental damage due to the lower risk of failure and oil expulsion.

2.2.1.1.4. Prioritization

Consequences of Deferral

If this project is deferred to the next planning period, or if adequate replacement levels are not achieved, then this asset group will pose an increased risk to safety and reliability. Transformers would continue to be unmonitored, and new monitoring systems will have to be implemented over a longer timeline alongside new transformer installations.

With 62 transformers that will be operating past their expected end of life by 2025, the need for monitoring technologies will become increasingly important to prioritize future renewal programs. Since there will be a backlog of end-of-life transformers that need to be addressed, this information will be important to determine which transformers should be renewed, and which ones will still be in acceptable operating condition.

Since developing faults can be identified by online monitoring technologies, there could be large financial consequences if this project were deferred. Due to the cost of unplanned transformer replacements, which can exceed $1M, if a single developing transformer fault is identified, this program will have paid for itself. The most recent transformer failure that required an emergency replacement was in 2015, and cost approximately $1.1M. The failure was identified as a developing fault, and the transformer was renewed before a catastrophic failure occurred. Due to the rapid increase of combustible gas concentration in the oil, a catastrophic failure was expected if the transformer was left in its existing state.

A considerable portion of Hydro Ottawa's station transformer population is nearing the end of its life. This program is expected to add value by identifying transformers whose health is degrading (e.g. via detection of increasing gassing) and providing data to be used to prioritize future renewal projects, as well as identifying potential developing faults before a major failure occurs.

Priority

This project is of high priority to Hydro Ottawa, as it will allow to better evaluate the health of ageing transformers and prioritize their replacements while minimizing the number of failures. The information provided by the proposed monitoring solutions is necessary to effectively conduct this end-of-life analysis.

2.2.1.1.5. Execution Path

Implementation Plan

Under this project, the following individual transformers would be scheduled to be outfitted with temperature monitoring and ODGA systems during the years 2021 to 2025.

Table 2.38 – Temperature Monitoring System Installations

2021			
• Bridlewood	T1 and T2	• Borden Farm	T1 and T2
• Centrepointe	T1 and T2	• Albion UA	T1 and T2
• Epworth	T1 and T2		
• Fallowfield	T1 and T2		
• Kanata	T1 and T2		
2022			
• Bayshore	T1	• Limebank	T1 and T2
• Beaverbrook	T1 and T2	• Rideau Heights	T1 and T2
• Janet King	T1	• Uplands	T3
• Jockvale	T1 and T2		
• Manordale	T1 and T2		
• Moulton	T1 and T2		
2023			
• Hillcrest	T1, T2 and T4	• Richmond N.	T1 and T2
• Bridlewood	T3 and T4	• S. March DS	T2
• Parkwood Hills	T1 and T2	• Clifton	T1, T2 and T4
• Woodroffe DS	T1		
2024			
• Brookfield	T1, T2 and T3	• Eastview	T1, T2 and T3
• Urbandale	T1, T2 and T3		
• Holland	T1 and T2		
• Carling SM	T1, T2, T3 and T4		
2025			
• Bantree	T1, T2 and T3	• Augusta	T1 and T2
• Slater SA	T1, T2 and T3	• Florence	T1, T2 and T3
• King Edward SK	T2, T2 and T4		

Transformers at Borden Farms and Albion DS have in-tank temperature sensors to verify the accuracy of the MMTSs in Hydro Ottawa’s environment. They’ll have magnetic-mount RTDs installed in 2021, along with the rest of the transformers listed above.

Table 2.39 – ODGA Installations

ODGA Installations	
2021	• Centrepointe T1 and T2 • Bayshore T1 • Beaverbrook T1 and T2
2022	• Epworth T1 and T2 • Bridlewood T3 and T4 • Casselman T2
2023	• Limebank T1 and T2 • Janet King T1 • Jockvale T1 and T2
2024	• Manordale T1 and T2 • Parkwood Hills T1 and T2
2025	• Moulton T1 and T2 • South March T1 and T2 • Woodroffe T1

Risks to Completion and Risk Mitigation Strategies

The greatest risk to the completion of this project is the availability of resources to execute the work. Stations electricians and technicians will be needed for the completion of the project, but there are other projects that compete for their time.

To mitigate this risk, a dedicated Stations department has the responsibility of ensuring the availability of resources for various stations-related programs and projects.

Timing Factors

Transformer-related projects are typically performed during the late-spring to early-fall months. This is due to the warmer weather experienced during the summer months, and that the work requires intricate wiring which is easier to perform in warmer weather.

Cost Factors

Cost factors that affect transformer-related projects are listed below:

- Project creep with including additional assets to be replaced. Most are identified early on in the project.

- Delays in the project schedule.
- Compatibility with existing equipment.

Other Factors

N/A

2.2.1.1.6. Renewable Energy Generation (if applicable)

N/A

2.2.1.1.7. Leave-To-Construct (if applicable)

N/A

2.2.1.1.8. Project Details and Justification

Table 2.40– Station Temperature Sensors

Project Name:	Station Temperature Sensors
Capital Cost:	$1,549,792
O&M:	
Start Date:	2021-2025
In-Service Date:	2021-2025
Investment Category:	System Service -Station Enhancement
Main Driver:	System Efficiency
Secondary Driver(s):	Reliability, System Operability
Customer:	System Wide
Project Scope	
Hydro Ottawa has budgeted funds for this project every year from 2021 to 2025. The scope of this program encompasses two activities: ● Retrofitting 72 transformers with temperature monitoring systems ● Retrofitting 23 transformers with ODGA units	
Work Plan	
See Section 2.1.1.5.1	
Customer Impact	

2.2.1.2. Station Cybersecurity

2.2.1.2.1. Project Summary

This project identifies the capital and operational expenditures that are necessary for purposes of implementing appropriate cybersecurity safeguards and controls at Hydro Ottawa's substations. These investments are consistent with the requirements and expectations set forth in applicable policy and regulation, and are commensurate with the utility's risk profile and business needs.

2.2.1.2.2. Project Description

Current Issues

The increasing sophistication and frequency of cyberattacks is one of the most significant business and operational risks facing the electricity sector in Ontario. The recognition of this fact has been reflected in several important provincial policy and regulatory developments in recent years, which have included actions directed specifically at local distribution companies ("LDCs").

For example, Ontario's *2017 Long-Term Energy Plan* ("LTEP") acknowledges cybersecurity as being "increasingly important in protecting critical infrastructure, such as the province's electricity system." What's more, the LTEP characterizes cybersecurity as "an operational necessity for the distribution sector," which encompasses "both the protection of customer-specific information held by LDCs and the protection of distribution-level system operations."[1]

Subsequent to the issuance of the LTEP, the Ontario Energy Board ("OEB") finalized amendments to the *Distribution System Code* ("DSC") in March 2018. The new provisions in the DSC require LDCs to report to the OEB on an annual basis regarding their level of cybersecurity readiness and capability, relative to the requirements, best practices, and expectations set forth in the industry-developed *Ontario Cyber Security Framework* ("Framework"). In its notice to affected parties regarding the adoption of these Code amendments, the OEB stated the following:

[1] Ministry of Energy, *Ontario's Long-Term Energy Plan 2017: Delivering Fairness and Choice* (2017), page 84.

> *"Application of the Framework by licensed transmitters and distributors will provide a method to assess existing capability against industry recommended best practices. The OEB expects this approach to provide a consistent reference point to assess licensed distributors' and transmitters' cyber security risk and capability. Licensed transmitters and distributors will be better informed as they work to incorporate cyber security into the enterprise risk management decision making, and investment planning that will ultimately form part of their business plans and their transmission and distribution system plans (as applicable)."*[2]

Moreover, the 2019 Revenue Requirement Submission of the Independent Electricity System Operator ("IESO") to the OEB was anchored in the IESO's 2019-2021 Business Plan, which had received approval from the Minister of Energy, Northern Development and Mines prior to submittal of the filing. Enhancements of its cybersecurity program were identified by the IESO as a major priority, in order to address the increasing complexity and growing threat of cyberattacks. What's more, the possible occurrence of a significant cybersecurity event that disrupts reliable grid operations was formally designated in the IESO's corporate risk register as one of the key risks facing the organization.[3]

The provincial policy and regulatory posture with respect to cybersecurity is matched and affirmed by a complementary layer of policy action at the federal level. In 2018, the Government of Canada released its *National Cyber Security Strategy* which, among other things, cautioned that "[s]ome cyber systems – such as electricity grids, communications networks, or financial institutions – are so important that any disruption could have serious consequences for public safety and national security."[4] The accompanying *National Cyber Security Action Plan* places immense emphasis on enhanced collaboration with the energy sector, with the aim of strengthening the unique expertise and capacity that is essential to bolstering defenses against advanced cyber threats.[5]

As the foregoing discussion illustrates, the public policy landscape in which Hydro Ottawa operates is one in which expectations and requirements have amplified considerably in recent

[2] Ontario Energy Board, *Notice of Amendments to Codes*, EB-2016-0032 (March 15, 2018).
[3] Independent Electricity System Operator, *2019 Revenue Requirement Submission*, EB-2019-0002 (January 28, 2019), Exhibit A-2-2, Page 23 of 27.
[4] Public Safety Canada, *National Cyber Security Strategy: Canada's Vision for Security and Prosperity in the Digital Age* (2018), page 18.
[5] Public Safety Canada, *National Cyber Security Action Plan: 2019-2024* (2019), pages 6-7.

years with regards to the steps that owners and operators of critical infrastructure – especially electricity infrastructure – must undertake to safeguard their assets against cybersecurity risks.

Against the backdrop of a policy landscape in which requirements and expectations are becoming more numerous and rigorous, Hydro Ottawa is in an advantageous position of having been an early adopter and industry leader amongst its Ontario LDC peers, as it relates to the implementation of best practices and cybersecurity protections.

Since 2012, the utility has had a formal cybersecurity program in place in which an annual roadmap of deliverables is defined and executed. For the first several years, the program was anchored in the ISO 27000 series of standards governing information security. Beginning in 2016, Hydro Ottawa started to implement core components of the cybersecurity framework developed by the U.S. National Institute of Standards and Technology ("NIST"). The decision to begin adhering to the NIST framework was based, in part, upon the results of a third-party maturity assessment commissioned by Hydro Ottawa, which underscored a broader shift taking place across the North American electric utility industry in adoption of the NIST framework. The industry-developed Framework in Ontario borrows heavily from the NIST structure, meaning that Hydro Ottawa occupied a vanguard position amongst Ontario distributors in terms of capability and readiness as new DSC provisions relating to cybersecurity and the Framework were taking effect in 2018. In addition to NIST implementation, other major cybersecurity initiatives at the utility in recent years have included assessments of program maturity, gaps, and privacy protections; the establishment of incident response and managed security services from external third-party experts; and regular penetration testing of corporate and operational networks and network segmentation.

Furthermore, for several years Hydro Ottawa has been a regular participant in, and contributor to, key forums inside and outside of Ontario for the advancement of cybersecurity knowledge and protection in the electricity sector. These include initiatives at the IESO, such as their Cyber Security Forum and cyber intelligence-sharing partnership with the Canadian Centre for Cybersecurity[6], as well as the biennial "GridEx" security exercise organized by the North American Electric Reliability Corporation ("NERC"), which is the largest such exercise of its kind

[6] http://www.ieso.ca/en/Powering-Tomorrow/Data/IESO-opens-the-door-to-sector-wide-cybersecurity-offensive.

and draws participation from thousands of participants from hundreds of utilities across the continent.[7]

Finally, it merits observation that, as the electricity distributor to the capital city of a G7 country, Hydro Ottawa conducts its business activity in a unique operating environment. Many of its customers, especially in the institutional sector, have distinct service needs which can only be met by a distribution system that is modern, reliable, safe, and secure.

To ensure that Hydro Ottawa can continue to fulfill its regulatory obligations and maintain best-in-class cybersecurity protections in a manner that is proportionate to its business and risk profile, it is imperative that the utility be able to sustain investments in a robust cybersecurity program which deploys a combination of controls focused on people, processes, technologies, and governance.

Project Scope

This project represents a natural extension and maturation of Hydro Ottawa's existing cybersecurity program, and is necessary to maintain compliance with OEB requirements and conformance with evolving best practices, including those that are captured within the cybersecurity Framework for electricity distributors in Ontario. This project consists of investments in technology and controls that will provide enhanced operational visibility into cybersecurity protections at Hydro Ottawa substations. The implementation of these safeguards will improve the utility's ability to identify, protect, detect, respond, and recover from cybersecurity incidents at these substations.

This project is a corollary to other investments being undertaken by the utility. More specifically, Hydro Ottawa has been executing a Telecommunications Master Plan during its 2016-2020 rate period. Covered within the scope of this plan has been the deployment of a high-capacity fibre optic network providing connectivity between central office locations and field offices and equipment, including substations. The creation of this network has facilitated a shift to Internet Protocol ("IP")-enabled communications for the utility's core operational technology ("OT") systems. This has allowed Hydro Ottawa to remotely access devices and infrastructure in a way

[7] https://www.nerc.com/pa/CI/CIPOutreach/Pages/GridEx.aspx.

that was not previously possible. This includes stations, whose connectivity was previously limited as a result of reliance on analog technology (i.e. serial connections). While the fibre-supported shift has opened the door to new efficiencies and benefits for system operations, it has also introduced a new area for which cybersecurity risk mitigation is required.

For each of Hydro Ottawa's 80+ substations, this project contemplates the following actions:

- Catalogue existing assets to form an accurate view of type, vendor, software, and firmware, including required patches;
- Implement appropriate perimeter safeguards to ensure all data is controlled between substations;
- Implement detective and protective controls; and
- Conduct real-time analysis.

The next generation of cybersecurity technologies are focusing heavily on addressing the foregoing use cases. There will be a wide range of technology solutions and vendors for Hydro Ottawa to assess and to engage.

Main and Secondary Drivers

As noted above, in step with regulatory mandates and public policy requirements, it is imperative for Hydro Ottawa's cybersecurity program to be adequately resourced and to fulfill the basic functions expected of critical electricity infrastructure owners and operators in relation to cybersecurity (i.e. identify, protect, detect, respond, and recover). In light of the present state of readiness and capability at Hydro Ottawa, the progression of industry best practices, the evolution of external threats and risks, and the need to safeguard system reliability, the targeted application of specific controls to enhance operational visibility at the utility's substations is warranted.

Performance Targets and Objectives

Hydro Ottawa has a well-established, defense in-depth cybersecurity program in place that consists of a blend of technical and administrative controls combining people, governance, process, and technology.

An overriding, fundamental objective of this project is securing Hydro Ottawa's distribution system against a cyberattack that could result in a widespread, prolonged power outage.

2.2.1.2.3. Project Justification

Alternatives Evaluation

Alternatives Considered

Do Nothing

This option is not considered viable, as it would introduce a severe risk into Hydro Ottawa's cybersecurity program and protections.

Evaluation Criteria

N/A

Preferred Alternative

N/A

Project Timing & Expenditure

Cybersecurity spending was previously allocated under General Plant. Accordingly, Table 2.41, which outlines the proposed budget allocated to Station Cybersecurity over the 2021-2025 period, does not include any information with respect to historical expenditures.

Table 2.41 - Station Cybersecurity Expenditures ($'000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
TOTAL	$0	$0	$0	$0	$0	$595	$149	$149	$149	$149

Benefits

The projected benefits associated with the Station Cybersecurity project are identified in Table 2.42.

Table 2.42 - Benefits

Benefits	Description
System Operation, Efficiency and Cost Effectiveness	Prevent cyber attacks from occurring. Ensuring risk is minimized.
Customer	Prevent cyber attacks from occurring. Ensuring risk is minimized.
Safety	Prevent cyber attacks from occurring. Ensuring risk is minimized. Ensure customer data is properly protected and the possibility of information loss is minimized.
Cyber-Security, Privacy	Prevent cyber attacks from occurring. Ensuring risk is minimized.
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	N/A

2.2.1.2.4. Prioritization

Consequences of Deferral

Hydro Ottawa believes that an appropriate means for evaluating and interpreting the consequences of deferring this project is to examine the cost impacts associated with a worst possible outcome – namely, a successful cyber attack. As shown in Table 2.43 below, an outage lasting four hours, affecting approximately 3,000 customers, and involving only one substation would cause economic impacts of $1.8M. A 12-hour outage involving all 88 substations would adversely impact all customers in Hydro Ottawa's service territory and would potentially incur economic damages of almost $240M.

Table 2.43 - Economic Impacts of Cyber Attack

Calculation Based on DSP	
SAIDI (Baseline Value)	1.58
Total Customers - Residential Class	303,571
Total Customers - Small & Mixed Commercial	27,177
Total Customers - Large Class	1,029
Total Customers Served	**331,777**
Average load not served during outage / Customer	3 kW
Average Value of Service (VOS) ($ per Minute of Outage)	**$1.00**
Number of Substations	88

Outage Information	Single Station	Nested Stations	Whole City	Duration	
Substations	1	2	88	**Minutes**	**Hours**
Customers	3,770	7,540	331,777		
Total Economic Impact	$904,846.36	$1,809,692.73	$79,626,480.00	240	4
	$1,357,269.55	$2,714,539.09	$119,439,720.00	360	6
	$1,809,692.73	$3,619,384.45	$159,252,960.00	480	8
	$2,714,539.09	$5,429,078.18	$238,879,440.00	720	12

Priority

- Hydro Ottawa's cybersecurity program defines a yearly roadmap based on priorities, gaps, risks, and budget, and will prioritize this and other projects accordingly.
- This project's priority status is high, seeing as it is a multi-year project, with 50% of capital expenditures planned for 2021.

2.2.1.2.5. Execution Path

Implementation Plan

The implementation will consist of identifying all of the substations and determining their priority status based on number of customers, size, equipment within the station, and risk profile. Implementation activities will focus on one substation at a time.

Risks to Completion and Risk Mitigation Strategies

For risk mitigation purposes, it is imperative that this project be completed during the 2021-2025 rate period.

Timing Factors

Execution of this project could be delayed by such factors as the introduction of new risks into Hydro Ottawa's cybersecurity risk landscape, constraints on resources, and availability of competencies and skill sets that will be required for project delivery.

Cost Factors

N/A

Other Factors

N/A

2.2.1.2.6. Renewable Energy Generation (if applicable)

N/A

2.2.1.2.7. Leave-To-Construct (if applicable)

N/A

Table 2.45 - Cybersecurity - OT Visibility and Safeguards for Substations

Project Name:	Cybersecurity – OT Visibility and Safeguards for Substations
Capital Cost:	$1,189,579
O&M:	N/A
Start Date:	2021
In-Service Date:	2022-2025
Investment Category:	System Service-Station Enhancement
Main Driver:	Reduce cybersecurity risks to OT environment
Secondary Driver(s):	Gain necessary level of visibility
Customer	All customers
Project Scope	
Implement adequate cybersecurity safeguards including ability to identify, protect, detect, respond, and recover from cyber attacks at all stations across Hydro Ottawa's distribution system.	
Work Plan	
Customer Impact	

2.3. DISTRIBUTION ENHANCEMENTS

2.3.1. DISTRIBUTION SYSTEM RELIABILITY

2.3.1.1. Program Summary

The prioritized projects under the Distribution Reliability Upgrade Program address existing reliability risks within Hydro Ottawa's distribution system, or those that will occur upon committed connections of new customers or upgrades of existing ones. These risks are identified and evaluated through Hydro Ottawa's Reliability Council's monthly meetings as well as annual system reviews.

In total, Hydro Ottawa plans to invest an estimated $13.32M in distribution system reliability upgrades in the 2021-2025 rate period compared to a historical spending of $18.92M in the 2016-2020 period. Hydro Ottawa's expenditure plan for the Distribution Reliability Upgrade Program in 2021-2025 are aligned with and responsive to the customer feedback received. When it comes to Reliability performance, Hydro Ottawa is seeking to minimize price increases by investing only what is necessary to maintain system reliability at current levels while improving the experience for customers with poor reliability and improving the resilience of the distribution.

2.3.1.2. Program Description

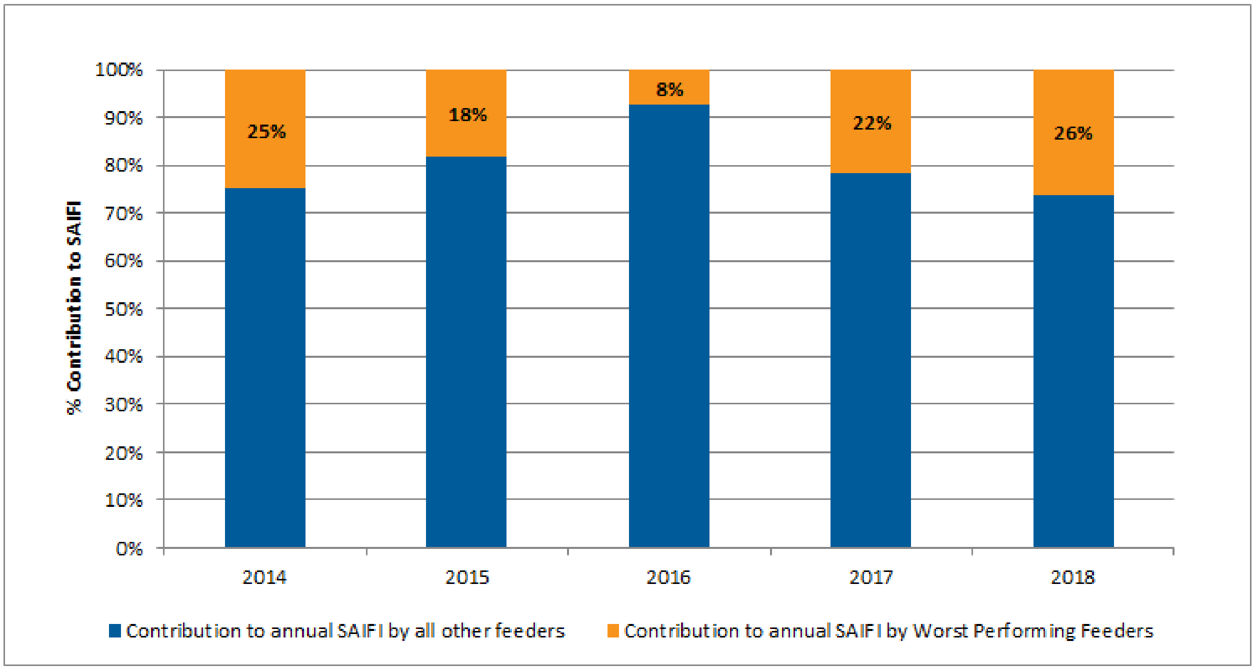
2.3.1.2.1. Current Issues

The following are the main drivers for projects planned for 2021-2025 under the Distribution Reliability Upgrade Program.

Worst Feeders

Annually, Hydro Ottawa reviews the performance of its feeders with respect to their impact on customer interruptions, customer hours and frequency of outages. A Feeder Performance Index (FPI) for each feeder is derived from these criteria and is assigned a ranking. This condition ranking process allows for annual performance review and trending while identifying which feeders would most benefit from targeted investments. Figure 3.1 shows the percentage annual contribution to SAIFI from the worst performing feeders. On average, the worst performing feeders annual contribution to SAIFI was 20% over the last 5 years.

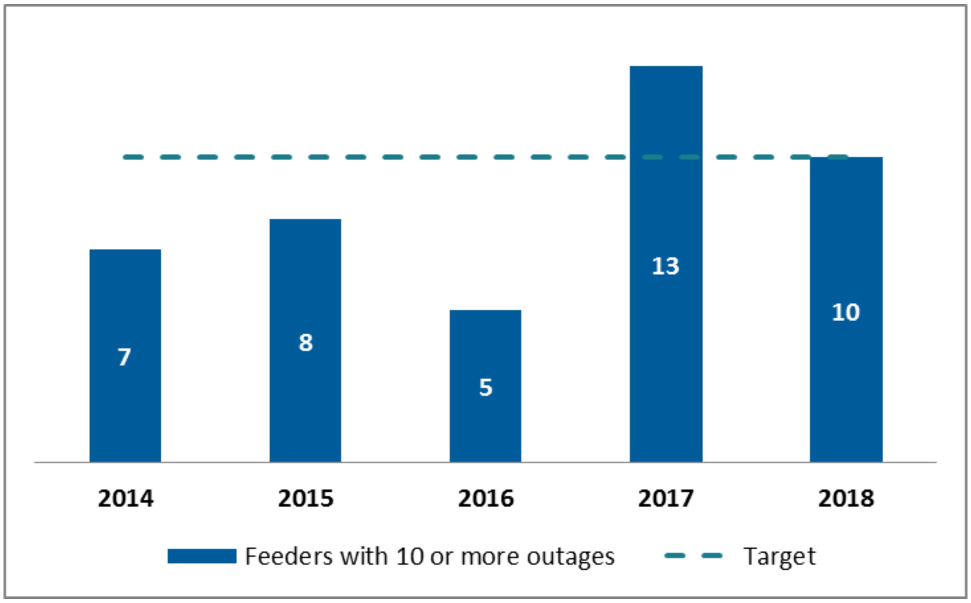
Figure 2.13 - Worst Feeder SAIFI Contribution



Feeders Experiencing Multiple Sustained Interruptions (FEMI)

On average, Hydro Ottawa has been achieving its targets for FEMI. Hydro Ottawa tracks and evaluates feeders that affect the performance of the FEMI metric monthly at its Reliability Council meetings, to identify projects to improve the reliability of these parts of the distribution system. Hydro Ottawa will continue to evaluate the performance of feeders that appear in the FEMI metric to ensure customer reliability is maintained. The historical system performance for FEMI is shown in Figure 3.2.

Figure 2.14 - FEMI Reliability Performance



Circuit Configuration

Over the last couple of years several stations have been rebuilt due to the end of life condition. With the station asset renewal program some stations have increased in capacity; however, feeders in the area were not reconfigured to fully take advantage of the additional capacity. Capacity based distribution upgrades are covered under the Distribution Capacity Upgrade Program. Merivale MTS has been under renewal since 2017, and as a result the demand normally supplied from the station has been redistributed throughout the Nepean Core 8kV system for the duration of the project. Merivale MTS is expected to be energized by the end of 2019, and the system will be put back to its normal configuration. Before the upgrade, some feeders from Merivale station were above their planning rating resulting in longer outages due to the need to sectionalize these feeders for restoration. The capacity upgrade at Merivale station is introducing two new feeders which could be utilized to balance loading below feeder planning ratings in the Merivale Business park area as well as to relieve adjacent stations approaching or at their planning ratings. The current configuration does not allow proper distribution among all feeders and stations supplying the Merivale Business Park area.

Line Extension for Reliability

King Edward TS

The 2018 coincident peak for King Edward TS was 85MVA, which exceeds the current planning rating by 6MVA. King Edward TS has limited ties to adjacent stations, considering the relative proximity to Overbrook TS, Riverdale TS and Slater TS. For example, Lisgar TS and King Edward TS are approximately the same distance (1km) from Slater TS. Lisgar TS has twelve (12) ties to Slater TS, while King Edward TS has seven (7). This is due to the location of King Edward TS, isolated between the Rideau Canal and Rideau River, with limited existing crossing points over both waterways. Ties to Overbrook TS (1) and Riverdale TS (2) are similarly scarce. As a result, King Edward TS relies more heavily on intrastation ties between alternating busses to provide redundancy than most other 13kV stations. Further, the Z-bus has no interstation ties, which has been identified by System Operators as a reliability issue.

Riverdale TS Feeder TR1UX

The feeder TR1UX, which supplies Gladstone DS (13/4kV) and acts as a backup to feeder 502 from Riverdale TS, is currently above planning rating. There is a risk of stranded load, approximately 1MVA, to either Gladstone DS or commercial customers supplied from 502 during peak periods.

2.3.1.2.2. Main and Secondary Drivers

The main driver for projects under this program is reliability and includes addressing worst performing feeders, reconfiguring feeders to optimize the system and line extensions for improving restoration times under contingency scenarios. Hydro Ottawa is seeking to minimize cost increases by investing in only what is necessary to maintain system reliability at current levels while improving the experience for customers with poor reliability and improving the resilience of the distribution system.

Secondary drivers for the program include system capacity and financial benefits. Leveraging existing station or feeder capacity that is either unused or not required for several years, based on existing forecasts, to alleviate existing capacity constraints makes better use of existing asset capabilities and defers capital investments.

2.3.1.2.3. *Performance Targets and Objectives*

The objectives of the project are as follows:

- Improve reliability by targeting areas with poor reliability
- Reduce the average load supplied by feeders to below planning ratings as a result SAIFI and SAIDI will be impacted. Currently, highly loaded feeders must be sectionalized before being restored by multiple feeders in order to not exceed equipment ratings.

Table 2.46- Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Improve SAIFI/SAIDI
Cost Efficiency & Effectiveness	Resource Efficiency	Labour Utilization	Reduce Labor Allocation to Outage Restoration
System Operations Performance	Levels of Service	Stations Capacity	Reduce Station Loading Below Planning Capacity
		Feeder Capacity	Reduce feeder load below Planning Capacity

All proposed projects under the program address one or more Key Performance Indicators (KPI) used by Hydro Ottawa to measure system performance and efficiency.

2.3.1.3. Program Justification

2.3.1.3.1. *Alternatives Evaluation*

Alternatives Considered

Worst Feeder Betterment Program

Do Nothing

This option is not a recommended alternative since it does not align with customer expectations to maintain and improve reliability. Reliability will continue to decline with no short term plans in place. As shown in Figure 3.1, on average, the worst performing feeders for any given year account for approximately one fifth of Hydro Ottawa's overall annual SAIFI. Investment in the Worst Feeder Betterment Program is required to manage the reliability for both customers supplied on those particular feeders as well as for Hydro Ottawa's overall system reliability.

Program to Address Immediate Reliability Concerns

The Worst Feeder Betterment Program is designed to address short term reliability issues in an immediate time-frame. Work under this program will be identified following feeder performance analysis and through identification by the Reliability Council during monthly meetings. Short term plans to improve the reliability of feeders identified as poor or very poor performers as a result of worst feeder assessment will be actioned through this program. An annual $1M budget has been allocated for this program. The goal of the program is to improve the reliability performance of Hydro Ottawa's worst performing feeders.

Feeder Reconfigurations

Do Nothing

Not reconfiguring circuits in areas where station capacity has been increased does not permit full utilization of the capacity in these regions. Most feeders currently above planning capacity will continue to be on the list. As load increased, the need for sectionalizing feeders to restore power will continue to increase outage duration.

Invest in Feeder Reconfiguration

Investing in feeder reconfigurations will allow to take full advantage of additional capacity installed in areas requiring station asset renewal. The main focus in the 2021-2025 rate period will be the Merivale business park area due to recent capacity upgrades at Merivale and Borden Farms stations as well as feeders in this area being above planning rating. Reconfiguring the feeders will improve load balancing between all stations and feeders in the area.

Line Extensions for Reliability Purposes

Do Nothing

Currently, the coincident peak for King Edward TS exceeds its planning rating by 6MVA, with limited ties to adjacent stations. At Riverdale TS, the TR1UX feeder is exceeding it's planning limit, with a stranded load risk of approximately 1MVA during peak conditions. Both these conditions represent reliability risk. In the absence of investment in line extensions, these reliability risks will not be addressed.

Invest in Line Extension for Reliability Purposes

By investing in line extensions for reliability purposes at King Edward Ts and the TR1UX feeder at Riverdale TS, contingency is introduced and the reliability risk at both locations is reduced.

Evaluation Criteria

The spending alternatives were compared based on whether they address the following requirements:

- Does the alternative address reliability issues, reduce/maintain performance and other related KPIs?
- Does the alternative address secondary drivers, such as Feeders or Stations above planning ratings, and Financial Benefits?
- Does the alternative take into account future asset plans, to avoid early asset retirement, depreciation costs and reduced project value?

Preferred Alternative

The preferred alternative for all three identified needs is Option 2. This program expenditure plan addresses all existing and forecasted reliability issues through Distribution System Enhancements, as determined by annual distribution system reviews. The projects prioritized under the program all maintain or improve reliability performance, with some providing additional system capacity in areas where feeders or stations are at or above planning criteria, and defer capital investments. Table 2.47 summarizes expenditure levels required for each need.

Table 2.47 - Preferred Alternatives Expenditure Level for 2021-2025 ($'000,000s)

Programs	2021-2025 Expenditure
Worst Feeder Betterment Program	$5.01
Circuit Reconfigurations	$4.63
Line Extension for Reliability improvements	$3.68
TOTAL	**$13.32**

Program Scope

The following projects have been developed to address the current risks discussed in Section 2.3.1.2.1:

Worst Feeder Betterment Program

The scope of the Worst Feeder Program varies depending on the interruption sources of poor performing feeders. This program will employ a host of mitigation strategies to eliminate or minimize the effect of outages. Some of the mitigation strategies include: installing sectionalizing devices (reclosers, remote controllable switches, etc.), distribution protection upgrades, animal guards installation in areas with high animal contacts, additional feeder at stations, feeder reconfigurations.

Circuit Reconfiguration

Merivale MTS has been renewed with increased capacity to service forecasted demand growth in Core Nepean 8kV region. In order to relieve surrounding stations and introduce additional capacity into the distribution system, reconfiguration of the existing 8kV system is required. Installation of new switches or changing open points with existing assets will bring several existing feeders and stations below or closer to their planning ratings.

Line Extension for Reliability

King Edward TS – Slater TS Distribution Feeder Ties

Hydro Ottawa has planned the extension of four (4) feeders to King Edward TS from the neighbouring Slater TS, which has a surplus of capacity through the forecast period. This will create new ties to King Edward TS that are necessary for quick power restoration during contingencies or for maintenance activities.

Riverdale TS Feeder TR1UX Exceeding Planning Rating

Hydro Ottawa has planned to extend a feeder from Slater TS to relieve the loading on 502, and create a new distribution tie between the stations.

2.3.1.3.2. Program Timing & Expenditure

Historical and forecasted expenditure levels for the program are summarized below in Table 2.48.

Table 2.48 - Historical and Future Distribution System Reliability Expenditures ($'000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	\$5.83	\$6.48	\$2.70	\$2.18	\$1.72	\$1.00	\$5.68	\$1.62	\$2.01	\$3.01

2.3.1.3.3. Benefits

The benefits of the project are listed in Table 2.49.

Table 2.49 - Project Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	System Operation efficiency will be improved through several benefits: (1) Improved outage detection and isolation, reducing time and scope of line patrols to determine outage cause/location, and (2) bringing feeders below planning ratings reduces the number of switching operations required to restore load.
Customer	Customers impacted by projects under this program should see maintained or improved reliability performance, with respect to duration. This is accomplished through upgrading existing distribution protection to current standards, bringing feeders and/or stations below planning ratings, and decommissioning end-of-life or legacy equipment. Several projects also defer significant capital investments at the station level, by leveraging existing asset capabilities, reducing rate impacts for all customers.
Safety	N/A
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	Projects addressing capacity as a secondary driver, such as the King Edward-Slater Ties, will reduce system expansion requirements for future developments in the affected supply areas. This will reduce costs for customer connections and promote development through increased system accessibility.
Environment	N/A

2.3.1.4. Prioritization

2.3.1.4.1. Consequences of Deferral

Consequences of deferral for each project under the program vary, depending on the risks inherent to the assets and total load served. Each project has different risks; however, increased outage duration, potential for stranded load and inadequate system capacity are some of the risks associated with deferral

2.3.1.4.2. Priority

Projects which impact larger numbers of customers or high demand, such as the Nepean 8kV System Reconfiguration, and King Edward - Slater Ties, have greater risks, and would therefore be considered ‘High’ priority with respect to other projects under the program.

Drivers affecting lower loads and customer counts, such as 4kV System Protection Upgrades, would be considered ‘Low’ priority.

2.3.1.5. Execution Path

2.3.1.5.1. Implementation Plan

All projects will be implemented in the 2021-2025 period.

2.3.1.5.2. Risks to Completion and Risk Mitigation Strategies

Hydro Ottawa-owned civil infrastructure crossing the Rideau Canal in the downtown region is limited. There is existing capacity for the four (4) feeder extensions proposed from Slater TS to King Edward TS. The condition of this civil structure in 2020 as part of the preliminary design process for the extensions.

The City of Ottawa has implemented new policies regarding utility-owned infrastructure in municipally-owned bridges. As a precursor to these projects, Hydro Ottawa will confirm with the City future plans for existing downtown Rideau Canal crossings, and whether utility infrastructure upgrades would be feasible.

2.3.1.5.3. Timing Factors

Unforecasted connections of large customers, within the supply area of King Edward TS, may require acceleration of the feeder extensions from Slater TS. This will be determined through the annual system review process and identifying potential development areas through consultation with Hydro Ottawa’s Distribution Design group and the City of Ottawa.

2.3.1.5.4. Cost Factors

N/A

2.3.1.5.4. Other Factors

N/A

2.3.1.6. Renewable Energy Generation (if applicable)

No additional barriers to Renewable Energy connections will be introduced as a result of these projects; however, the feeder extensions from Slater TS, which HONI does not currently allow new generation facilities to connect to, will expose more customers to this limitation.

2.3.1.7. Leave-To-Construct (if applicable)

N/A

2.3.2. SYSTEM VOLTAGE CONVERSION

2.3.2.1. Program Summary

This program consists of various voltage conversion projects which are carried out to address capacity constraints in areas with significant forecasted growth. System voltage conversion projects typically coincide with the retirement of existing distribution assets due to condition or failure risk.

The projects covered in this business case include full voltage or partial conversion projects in order to prepare for future area voltage conversions. The target conversion areas and projects discussed in this business case include converting the remaining 12kV system in the West to 28kV and former rural areas supplied by the 8kV system to 28kV. The program intends to increase system reliability, address capacity constraints, improve operational flexibility, and decrease the risk associated with aging assets.

Hydro Ottawa plans to invest $5.86M towards System Voltage Conversion program over the 2021-2025 period. The investment in Historical Years 2016-2020 was $13.56M. The last period involved several larger scaled voltage conversion projects such the Glen Cairn neighbourhood and the Richmond South Voltage Conversion in preparation for the new 28kV station in South Nepean. The report below discusses the main projects for the 2021-2025 period.

2.3.2.2. Program Description

2.3.2.2.1. Current Issues

The System Voltage Conversion Program addresses capacity and reliability concerns. The projects under this program include radial feeders which result in longer outages due to the unavailability of alternate supplies via feeder ties. Aging assets in the project regions also create a reliability concern due to the high probability of failure and ultimately a higher than typical frequency of outages. Another issue that is addressed through this program is the lack of new supply points to new future developments where there are currently none. This issue increases system operation costs from switching operations needed to change transformer taps.

The projects planned under the System Voltage Conversion program for the upcoming 2021-2025 rate period are categorized by four different project types: Richmond South 28kV, West 12kV, Nepean South 8kV, and Navan Road. Summarized below are the current issues for each category.

West 12kV

The West 12kV supply region is currently supplied by Beaverbrook MS and South March DS. Over the past several years, there has been little growth and minimal forecasted growth over the next several years. This 12kV supply area has no distribution capabilities beyond the current region it covers and no additional station capacity is required. Some of the oldest underground cables in the West service territory reside in this region. The majority of these conductors are direct-buried with significant access issues and customer impact from backyard-routed primary assets. Crew safety, poor reliability, and ease of maintenance and replacement are the main issues in this supply region. It is Hydro Ottawa's objective to fully decommission both 12kV stations in the near future.

South Nepean 8kV

The South Nepean 8kV supply region has been forecasted to experience new growth over the next several years. As the asset condition of this 8kV pocket continues to age and new customers are connected to this region, this area would benefit by converting it to operate at 28kV, similar to the system surrounding the area. The long term goal of completely consolidating to 28kV in that region would further improve capacity and reliability from the increased redundancy of multiple station backups.

Navan Road

Navan Road east of Renaud Road exists currently as a radial overhead 8kV line with ageing infrastructure surrounded by 28kV distribution. The reliability of this area continues to decline as assets reach end-of-life. This current configuration suffers capacity constraints as residential growth that is forecasted to materialize in the next several years will not be able to be supported. This is due to no available supply points to support the forecasted developments which will result in increased system operation costs from switching operations needed to change transformer taps.

2.3.2.2.2. Main and Secondary Drivers

The main driver for System Voltage Conversion projects is reliability. Capacity constraints and system efficiency are secondary drivers.

There is a need to replace the aged West 12kV infrastructure with assets rated 28kV assets and integrate them into the greater West 28kV system in the long term. The addition of ties, distribution loops, and reliable new assets allow outage frequency and duration to be decreased. This new system will be more reliable and operational efficiency will be added to the region.

The South Nepean 8kV region has the potential to be made more reliable by connecting to the South Nepean 28kV system with more ties between stations and available capacity on the larger system. The long term goal of consolidating this region to one voltage progresses the supply region to greater efficiency and increased capacity.

On Navan Road, the age of current 8kV infrastructure in older asset regions has resulted in low reliability due to increased failure risk and increasing frequency of outages. Longer duration outages are the result of radial 8kV regions and the unavailability of alternate supplies. This reliability issue is addressed by creating the additional ties and loop which provide alternate supply points and shorter outage durations. In regions where there are no available 28kV supply points and significant forecasted growth to substantiate over the next few years, those developments may be supplied by both 8kV and 28kV. The result would be increased switching time and cost required to change transformer taps. A voltage conversion would save time and operation costs, and increase operational efficiency.

2.3.2.2.3. Performance Targets and Objectives

The System Voltage Conversion Program’s Key Performance Indicator (KPI) Targets by Category are shown in Table 2.50 below.

Table 2.50 - Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Improve System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI)
Cost Efficiency & Effectiveness	Resource Efficiency	Labour Utilization	Reduce Labour Allocation to Outage Restoration
Asset Performance	Asset Value	Defective Equipment Contribution to SAIFI	Reduce end-of-life equipment with high probability of failure
	Health, Safety & Environment	Oil Spilled	Reduce oil remediation cost
System Operations Performance	Levels of Service	Feeder Capacity	Increase usable feeder capacity

The main objectives of this program are to:

- Decrease outage durations by decreasing or eliminating radial portions and adding redundancy
- Decrease the frequency of outages in regions where the assets have reached or are approaching end-of-life and have a high probability of failure
- Increase the capacity of region by completing the conversion and accommodating future forecasted growth,
- Increase system efficiency and save cost by no longer requiring to change transformer taps in areas supplied by two primary voltages, and consolidating 28kV regions by removing or reducing lower voltages within the supply area.

2.3.2.3. Program Justification

2.3.2.3.1. Alternatives Evaluation

Alternatives Considered

There are two alternatives considered for System Voltage Conversion projects. The Do Nothing and Voltage Conversion Project alternatives are detailed below.

Do Nothing

In this alternative, existing aged assets will not be replaced until asset failure or planned replacement based on inspection data. Additional costs will be required to supply future growth with additional 28kV supply points to accommodate forecasted load growth in lower voltage regions with capacity constraints. Customers who are currently radially supplied will continue to experience planned outages of longer durations due to the unavailability of backup ties. New customers connecting to the system will not be connected to the available 28kV feeders in the area, nor will they be equipped with 28kV infrastructure in preparation for future voltage conversion. If voltage conversions are planned in the future, the infrastructure that is not already properly built and equipped to the 28kV standard may be decommissioned before the end of their financial life and the entire region will need to be replaced.

In addition, Beaverbrook and South March stations will require to be rebuilt due to end-of life considerations.

Voltage Conversion Projects

This alternative involves executing the proposed voltage conversion projects. Ageing infrastructure will be replaced to accommodate the new 28kV infrastructure and reduce the probability of failure. Additional 28kV distribution loops or trunk ties are also proposed to increase capacity, eliminate the regions with multiple primary voltages, reduce or eliminate radial regions, and reduce switching times by providing alternate supply points. Depending on the project, the feeder path will be upgraded to be equipped with 28kV infrastructure and remain on the 8kV system until the region is prepared for complete conversion. This option promotes the consolidation of voltages to create a more reliable and robust network with multiple interconnections between uniform voltage stations.

Evaluation Criteria

To compare the different alternatives, the following criteria were considered: capital cost, reliability improvement, asset condition and depreciated value, the number of customers affected, the ability to accommodate future proposed growth, operational flexibility, and useful or efficient distribution system configuration. The projects under this program are evaluated to optimize value to cost ratios with respect to benefit and risk as described in DSP Section 5.2.

KPI improvements mentioned in the previous subsection are also considered in the evaluation and prioritization. The overall program value is evaluated by the cost to value ratio in comparison to all other programs.

Preferred Alternative

Alternative 2: Voltage Conversion Projects is the preferred alternative as it provides the greatest value to cost ratio and KPI benefits.

Program Scope

The scope of this program mainly involves either the complete or partial voltage conversions within the Richmond South 28kV system, West 12kV, South Nepean 8kV, or Navan Road with the purpose of increasing system resilience through the addition of capacity, and distribution ties which ultimately reduce outage durations across the network.

Richmond South 28kV

To create ties between the Richmond South 28kV system and the surrounding 28kV network, areas along the circuit's tie path will be converted from 8kV to 28kV. This involves overhead line extensions and pole replacements to either fully convert along the circuit route, or convert immediate taps off the trunk to 28kV and equip the path with 28kV infrastructure to prepare the area for complete conversion as assets reach end-of-life.

West 12kV

Projects in the West 12kV supply region involve voltage conversion projects which are proposed to eliminate the 12kV supply voltage and convert them into 28kV. This involves upgrading existing primary routing to road right of ways, placing transformers and preparing for connections with new trunk infrastructure, and allowing for the transfer of new loops onto the 28kV system.

South Nepean 8kV

The South Nepean 8kV projects have the long term goal of reactively converting the supply region from 8kV to 28kV at the pace of asset deterioration and demand growth. Projects in this area only occur as assets reach end-of-life and require replacement, or when new customers and commercial growth facilitates new connections. When a pocket of aged 8kV infrastructure is identified to require replacement, the goal is to convert and connect to the South Nepean 28kV system. As new customers and developments occur, they will also be connected to the 28kV system. Depending on the project, the assets may only be equipped with 28kV infrastructure and remain on the 8kV system until the region is prepared for complete conversion (usually when the asset reaches end-of-life).

Navan Road

The Navan Road 28kV to 8kV conversion includes replacing end of life poles which are currently insulated for 8kV with poles which are updated to standard 28kV distribution. Additional ties are also created to remove or reduce radial feeds, increase redundancy, reduce outage time, and ultimately better the area's reliability. Isolated 8kV pockets surrounded by 28kV distribution are eliminated through this conversion. This addresses this road's capacity and supply point needs, and eliminates the remaining 8kV radial along Navan Road.

2.3.2.3.2. Program Timing & Expenditure

Historically from 2016-2020, a total of $13.560M was spent on the System Voltage Conversion program. The projects in this period involved 4kV to 13kV conversions from 2016-2020, 8kV to 28kV conversions from 2016 to 2020, Richmond South 8kV to 28kV conversions that will continue in the upcoming period, and 12kV to 28kV conversions in the West which will be completed in 2022.

The voltage conversion projects included in the 2021-2025 period include those located in areas described throughout this report. The Richmond South 28kV ties and conversions will occur in 2021, West 12kV conversion projects in 2021-2025, South Nepean 8kV to 28kV projects will be from 2023-2024, and Navan Road will be completed in 2023. Table 2.51 below displays the program level expenditures in the historical and future period.

Table 2.51 - Historical and Future System Voltage Conversion Expenditure ($'000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$4.50	$2.23	$2.06	$2.97	$1.81	$0	$3.03	$2.10	$0.73	$0

2.3.2.3.3. Benefits

The benefits of the System Voltage Conversion program are described in Table 2.57 - Program Benefits below.

Table 2.52 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Converting dual voltage regions to 28kV increases the availability of 28kV feeders and backups and eliminates the need to supply future distribution loops with primary voltage feeders. This results in reducing switching time, reducing forced outage duration from changing transformer taps in order to restore power, and ultimately saving cost. Investing in infrastructure for 28kV now when assets reach end-of-life saves on capital expenditure in the future when the entire region is ready to be converted.
Customer	Where end of life assets are being replaced as part of the voltage conversion, the number of potential outages experienced by the customer will be reduced. Where additional trunk loops are created as part of the project, the number of radially supplied customers will be reduced. The outage durations for customers will be reduced because of the added redundancy.
Safety	Ageing infrastructure prone to near term failure and hazards will be eliminated with upgrades associated with the voltage conversions.
Cyber-Security, Privacy	N/A
Coordination, Interoperability	Radial regions of lower primary voltage trunk replaced with 28kV trunk and additional ties will increase redundancy, coordination, and operational flexibility.
Economic Development	Where feeder capacity is increased with the conversion, forecasted growth and future customers will be able to be connected.
Environment	N/A

2.3.2.4. Prioritization

2.3.2.4.1. Consequences of Deferral

Deferring the proposed voltage conversion projects will result in several consequences. The current lower primary voltages may have insufficient capacity to supply future customers given the forecasted growth. As the proposed project regions continue to reach or surpass end of life, the probability risk of failure will continue to increase. Radial customers will also continue to experience extended outages due to the lack of trunk ties or not being connected to a distribution loop. For voltage conversions planned in the future, the infrastructure that are not already properly equipped to the 28kV standard may be decommissioned before the end of their financial life and the entire region will need to be replaced.

2.3.2.4.2. Priority

Distribution Enhancements at the program level are ranked as high priority. This is due to the reliability, capacity, and operational efficiency needs in the voltage conversion regions. Assets that have reached end-of-life are required to be replaced to reduce the reliability risk in the area due to the probability of asset failure. Capacity constraints necessitate the upgrade in primary voltage along with the replacement of vintage assets which are prone to failure. Where radial feeds cause longer restoration times and alternate supply points do not exist, reliability is also at risk.

2.3.2.5. Execution Path

2.3.2.5.1. Implementation Plan

Richmond South 28kV: 2021

In 2021, a voltage conversion entailing the completion of a 28kV distribution loop in the Richmond South supply region and converting sections along the feeder path will be completed. All necessary infrastructure upgrades to 28kV and installations are involved.

West 12kV: 2021 and onwards

The Beaverbrook 12kV pocket will be converted in 10 phases from 2021 and onwards. This involves all conversions that are needed for the cable renewal. The scope may include upgrading existing primary routing to road right of ways, replacing transformers, and preparing for connections with new trunk infrastructure.

South Nepean 8kV: 2023-2024

South Nepean projects will occur as developments appear and assets reach end-of-life in this region. The conversion from 2023-2024 will be along Prince of Wales Road and Greenbank Road south of Cambrian Road. This pole line will be replaced, upgraded, and be converted to 28kV once more capacity is available on the 28kV system.

Navan Road: 2023

The Navan Road project will take place in 2023. This job will involve converting the existing radial 8kV circuit to 28kV. End of life poles will be replaced, built and insulated to current 28kV standards.

2.3.2.5.2. Risks to Completion and Risk Mitigation Strategies

Risks to completion vary between projects. There are currently no foreseen risks to completion for the given projects.

2.3.2.5.3. Timing Factors

Timing factors vary between projects. Unexpected delays due to the City of Ottawa's scope of work with regards to deep services installations are possible. The yearly asset management cycle throughout the year where areas for voltage conversion projects are identified. This process may cause a change in ranking on the list of planned projects as projects are added or removed.

2.3.2.5.4. Cost Factors

N/A

2.3.2.5.5. Other Factors

N/A

2.3.2.6. Renewable Energy Generation (if applicable)

N/A

2.3.2.6. Leave-To-Construct (if applicable)

N/A

2.3.3. DISTRIBUTION ENHANCEMENT

The Distribution Enhancements Budget Program includes two main programs - The Smart Grid Fund Initiatives and The GREAT DR V2, as well as other minor Distribution Enhancements projects.

Through this program, Hydro Ottawa's total investment over the 2021-2025 period is $12.1M. In Historical Years, Hydro Ottawa has invested $8.9M in the 2016-2020 period. Projects covered under this program are discussed in further detail in the following sections.

2.3.3.1. Smart Grid Fund Initiatives

2.3.3.1.1. Project Summary

The Smart Grid Fund Initiatives program is designed to provide a funding stream for a portfolio of innovation initiatives. These innovation initiatives will provide for the enhancement of tools, technologies, training, or processes in a system operating context that are core to Hydro Ottawa operations and effectiveness. In addition to having a continued internal funding mechanism, Hydro Ottawa will pursue external innovation funding sources such as provincial and federal governments and non-government organizations (e.g Natural Resources Canada, Ontario Ministry of Energy or Independent Electricity System Operator of Ontario). Having a planned investment level and timing will enhance the planning and execution of innovation projects as staff across the organization will be able to provide input towards a known timeline and funding envelope.

2.3.3.1.2. Project Description

Current Issues

The Smart Grid Fund Initiatives project includes innovative initiatives which are part of Hydro Ottawa's Smart Energy Roadmap - a comprehensive plan developed by a cross-functional team of employees forming Hydro Ottawa's Smart Energy Steering Committee. This committee is primarily a combination of management staff from the Information Technology and Distribution Engineering and Operations divisions. With this cross sectional nature and the active participation from the executive management team, the committee is an effective driver for innovation and improvement.

The Smart Energy Roadmap, is the integrated “whole of company” plan to achieve Hydro Ottawa’s Smart Energy vision. This vision is articulated in the company’s Strategic Direction 2016-2020, which also offers the following definition of “smart energy”: “an energy system that makes effective use of available technologies to maximize consumer, community and environmental benefit. It is sustainable, customer-centric, reliable, cost-effective, secure, and constantly evolving. It is responsive to evolving needs and opportunities, and focused on tangible benefit.” The projects under the Smart Grid Fund Initiatives program represent only a subset of the Smart Energy Roadmap initiatives, other initiatives are being undertaken as their own program, or integrated augmentation to existing activities. Some of the initiatives being undertaken as their own program include: Self Healing Grids (Section 4.2.1), AMI outage management Integration (Section 4.1.4) and The GREAT-DR v2 (Section 3.3.2).

Project Scope

Projects planned for the 2021-2025 window include:

- Outage Intelligence. The development of the ability to automatically locate and identify the root cause of distribution system faults.
- Outage Analytics. The development of custom reporting and analytics to be available to any and all Hydro Ottawa staff.
- Smart System Planning: Expand and augment the tools and techniques to provide system information to key decision makers in order to support decisions that align to the real condition of the grid.
- Outage Prediction. Machine learning and Artificial intelligence to identify and prevent incipient faults.

Main and Secondary Drivers

The primary drivers of the Smart Grid Fund Initiatives are:

- Reliability: The primary strategic outcome sought by the Smart Energy Roadmap is the target of developing enhanced grid reliability, and service offerings to enable the provision of 100% reliable electrical service.
- Other Performance/Functionality: The second strategic outcome sought by the Smart Energy Roadmap is to Position Hydro Ottawa to provide its customers with proactive and innovative energy solutions which align with our our customers' needs, preferences, and objectives. Leveraging innovation and technology to align Hydro Ottawa with both current and future market trends
- System Efficiency: One of the key pillars of the Smart Energy strategy as defined in the roadmap is to leverage existing infrastructure and personnel by seeking opportunities that leverage staff's existing knowledge, key competencies, and Hydro Ottawa's physical infrastructure

Performance Targets and Objectives

In selecting specific projects or initiatives to support under the Smart Grid Fund program, the Smart Energy Steering Committee will apply the following criteria:

- Innovation and Technology – Initiatives that leverage technology to align with both current and future markets and position Hydro Ottawa to be Best in Class will be supported.
- Reliability and System Resilience – Initiatives that assist Hydro Ottawa in moving closer to 100% reliability, by improving customer service continuity measures will be supported.
- Environmental Sustainability – Initiatives that serve to reduce environmental impact, supporting Hydro Ottawa and its customer's transitional goal to achieve a net zero carbon future will be supported.
- Revenue Growth and Diversification – Initiatives that have the potential to expand current value and revenue streams, while increasing efficiency of Hydro Ottawa's grid will be supported.
- Leveraging Infrastructure and People – Initiatives that provide opportunities to leverage existing knowledge, key competencies, and physical infrastructure will be supported.

2.3.3.1.3. Project Justification

Alternatives Evaluation

Alternatives Considered

Alternatives considered for the Smart Grid Fund Portfolio:

- Proceed with proposed Smart Grid Fund investments
- Proceed with a different or curtailed portfolio of investment or
- The 'do-nothing' alternative which would ultimately result in a reduced capacity for innovation

Evaluation Criteria

The investment alternatives were evaluated for alignment with the performance objectives listed in Section 3.3.1.2.4. Further evaluation was completed considering support of the System Service criterion of:

- Safety
- Reliability
- Power quality
- System efficiency
- Other performance/functionality

Preferred Alternative

As described in Section 3.3.1.2.3 above, the strategic direction of the Smart Energy Roadmap and the processes that will be used by the Smart Energy Steering Committee to evaluate and specific initiatives to support under the Smart Grid Fund Portfolio align very well to 3 of the above 5 criteria, and the investment portfolio has been prioritized through its impact to performance objectives. It is therefore preferred to proceed with the selected project portfolio.

Given the ongoing initiatives in the 2018 through 2021 time frame (as described under The GREAT-DR project 9202014255) and the other technology investment projects in flight through the 2021 through 2025 time frame it was decided to create a funding envelope that met the following criteria:

- Timing: The years 2022-2025 contained the least number of complex innovation/technology investment projects therefore these years were chosen for the innovation investments
- Funding Levels: The years 2022-2025 contained a reduced level of innovation/technology investment, therefore the following investment levels were selected

Table 2.53 - Historical and Future Smart Grid Fund Program ($'000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure							$0.50	$1.01	$1.05	$0.93

Benefits

While the benefits of the individual initiatives are yet to be completely defined, the process by which the initiatives are selected for funding does take into account the benefits in the following categories.

Table 2.54 - Project Benefit

Benefits	Description
System Operation Efficiency and Cost Effectiveness	As stated above, one of the key pillars of the Smart Energy strategy as defined in the roadmap is to leverage existing infrastructure and personnel by seeking opportunities that leverage staff's existing knowledge, key competencies, and Hydro Ottawa's physical infrastructure. This leveraging will result in direct improvements to the System Operation efficiency and cost effectiveness. Furthermore, one of the key criteria used to evaluate projects for support is Innovation and Technology.
Customer	The primary strategic outcome sought by the Smart Energy Roadmap is the target of developing enhanced grid reliability, and service offerings to enable the provision of 100% reliable electrical service. The second strategic outcome sought by the Smart Energy Roadmap is to Position Hydro Ottawa as the provider of proactive and innovative energy solutions which are driven by our customers' needs, preferences, and objectives.
Safety	While safety is not a specific criterion that has been called out by the Smart Energy Roadmap, it is expected that safety remains at the core of all Hydro Ottawa projects and as such initiatives the further enhance the safety of customers and staff will be given priority.
Cyber-Security, Privacy	While cyber-security is not a specific criterion that has been called out by the Smart Energy Roadmap, it is expected to be a factor in the evaluation of the initiatives alignment to the Innovation and Technology criteria.
Coordination, Interoperability	N/A
Economic Development	Initiatives that have the potential to expand current value and revenue streams, while increasing efficiency of Hydro Ottawa's grid will be supported, therefore there is a significant potential for the development of new business within the Hydro Ottawa group of companies or through partnerships with other utilities and 3rd parties.
Environment	Initiatives that serve to reduce environmental impact, supporting Hydro Ottawa and its customer's transition to a net zero carbon future will be supported

2.3.3.1.4. Prioritization

Consequence of Deferral

The Smart Grid Fund Program is intended to foster and support innovation and improvement within Hydro Ottawa. Deferral of the creation of the Smart Grid Fund program could result in missed or delayed opportunities for innovation, improvement, or 3rd party funding support.

Priority

Based upon the issues described in section 2.1, and potential benefits described in section 3.3; this program is considered a Medium priority.

2.3.3.1.5. Execution Path

Implementation Plan

The implementation plan for the Smart Grid Fund program is based on a governance model as provided by the Smart Energy Steering Committee. This includes an intake process for innovation ideas and proposals and evaluation criteria that is articulated in the Smart Energy Roadmap document. Through the 2021-2025 window Hydro Ottawa will undertake to:

- Outage Intelligence. The development of the ability to automatically locate and identify the root cause of distribution system faults. Investing in models to leverage existing, and newly available data to respond to system outages.
- Outage Analytics. The development of custom reporting and analytics to be available to any and all Hydro Ottawa staff.
- Smart System Planning: Tools and techniques to provide system information to key decision makers in order to support decisions that align to the real condition of the grid. Dissemination of asset data in real time, and forecasting system loads in local neighborhood levels.
- Outage Prediction. Machine learning and Artificial intelligence to identify and prevent incipient faults.

The individual projects will be evaluated and prioritized according to impact, timing, and budget.

Risks to Completion and Risk Mitigation Strategies

As the Smart Grid Fund program contains many initiatives, there is little risk to execution of the overall program. Projects and initiatives can be exchanged or re-prioritized based on the issues or constraints discovered.

Timing Factors

There are essentially two elements that could affect the timing of the investments under the Smart Grid Fund Program.

- Availability of external funding: There is a potential that the funding available requires the adjustment of the internal investment profile.
- Availability of staff: As with any project execution, internal resources are critical in order to ensure success. Innovation projects have the potential of being deferred in order to support programs and projects that are considered essential to Hydro Ottawa.

Cost Factors

As with any innovation portfolio, there is a possibility that the technology aspects of the initiative proeve to be more complex and therefore costly than originally anticipated. The mitigation strategy is to secure external funding so that the risk is shared across multiple sources of funds.

Other Factors

As with any innovation portfolio there is the potential of new technology developments or regulatory constraints that could affect the overall execution of the program. However, as there are several candidate initiatives under the Smart Grid Fund Program, the potential of failure is significantly reduced.

2.3.3.1.6. Renewable Energy Generation (if applicable)

N/A

2.3.3.1.7. Leave-To-Construct (if applicable)

N/A

2.3.3.1.8. Project Details and Justification

Table 2.55 - Project Benefit

Project Name:	Smart Grid Fund Initiatives
Capital Cost:	$3.49M
O&M:	TBD
Start Date:	1-Jan-2022
In-Service Date:	Multiple
Investment Category:	System Service
Main Driver:	Reliability
Secondary Driver(s):	System Efficiency and Other Performance objectives
Customer/Load Attachment	All customers
Project Scope	
The scope of initiatives that will be supported under this portfolio will be determined according to Hydro Ottawa's Smart Energy Roadmap that has been prepared by a cross-functional team of employees known as the Smart Energy Steering Committee. This committee is focused on developing a strategy for innovation and process improvement within the utility operations in order to improve both efficiency and effectiveness	
Work Plan	
The planned initiatives will be executed in the windows listed below. ● Outage Intelligence (2022-2023) ● Outage Analytics (2021-2022) ● Smart System Planning(2023-2025) ● Outage Prediction (2025)	
Customer Impact	
The primary strategic outcome sought by the Smart Energy Roadmap is the target of developing enhanced grid reliability, and service offerings to enable the provision of 100% reliable electrical service. The second strategic outcome sought by the Smart Energy Roadmap is to position Hydro Ottawa as the provider of proactive and innovative energy solutions which are driven by our customers' needs, preferences, and objectives.	

2.3.3.2. The Grid Edge Active Transactional Demand Response 2.0 (The GREAT-DR v2, currently known as "MiGen")

2.3.3.2.1. Project Summary

There are many stressors on the electricity grid including cost, grid management, climate change, electrification, and meeting increasing customer expectations for more autonomy.

To evolve and enhance the electricity system, The GREAT-DR v2 (TGDR2) project was created to address these stressors for the stakeholders with an open source, worldwide royalty free interoperable solution platform in place of the standard costly one outcome wires solution. This end-to-end interoperable platform and by design adheres to Privacy-by-Design, best cybersecurity practices and interoperability. The architecture is hierarchical to serve from the market operator to the prosumer at the edge, and is largely decentralized in grid management for visibility, autonomy, resiliency and scalability. The GREAT-DR largely consists of smart software solutions with physical hardware for monitoring, computing and communicating.

The GREAT-DR effect on the grid is to optimize existing distribution, transmission and centralized generation infrastructure by managing supply-demand locally. This will thus enable:

(1) Customer loads to follow supply of GHG-free electricity sources and minimize need for new fossil generation;
(2) Grids to optimize utilization to their dynamic capacity (not just the lower set planning limit), minimizing need for costly infrastructure upgrades;
(3) DERs to effectively integrate to the grid; and
(4) Markets that encourage prosumers to automatically bid their DERs into the grid and trade with others.

This will be done by establishing premise, local, zonal and grid level DER management while providing a Transactive Energy Market (TEM) that compensates participating prosumers.

The project will establish DERs at community housing complexes and private residences in the Ottawa-area and demonstrate the solution through 2020 at approximately 200 customer premises.

2.3.3.2.2. Project Description

Current Issues

There are several stakeholders in the electric utility industry, and each has issues that are unique and also similar. The current major issues are:

1) Grid Management Constraints

Factors affecting market operator and local distribution company optimization of grid management (planning, investing and operating) are level of grid visibility, control, and ability to act (personnel plus systems resources). Spinning reserve, lower asset loading, and single contingency are examples of costly idle buffer capacity to cover for comfortable margins of error. Also, provincial demand response has addressed the provincial peak for reasons largely to balance supply to demand. However, peak loading of any distribution system asset is very much likely not coincident to another asset or the provincial peak.

Another constraint is that many utility grid management tools are not interoperable and that can lead to increased cost pressure and stranding of assets if the asset can't keep up to the required functionality.

The GREAT-DR will provide grid edge level very near real time visibility to the utility and market operator for optimal planning and operation, plus control of loads and sources that can aggregate to meaningfully benefit grid loading, quality and stability.

2) Social

Customers are seeking more autonomy, personalized service, or more control of their usage and thus the amount of their bill. Time-of-Use rates have helped move off the traditional provincial peak, but the peak has shifted because of more dispersed generation and change in customer behaviour. However, the system peak is not the same across the transmission planning zones, the utilities within these zones, or neighbourhoods within a utility service area, so the challenge is in socializing customers to local constraints too without confusing or overburdening them. Also, customers vary in their want (behaviour) or ability (demographic, tool or premise constraints) to participate in energy reduction or load offset activities.

The GREAT-DR democratizes the grid and provides benefits to all stakeholders, including those living in community housing. By managing at the edge and scaling to hundreds of thousands of customers, shoring of the grid can be shared across all prosumer types and amongst more variety of meaningful loads and energy sources at the edge. Transactive Demand Response over a larger prosumer base would reduce the reliance, or burden, on few participants and increase probability of achieving grid shoring targets. By actively managing the loads and sources to the dynamic asset capacity rating, the customer benefits with greater ability to electrify more, connect more green energy sources, and storage, plus be benefit from the increased utilization of their and the utility's existing assets. Added social benefit is the fact that The GREAT-DR is built on the three pillars of Privacy-by-Design, cybersecurity, and Interoperability.

3) Economic:

Economically, the bottom line for a customer is their electricity bill and fees imposed to meet interconnection requirements when adding more load or energy sources within their premise, including service entrance upgrades if needed.

Present rate structures are not conducive to non-incented introduction of dispersed generation or energy storage. However, tools for the customer to manage their bill under a fixed load contract or critical peak pricing structure, or even to have or take advantage of a Transactive Energy Market are not mature. Grossly breaking down the rate structure into the commodity and delivery components, it is the latter that the utility can influence through its investment and management of the grid.

The GREAT-DR, as a tool, will help create optional rate structures for prosumers, similar to mortgage structure options, which are suitable for the type of participation they want in the grid. Also, by providing a more feasible non-wires solution, The GREAT-DR can help utilities reduce spending on bulking up the grid assets and save money or refocus on under met reliability needs. Because of the interoperability requirements of the GREAT-DR, there is a higher likelihood of not-stranding grid-supporting assets. Other economic benefits come from: the ability to allow higher penetrations of electrified loads and sources; greater competitiveness in provision of The GREAT-DR shore supporting devices because of the open source, worldwide royalty free platform, and it will allow; compensation of prosumers for helping shore the grid, through establishing a Transactive energy market that also allows prosumers to trade energy amongst themselves; lower commodity prices since The GREAT-DR machine learning will allow the market operator to forecast and predict better, and rely on other methods of providing least cost of service; provision of ability to improve reliability by autonomously managing energy source interconnection set-points adhering to the IEEE 1547-2018 generation interconnection standard i.e., ride through transient aberrations in the grid, plus help in restoring service quicker by allowing generation to offset load and provide for more than an N-1 contingence, including sustainment of an isolated micro-grid.

4) Environmental

The environmental issues reflect in physical, social and economic implications. Climate change can radically change the asset dynamic loading capacity, and can create transient aberrations or longer term disruptions to electrical service. Customers are increasingly concerned about their impact on the environment and policy makers are following suit to transition, for example, to net-zero carbon (NZC) buildings and homes.

Overall, The GREAT-DR will help evolve the grid from being load-following to supply-following. The GREAT-DR, by dynamically managing loads and energy sources at the grid edge, will help reduce reliance on fossil fuel peaking plants to mitigate intermittence of green sources or a bit longer peaking periods. It can also manage the balance across prosumers to achieve Net Zero Carbon Communities, and accelerate electrification (transportation and heating) required to meet climate change goals by ensuring existing grid infrastructure can accommodate load growth.

Project Scope

This is a project that will demonstrate an alternative to the wires and centralized generation solution for growing electrical load, plus a least-cost-of-service option for shoring the grid.

The GREAT-DR v2 (which has more recently been re-branded as “MiGen”) will span approximately three years from Nov. 20/’18, to Mar. 31/’22 under the NRCan Smart Grid Fund, and will extend an additional five years for monitoring performance.[8] Hydro Ottawa will own the assets and be responsible for such for the duration of its useful life. These assets include a mix of solar PV, smart inverter types, battery energy or thermal storage systems, air-source heat pumps, smart thermostats and load control modules, plus The GREAT-DR elements and subscribed requisite software supporting systems, such as the software for machine learning, Transactive Energy Market, Back Office System, customer loyalty and settlement, and user GUI.

The GREAT-DR solution platform will be standards based and remain an open source, worldwide royalty free platform is pillared by Privacy-by-Design, best cybersecurity practices, and interoperability principles. The IEEE 2030.5 standard is the foundation for interoperability. Through IEEE, not-for-profit worldwide organisation that advanced technology for the benefit of humanity, Hydro Ottawa and its partners will inform the standard roadmap and certification assessment program. IEEE will host and protect The GREAT-DR within its Open Source Community.

An outcome of The GREAT-DR platform will be a template strategy for achieving a Net-Zero Carbon Community (NZCC) community overlaid with market-driven Transactive Demand Response (TDR) solution that optimizes energy sources and loads in real-time for an overall smart energy network (TGDR2) and encourages prosumer behaviour change. Thus, it will be used to:

i) engage and educate participating customers and others towards becoming prosumers,

ii) directly connect prosumers with the system and market operator through a Transactive Energy [shadow] Market (TEM) and compensate them for savings they provide the utility and bulk system, and

[8] Natural Resources Canada ("NRCan") is a critical partner for this project. At the time of writing, in response to expressions of interest from NRCan itself, Hydro Ottawa is engaged in detailed discussions with NRCan regarding the lessons learned from the initial phase of the project and how these lessons can be incorporated into the next phase. Through this engagement, NRCan has signalled openness to adjusting the parameters of the project, if it can be demonstrated that such adjustments will add value and ensure that the broader objectives of both the project and NRCan's funding program will be met. Depending upon the outcome of further discussions with NRCan, Hydro Ottawa may subsequently submit updates to the project information included in this Application.

iii) engage the regulator, market operator, and governments for informing policy and program development.

TGDR2 will manage DERs in real-time within the grid's dynamic operating limits through automatic and active negotiation between devices that use or produce electricity at the customer-level. This is through:

i) at the premise-level, a home energy management system controller (HEMS-C) and customer agent (CA),

ii) at the local (i.e., neighbourhood) and zonal-level through transactive / transformer agents (TA), and

iii) at the grid-level, a back office system (BOS).

The second version of The GREAT-DR platform will be enhanced beyond Technology Readiness Level Five (TRL5) – Demonstration and thus much closer to providing sustained grid benefit. It will be deployed to the participants in the first version, and the 200+ participants in the second version. The participant demographic varies include a variety of age groups, income levels, states of employment, load types and sources, plus personalities.

Main and Secondary Drivers

The main and secondary drivers for The GREAT-DR (currently known as "MiGen") follow.

Proprietary and Non-interoperable Grid Solutions:

There are many solutions for Demand Response and though they may have some interoperability features, they are not truly interoperable because of selectivity from within a standard and proprietary additional layers. This situation handcuffs the adopting utility to, for example, a specific product development roadmap, vendor's service or product line, and ongoing fees. Also, few solutions have been developed with the utility full spectrum need in mind. The utility should demand systems used in the management of the grid to be interoperable, but can only do so if there is a common rule book to follow i.e., IEEE2030.5, and platform to plug into i.e., The GREAT-DR.

Poor Resiliency from Centralized Systems:

There are other parties attempting a Transactive Demand Response platform, however, development is in infancy and not gaining interest for three reasons: relying on a centralized architecture, being proprietary, and lax on customer privacy. A data heavy, centralized system is inherently costly in infrastructure, more latent, plus lower in performance and wider in affected service area when parts of the central system fail.

Sole Purpose Solutions:

The many behind-the-meter technology management devices serve a single purpose, like thermostats for temperature, load controllers for on/off of medium or large loads, solar inverters for generation output, and battery systems for absorbing or sourcing energy. For a utility to interact with each of these devices individually is impractical, and non-optimal. An intelligent device that can manage each and be the contact to the grid is ideal. The GREAT-DR Home Energy Management System Controller element would be the interface that smartly coordinates management of these technologies.

Fear of Overwhelming Data Management and Communications:

Data from behind-the-meter devices have been seen as a treasure, and the overhead, security and privacy concerns of funnelling all that data to a centralized location for processing and storing has typically been ignored. True, the speed and cost of managing big data is improving, but the other problems remain. A data governance model for defining the necessary data, handling and storage in a hierarchical, decentralized system can overcome these problems. TGDR ensures an efficient, secure and open-format data management. As a result, the project right-sizes data exchange (2-4kB files), ensures privacy, and establishes a cyber-secure firewall between prosumers and the grid (both in terms of its depth and breadth). Predictive analytics forecasts when DER support is needed.

Supervision-Intense:

The system operator, grid planner and prosumers are overtaxed with tasks and data. For the utility, it's becoming increasingly complex to decipher, forecast or predict the load profile, prepare work plans, restore power, and determine infrastructure needs because of the radical dynamics in the grid caused by intermittent or dispersed generation, micro-grids, mobile loads, and energy storage. For the customer, it's becoming increasingly complex to adapt to changing messaging regarding grid needs (energy conservation or demand reduction), and stay diligent in complying so they can reduce their bill. These issues will become increasingly difficult with higher penetrations and introduction of Transactive Demand Response, unless the data is streamlined, and the activities more automated, as is being done with The GREAT-DR. As an example, without automation and machine learning of The GREAT-DR, the utility's management of the set-points per the new generation interconnection standard IEEE 1547-2018 as the grid feeder connection (normally open point) changes, and a planner's ability to know an asset's real loading becomes intensely laborious, prone to error and nevertheless costly.

Complex Integration & Management of New Technologies:

Utility and prosumer integration and management of new technologies is complex to assess and because of lack of good tools and skill, penetration levels are constrained, interconnections costly, and management complex as explained herein.

Microgrids:

TGDR negotiates to optimize load-source-infrastructure balance where renewables, storage and load control exists in reasonable proportion. It will control fuel-source optimization, for example between a fossil fuel and electricity. It can be used to interact with ant tertiary controllers for a microgrid.

Energy Storage:

TGDR2 will strategically use TRL5+ battery and thermal storage technology to increase power and other energy system flexibility as an integrated solution, and will prove stacked value.

Distributed Energy Resource Management (DERM):

Our approach will integrate behind-the-meter customer energy loads and sources into the grid. Optimization decisions dispatch, storage, and on best fuel source will be made at the customer level using system-level information. The back office system contemplated as part of this project is an innovative DERMS.

EV integration:

TGDR2 treats EVs as watts and nega-watts for Vehicle-on-Grid (VoG) management. Thus, the intent is to manage EV charging within electrical service constraints to avoid service upgrades still providing for customer-centric charging.

Forgetting the Customer:

Customers are no longer just complaining about their electricity bill or concerned about the environment, they want to act. When they purchase an EV, generation or storage system they expect simple, non-costly interconnection service from the utility, and the best return. Also, when Demand Response strategies are adopted, they want their comfort, privacy and no complexity, and final say. Customers in effect are becoming prosumers, and their satisfaction can be improved by involving them to the extent they wish, in helping reduce their bill with minimal effort on their part. TGDR includes a novel approach to engage them and encourage participation in shoring the grid through an automated approach that considers their preferences, keeps their activity private and secure, provides feedback, and is powered by voice assistance. The prosumers will be rewarded for their contribution to shoring the grid. Using a tier prosumer classification approach, different awareness strategies can be used to educate or encourage prosumers in their energy use.

Performance Targets and Objectives

The targets to achieve with TGDR are:

1. To have 90%+ participant satisfaction.
2. To demonstrate the economic benefit to the ISO, DSO and prosumer in helping shore the grid using The GREAT-DR.
3. To be able to offset at least on average of 2kW of coincident load on a neighbourhood transformer for each participating premise.
4. To have a Transactive Demand Response activity issued and acted upon, in non-emergency cases, and targets achieved within five minutes; in emergency cases, to do so within 30 sec.

5. To demonstrate how generation can help restoration efforts and not remain off until five minutes have passed after restoration.

2.3.3.2.3. Project Justification

Alternatives Evaluation

Alternatives Considered

Purchase of DERMS system: these are centralized back-office systems that can indirectly control dispersed generation assets. However, they are complex, highly dependent on accurate grid modeling and data mapping, plus costly to implement and maintain. Also, they do not involve the customer as a prosumer and add-on equipment, modules or services are likely restricted to OEM-only options.

Increasing grid asset capacity: commonly referred to as “the wires solution,” this is a relatively simple, traditional though costly solution. Decisions on increasing grid infrastructure capacity are typically made when peaking is just even a few hours a season because of poor grid visibility, data analytics, or alternative tools for mitigating relatively short loading periods. The ramifications of increasing distribution transformer size at the edge trickles upstream and translates to requirement for increasing capacity of cabling, wiring, duct bank sizes, pole classes, switching equipment, station transformation, and so on. Money saved could better be left as saved if not spent to address reliability.

Adopt proprietary non-interoperable interfaces: there are vendors that offer demand or energy management systems, and if they have an interface for utility oversight or management, require their own interfaces with the utility. These systems only work with certain consumer behind-the-meter devices sold from or aligned with the same OEM. It would be costly and complex for a utility to manage an interface per OEM or even align to one OEM; customers will want choice and not accept imposition of what to procure and from whom. The concept behind TGDR is to have one interface for the utility and customer, and same rules for the OEMs to follow if they want their products or services to interact with the grid.

Do-Nothing:

Potentially costly – to the customer -- generation, storage or electrified load interconnection, and costly accommodation for the utility. Doing nothing can prematurely age assets and lead to worsening reliability. It will also reduce penetration of electrified loads, generation or storage. Also, there won't be a feasible way to manage inverter connected generation under IEEE 1547-2018.

Preferred option:

Other than TGDR, it is increasing grid asset capacity, though costlier it provides for customer choice and simplicity for the utility.

Evaluation Criteria

Provide a description of evaluation criteria that were used to compare alternatives.

The evaluation criterion for comparing alternatives at this project demonstration phase is qualitative. During the third year of the three-year demonstration project, a qualitative assessment will be more meaningful.

Preferred Alternative

The preferred alternative to The GREAT-DR solution is simply defaulting to increasing grid asset capacity. Assessment of this project using traditional asset management investment tools are not suitable as The GREAT-DR project is a novel demonstration project at this time to learn and provide the industry an alternative to other non-ideal solutions, including an alternative to the "preferred alternative" selected here. The strong potential upside benefit to all the stakeholders should justify this trial. The lessons learned will provide the necessary information for traditional asset investment evaluation methods.

Project Timing & Expenditure

Despite many challenges, for the first version of The GREAT-DR, Hydro Ottawa recruited 13 participants, plus kept its expenditure commitment to within 2% of budget. The first TGDR platform was partially funded by the Ontario Smart Grid Fund (OSGF) and the LDC Tomorrow Fund. Hydro Ottawa's proposal was to demonstrate the platform using five computers mimicking five different customers. Instead the OSGF asked if Hydro Ottawa could demonstrate with up to 30 real participants. Without additional funding to cover behind-the-meter installations, Hydro Ottawa was able to secure partners that provided greatly discounted products and services, and provided the discounted package for Participants. Prospective participant interest was high and oversubscribed; however, project conditions (e.g., roof condition & orientation; electrical service; interest of others connected to the same distribution transformer, load variety, etc.) ruled any out, and political climate leading up to the provincial elections complicated and hindered recruitment.

In the second year of this three-year demonstration project, additional to the technical assessment for TGDR, Hydro Ottawa will conduct a comprehensive economic and social assessment versus alternative solutions.

Cost on TGDR2 is being mitigated by:

- Applying for funding from other sources.
- Requiring collaborating partners to “have skin in the game” by: providing products and services at or below most preferred customer pricing; agreeing, where reasonable, to fixed paid budget; providing in-kind support to cover risk that may arise during execution of their role.
- Planning heavily upfront in the project execution process and managing the project professionally throughout the timeline.

Table 2.56 - Historical and Future Expenditure Levels ($’000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Expenditure (Gross)				$1.07	$1.48	$4.65	$1.01			
Capital Contribution					$(2.68)	$(3.08)	$(1.98)			
Contributed Plant					$1.50	$1.06	$0.25			
Expenditure (Net)				$1.07	$0.31	$2.63	$(0.71)			
Total Expenditure				$1.07	$0.31	$2.63	$(0.71)			

Table 2.57- Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Since TGDR (currently known as "MiGen") provides benefits to the Prosumer, utility and market operator, the cost is also spread across these stakeholders and makes it more affordable to each. Unlike traditional solutions, TGDR offsets costs for each stakeholder. System Operating Efficiency: helping restoration by semi-autonomously staggering large load pick-up versus having the system operator concerned with avoiding cold or hot load pick-up; allowing energy sources to reduce load whereby in the past sources were kept off until five minutes after the grid was stable; providing better visibility into the grid and, through machine learning, better forecasting and predicting of load shape so better dispatching of central generation. Cost-effectiveness: providing decentralized management solution that is flexible to the feeder reconfiguration; providing a field proven interoperable platform that is open source, worldwide royalty free to encourage competitive offering of more choice products and services that encourages competitiveness and prosumer adoption; providing an alternative to service upgrades for customers who electrify more or introduce generation, and thus avoid trickle up grid upgrade costs that get socialized. Set-targets for key performance: the ultimate objective is to support the five-minute market as a preferred method for providing least cost of service. This means that a Transactive Demand Response (TDR) request needs to be acted upon by a prosumer device within five minutes in non-grid emergencies, and within 30seconds in a grid emergency; TDR requests are met 75% of the time in the first call. Other efficiencies come from utilities being able to use TGDR as a cost effective tool for managing inverters per IEEE1547-2018.
Customer	TGDR2 offers many values to a prosumer, namely by: 1. Sharing in the value from helping shore the grid. So, when prosumers help the grid, they receive benefit through a loyalty program and settlement program that's tied to a Transactive Energy Market. The activity is conducted automatically with minimal prosumer involvement beyond setting preferences on how their assets can be used. 2. Deferring or avoiding service entrance upgrades when adding more electrified loads or sources. 3. Containing or reducing energy source interconnection costs related to monitoring and protection & control. 4. Trading opportunity, though utility or aggregator mediation, to trade energy with others. 5. Improving more timely visibility and analysis of their energy use and production. 6. Increasing autonomy with how and when they can meet grid needs so comfort is maintained. 7. Increased reliability as energy sources can help more quickly restore service and sources that are IEEE1547-2018 complaint can be used to avoid outages stemming from transient aberrations in the grid. TGDR2 also helps the customer rate base monetarily or through improved reliability when respectively used to defer investment in increasing grid capacity, or shifting that investment to reliability improvement projects.

Benefits (Cont'd)	Description (Cont'd)
Safety	A practical assessment on how TGDR may help health and safety protections and performance will be completed in the third year of the demonstration. Anecdotally, TGDR should help prescribe when energy sources can generate while crews are working on the grid.
Cyber-Security, Privacy	TGDR follows Privacy-by-Design principles and will follow or exceed best cyber-security standards, period. TGDR is based on the IEEE 2030.5 interoperability standard, and the inverter based generation shall comply with IEEE1547-2018 interconnection standard. Communications will employ a WiFi mesh based on IEEE standards. The lessons learned through the TGDR demonstration project have been, and will continue to be, used for informing the standards roadmaps and updates. Members of TGDR are on the DOE sponsored IEEE2030.5 roadmap, and the IEEE Conformity and Assessment Program (for certifying against the standard) committees. The TGDR hardware elements are certified before installation: the Transformer/Transactive Agent (TA) is utility O.Reg. 22/04 compliant; the Customer Agent (CA) and the Home Energy Management System Controller (HEMSC) are both field certified by ESAFE to be CSA approved.
Coordination, Interoperability	If applicable, please explain how the investment applies recognized standards, referencing co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry. In addition to the commentary under "Cyber-Security, Privacy," the IEEE2030.5 is a standard that applies from the Market System Operator to the Prosumer. Other interoperability standards like DNP3, OpenADR, OpenFMB, or Sunspec are specific to the utility, customer or a product and not broadly i.e., end-to-end, applicable as IEEE2030.5 and not nearly as comprehensive either. The essentials of TGDR will be available to the public as an open source, worldwide royalty free platform. This is to encourage adoption by all stakeholder groups, and through this demonstration, the partners will be the pioneers. Hydro Ottawa is gaining interest in the platform from other vendors, the IESO, and other utilities. Part of its mandate under the funding agreement is to disseminate information on TGDR and build the ecosystem for it to succeed.
Economic Development	If applicable, please describe the effect of the investment on Ontario economic growth and job creation. The demonstration is taking place in Ontario and many of the partners are from Ontario. The benefits with operating TGDR will remain in Ontario.
Environment	If applicable, please describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies. The TGDR demonstration will show how smart management of green generation, battery and thermal storage, increase in electrified loads and load control can help communities achieve Net-Zero Carbon status and maintain it through changes on the prosumer side. TGDR will also demonstrate how it can provide least cost of service for the market operator and help offset costly – environmentally and monetarily -- fossil fuel peaking plants.

2.3.3.2.4. Prioritization

Consequences of Deferral

Deferral of this project first and foremost jeopardises funding from NRCan. Secondly, deferral will place the utility in a precarious position with generators complying with IEEE 1547-2018. The utility will be able to request set-points in the inverter, however, will not have the appropriate tools for confirming continued compliance, or changing the set-points dynamically to changing feeder conditions.

The demonstration project will provide data for addressing the consequences / risks in the remaining categories.

Priority

TGDR is a high priority in context to other grid modernization demonstration projects. Funding and resourcing for projects in the DSP are constantly under pressure and a remedy is needed that breaks traditional approach to solving grid growth and reliability, plus management of the grid by system operations and asset planning. TGDR is a demonstration and not an immediate replacement solution to a project in the DSP; however, it has the great potential to be, and this demonstration must be undertaken to provide the results, knowledge and experience for application.

2.3.3.2.5. Execution Path

Implementation Plan

The project will work with Ottawa-area community housing authorities (who this consortium considers to be ideal benefactors of this funded project), to embed Distributed Energy Resources (DERs) into their premises and bring them towards Net-Zero Carbon Community (NZCC) status and maintaining such. To enhance and scale TGDR responsibly, the project will be managed in three overlapping phases:

- Phase-I: starting in Q2-2019, begin retrofitting a community with CA+HEMS-C, solar PV, smart inverter, battery energy storage, air-source heat-pump with thermal storage, and HEMS (smart thermostat, load controllers). If funding becomes available through other sources, we would propose adding smart lighting, and smart appliances (i.e., fridge and dryer). TGDR1 and TGDR2 will be demonstrated here, when proven with existing participants in TGDR1.

- Phase-II: starting Q2-2020, the software modules interfacing with TGDR will begin stand-alone testing in the lab. By Q2-2021, the software modules would have been interfaced with TGDR and tested before full deployment in the test communities.
- Phase-III: starting Q3-2021, after having designed and installed DERs into a second community, TGDR2 will be ready for full scale demonstration, strategizing use for achieving and maintaining a near-NZCC, running use cases, monitoring results, tweaking for enhancement, reporting and closing out the project.

Risks to Completion and Risk Mitigation Strategies

Table 2.58 - Risk to Completion & Risk Mitigation Strategies

Type of Risk (Choose an item.[9])		Mitigating Measures / Estimate Likelihood (Choose an item.[10])		Residual Risk to Project
Large complex project with many partners that may go over budget or be delayed.	Financial	Establish rigorous utility project governance with a steering committee and a dedicated project manager along with a Project Management Office to manage the partners and their individual workstream. Create fixed budget with developers, devote great effort in the SOW, Gantt, and collaboration agreements with the partners	Medium	While project risk will be reduced with project management office established, there will still be some residual project risk due to unforeseen circumstances from factors not in our control (i.e., regulatory, political, economic, trial site owner issues).

[9] Financial – e.g. project funding issues; Market – e.g. market environment, product entry; Technical – e.g. equipment failure; Regulatory – e.g. environmental approvals, permitting issues; Personnel.
[10] Likelihood – Low – unlikely to occur <5%; Medium – moderately likely to occur ~25%; High – very likely to occur > 50%.

Type of Risk (Choose an item.[11]) (Cont'd)		Mitigating Measures / Estimate Likelihood (Choose an item.[12]) (Cont'd)		Residual Risk to Project (Cont'd)
As there are many elements in the TGDR2, full interoperability amongst project elements may not be achieved.	Market, Technical	TGDR2 has selected a well-defined industry standard as the interoperability approach (IEEE 2030.5). As this is well-defined, the partners will be including this in the product development.	Low	Product partners are committed to IEEE2030.5 to ensure interoperability. The standards expert on the project is engaging with others to identify the critical elements for interoperable interfaces.
Customers may be uninterested in participating in the TEM.	Market	Project includes professional resources to engage and educate participants in the TGDR2 and TEM. These resources will develop materials to inform customers upfront. The TEM will be made attractive for participants by stacking the value from all sources (i.e. utility, market, carbon, other participants). There will also be ongoing engagement through Algonquin College in communications, real-time monitoring and satisfaction survey tracking.	Medium	The Loyalty program is intended to help increase prosumer participation. Also, autonomous operation of TGDR once prosumer preferences are set should improve their acceptance of TGDR as a non-burdensome and rewarding system. The TGDR Team will also engage with the prosumers in the trial to inform and motivate them.
Many concurrent partner work streams are dependent on each others' milestones.	Technical	The established Project Management Office will manage and track the partner milestones. There are technology milestones associated with establishing the TGDR2 and the TEM, and there are construction milestone associated with installing the DERs at the customer sites. The technology milestones and construction milestones can be partially decoupled.	Medium	Should a technology milestone not be met by a partner, an emulation for the partner segment can be used until ready.

[11] Financial – e.g. project funding issues; Market – e.g. market environment, product entry; Technical – e.g. equipment failure; Regulatory – e.g. environmental approvals, permitting issues; Personnel.
[12] Likelihood – Low – unlikely to occur <5%; Medium – moderately likely to occur ~25%; High – very likely to occur > 50%.

Type of Risk (Choose an item.[13]) (Cont'd)		Mitigating Measures / Estimate Likelihood (Choose an item.[14]) (Cont'd)		Residual Risk to Project (Cont'd)
Key resources may change within the partners (e.g. retirement, organizational restructuring).	Personnel	The project has engaged with partners at the highest level and have received commitment from the organization. Should individual resources change, the organization will still be able to retain the knowledge to follow through on their contributions.	Low	There are no planned retirements in the next four years. Documentation and assessment of this risk will be on going.
Other government funding sources may fall through.	Regulatory	There are many funding sources available from federal, provincial and municipal sources along with government agencies and academic grants. Should any one source fall through, the Project Management Office will seek alternative sourcing from another funder.	Medium	Negotiating de-scoping with the primary funder, and any other funder, is an option, though non-ideal.
Engineering challenges and technical issues may arise with components of the TGDR2, TEM and DERs.	Technical	The project will establish a robust solution architecture upfront to ensure the engineered solution is sound and built in an interoperable manner. Once the system is launched, the project will have dedicated resources to monitor the system and respond immediately to any break-fix issues.	Low	Lessons learned from TGDR1 will be very helpful.
Prices of some of the components of the TGDR2 may increase (i.e. cost of lithium rises, cost of silicone for solar panels rises)	Market	While the prices of project components are expected to decrease over the course of the project, should there be any temporary sharp rise in the cost of any individual component, the Project Management Office will examine pivoting scope to a lower-cost solution.	Medium	De-scoping on quantity is an option. Some products are in USD, and the CDN is forecasted to drop over the project life.

[13] Financial – e.g. project funding issues; Market – e.g. market environment, product entry; Technical – e.g. equipment failure; Regulatory – e.g. environmental approvals, permitting issues; Personnel.

[14] Likelihood – Low – unlikely to occur <5%; Medium – moderately likely to occur ~25%; High – very likely to occur > 50%.

Type of Risk (Choose an item.[13]) (Cont'd)		Mitigating Measures / Estimate Likelihood (Choose an item.[14]) (Cont'd)		Residual Risk to Project (Cont'd)
Integration of new software components with existing Hydro Ottawa's Business Support Systems	Technical	BluWave, and Back-Office-System components may need to connect to existing Hydro-Ottawa systems. Some partners have done such integration in other projects. However, TGDR will be designed to rely on field generated information and not secondary handled data, so ties to Hydro Ottawa's systems may be limited or avoided.	Medium	Offline file transfer for seeding machine learning can be done. Emulation may be needed in the worst cases.

Timing Factors

The priority of this project will remain high unless during development there becomes a serious lack of progress, funding, or achievement of intended outcomes.

Project phase timing may be adjusted depending on material availability, site readiness, technical readiness, cashflow, regulatory or political changes.

Cost Factors

Include any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.

CRA is not a factor in this project because the generation capacity is below the threshold of concern (less than 250kW of solarPV on any High Voltage Distribution Station).

[15] Financial – e.g. project funding issues; Market – e.g. market environment, product entry; Technical – e.g. equipment failure; Regulatory – e.g. environmental approvals, permitting issues; Personnel.

[16] Likelihood – Low – unlikely to occur <5%; Medium – moderately likely to occur ~25%; High – very likely to occur > 50%.

Factors that may change the project cost are: unforeseen site conditions that would affect installation cost; increase in material costs due to USD exchange rate; change in permitting and approval costs; unexpected increase in labour costs.

Other Factors

Success of this demonstration project will depend on customer/prosumer acceptance; however, that factor is under test in this project. So, through the automation of TGDR and use of the Loyalty and eWallet components, the chance of success is anticipated to increase.

Behind-the-meter product discontinuance may be a concern, though continued support is anticipated through the collaboration agreement with the participating partners.

2.3.3.2.6. Renewable Energy Generation (if applicable)

The inverters used will be IEEE1547-2018 compliant, and this standard by nature should allow higher REG penetration levels, especially when managed through TGDR. No impact on the grid is anticipated by introducing the behind-the-meter REG devices as this was assessed when selecting the sites. Nonetheless, a TGDR use case will be testing how TGDR can be used to avoid accommodation of REGs on the grid.

2.3.3.2.7. Leave-To-Construct (if applicable)

N/A

2.3.3.2.8. Project Details and Justification

Table 2.59 - The GREAT-DR Overview

Project Name:	The GREAT-DR (currently known as "MiGen")
Capital Cost:	~$3.3M Hydro Ottawa cost (2019-2022)
O&M:	$0.75M (2023-2025)
Start Date:	2018-11-20
In-Service Date:	2021-03-31 (anticipated)
Investment Category:	Enter Investment Category
Main Driver:	Customer and Utility Centric Non-wires solution
Secondary Driver(s):	Improved grid management (planning & operation)
Customer/Load Attachment	Site#1: ~39; Site#2: ~152
Project Scope	
This project is an evolution from the first version and augments enhanced security, intelligence in forecasting and prediction of load profile and customer behaviour, advanced functions, shadow Transactive Energy Market, plus customer loyalty and settlement.	
Work Plan	
Nov./'18 – May/'19: planning; development of the requirements & system architecture document; contracting May/'19 – Mar./'21: installation, development, integration & testing Mar./'21 – Mar./'22: field trial, tweaking, monitoring, reporting and project close-out	
Customer Impact	
Immediate prosumer benefit is reduced electricity bills from self-generation, and the use of more efficient heating from air source heat pump versus electric baseboard. Longer term benefit to a larger customer base comes from deferral or re-direction of grid growth investment that impacts largely the delivery fee. The funds can either be not-invested or redirected to reliability improvement, which is also a benefit to beyond the self-generating customer. Should Ontario provide a Transactive Energy Market, the prosumer would receive more benefit than simply HOEP for offering their assets for shoring the grid. Intangible benefits are: empowerment of the customer to be part of the industry transformation, and move to become a prosumer; ability to introduce more electric loads as new, replacement or supplement to other fuels; potential for choice in rate structure (eg., tiered, critical peak pricing, contracted demand, etc.).	

2.3.3.3. Other Distribution Enhancements Projects

2.3.3.3.1. Program Summary

This program contains projects which make modifications to the existing distribution system in order to improve system operation efficiency and reliability. In general this involves smaller distribution system enhancements such as minor circuit reconfigurations and increasing system automation. Through this program, Hydro Ottawa's total investment over the 2021-2025 period is $6.73M. Projects covered under this program are discussed in further detail in the following sections.

2.3.3.3.2. Program Description

Current Issues

The projects planned under the Distribution Enhancements program for the upcoming 2021-2025 rate period are primarily focused on circuit automation projects. The current issues for each category are summarized below.

The South Nepean 28kV supply will be undergoing significant upgrades in capacity to accommodate the forecasted rapid load growth over the next decade. To make available the 100 MVA of new station capacity from the New South, six feeders are planned to be extended from the new station. These feeders will be integrated to the existing South Nepean 28kV distribution system and will require means for effectively reducing outage durations by making use of redundancies and ties.

Program Scope

The overall program scope includes projects which are smaller in scale such as minor circuit reconfigurations, and adding automation to the system. Projects within the scope of the Distribution Enhancement Program are purposed to achieve network stability, increase operational efficiency, and better reliability. Outside of the program scope are larger scale modifications where the main driver is improving problematic areas with reliability issues or projects driven by capacity needs.

In the period of 2021-2025, the two main project types are planned to be executed citywide under this program. Other similar needs which fall under the Distribution Enhancements category are identified through annual system reviews and will also be included in this program.

To address the need to usefully integrate the New South feeders into the rest of the South Nepean 28kV distribution system, automation will be added to strategically chosen normally open points in the region. The automated open points are selected to effectively maintain or increase feeder redundancy, reduce outage duration.

Main and Secondary Drivers

The main driver for Distribution Enhancement projects is operational effectiveness. The projects described above increase operational efficiency in a number of ways. Increasing the availability of circuit interconnections in the South Nepean 8kV region helps with operational effectiveness by utilizing the existing station capacity at Borden Farms and bringing feeders below their N-1 rating.

Secondary drivers under the Distribution Enhancement program are reliability and capacity constraints. Reconfiguring the circuits in targeted regions will ultimately improve reliability by bringing feeders under their N-1 contingency rating and make available the station capacity. Circuit automation will enhance reliability by reducing outage duration that would otherwise be longer from manual switching operations.

Performance Targets and Objectives

The System Voltage Conversion Program's Key Performance Indicator (KPI) Targets by Category are shown in Table 2.60.

Table 2.60 - Key Performance Indicator Target by Category

Category	Asset Management Objective	Sub-Category	Target
Customer Oriented Performance	Levels of Service	System Reliability	Improve System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI)
Cost Efficiency & Effectiveness	Resource Efficiency	Labour Utilization	Reduce Labour Allocation to Outage Restoration
Asset Performance	Asset Value Health, Safety & Environment	Defective Equipment Contribution to SAIFI	Reduce end-of-life equipment with high probability of failure
System Operations Performance	Levels of Service	Feeder Capacity	Increase usable feeder capacity

2.3.3.3.3. Program Justification

Alternatives Evaluation

Alternatives Considered

The following two alternatives were considered under the Distribution Enhancements Program.

Do Nothing

This alternative involves no implementation of the above discussed projects.

The New South station will be inefficiently integrated to the greater 28kV South Nepean system if no automation is added to strategically placed normally open points. SAIDI metrics will not be improved and there will be an ongoing labour cost associated with manual switching operations.

Distribution Enhancement Projects

This alternative involves implementing the circuit reconfiguration and automation projects. The South Nepean 8kV system will properly and efficiently integrate the new capacity provided by

Borden Farms and bring feeder loading levels up to their N-1 planning ratings. Grid automation will be strategically added to the South Nepean 28kV system to also properly and efficiently integrate the New South station, reduce outage durations, reduce operation costs and ultimately improve SAIDI metrics.

A summary of this alternative's expenditure is shown in the table below.

Table 2.61 - Expenditures ($'000,000s)

	Test				
	2021	2022	2023	2024	2025
Total Expenditure	$1.31	$2.50	$1.26	$0.81	$0.85

The New South Station and the additional load it provides to the South Nepean 28kV system will require automation to be properly integrated. Automation will be added to strategically selected normally open points with the goal of reducing outage durations, accommodating forecasted load growth, and maximizing the use of redundancies and ties.

Evaluation Criteria

The two alternatives are evaluated in regards to system reliability, cost efficiency, and feeder capacity.

Preferred Alternative

Alternative 2 is the preferred alternative as it complements other Capacity Upgrades projects that have been completed or are currently ongoing increasing the value obtained from those projects.

Program Timing & Expenditure

From 2016-2020, historical spending had been dedicated to switch automation, VBM's, adding fusing or permanent switches, and minor circuit reconfigurations similar to those discussed in this business case. Smaller scale enhancement projects were also completed with the same goals and objectives of the above discussed projects.

Future spending in the 2021-2025 period will entail the projects discussed in this report.

Table 2.62 - Other Distribution Enhancement Program Expenditure ($'000,000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0.92	$1.25	$1.27	$1.69	$2.41	$1.31	$2.50	$1.26	$0.81	$0.85

Benefits

The benefits of the Distribution Enhancements program are described in Table 3.16 Program Benefits below.

Table 2.63 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The number of circuits and station transformers operating above planning rating will either be eliminated or significantly reduced. Switching operations to restore outages will be reduced in time. Costs for future station decommissioning or operating and maintenance costs will be eliminated.
Customer	The customer is benefitted by faster restoration times from the circuit reconfigurations and added system automation. Reconfiguring downtown circuits and preparing a dedicated backup for the Rideau Centre will benefit the customer and ultimately improve SAIDI and CAIDI.
Safety	N/A
Cyber-Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Economic Development	The circuit reconfigurations are configured to make use of available feeder capacity and allow for future connections to the system, ultimately inviting economic development in the region.
Environment	N/A

2.3.3.3.4. Prioritization

Consequences of Deferral

Deferring the discussed Distribution Enhancement projects have various impacts on reliability, capacity, and system operational efficiency.

Inefficient integration will occur if automated open points are withheld when adding the New South into the greater 28kV South Nepean system. KPI metrics such as SAIDI will not be improved and labour costs associated with manual switching operations will continue.

Priority

Distribution Enhancements at the program level are ranked to be of high priority. This is due to the need for operational efficiency, requirement for increased or maintained reliability, constraints on capacity, consequential effects on the customer, and opportunities for improved interoperability, economic development, and environmental impacts.

2.3.3.3.5. Execution Path

Implementation Plan

Project implementation will be executed as discussed in the program timing and expenditure section. Annual system studies will be factored into this program; if any projects under this category are of higher urgency, projects may be switched, deferred, added, or removed.

Risks to Completion and Risk Mitigation Strategies

N/A

Timing Factors

The yearly asset management cycle throughout the year where areas for distribution enhancements are identified. This process may cause a change in ranking on the list of planned projects as projects are added or removed.

Cost Factors

N/A

Other Factors

N/A

2.3.3.3.6. Renewable Energy Generation (if applicable)

N/A

2.3.3.3.7. Leave-To-Construct (if applicable)

N/A

2.3.3.3.8. Project Details and Justification

Table 2.64 - Distribution Enhancements

Project Name:	Distribution Enhancements
Capital Cost:	$6,727,914
O&M:	TBD
Start Date:	1-Jan-2021
In-Service Date:	2021-2025
Investment Category:	System Service
Main Driver:	Operational Effectiveness
Secondary Driver(s):	Reliability, Capacity Constraints
Customer/Load Attachment	All customers
Project Scope	
The Distribution Enhancements program contains projects which make modifications to the existing distribution system and is intended to improve system operation efficiency and reliability, and address capacity constraints. In general this involves smaller distribution system enhancements such as circuit reconfigurations and increasing system automation	
Work Plan	
Annual system studies will also be factored into this program; if any projects under this category are of higher urgency, projects may be switched, deferred, added, or removed.	
Customer Impact	
The customer benefits by faster restoration times from the circuit reconfigurations and added system automation. Reconfiguring downtown circuits and preparing a dedicated backup will benefit the customer and ultimately improve SAIFI and SAIDI	

2.4. GRID TECHNOLOGIES

2.4.1. SCADA Upgrades

2.4.1.1. Outage Management System Replacement

2.4.1.1.1. Project Summary

The purpose of this project is to replace the current Outage Management System (OMS) in use at Hydro Ottawa's Control Room. The current OMS platform has been in use for over ten years and is in need of a significant upgrade due to critical components not having current and beneficial technologies on the market today. While the existing system is completely functional and has many of the features that System Operators need to effectively manage outages, there are several gaps that need to be addressed with a full OMS replacement, in order to modernize Hydro Ottawa's response and reporting mechanisms.

2.4.1.1.2. Project Description

Current Issues

The current OMS system in use at Hydro Ottawa is the Hexagon (Intergraph) InService product that has been in use for over ten years. While this system has been regularly upgraded by the vendor and there have been numerous customizations made to its functionality, there is a growing need to perform a significant update to the software and hardware implementation in order to address the following needs:

- The problem of Multiple Tools. One of the most significant issues in the Hydro Ottawa control room is the presence of multiple tools and the resulting need for the system operator to manage data and decisions across these tools. While each of the tools represent 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. Efforts have been made to synchronize tools using back office integration; however, there are remaining gaps that need to be addressed. The added workload ultimately has a twofold impact on performance; first, it causes delay in outage response and second, it reduces the visibility and situational awareness of the operations management staff in directing the broader response.

- Cyber Security: The current implementation of the Hydro Ottawa OMS system resides within the ‘corporate’ network environment and does not have many of the special security controls that it could have. In particular, there are a number of improvements that could be made to ensure that the system is further protected much like the SCADA network environment typically is. This additional protection would apply to the critical functions of the tool as well as the private data that is stored within the system. A significant upgrade and/or re-platform of this tool would implement the additional protections that can only be accomplished as part of a re-architecture exercise.
- Functionality and Ease of Use: The existing OMS system at Hydro Ottawa contains several gaps that require improvement or correction in order to further improve operations performance. In particular these are:
    - Call-Centre Integration/Functionality. The current integration of call-centre personnel is problematic and does not meet the needs of Hydro Ottawa. There is a significant amount of time spent on the administration of account access for Call center personnel. Due to the high personnel turnover, password management and regular administration is always required. In the past, it was decided that due to cost constraints, Hydro Ottawa would not implement the specific module for call-centre personnel. This decision, while in the short term reduced the budgetary impact to Hydro Ottawa (in implementation and licensing), in the long term caused additional labour and overtime costs. The proposed integrated solution would provide ease of management that would address the previously mentioned concerns.
    - Dispatch integration and Crew Visibility: The current integration of dispatching tools is limited and does not include outage response vehicles nor does the OMS system currently integrate with the vehicle tracking tools.
    - Remote Crew Interface: The existing OMS system requires the use of a full computer or tablet and does not offer the use of a mobile phone or other lightweight device.
    - Meter Data integration: While this feature and functionality is primarily addressed in another project, the OMS system will need to be modified before it can accept outage data from the Metering infrastructure.

Project Scope

This project is essentially an advanced back office software technology deployment. As such the project will include the following scope:

- Design and vendor selection: There will be an initial phase of requirements gathering, architecture and solution design.
- Software and Services: There will be an engagement with the selected vendor to design, implement and configure the selected tools/platform.
- Hardware: There will need to be additional hardware purchased in the form of servers, storage, networking and security equipment as well as any customized database appliances if needed.
- Security: There will be software, hardware, and services to design and implement any and all required security measures to ensure that the OMS system is implemented using industry best practices.

Main and Secondary Drivers

The primary drivers of this project are:

Reliability

The Outage Management System is designed to improve response times for outages and provide management staff and inform the general public up to date situational awareness of the restoration efforts so that any service interruptions are minimized in both duration and the number of customers affected. The Crew interface is designed to provide field staff with the required information and visibility into the problem areas or restoration jobs so that they can operate quickly and efficiently. The primary driver for this project is therefore to improve all of these factors in order to reduce the impact of outages in terms of both duration and number of customers.

Other Performance/functionality

With an Updated OMS system, Hydro Ottawa will have an enhanced tool for the tracking and management of outages. This enhancement will include additional training and the collection of key performance data for operations staff in order to help drive efficiency and outage response performance.

Secondary driver of this project is:

Safety

It is anticipated that having fewer tools in front of the operator will result in the operators being able to focus their attention on critical tasks. Furthermore, the enhanced situational awareness will empower Operators, Managers, and field staff to better direct the restoration efforts and therefore enhance the safety of the Utility staff as well as inform the general public of outage impacts and restoration status. Thus, allowing us to provide improved customer communications and notifications.

Performance Targets and Objectives

The performance targets for this project will be quite conservative as there are a number of highly complex factors that will ultimately affect the performance of Hydro Ottawa's distribution operations; in particular, the response to outages. While many of the components within the OMS platform are geared towards streamlining system office performance, several proposed upgrades will have a direct impact on the end to end lifespan of an outage (i.e. from the customer being impacted and informing the Utility, to the identification of the root cause, to the dispatch of responding crews, and finally to the crew themselves in understanding the job and reporting back the corrective measures). The performance target most readably measured is the improved performance of outage restoration (reduction in System Average Interruption Duration Index (SAIDI)) as the OMS system will serve to reduce the duration and the size of an outage.

For this implementation project to be considered successful, the full cost of implementation should be fully offset within a ten year period through a reduction in system outages and a reduction in the SAIDI metric. To achieve this result the following performance target should be met:

- Target Reduction of SAIDI: Reduction of at least 1.0% from 1.58 to 1.564

2.4.1.1.3. Project Justification

Alternatives Evaluation

Alternatives Considered

There are essentially three alternatives to consider in the upgrade of the OMS at Hydro Ottawa:

- Select a new OMS vendor that has a significant tool set already present in the control room (i.e. the SCADA/DMS vendor) that can provide a 'single pane of glass' type of solution to the operator.
- Improve the existing OMS using the existing vendor. This would provide the simplest path for improving individual functions of the OMS system, however it would not necessarily be easier to solve the cyber security issues, nor would it solve the problem of multiple tool-sets within the control room.
- Finally there is the do-nothing approach which would have the lowest cost; however it would address none of the identified gaps.

Evaluation Criteria

Given the current issues described in section 2.4.1.1.2. above, the evaluation criteria is simply a determination of whether or not the proposed solution resolves the identified gaps.

Preferred Alternative

The preferred alternative is to replace the existing OMS system at Hydro Ottawa with a system that is fully integrated and supported by the SCADA/DMS vendor. Deploying a new Advanced Distribution Management System (ADMS), which included an integrated OMS, will result in a single ADMS tool for the operator to utilize in the control room and will eliminate the inefficient use, management, and support of multiple platforms. Furthermore, it will allow the OMS functionality to be brought closer to the SCADA/DMS cyber security environment and therefore enhancing the protection of this critical tool. Finally, transitioning to a modern ADMS platform will bring with it enhanced tools and support features such as mobile applications and improved call centre integrations.

Project Timing & Expenditure

This project is scheduled to be completed in 2022 with an estimated budget of approximately $2.46M.

Table 2.65 - Advanced Distribution Management System Program ($'000,000s)

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	0.00	0.00	0.00	0.00	0.00	0.00	2.46	0.00	0.00	0.00

Benefits

The OMS upgrade project is anticipated to have the following benefits to Hydro Ottawa and its customers.

Table 2.66 - Project Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Bringing the OMS functionality into the same platform as the SCADA and DMS systems will provide a significant benefit to the Hydro Ottawa operations staff. While the improvement in efficiency is difficult to quantify, reducing the number of tools that an operator must deal with on an ongoing basis has the potential to significantly reduce their workload. It is expected that the reduced workload on the operators will translate to improved work performance and a higher quality of information being supplied by the control room staff to management and to the field crews. This improved information will therefore further improve overall performance during significant outage events.
Customer	As stated in Section 2.4 above, the objective of this OMS system replacement is to improve the SAIDI metric (including MEDs) by at least 1.0% from 1.58 to 1.564. The OMS system is particularly useful during a major storm event where an operator will see the most benefit from improved situational awareness and reduced workload. Using the Hydro Ottawa calculation for the average cost to a customer per minute of outage ($1.00 per minute, per Section 5.2.2.3), times the total number of customers (331,777), times the target SAIFI value (1.564), times 60 mins will result in an annual reduction in customer costs of approximately $314,524 versus the existing SAIFI value of 1.58. This calculation is illustrative of what the impact of an improved OMS platform could potentially have on the economic costs to customers.
Safety	It is expected that an improved OMS system will have second order effects on safety due to Operators having better situational awareness through enhanced data presentment and information clarity. This will allow them to focus more attention on safety critical decisions and less time on distilling information from multiple tools and entering decisions back into those same tools.
Cyber-Security, Privacy	As one of the main objectives of this project is the enhancement of the cyber security posture of the OMS, it is expected that this project will make significant improvements in the protection of the grid as well as maintaining the confidentiality of customer information.
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	N/A

2.4.1.1.4. Prioritization

Consequences of Deferral

Deferring the implementation of a fully integrated OMS platform will mean that Hydro Ottawa will not make use of advanced and industry standard technology innovations. While it is indeed possible that Hydro Ottawa would still achieve improvements in efficiency and outage restoration performance using the traditional methods (additional staff, improved materials and construction standards etc.) it is unlikely that these will have further significant system wide benefits. Furthermore, the use of advanced software technology will allow Hydro Ottawa to make significant steps forward by leveraging the existing assets in the field and further empower existing staff to operate more efficiently and effectively.

Priority

This project is considered Medium Priority based on the following considerations:

- This project has the significant potential of improving performance within the Hydro Ottawa system control room and therefore, a more positive experience of all customers when outages occur.
- This project has a focused scope of activity within the Hydro Ottawa technology systems and will therefore have a clear set of resources outside of the traditional Utility asset and maintenance staff, thereby reducing complexity of project execution.
- This project has many second order benefits in that it will drive utility staff towards improving the records within the Hydro Ottawa technology systems and with the availability of integrated holistic data, Hydro Ottawa will potentially see an improvement in the performance of other related tools (DMS, SCADA) that make use of this readily available data.
- Finally, this project will serve to eliminate one of the most significant hurdles to process improvement in the control room. That is the management, support, and maintenance of multiple tools within the control room. By addressing this problem, a significant barrier to process measurement and improvement will be eliminated.

2.4.1.1.5. Execution Path

Implementation Plan

As this is a back office technology implementation project, the overall plan is to set-up a project management structure, documentation. Followed by engagement of Hydro Ottawa's internal stakeholders and consider affected business processes, in order to gather requirements in the 2021 timeframe. Once this phase is complete, the team will validate the selected alternative and engage with the vendor team to define the project execution plan and schedule. Finally, in the execution phase of the project in late 2021 to early 2023, the vendor and Hydro Ottawa teams will work together to configure the software tools and train the operations staff in its efficient use.

Risks to Completion and Risk Mitigation Strategies

As with any software implementation project there are risks associated with the following areas:

- Interfaces: There are a number of different software platforms that the OMS will need to interface with including the GIS and Customer Information systems. While the GIS interface will have been built during the SCADA Replacement project and further enhanced as part of the Distribution Management System project, the Customer information, public outage map interfaces will be new implementations. The mitigation plan will require careful coordination between the Hydro Ottawa team and various vendor teams (OSI for DMS, and Hexagon for the GIS platforms) to ensure that the requirements are fully captured in the project planning and execution phases. Finally, there will be extensive testing of the final product to ensure that the interfaces are fully functional.
- Cost: As with many technology projects, costs can be a challenge to manage as there is a significant scope of work planned for the OMS replacement implementation. The strategy to minimize the risk of cost overrun is to only engage the vendor on the OMS replacement project once there has been continued success in the DMS implementation project. This will incentivize the vendor to perform adequately as future contracts will be put at risk due to poor performance. Furthermore, the project will have a dedicated project manager and executive sponsor within Hydro Ottawa to ensure that the governance surrounding the project is sound and full management visibility is provided.

Timing Factors

The timing of this implementation project will be dependent on vendor performance on the current Distribution Management System (DMS) deployment project and Hydro Ottawa staff availability. As this project will be improving the tools within the control room, it will also necessitate careful coordination with ongoing work and availability of the control room staff.

Cost Factors

As discussed above, technology investment projects can be difficult and incur significant additional cost. The strategy to minimize the risk of cost overrun is to provide a professional technology project and change management structure around this OMS replacement project. Furthermore, there will be an executive sponsor team providing guidance and oversight to the project management team.

Other Factors

There is a possibility that there is regulatory or other management pressure that requires the de-prioritization of the OMS replacement project. This will likely result in a significant de-scoping of the project as to reduce the impact on cost and staff, however it is likely that the project would continue in a smaller and targeted manner in order to reduce the workload for the Hydro Ottawa System Operators and therefore improve overall performance.

2.4.1.1.6. Renewable Energy Generation (if applicable)

N/A

2.4.1.1.7 Leave-To-Construct (if applicable)

N/A

2.4.1.1.8. Project Details and Justification

Table 2.67 - Outage Management System Replacement Overview

Project Name:	Outage Management System Replacement
Capital Cost:	Approx. $2.5M in 2022-2023
O&M:	Approx. $1.5M from 2022 to 2025
Start Date:	1-Jan-2022
In-Service Date:	1-Nov-2023
Investment Category:	System Service
Main Driver:	Improved Performance
Secondary Driver(s):	Reliability
Customer/Load Attachment	All Customers
Project Scope	
This project entails the re-platforming of our existing Outage Management System onto the same platform as our SCADA/DMS solution making it a true ADMS platform. This project would include software and services from our SCADA/DMS vendor as well as hardware to run the system.	
Work Plan	
This project would start in 2022 with investments in hardware and services and complete in 2023 with a go-live of the new tool. Employee training and software deployment would likely occur in the late 2022 to early 2023 timeframe.	
Customer Impact	
This investment will enhance the efficiency and performance of system operators in the control room by removing a separate interface and improving their situational awareness by collapsing all SCADA, Distribution Management and Outage Management functionality into a single view.	

2.4.1.2. SCADA Upgrades

2.4.1.2.1. Project Summary

The Supervisory Control and Data Acquisition (SCADA) system provides Hydro Ottawa system operators with real-time visibility of the status of our electrical system; thereby, allowing us to monitor and respond to outages, and to operate our equipment safely. This project will ensure that versions of the SCADA and Core Distribution Management System (DMS) Platform in use at Hydro Ottawa remains up-to-date and that it runs on Hardware that is not readily subject to failure. Therefore this project will purchase and install software and services from the vendor as well as purchasing hardware for the platform to run on.

2.4.1.2.2. Project Description

Current Issues

There are no current issues or major gaps; this project addresses customary software and hardware updates to maintain the integrity of the SCADA system and enables future growth of the platform.

Project Scope

SCADA is an important tool as it is used by system operations to monitor our distribution system, control automated devices, and collect data on the system. This data is referenced by Hydro Ottawa departments including Assets, Operations and Grid Technology. In 2018, Hydro Ottawa went live with a new SCADA (OSI Monarch) platform which is designed to be the foundation for additional products and advanced technology used by system operations. As the vendor improves the performance and stability of the SCADA platform overtime, it is important to capture these changes by completing software updates. In the year 2021, 2023 and 2025 there will be software upgrades that will enable additional DMS functionality to be installed. As the hardware is used and approaches its end of life, it is important to replace it prior to failure. Hardware will be replaced in 2023.

Main and Secondary Drivers

The main driver for this project is: Risk of Failure. Without completing software and hardware upgrades we put the SCADA system at risk of failure. If the platform is not running on an updated version, the system might not be compatible with other products required for DMS and also puts the system at risk for cyber security vulnerabilities which can lead to failure. The secondary driver is: Reliability. Reliability projects are designed to reduce outage frequencies or duration and as mentioned in Section 2.2, Hydro Ottawa relies on the SCADA system to monitor and respond to outages. SCADA system renewal ensures the overall health of the system, software and hardware, is maintained and improved overtime.

Performance Targets and Objectives

As mentioned in Section 2.3, The SCADA platform was designed to be the foundation for other operational technology applications therefore it is important to maintain and update the software and replace hardware prior to end of life to sustain the integrity of the system and allow for further growth; such as an advanced distribution management system.

2.4.1.2.3. Project Justification

Alternatives Evaluation

Alternatives Considered

There are no alternatives for this project, without this investment we will not be able to add to our DMS functionality and maintain reliability. As mentioned in Section 2.2, the vendor continuously improves software and hardware performance which needs to be captured through system renewal (upgrades). This is also necessary in order to remain compatible with products required to build the DMS platform and leverage new technologies and programs.

Evaluation Criteria

Industry best practices for operational technology and hardware relies on system renewal; both software and hardware upgrades.

Preferred Alternative

There is not a preferred alternative. If we do not move forward with the system renewal project, we are at risk of failure of the SCADA system and loss of reliability.

Project Timing & Expenditure

The historical period represents the purchase and installation of the new SCADA platform. The future costs are to maintain this system as well as improve performance as the vendor releases new updates as well as to ensure the system is running on suitable and reliable hardware.

Hydro Ottawa has minimized the controllable costs through this project as it enables multiple operational tools to run off of the SCADA platform.

Table 2.68 - SCADA Platform ($'000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$612	$759	$1,282	$282	$462	$286	$0	$570	$0	$334

Table 2.69 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The recent SCADA upgrade facilitates the implementation of DMS and other tools into a single platform. This investment will enhance the efficiency and performance of the system operators in the control room by removing separate interfaces and incorporating SCADA and the tools required for a Distribution Management System into a single view. The SCADA platform is the foundation for these products; therefore it requires system renewal in order to support additional products over time.
Customer	As mentioned in Section 8, this investment will ensure that the SCADA system is running on the latest platform that is supported by the vendor and will further enable the DMS investments in another portfolio. Failure to maintain this system on a current version and viable hardware would represent a significant and unacceptable risk. The SCADA system is used to monitor and control our distribution system and assets and is the primary tool used to re-route or restore power to customers during an outage. By combining automated devices and a reliable SCADA system, this can contribute to reducing outage frequencies and outage durations.
Safety	As mentioned in Section 2.3, the main and secondary drivers are risk of failure and reliability. By operating from the latest software version and hardware, operators can rely on SCADA to complete switching orders for isolation and restoration in the field with confidence that the system will function as intended without failure.
Cyber-Security, Privacy	As the vendor releases new versions of software, it will include cyber security patches. It is important that we continue to perform system upgrades in order to capture these fixes. With continued effort in identifying security risks, system renewal allows for these updates to be made to our system.
Coordination, Interoperability	As discussed in Section 2.3, the drivers for SCADA renewal are to reduce the risk of failure and maintain system reliability. As SCADA includes ICCP links to both Hydro One and IESO, it is important that our system continues to retain these connections and provide properly synchronized and correct data as required by these organizations.
Economic Development	N/A
Environment	N/A

2.4.1.2.4. Prioritization

Consequences of Deferral

The consequences of deferring SCADA system renewal is that our system would be at risk of system failure as well as loss of reliability. Risk increases over time regarding both SCADA software and hardware upgrades. It also means deferring the addition of other products required for DMS functionality and can put our system at risk for cyber security vulnerabilities until updates are applied.

Priority

This project is a high priority (mandatory) – without this investment we will not be able to add to our DMS functionality.

2.4.1.2.5. Execution Path

Implementation Plan

The implementation plan will be as follows: update software in 2021, hardware and software in 2023 and software again in 2025.

Risks to Completion and Risk Mitigation Strategies

This is a risk mitigation project, with the initial investment made in order to support the addition of products for DMS functionality, it is following best practices to complete software and hardware upgrades to continue to improve performance and it mitigates cyber security risks.

Timing Factors

If early hardware failure occurred or poor software performance and compatibility issues occurred, or if there was a cyber security issue, the software and/or hardware renewal would need to be completed sooner than planned.

Cost Factors

Factors that might affect the final cost of the project include significant changes on the hardware manufacturing side, early failure or unanticipated issues.

Other Factors

N/A

2.4.1.2.6 *Renewable Energy Generation (if applicable)*

By renewing the SCADA system, Hydro Ottawa is better prepared to add additional products for renewable energy generation if preferred and will continue to be able to provide visibility to operators and other relative departments for system loading and data captures for renewable energy generation.

2.4.1.2.7. *Leave-To-Construct (if applicable)*

N/A

2.4.1.2.8. Project Details and Justification

Table 2.70 - SCADA System Renewal Overview

Project Name:	SCADA System Renewal
Capital Cost:	Approx. $1.19M total for 2021 to 2025
O&M:	Included in the DMS Project O&M Budget
Start Date:	1-Jan-2021
In-Service Date:	Same Year
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	ALL Customers
Project Scope	
This project will ensure that version of the SCADA and Core DMS Platform in use at Hydro Ottawa remains up-to-date and that it runs on Hardware that is not readily subject to failure. Therefore, this project includes the purchase and installation of software and services from the vendor as well as purchasing of hardware for the platform to run on.	
Work Plan	
In Years 2021 and 2025 there will be a software upgrade to enable the additional DMS functionality to be installed. In 2023 there will be a software and hardware purchase as the existing hardware will reach its end of life (5yrs after go-live of SCADA project in 2018)	
Customer Impact	
This investment will ensure that the SCADA system is running on the latest platform that is supported by the vendor and will further enable the DMS investments in another portfolio. Failure to maintain this system on a current version and viable hardware would represent a significant and unacceptable reliability risk.	

2.4.1.3. Distribution Management System

2.4.1.3.1. Project Summary

The Distribution Management System (DMS) Project is a follow-on from the SCADA Replacement project from the previous rate period. As part of the SCADA Replacement project, Hydro Ottawa not only replaced its SCADA system with a modern platform, but also installed the foundational element of a DMS system, which contains an electronic map within the platform that is fully integrated with the Geographical Information System (GIS). This project seeks to build upon the success of the SCADA replacement project by adding additional functional modules onto the foundational DMS software platform; these modules will utilize the mapping and SCADA telemetry to develop analysis products and automation functions that will improve Hydro Ottawa's efficiency and outage restoration performance in real-time.

2.4.1.3.2. Project Description

Current Issues

This project is primarily targeted at operational efficiency within the system control room and improving Hydro Ottawa's performance in the management of its distribution assets both during normal day-to-day operations as well as during outage events. At this time, Hydro Ottawa utilizes three separate and independent tools to manage the distribution system within the control room:

- SCADA system. This tool was recently upgraded in 2018 to a new platform called OSI Monarch
- Outage Management System (OMS) from Intergraph (Hexagon SI).
- Electronic Schematic Map tool called P-Tech by Primate Technologies

These tools provide excellent situational awareness and visibility into the real-time status and health of the distribution system; they do not however provide any automation or intelligence around optimization of the system. In particular there is a need for an analysis system to provide the following functionality and integrations:

- Fault Locating, Isolation, and Service Restoration (FLISR)

- Voltage optimization
- Feeder Reconfiguration and Optimization
- Distributed Energy Resource Management
- Automated Metering Infrastructure (AMI) Data consumption

Project Scope

This project will be a multi-year advanced technology implementation effort focused primarily in the back-office software platform used in the control room. This project will include the following items:

- Software Modules from the DMS Vendor
- Implementation services from the DMS Vendor
- Training services from the DMS Vendor
- 3rd party vendor Integration with associated tools (e.g. GIS, OMS)
- Limited Customization services from the DMS Vendor

Certain integrations are considered out of scope for this project (e.g. linkages to the AMI system) as they are covered in another project scope. The specific Software Modules under consideration for implementation in this project are the following:

- Power Flow (Intelligent prediction of energy flow within distribution feeders)
- Enhanced Electronic Switch Order Management
- Fault Locating, Isolation, and Service Restoration (FLISR)
- Voltage optimization (VAR optimization is included in this module)
- Feeder Reconfiguration and Optimization
- Distributed Energy Resource Management
- State Estimation
- Short Circuit Analysis

Main and Secondary Drivers

The primary drivers of this project are:

System Efficiency: The Voltage Optimization and the Feeder Reconfiguration modules are designed to provide the system operator suggested settings and configurations of the distribution system for the improvement of overall system efficiency, including line loss reduction.

Reliability: The FLISR module and the Power Flow modules are designed to improve the response to outages and in some cases automate the restoration efforts so that any service interruptions are minimized in both duration and the number of customers affected.

Other Performance/functionality: The Distributed Energy Resource Management tool within the DMS platform will provide system operators a consolidated view Distributed Energy Resources (DERs). This is seen as a critical function as the number of DER installations within the Hydro Ottawa service territory will continue to grow throughout the next rate period.

Power Quality: Finally, the Voltage Optimization Module is specifically targeted at addressing power quality issues at the very edge of the distribution system. Using telemetry collected from the field, the module provides recommendations and automatic functions to reduce system losses and improve PQ performance.

Secondary drivers of this project include the following:

Safety: It is anticipated that by having higher level automation and analysis modules built into the DMS platform, system operators will be far less distracted by trivial nuisance alarms (e.g minor voltage alarms) and will be able to focus their attention on critical tasks, the same would be true during an outage event. The FLISR module would provide the operator with suggested options for restoration while freeing the operator to focus on the critical tasks of managing an outage (i.e. the operator would be focused on the problem area such as a downed wire, and not distracted by restoring customers off of a distant tie switch) .

Performance Targets and Objectives

The performance targets for this project will be quite conservative as there are a number of highly complex factors that will ultimately affect the performance of Hydro Ottawa's distribution operations. While many of the modules within the DMS platform are geared towards general improvements and streamlining of system office performance or foundational analysis, several will have a direct impact on system performance. The performance targets most reliably measured are the measure of system efficiency (through the reduction in system losses) and the improved performance of outage restoration (reduction in System Average Interruption Duration Index (SAIDI)).

For this implementation project to be considered successful, the full cost of implementation should be fully offset within a ten year period through a reduction in system losses and a reduction in the SAIDI metric. To achieve this result the following performance target should be met:

- Target Reduction of system Losses: Reduction of losses of at least 0.1% from 3.20% to 3.10%
- Target Reduction of SAIDI: Reduction of at least 1.0% from 1.58 to 1.564

2.4.1.3.3. Project Justification

Alternatives Evaluation

Alternatives Considered

As this project is an advanced technology deployment project there are essentially three alternatives to consider: first, the project as described involving a back office software implementation; second, a field centric approach that would involve technology deployed at the substations, and finally the “do nothing” approach.

In the ‘do nothing’ approach, traditional improvements would still be made incrementally over time (e.g. asset improvements, feeder improvements, etc.); however, there would be no advanced automation or analysis functionality in the back office or at the distribution edge.

The second alternative is to deploy advanced technology in the substations and along the distribution feeders. This technology would include automation schemes, co-ordinated devices, and point-to-point communications links. While this type of implementation would likely be successful in providing significant performance improvements to the distribution feeder where these are installed on, it involves a significant effort to retrofit existing field assets and substation systems.

Evaluation Criteria

The alternatives were evaluated using a qualitative criteria based on Hydro Ottawa's past experience in managing technology within the substation. These criteria are:

- Flexibility: The chosen solution must seamlessly adapt to the system conditions and configurations that are possible at any time.
- Upgradability: The chosen solution should not involve replacing significant portions of the physical assets in the field.
- Universality: The chosen solution should not lock Hydro Ottawa into a specific vendor for distribution automation assets
- Consistency: The chosen solution should behave consistently across the distribution system and should have a consistent interface to the system operator

Preferred Alternative

Using the criteria above, the preferred alternative is to implement a DMS solution that is fully integrated into the Hydro Ottawa SCADA platform. Evaluating the alternatives against the criteria yields the following results:

Flexibility: The preferred alternative will result in a system that is consistently flexible as it will be inherently aware of the distribution system state (through SCADA telemetry) as well as the system configuration (through the electronic system map). Having a DMS system fully integrated to the back office systems, further reinforces Hydro Ottawa's use of its GIS system as a single source of record of the distribution system. In the alternative case, the technology deployed at the station will not be consistently aware of the system topology and will therefore be unable to remain active when the distribution system is re-configured in temporary situations. In a previous pilot project using Station based tools to optimize voltage, the system needed to be turned off during any switching activity as the system was unable to accommodate changes to feeder topology. This resulted in the system being deactivated for significant periods of time.

Upgradability: As it will be integrated into the back office SCADA platform the DMS system will be inherently upgradeable along with the SCADA platform. In the alternative case, technology within the substation will require a more intensive effort to upgrade on a case by case basis.

The alternative case is further complicated in that the assets in the substation typically have a longer life span (as in other utility field assets) which could limit the longer term viability of upgrades without full scale asset replacement. Implementing intelligent or advanced back office software systems is seen as a superior approach as the system vendor will have a clear path to upgrade their own software. In the alternative case, generic automation systems at the substation typically require customized automation logic being implemented on a generic hardware platform. This approach poses a significant risk that the customized logic will have to be re-written in the event there is any significant change in the hardware it is implemented on.

Universality: As with any SCADA integrated technology, the DMS system is designed to work with any number of substation assets from a variety of manufacturers as these assets communicate to the SCADA system using industry accepted protocols and will be configured to provide the correct data points to the SCADA/DMS platform. In the alternative case the customized system at the substation will likely have limitations around the direct connections to other devices (particularly those from other vendors) and there will be a need for customized interfaces developed and engineered for each location. This customized approach represents additional cost and complexity.

Project Timing & Expenditure

This project is essentially a follow-on to the SCADA replacement project of the previous rate period. During the next 5 years, Hydro Ottawa proposed to incrementally invest in the DMS platform by adding modules and functionality. The costs associated with this effort will include both third party software and services as well as internal labour. The timing of these investments is dependent on the progress that is made by Hydro Ottawa on improving the data that is stored in its GIS system (N.B. While Hydro Ottawa has an exceptional level of quality in its GIS data, a DMS system requires additional asset information that is not typically present in a GIS system). This additional data will require research, and potentially field verification in order to provide the necessary quality required to fully leverage the DMS functionality. In addition, it will take time to effectively operationalize the new software functionality with the System Operations team. While there will be training involved with the deployment of the system, it will still take time to make full use of the system. This data gathering and operationalization poses a risk to the planned timing of the investments. While every effort has been made to plan the deployment of the functionality and the associated expenditures in order to accommodate the necessary work, Hydro Ottawa will not proceed with additional modules until prior installations have been fully utilized.

Table 2.71 - Distribution Management System Program Expenditure ($'000,000s)

	Historical					Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0	$0	$0	$0	$0	$0.27	$0.0	$0.70	$0.0	$1.56

Benefits

As discussed earlier, the DMS project will serve to improve several areas of Hydro Ottawa operations including efficiency and outage restoration.

Table 2.72 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	This project is essentially an advanced technology deployment project. Therefore, it is expected that the benefits from the system will improve over time as the system becomes operationalized and the data that is used in the system model is improved. As stated in Section 2.4 above, the objective of this DMS system is to help to reduce overall system losses (which total 244,824,564 kWh) by at least 0.1% from 3.20% to 3.10%. Using a very conservative assumption that the saved kWh could instead be sold by the LDC (at the calculated distribution revenue rate of $0.02 per kWh), the reduced losses would in turn reduce the revenue requirement of Hydro Ottawa. A reduction of 0.1% of system losses translates to approximately 7,645,263 kWh saved. This savings recovered at the Distribution Revenue ($0.02 per kWh) will mean approximately $152,905 per year. This savings does not include the additional system benefits to the provincial transmission grid or to the generation market overall. It is clear however that even this modest reduction in system losses could provide an annual benefit to the Hydro Ottawa rate payers that will far exceed the cost of implementing the required DMS modules (in this instance; Voltage Control and Feeder Optimization).
Customer	In addition to the savings anticipated from improved system efficiency, two of the DMS modules (Power flow and FLISR) are specifically targeted towards improving situational awareness for the operators and for improving outage response through automation. As stated in Section 2.4 above, it is the objective of this DMS system to improve the SAIDI metric by at least 1.0% from 1.58 to 1.564 (N.B. For this evaluation, the SAIDI metric that includes major event days has been chosen as a DMS system is particularly useful during a major storm event where an operator will see the most benefit from improved situational awareness and automation). Using the Hydro Ottawa calculation for the average cost to a customer per minute of outage ($1.00 per minute), times the total number of customers (331,777), times the target SAIFI value (1.564), times 60 mins will result in an annual reduction in customer costs of approximately $314,524 versus the existing SAIFI value of 1.58. This calculation is illustrative of what the impact of a DMS platform could potentially have on the economic costs to customers.

Benefits (Cont'd)	Description (Cont'd)
Safety	A DMS system will have second order effects on safety due to: 1. Operators will have better situational awareness through enhanced data presentment and information clarity. This will allow them to focus more attention on safety critical decisions and less time on distilling information from disparate SCADA displays. 2. Operators will have automation tools at their fingertips which will allow them to focus more attention on safety critical decisions and less time on minor or routine activities.
Cyber-Security, Privacy	By implementing the DMS platform within the SCADA security environment the new system will make use of all of the additional controls that are in place to protect Hydro Ottawa's SCADA environment. This environment features additional controls, firewalls, surveillance, protections, and governance that will serve to safeguard the DMS platform against malicious activity.
Coordination, Interoperability	As part of the selection process for the SCADA/DMS platform, a significant portion of the evaluation was spent on ensuring that the chosen vendor utilizes industry recognized communications and interface protocols. These include: - Inter-Control Centre Protocol (ICCP) - IEC 61850 - Distributed Network Protocol 3.0 (DNP3) - Multispeak
Economic Development	Not Applicable
Environment	One of the later modules selected for implementation in the DMS platform is the Distributed Energy Resource Management System (DERMS). This module will allow Hydro Ottawa operators to have a consolidated view of the embedded energy resources (such as storage or PV generation) on the system. By having a consolidated management view of these resources, it will allow Hydro Ottawa to enable additional deployments and higher levels of DER penetration across its system.

2.4.1.3.4. Prioritization

Consequences of Deferral

Deferring the implementation of the full DMS platform will mean that Hydro Ottawa does not make use of advanced and industry standard technology innovations. While it is indeed possible that Hydro Ottawa would still achieve improvements in efficiency and outage restoration performance using the traditional methods (additional staff, improved materials and construction standards etc.) it is unlikely that these will have the broader effects across the distribution system expected from a DMS. Furthermore, the use of advanced software technology will allow

Hydro Ottawa to make significant steps forward by leveraging the existing assets in the field and further empower existing staff to operate more efficiently and effectively.

Priority

This project is considered Medium Priority based on the following considerations:

- This project has significant potential of improving performance across the Hydro Ottawa distribution system and therefore the experience of all customers.
- This project has a focused scope of activity within the Hydro Ottawa technology systems and will therefore have a clear set of resources outside of the traditional Utility asset and maintenance staff. Thereby reducing complexity of project execution.
- This project has many second order benefits in that it will drive utility staff towards improving the records within the Hydro Ottawa technology systems and will improve the performance of other related tools (Outage Management System, SCADA) which will in turn further improve performance of the utility.
- Finally, this project will serve as a focus point for Utility staff to embrace technology and automation within the system control room. This, in turn, will help to drive the deployment of improved automation devices and sensors in the field to make the most out of the DMS platform.

2.4.1.3.5. Execution Plan

Implementation Plan

As discussed in the previous sections, the DMS system is a back office software platform that relies on the data collected from the field as well as a very detailed model from which the system will base its analysis. The intent of the plan to make incremental investments in the software modules within the DMS platform in alternating years so that there is time to develop the project, collect the required data for the model, identify shortcomings and close gaps in the modeling data, and lastly, implement the module. Once the module is in place, it will take several months for the system operations team to develop processes around its use and to fully operationalize it. Only when this process is substantially completed does it make sense to embark on the installation of another module.

Risks to Completion and Risk Mitigation Strategies

As with any software implementation project there are risks associated with the following areas:

Interfaces: There are a number of different software platforms that the DMS will need to interface with including the GIS and OMS systems. For the most part, these interfaces have been substantially built as part of the initial model development completed in the SCADA Replacement Project; however, there are new elements to these interfaces that will require implementation. The mitigation plan has been and will continue to be a careful coordination between the Hydro Ottawa team and both vendor teams (OSI for DMS, and Hexagon for the GIS and OMS platforms) to ensure that the requirements are fully captured in the project planning and execution phases. Finally, there will be extensive testing of the final product to ensure that the interfaces are fully functional.

Cost: As with many technology projects, costs can be a challenge to manage as there is a significant scope of work planned for the DMS implementation. The strategy to minimize the risk of cost overrun is to only engage the vendor on a module by module basis while providing full visibility to the intended roadmap. This will incentivize the vendor to perform adequately as future contracts will be put at risk due to poor performance. Furthermore, the project will have a dedicated project manager and executive sponsor within Hydro Ottawa to ensure that the governance surrounding the project is sound and full management visibility is provided.

Timing Factors

As discussed above, the timing of this project will be based on the successful completion of the modeling and integration work. Therefore, if the efforts in modelling take additional time, the future modules could be delayed however it is expected that the overall project scope will be completed in a timely fashion within the next rate period.

Cost Factors

As discussed above, technology investment projects can be difficult and incur significant additional cost. The strategy to minimize the risk of cost overrun is to only engage the vendor on a module by module basis while providing full visibility to the intended roadmap. This will incentivize the vendor to perform adequately as future contracts will be put at risk due to poor performance.

Other Factors

There is a possibility that there is regulatory or other management pressure that requires the de-prioritization of the DMS implementation project. This will likely result in a significant de-scoping of the project as to reduce the impact on cost and staff, however it is likely that the project would continue in a smaller and targeted manner in order extract the benefits of the automation and enhanced situational awareness for the Hydro Ottawa System Operators.

2.4.1.3.6. Renewable Energy Generation (if applicable)

N/A

2.4.1.3.7. Leave-To-Construct (if applicable)

N/A

2.4.1.3.8. Project Details and Justification

Table 2.73 - Distribution Management System Investments

Project Name:	Distribution Management System Investments
Capital Cost:	Approx. $2.53M total for 2021 to 2025
O&M:	Approx. $1.11M total for 2021 to 2025
Start Date:	1 January 2020
In-Service Date:	Multiple – Incremental Functionality added through the Rate Period
Investment Category:	System Service
Main Driver:	Improvement of Performance - Reliability
Secondary Driver(s):	Efficiency and Effectiveness
Customer/Load Attachment	All Customers
Project Scope	
The DMS project is a continuation of a portfolio of work that started in the 2016-2020 Rate Application Period. This earlier effort saw the replacement of the SCADA system with an initial purchase of some DMS functions. This project will see the addition of substantial functionality to the DMS system such as analysis and automation as well as integrations to our other tools.	
Work Plan	
Due to the fact that this is an additional investment into an existing platform, the work will consist of the following elements: 1. Purchase of vendor software and installation/integration services 2. Grid Technology Team support for project implementation 3. Training and operationalizing of the tools within the System Operations Department.	
Customer Impact	
With the software alone it is expected that the System Operators will become far more efficient at identifying and correcting issues and inefficiencies on the distribution system. The customer impact of this program can become quite significant if ancillary investments in remotely operated devices and sensors are made which would allow for additional automation to take place.	

2.4.1.4. AMI Outage Management Integrations

2.4.1.4.1. Program Summary

The purpose of this project is to leverage existing assets to improve the current outage management process. This will be accomplished by converting MAS data into actionable intelligence in OMS. This project will ultimately increase meter polling frequency, enabling Hydro Ottawa to process near real-time outage flags. It will also enable meter auto-pinging to improve outage visibility.

2.4.1.4.2. Program Description

Current Issues

Meter Data Services currently processes meter flags once every 24 hours. As a result, Hydro Ottawa does not analyze near real-time last gasp and power-restored meter flags to identify customer interruptions, and relies primarily on customer reporting to identify outages.

The current infrastructure also does support auto-pinging meters; however, there is additional integrations and software required to make full use of this feature. In the case of a service interruption, meters must be pinged individually to check that there is utility side power. As a result, in the case of single lights out trouble calls, partial restorations or nested outages, AMI auto-pinging is not being leveraged to reduce field investigations increasing Operations and Maintenance costs. The limited visibility provided by the current system increases the time required to locate outages, delays customer restoration and increases the system-wide SAIDI.

There is currently limited knowledge of the system-wide performance in real time and validation of exact outage durations. The current system also places the burden of outage reporting primarily on the customer. Additionally, customers currently receive inaccurate restoration updates and experience increased outage times.

Program Project Scope

This program will create and implement software and integrations to convert MAS data into actionable intelligence in OMS. This initiative will increase meter polling frequency, enabling Hydro Ottawa to process near real-time outage flags. It will also enable meter auto-pinging to improve outage visibility.

Main and Secondary Drivers

The main drivers of this project are operational efficiency and customer value and service.

By investing in infrastructure to process and relay timely meter flags to OMS, Hydro Ottawa can process near real-time outage flags and use this actionable intelligence to identify customer interruptions. This decreases crew dispatch time and increases the efficiency of outage restoration. Leveraging AMI ping power verification reduces O&M costs associated with field investigations for nested outages, partial restorations and trouble calls. Enhancing the OMS via pinging will reduce the system-wide SAIDI metric, improve the knowledge of system performance and validate exact outage durations.

Increased outage visibility will have several customer benefits. Firstly, the customer will no longer be relied upon for reporting outages. They will also experience shorter service interruptions on average. Additionally, Hydro Ottawa will be able to provide highly efficient restoration updates via system wide pinging and polling to confirm OMS outage information.

Performance Targets and Objectives

The performance targets for this project include:

- Reduce restoration time to decrease system-wide SAIDI
- Process meter flags every 5 minutes
- Decrease instances of customer reported outages from 100% to 60%
- Enable auto-pinging of meters

2.4.1.4.3. Program Justification

Alternatives Evaluation

Alternatives Considered

The three alternatives considered were the do nothing option, building the infrastructure to provide actionable intelligence to OMS and a complete metering fleet replacement with built in outage management infrastructure.

An entire metering replacement would cost approximately $95M.

In the case of the do nothing option, Hydro Ottawa would continue to have limited outage insight into customer outages. Auto-pinging would remain a manual process, leading to low confidence in partial restoration and nested outages. Furthermore, the burden of outage reporting will continue to be on the customer, and the ability to provide accurate restoration information to customers will continue to be limited.

Evaluation Criteria

The evaluation criteria used to determine the preferred alternative were:

- Total project cost
- Availability of resources to complete capital work
- Reduction in outage duration (SAIDI)
- Customer value and service

Preferred Alternative

The preferred alternative is to invest $1.25M over 5 years on the communication infrastructure upgrade. This project will permit Hydro Ottawa to process near real time meter data to identify interruptions, decrease the restoration time and permit Hydro Ottawa to leverage existing technologies including meter flags and auto-pinging capabilities. This will also enable accurate restoration information and outage notifications for customers. This option improves outage management at 1.13% of the cost of an entire fleet replacement. An entire fleet replacement would also require approximately 100,000 labour hours. For the do nothing option, Hydro Ottawa would continue to operate with a higher than necessary SAIDI and under-deliver customer value and service.

Program Timing & Expenditure

This project will begin in 2021, and is contingent on the completion of both the transformer-rated and self-contained phone line elimination projects. Delays in the phone line removal projects could in turn delay the completion date of this project.

Table 2.74 - Project Historical Expenditure ($'000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0	$0	$0	$0	$0	$251	$251	$251	$501	$0

Table 2.75 - Project Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	**Communication** ● Increase number of meter polls from daily to once every 5 minutes ● Enable last gasp and power restored flags to be processed in near real-time ● Enable auto-pinging of meters to increase restoration confidence ● Decrease restoration time ● Decrease SAIDI ● Decrease O&M costs associated with outage field investigations
Customer	● Improve outage restoration time ● Remove the responsibility of outage reporting from the customer ● Enable proactive customer communication regarding outages and highly efficient restoration updates
Safety	
Cyber-Security, Privacy	As the metering infrastructure communicates over a *private network*, traffic is monitored and firewalls are in place throughout, under Hydro Ottawa's control. All integrations and software contemplated under this project will not expose any additional risks to privacy, cyber security, or grid protection.
Co-ordination, Interoperability	N/A
Economic Development	N/A
Environment	The project will reduce the emissions associated with rolling a truck to locate the outage and to investigate trouble calls in the field.

2.4.1.4.4. Prioritization

Consequence of Deferral

Deferring the project will present several consequences to Hydro Ottawa:

- Inability to analyze near real-time last gasp and power-restored meter flags to identify customer interruptions. Customers will continue to be relied upon for outage reporting
- Meters will continue to be pinged individually to ensure that there is utility side power to the service.
- In the case of single lights out trouble calls, partial restorations or nested outages, AMI ping power verification will not be leveraged to reduce field investigations. This leads to increased Operations and Maintenance costs.
- Increase the time required to pinpoint an outage location, delay customer restoration time and decrease SAIDI
- Inaccurate estimated time of restoration (ETRs) for customers

Priority

This project is categorized as medium priority.

Deferring these investments will mean that Hydro Ottawa will not make use of advanced and industry standard technology innovations. While it is indeed possible that Hydro Ottawa could still achieve improvements in efficiency and outage restoration performance using traditional methods (additional staff, improved materials and construction standards etc.) it is unlikely that these will have system wide effects.

2.4.1.4.5. Execution Path

Implementation Plan

Each year of this project will have a targeted investment:

2021- Utilize event flag to build customer specific stats, including momentaries

2022- Develop script to allow automated pinging of single lights out (Dispatch)

2023- Utilize last gasp notifications to generate simulated IVR calls

2024- Integrate last gasp notifications into OMS (automated fault identification & map updates)

Risks to Completion and Risk Mitigation Strategies

The primary risk to completion is a shortage of labour due to the prioritization of reactive maintenance work or capital work. To mitigate this risk, Hydro Ottawa has developed a contingency plan to distribute the work to an independent contractor if required.

Timing Factors

The timing of this project can be affected by:

- Completion date of the transformer-rated and residential phone line elimination
- Timing of the OMS and MAS replacement projects
- Contracting out work to third parties due to resource constraints

Cost Factors

The cost of the project can be affected by:

- Software integration delays
- Vendor pricing
- Contracting out work to third parties due to resource constraints

Other Factors

N/A

2.4.1.4.6. Renewable Energy Generation (if applicable)

N/A

2.4.1.4.7. Leave-To-Construct (if applicable)

N/A

2.4.1.4.8. Project Details and Justification

Table 2.76 - AMI Outage Management Integration Overview

Project Name:	AMI Outage Management Integration
Capital Cost:	$1.25M
O&M:	N/A
Start Date:	2021
In-Service Date:	2021-2024
Investment Category:	System Service
Main Driver:	Operational Efficiency, Customer Value and Service
Secondary Driver(s):	
Customers	N/A
Project Scope	
The primary purpose of this project is to develop infrastructure to process near real-time outage flags and relay them to the Outage Management System (OMS). This will be accomplished by increasing the meter polling frequency and enabling auto-pinging of meters.	
Priority	
Medium	
Work Plan	
All work will be done by 2024 to maximize the rate of return on the investment. Total Expenditures 2021: $251,000 2022: $251,000 2023: $251,000 2024: $501,000 2025: $0	
Customer Impact	
This project will have several operational benefits, including: ● Improve outage restoration times ● Remove the responsibility of outage reporting from the customer ● Enable proactive customer communication regarding outages and highly efficient restoration updates	

2.4.2. RTU Upgrades

2.4.2.1. Self Healing Grid

2.4.2.1.1. Project Summary

This project will invest $1.27M over 5 years to install sensors and remotely operated devices throughout the distribution system. These devices will improve system-wide outage visibility and provide actionable intelligence required to enable future grid-automation. These upgrades will ultimately improve the efficacy of outage restoration.

Current Issues

The current distribution system has limited continuous monitoring and outage visibility capabilities. Without devices providing real-time, actionable intelligence, future grid-automation technology cannot be fully leveraged. Additionally, without increasing visibility and automation in the distribution system, Hydro Ottawa has limited ability to monetize concurrent investments in the DMS and FLISR.

The current lack of real-time data also limits the system operator's ability to locate the source of an interruption. As a result, crews dispatched must line patrol large areas to locate and restore outages. From a customer perspective, this leads to elongated outages and inaccurate Estimated Time of Restoration (ETR) notifications. Hydro Ottawa also has limited ability to notify customers about high-risk areas to avoid while crews are working to restore power.

Project Scope

This program will invest $1.27M over 5 years to purchase and install sensors and remotely operated switching devices in the field. These devices will increase system-wide outage visibility, as well as enable sectionalizing and fault finding. Strategic locations for device installation will be identified via an annual system wide review of operations and performance.

Main and Secondary Drivers

The primary drivers for the self-healing grid project are:

System Efficiency: Installing devices that enable sectionalizing and fault finding in the field provides actionable intelligence that enhances the system operator's ability to pinpoint outages.

This will resultantly increasing the efficiency and minimize the frequency of crew dispatch, reduce outage duration and improve SAIDI.

Customer Experience: This project will shorten customer restoration times and increase the accuracy of ETR notifications. Hydro Ottawa will also be able to alert customers of high-risk areas to avoid while crews are working to restore power during an interruption.

Safety: Enhanced visibility of the distribution system has several impacts on the safety of both crews and customers. Having access to actionable outage intelligence enhances the decision-making capabilities of the system operator. Additionally, pinpointing outages reduces the amount of line patrolling and overall contact with failed equipment for crews in the field. The improved system visibility enables Hydro Ottawa to provide notifications about high-risk areas to avoid while crews are working to restore power.

The secondary drivers of this project are:

Reliability: The devices installed to monitor the distribution system will minimize customer interruption in both duration and the number of customers affected, thus improving the overall reliability of the system. This project is expected to reduce the failure rate of the assets by reducing the switching operations performed during an outage, thus reducing instrument fatigue.

Performance Targets and Objectives

The performance targets for this project are:

- Reduce customer interruption hours and system-wide SAIDI
- Reduce the number of trucks rolled for field investigations and switching operations
- Increase the annual outages restored in 15 or less minutes by 7.8%
- Optimize the efficiency of current infrastructure

Table 2.77 - Historical Outage Restoration Data

	2016	2017	2018
Momentary Outages (Outage Duration ≤ 60 seconds)	145	195	171
Outages Restored in 15 Minutes or Less	295	331	540
Total Number of Yearly Outages	2407	2555	2687
% Momentary Outages	6.02%	7.63%	6.36%
% Outages Restored In 15 Minutes Or Less	12.25%	12.95%	20.10%

2.4.2.1.2. Project Justification

Alternatives Evaluation

Alternatives Considered

The only alternative considered was the do nothing option. In this case, there would be no improvements to the long-term efficiency and reliability of the distribution system via outage visibility and automation.

Evaluation Criteria

The evaluation criteria of this project include:

- Project Cost
- Projected benefit to system efficiency
- Customer experience
- Safety

Preferred Alternative

The preferred alternative is to invest $1.27M in monitoring devices over 5 years. Though the cost exceeds the do nothing cost, this project is expected to improve the efficacy of outage restoration. The monitoring devices installed will provide actionable intelligence that enhances the system operator's ability to pinpoint outages in the field. This will resultantly increasing the efficiency and reduce the frequency of crew dispatch as well as reduce restoration time.

From a customer experience perspective, this project will shorten restoration times and improve the accuracy of customer ETRs.

Enhanced outage visibility has several impacts on the safety of both crews and customers. Having actionable outage intelligence enhances the decision making capacity of the system operators. Pinpointing outage locations reduces the amount of line patrolling and crew contact with failed equipment in the field. The improved system visibility enables Hydro Ottawa to notify customers about high-risk areas to avoid while crews are working to restore power.

In the do nothing approach, traditional improvements, including asset replacement and feeder betterment, would continue to be made to the grid incrementally over time. However, there would be no initiatives made to enable continuous monitoring, which limits Hydro Ottawa's future ability to integrate advanced automation into the distribution system.

Project Timing & Expenditure

This project will invest $250K each year from 2021 to 2025, as shown in Table 4.9. There is no historical spend on this project.

Table 2.78 - Self Healing Grid Project Historical and Forecast Expenditure ($'000s)

	Historical			Bridge		Forecast				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0	$0	$0	$0	$0	$253	$253	$253	$253	$253
Units	0	0	0	0	0	50	50	50	50	50

Benefits

The benefits of the project are listed in Table 2.79.

Table 2.79 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	● Enhance Hydro Ottawa's ability to pinpoint outage locations, ● Reduce time and resources required to locate outages in the field ● Reduce frequency and improve efficiency of crew dispatch ● Enhance system operator's decision making ability ● Allow for faster identification of outages requiring manual switching ● Leverage and monetize software investments including FLISR and the DSM ● Decrease asset failure rate due to decreased fatigue caused by switching during outages
Customer	● Reduce customer outage duration ● Provide more accurate estimated time of restoration notifications ● Provide customers with notifications about high-risk areas to avoid while crews are working to restore power
Safety	● Decrease the chances of human operating error and increase system operator ability to make informed decisions. ● Reduce the amount of line patrolling and overall crew contact with failed equipment in the field via precise fault finding and sectionalizing of feeder segments ● Enables Hydro Ottawa's ability to provide customers with notifications about high-risk areas to avoid while crews are working to restore power
Cyber-Security, Privacy	● Controls, firewalls, surveillance, protections, and governance that will serve to safeguard the DMS platform and associated automated devices against malicious activity
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	● Increasing grid automation reduces the frequency and scope of field investigations during interruptions, thus reducing the emissions released via crew vehicular travel during a power restoration.

2.4.2.1.3. Prioritization

Consequences of Deferral

Deferring this project will limit Hydro Ottawa's ability to leverage and monetize concurrent software investments in FLISR and the DMS. Integrating continuous monitoring devices provides the foundation for future grid automation, namely auto-switching devices. By deferring the implementation of continuous monitoring instruments, it inhibits Hydro Ottawa's ability to leverage future investments in auto-switching devices. Additionally, deferring this project will limit Hydro Ottawa's ability to improve restoration time and outage communication with customers.

Priority

This project is a medium priority.

2.4.2.1.4. Execution Path

Implementation Plan

Strategic locations for device placement will be identified via an annual system wide review of operations and distribution reliability performance.

Risks to Completion and Risk Mitigation Strategies

The primary risk to completion for this project would be dispersing the automated devices throughout the service territory as opposed to concentrating investments in a smaller, poorly performing region. Dispersing investments would require a higher investment level to achieve the targeted outcome, thus threatening the project completion. To mitigate this, investments in automated devices will be concentrated to maximize results and ensure timely project completion.

Timing Factors

Timing of the implementation of the DMS and FLISR will affect the efficacy of the self healing grid investment. Additionally, dispersing investments across the service territory would require further installations in each region to achieve the targeted outcome. This could delay project completion. To mitigate this, investments in automated devices will be concentrated to maximize results and ensure timely completion.

Cost Factors

Dispersing the automated devices throughout the service territory would increase the cost of the project by requiring additional device installations. Variable vendor pricing on monitoring devices and sensors can also influence the overall cost of the project.

Other Factors

N/A

2.4.2.1.5. Renewable Energy Generation (if applicable)

N/A

2.4.2.1.6. Leave-To-Construct (if applicable)

N/A

2.4.3. COMMUNICATION INFRASTRUCTURE

2.4.3.1. Optical Telecommunications Network Replacement

2.4.3.1.1. Project Summary

This project will ensure the Optical Telecommunications Network (OTN) is operating on equipment that has not failed and is not close to the end of life in order to utilize the full benefits of the system as designed. This equipment includes, but is not limited to, Nokia: PSS32 (Photonic Service Switch - optical backbone), 7750 (service aggregation router), 7705 (service access router), and 7210 (service access switch).

2.4.3.1.2. Project Description

Current Issues

As OTN equipment reaches the end of life or is run to failure, it will need to be replaced. This project recognizes and plans for the economic replacement of equipment in order to maintain the system as it becomes more critical for Hydro Ottawa's distribution system and automation. The network is made up of many parts (as noted in Section 1); the fiber optic cable has a longer economical life compared to the equipment that connects station to station and core to core sites. As the investment was made to initially install the network, this project ensures we are prepared to replace necessary equipment as it reaches the end of life. This is necessary in order to avoid compromising the network.

Project Scope

This project involves replacing end-of-life telecommunications assets that were installed under the previous rate-application period of 2016-2020. In 2025 some of the OTN equipment will reach its predicted end of life as it was installed in 2017-2018.

Main and Secondary Drivers

The main driver for this program is Risk of Failure. If failed equipment (or equipment close to failure) is not replaced, the system will not function as designed and puts the network as a whole at risk for failure. The secondary driver is reliability. As the OTN is crucial for carrying both corporate and SCADA network traffic, the system needs to be in working order.

Performance Targets and Objectives

The OTN includes a level of redundancy by design in order to provide re-routing of traffic due to a break or failure in the network. Though the network can still function with a break between redundant nodes, equipment that has failed needs to be replaced in order for the system to function as designed. As described above, this network is crucial for Hydro Ottawa for the corporate activities and system operations (e.g. SCADA). Additionally, performance targets are outlined in the Telecommunications Asset Management Plan through Hydro Ottawa's alignment with the ISO 55001 Asset Management System. This includes evaluating data such as packet loss between two nodes in the network in order to indicate areas of the network that need to be updated or replaced.

2.4.3.1.3. Project Justification

Alternatives Evaluation

Alternatives Considered

There are no alternatives for this program. The investments are required to upkeep the equipment necessary for the entire Network to function as designed.

Evaluation Criteria

The investment is necessary in order for the Network to function as designed and support corporate and SCADA communications traffic. This evaluation considers the original investment and that the dependencies on the network continue to increase on both the corporate side and operational side, such as SCADA communications to stations in our service territory.

Preferred Alternative

As mentioned, there are no alternatives to be considered for this project. In order to maintain the original investment into the Network, continued investments need to be made. This project derives from the economic lifetime of 8 years for equipment that was installed in 2017/2018 timeframe and should be replaced by 2025. The "do-nothing" option puts the network at risk for failure and Hydro Ottawa would not see the benefits.

Project Timing & Expenditure

The historical expenditure values in Table 4.11 represent the installation and procurement of the OTN, including fibre optic cables. Future expenditures replace equipment due to end of life or failure in order to keep the system running and redundant where applicable. Hydro Ottawa minimized overall costs and has gained from this investment by owning the OTN used instead of leasing from 3rd parties.

Table 2.80 - Expenditures ($'000,000s)

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0.66	$5.34	$6.73	$4.30	$1.54	$0	$0	$0	$0	$0.99

Table 2.81 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	System operational efficiency is gained through the OTN as it provides a fast and reliable communication from the field to the SCADA system in order to monitor and control the grid. If a failure occurs in the network, where built in redundancy is present, traffic is rerouted ensuring communication is available between operations and the field. By owning the OTN, SCADA traffic was designed with extended resources for additional reliability. In the future, as more automated devices are added to the distribution system, this network will provide a robust, fast and reliable means of communication to support these new technologies, including the path towards an Advanced Distribution Management System (ADMS).
Customer	Investing in the OTN network is crucial for Hydro Ottawa from corporate to SCADA traffic, including security cameras. Hydro Ottawa’s network provides secure and reliable connections to other hardware and software investments made. Additionally, monitoring and collecting data can become expensive when leasing network infrastructure; this is mitigated by having sole ownership. By continuing the investment into the network, customers benefit by having reduced outage duration due to the fast and reliable communication between the field and system operators, ensuring all substations and facilities are monitored via security cameras also connected to the network and the ability for Hydro Ottawa to collect data regarding our distribution system reliably to identify and mitigate areas at risk.
Safety	As described in System Operation Efficiency and Cost Effectiveness, section, this network allows operators to safely isolate and restore parts of the grid through reliable communication from SCADA to field devices. Additionally, Hydro Ottawa is able to connect security cameras to the network to monitor access to substations to ensure workers and public and Hydro Ottawa owned assets are kept safe.
Cyber-Security, Privacy	As this is a private network, traffic is monitored and firewalls are in place throughout it under Hydro Ottawa’s control. By keeping the hardware up to date, we gain the latest security features and can continue to improve our ability to monitor the network and avoid any cyber security breaches. This enables Hydro Ottawa to maintain customer privacy, cyber security and grid protection.
Coordination, Interoperability	Investing in Hydro Ottawa’s OTN has a second order effect regarding interoperability and co-ordination with utilities as it facilitates the collection of up to date and correct data and information to share with Hydro One and the IESO.
Economic Development	OTN services were procured in an open process and successfully awarded to Nokia. Nokia continues to provide local engineering services to Hydro Ottawa based out of a local office.
Environment	By having access to a high speed network, Hydro Ottawa can effectively manage both existing and new assets and identify risks that could be harmful to the environment.

2.4.3.1.4. Prioritization

Consequences of Deferral

If investments in Hydro Ottawa's OTN are deferred there is a high risk of failure in the network resulting in the loss of System Operation efficiency such as the network failing and restoration conducted solely via field staff, unable to utilize automation installed in the field, or severed communications from the control room to field devices, resulting in poor reliability. Without maintaining the network, advanced technologies may not be compatible and therefore of no use.

Deferral could result in prolonged outages for customers due to the loss of system operation efficiency described above. It would increase the chances of cyber security vulnerability and reduce visibility into Hydro Ottawa's safety measures. All benefits outlined in Section 3.3 would be at risk if the project is deferred, and as mentioned in Section 3.1.3, the economic lifetime of 8 years would be surpassed.

Priority

The priority is high as failure of the Optical Network will result in a failure of Hydro Ottawa's Critical Networks.

2.4.3.1.5. Execution Path

Implementation Plan

In 2025, we will replace any assets that have failed as equipment reaches its predicted end of life.

Risks to Completion and Risk Mitigation Strategies

This project is a risk mitigation investment. Hydro Ottawa has to be investment in upgrades to maintain the OTN, as the original investment will exceed the economic lifetime for equipment at 8 years.

Timing Factors

Factors that might affect the timing and priority of the project are directly associated with failure of equipment. Early failures could lead to necessary early uneconomic investments.

Additionally, if the failure occurred on network core equipment that would significantly increase the priority to critical.

Cost Factors

Factors that might affect the final cost of the project would be any significant changes on the manufacturing side or if there was early, unanticipated hardware failure. Another factor would be if there was a cyber security vulnerability identified within the hardware or software currently in place, the cost to replace necessary equipment could increase.

Other Factors

N/A

2.4.3.1.6. Renewable Energy Generation (if applicable)

This investment has secondary benefits for Renewable Energy Generation, as it maintains the network for effective communications which would be connected to this network as well as providing continuous situational awareness over the high speed network for better awareness on system loading.

2.4.3.1.7. Leave-To-Construct (if applicable)

N/A

2.4.3.1.8. Project Details and Justification

Table 2.82 - Optical Telecommunications Network Investments Overview

Project Name:	OTN – Optical Telecommunications Network Investments
Capital Cost:	$0.99M in 2025
O&M:	TBD
Start Date:	1-Jan-2025
In-Service Date:	21-Dec-2025
Investment Category:	System Renewal
Main Driver:	Risk of Failure
Secondary Driver(s):	Reliability
Customer/Load Attachment	ALL
Project Scope	
This project will see the replacement of end-of-life telecommunications assets that were installed under the previous rate-application period of 2016-2020. In 2025 some of the OTN equipment will be reaching its predicted end of life as it was installed in 2017-2018.	
Work Plan	
Based on the individual assets that are near the end of life or have failed, we will replace these components.	
Customer Impact	
The customer could be significantly impacted if this network is not kept in working order and allowed to fail. These communications links allow our corporate facilities to communicate as well as allowing our Operational Networks to reach the substations.	

2.4.3.2. Field Area Network

2.4.3.2.1. Project Summary

As part of the Telecommunications Master Plan project that was created and executed during the previous rate period (2016-2020), a portion of the investments were designated for a Field Area Network (FAN). The FAN was intended to provide robust, secure, private, high bandwidth, and low latency wireless connections from field devices (e.g. automation devices, sensors, etc.) to Hydro Ottawa owned and operated towers along the Optical Telecommunications Network (OTN). Unfortunately, during the early execution phase of the Telecommunications Master Plan, it was discovered that the technology originally selected for the FAN was not an appropriate or prudent choice (WiMAX) therefore the decision was made to postpone the FAN investment to the next rate period (2021-2025). This project is designed to deploy a FAN that will enable Hydro Ottawa to securely communicate to its existing and future field assets.

2.4.3.2.1.2. Project Description

Current Issues

There are several gaps being addressed by the FAN project:

- Connectivity: There is a significant need to have wireless access and connectivity from Hydro Ottawa back office systems to the various switches, sensors, automation devices, and metering aggregation points across the service territory. Wireless is the preferred alternative as fibre connectivity becomes cost prohibitive to each individual device.
- Security/Privacy: The Field Area Network selected by Hydro Ottawa must take into account the critical nature of the Utility Infrastructure and as such, any wireless system used must provide for the protection of that infrastructure and the data that it transmits.
- Reliability/Availability: The FAN must perform particularly well when there are severe weather events or other power interruptions. The selected FAN technology and implementation will need to contain features and design aspects that make it reliable and available during these events.
- Flexibility: There are several needs particular to the utility sector, including priority and latency. Not all utility network traffic is classified equally; special functions like a transfer-trip protection signal will require priority and lower latency than routine data collection.

The selected FAN technology must accommodate this type of traffic classification and prioritization.

Project Scope

This project is essentially an advanced technology application that will include the deployment of a wireless system to enable communications to remote field devices from Hydro Ottawa owned facilities (offices, substations). This project will encompass the following elements:

- Back Office Systems: There will be a need for software and hardware systems solution that will provide the connection between the wireless network and the wired network within the utility back office systems. Furthermore the back office system will enable the configuration, monitoring, management, and control of the wireless network and its constituent parts.
- Towers: There will be physical towers and associated infrastructure to mount the base-station radio equipment. This includes tower structures, roof mounting equipment, radiofrequency (RF) and power cabling as well as any small buildings or cabinets designed to hold power and interface equipment.
- Base Station Radio equipment: This will encompass the physical antennas and RF equipment and supporting systems at the base stations.
- Modems or Customer Premise Equipment (CPE): These are the remote radios that will be used at the location of the remote field devices. This will encompass any antenna, radio device and supporting equipment. It is expected that this project will deploy many CPE radios and that Hydro Ottawa will continue this deployment
- Radio or Spectrum Licenses: Due to the need for privacy as well as reliability it is expected that Hydro Ottawa will secure licensed frequencies for its FAN system.

Main and Secondary Drivers

The primary drivers of this project are:

- System Efficiency: In order to effectively optimize and control the Hydro Ottawa system, there is a need to remotely operate the various switches and intelligent devices in the field. In order to fully realize the benefit of these devices and the software systems that control them, a reliable and secure wireless connection must be made so that the devices can be used and monitored in real time.

- Reliability: In order to effectively and quickly respond to outage events, the Hydro Ottawa control room must have the ability to view real time information from sensors and meters as well as remotely operated switches or other devices (either manually or through advanced software systems such as the SCADA/DMS or OMS platforms) so that any service interruptions are minimized in both duration and the number of customers affected.
- Other Performance/functionality: The FAN will allow Hydro Ottawa to deploy CPEs at customer locations that have Distributed Energy Resources (DERs). This is seen as a critical function as the number of DER installations within the Hydro Ottawa service territory will continue to grow throughout the next rate period.
- Power Quality: Finally, the FAN will enable additional telemetry collection that can assist control room operators to address power quality issues at the very edge of the distribution system. Using telemetry collected from the field, the DMS and SCADA platform can provide operators recommendations and automatic functions to reduce system losses and improve performance.

Secondary drivers of this project include the following:

- Safety: It is anticipated that having the FAN available will improve telemetry collection, enable higher levels of automation, and enable remote operations of field devices. This additional telemetry and remote control of devices will have a net positive effect on employee and public safety as Hydro Ottawa control room staff will have enhanced visibility and control over potentially hazardous situations.

Performance Targets and Objectives

The FAN project is a foundational and enabling technology. It is therefore difficult to attribute specific system performance objectives to the deployment of this system. The connectivity, security, and reliability factors of the proposed FAN solution all serve to support the effective and efficient management of the Hydro Ottawa grid during normal operations as well as during an outage response.

2.4.3.2.3. Project Justification

Alternatives Evaluation

Alternatives Considered

There are essentially five alternatives for consideration in the Field Area Network Project:

- The proposed approach is a private LTE (Long Term Evolution) network deployment using licensed spectrum in the 3GPP Band 43 or Band 48 (The LTE technology standard is the current global standard for the 4G wireless used in personal cell phones. This standard is governed by two international bodies; the 3GPP or 3rd Generation Partnership Project and the ITU or International Telecommunication Union). This approach, while being the most capital intensive, does address all of the problems identified.
- The first alternative considered is the 'do-nothing' approach which is to continue with the existing practice of using individual public carrier LTE networks (e.g. Rogers, Bell, or Telus etc.). This alternative is by far the simplest approach in that the infrastructure is managed by a 3rd party and the utility simply pays for the CPE and a monthly connection fee. Unfortunately, this simplicity comes at the cost of reliability, security, and flexibility. Furthermore it represents an ever increasing risk for both operational costs (OM&A dollars) and the dependency on a 3rd party to maintain the network to the required service levels that a public utility is expected to maintain.
- The second alternative is to create or join a Private Virtual Network Operator (PVNO) and operate the utility CPEs outside of the normal contractual relationship with an individual public LTE carrier. This alternative represents the ideal approach in that it removes many of the issues related to engaging a single carrier (improved reliability by roaming onto many carrier networks, prevention of carrier lock-in by having to replace SIM cards in the CPEs when changing providers). Furthermore, it would allow the utility to negotiate lower cost agreements for the volume of data transmitted. Unfortunately, this approach is under regulatory review by the Canadian Radio-Television and

Telecommunications Council (CRTC) and is not yet available in Canada and therefore, eliminated from further consideration.

- The third alternative is to join the growing Public Safety Broadband Network (PSBN) and leverage the deployment of LTE network that is being designed and deployed across Canada to support first responders and other emergency services. This alternative would solve many of the issues identified; however, at this time; Public Utilities are not considered priority users of the Band 14 frequency spectrum that has been selected for the PSBN to utilize. The PSBN network architecture is one that will feature the ability for the network to prioritize emergency first response organizations over all other users. This feature will not impact utility traffic during a normal day, however in the event of a major catastrophe or extreme weather event the utility use of this network could be severely curtailed. Therefore with these constraints to the use of the PSBN network, is not recommended in the Hydro Ottawa area given the number of public safety and emergency response organizations in close proximity to the Ottawa area.
- The final alternative is the non-LTE based solutions such as:
    - WiMAX: WiMax was the original technology selected for the FAN deployment. Unfortunately, this technology is near end of life and there are currently only 2 vendors that are selling WiMAX systems in the Utility reserved frequency space.
    - Unlicensed Radio systems: These include 900MHz, 2.4GHz or other similar technologies. These systems have the advantage of completely avoiding the problem of licensing and do not suffer any onerous constraints pertaining to the deployment of the radio devices. Unfortunately, the lack of constraints and the no-cost nature of the spectrum mean that there are typically far too many users and no protections offered against interference.

Evaluation Criteria

There are no specific performance measures that would differentiate the alternatives discussed. Therefore, the solution that best resolves the identified issues will be selected.

Preferred Alternative

The preferred alternative is the Private LTE network deployment using licensed spectrum as it best resolves the current issues while still allowing for a transition to one of the other LTE based alternatives should any of the regulatory or governance issues be resolved.

- Connectivity: The preferred alternative provides for the connectivity that is required for effective field asset control and monitoring.
- Security/Privacy: The preferred alternative brings the LTE back end systems under Hydro Ottawa control and will therefore allow the utility to control the encryption from end to end. This encryption is inherent to the LTE technology however the encryption of the radio transmissions is typically controlled by the network operator.
- Reliability/Availability: The preferred alternative will be deployed with reliability and availability at the top of mind. This will ensure that the network contains all of the requisite features and redundancies that are necessary to meet the reliability and availability goals.
- Flexibility: As Hydro Ottawa will be deploying this network it will remain flexible to the needs of the utility and the investments will be targeted towards the priority geographical areas.

Project Timing & Expenditure

This project does not have any expenditure prior to 2021 as the project was deferred from the previous rate period. For the years 2021 to 2025 the timing and expenditure appears in Table 2.83.

The first year (2021) will see the purchase and installation of the back-office systems as well as the initial base-station and up to 30 CPEs.

For the subsequent years (2022-2025) Hydro Ottawa will purchase and install up to 20 base stations and approximately 30 CPEs per year.

Table 2.83 - Expenditures ($'000,000s)

	Historical					Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0.00	$0.00	$0.00	$0.00	$0.00	$1.79	$1.04	$1.04	$1.04	$1.04

Benefits

As discussed above, the FAN project is a foundational and enabling technology deployment project. As such, the benefits from the FAN deployment are not readily quantified but the FAN availability will enable additional tools and devices in support of automation, listed in Table 2.84.

Table 2.84 - Project Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	The FAN provides high-bandwidth and low latency connectivity to the various devices in the field which includes the metering infrastructure and automated switches and sensors. This connectivity will enable the optimal configuration of the utility grid as operations personnel will receive near real-time information on system performance and enable them to take corrective action.
Customer	As discussed above, the connectivity provided by the FAN will further enable the deployment of automation devices and sensors to assist the utility in managing outages. This improved management will result in a reduction in the outage durations and will therefore have a significant positive impact on the customer.
Safety	Having the FAN available will improve telemetry collection, enable higher level automation, and enable remote operations of field devices. This additional telemetry and remote control of devices will have a net positive effect on employee and public safety in that Hydro Ottawa control room staff will have enhanced visibility and control over potentially hazardous situations
Cyber-Security, Privacy	The private LTE based FAN includes encryption that is inherent to the LTE technology. Furthermore the use of licensed spectrum will further enhance the privacy and security of the information and control data that is transmitted.
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	N/A

2.4.3.2.4. Prioritization

Consequences of Deferral

As the FAN is an enabling technology project, deferring this investment will result in a further delay on the overall operational efficiency and reliability performance improvements of Hydro Ottawa. While the FAN is not the only element required for the increased automation of the Hydro Ottawa system, the lack of a coherent wireless connectivity system will result in additional and potentially costly engagements with the public carriers.

Priority

This project is considered Medium Priority based on the following considerations:

- This project has significant potential of improving performance across the Hydro Ottawa distribution system and therefore the experience of all customers.
- This project has many second order benefits in that it will drive utility staff towards improving the records within the Hydro Ottawa technology systems and will improve the performance of other related tools (Outage Management System, SCADA) which will in turn further improve performance of the utility.

2.4.3.2.5. Execution Path

Implementation Plan

This project will begin in the back office communications systems as Hydro Ottawa purchases and installs the required technology to manage, operate, and maintain the FAN. Once the back office systems are in place, the deployment of the Towers and base stations will proceed in a prioritized fashion starting with geographic areas that contain the greatest amount of automated devices and sensors and proceeding to areas that are targeted for additional automation.

Risk to Completion and Risk Mitigation Strategies

As with any new technology implementation there are associated risks such as those outlined in the following areas:

- Complexity: There are a number of different software and hardware systems that will be required to effectively deploy and operate the FAN. For the most part, these systems are quite mature as they have been in use throughout the world in public carrier networks. However, this type of technology is new to Hydro Ottawa. The mitigation plan for such complex technology deployments is the careful engagement and co-ordination between the Hydro Ottawa team and the vendor teams (the vendor that deployed the Optical Telecommunications Network for interfacing with the existing network, and the vendor for the FAN platform) to ensure that the requirements are fully captured in the project planning and execution phases. Finally, there will be extensive testing of the final product to ensure that the systems are fully functional.

- Cost: As with many technology projects, costs can be a challenge to manage as there is a significant scope of work planned for the FAN implementation. The strategy to minimize the risk of cost overrun is to only engage the vendor on an ongoing service basis while providing full accountability to the intended roadmap. This will incentivize the vendor to perform adequately as future contracts will be put at risk due to poor performance. Furthermore, the project will have a dedicated project manager and executive sponsor within Hydro Ottawa to ensure that the governance surrounding the project is sound and full management visibility is provided.

Timing Factors

The following factors could affect the timing of the FAN deployment:

- Successful engagement with a vendor and the timely completion of the architecture and detailed planning stems.
- Staff availability to support the deployment and installation of the FAN hardware.
- Availability of the locations for the base station installations
- Technology availability, the LTE technology used in the FAN is industry standard as a result there can be increased lead times as a result of global demand.

Cost Factors

As discussed above, technology investment projects can be difficult to implement and incur significant cost pressure. The strategy to minimize the risk of cost overrun is to engage the vendor on an ongoing service basis while providing full visibility to the intended roadmap. This will incentivize the vendor to perform adequately as future contracts will be put at risk due to poor performance.

Other Factors

With any wireless system deployment there is risk associated with the regulatory environment. With the use of LTE technology and licensed spectrum there are a number of organizations that could alter regulations that could have an impact on the planned Field Area Network. The mitigation strategy for this is to engage with other utilities making similar investments (in forums such as the Utility Telecommunications Council and the Canadian Electricity Association). There is also the possibility that there is regulatory or other management pressure that requires the de-prioritization of the DMS implementation project. This will likely result in a significant de-scoping of the project as to reduce the impact on cost and staff, however it is likely that the project would continue in a smaller and targeted manner in order to extract the benefits of the automation and enhanced situational awareness for the Hydro Ottawa System Operators.

2.4.3.2.6. Renewable Energy Generation (if applicable)

As discussed above, the FAN is a foundational technology investment that enables the communications between the Hydro Ottawa back office systems and field area assets. These assets could include ERFs that include renewable technologies such as solar. Therefore, the FAN could serve as an enabling technology to the deployment of renewable energy generation as the additional visibility and control the FAN provides would allow Hydro Ottawa to accommodate greater amounts of ERF within its distribution system.

2.4.3.2.7. Leave-To-Construct (if applicable)

N/A

2.4.3.2.8. Project Details and Justification

Table 2.85 - Field Area Network Overview

Project Name:	Field Area Network
Capital Cost:	Approx. $5.97M
O&M:	Approx. $1.0M
Start Date:	1-Jan-2021
In-Service Date:	Multiple - Incremental Functionality added each year
Investment Category:	System Service
Main Driver:	Connectivity to Field Assets for Reliability
Secondary Driver(s):	Efficiency
Customer/Load Attachment	Enter Number of Customers/Load Attached
Project Scope	
This project would see the creation of a full Private LTE deployment in critical areas of our service territory. This private wireless network would be made up of the following elements: 1) A back end software and hardware solution 2) 20 Towers at select locations (4-per year) 3) 30 Radio devices in the field per year	
Work Plan	
In the first year, the bank end system would be installed on the existing Optical Telecommunications Network and for each year, 4 tower sites and 30 remote radios would be added. It is expected that the cost of these radio devices would continue to decline which would result in additional devices being purchased to increase the total number installed and provide greater connectivity.	
Customer Impact	
The customer would benefit from this additional network as it would be used to both offset the existing wireless services that are purchased by Hydro Ottawa as well as increasing the number of field assets that are wirelessly connected to our back office systems. This additional connectivity would result in better real-time data from the field as well as improved ability to remotely operate devices and therefore improve Outage Performance and therefore reliability.	

2.5. METERING

2.5.1. REMOTE DISCONNECT SMART METER

Table 2.86 - Remote Disconnect Smart Meter Overview

Project Name:	Remote Disconnect Smart Meter
Capital Cost:	2021 to 2025 - $2.5M
O&MA:	N/A
Start Date:	2021
In-Service Date:	2021-2025 yearly individual in service dates
Investment Category:	System Service- Metering
Main Driver:	System Efficiency
Secondary Driver(s):	Functional Obsolescence
Customer	17, 500 customers each with up to 50 KW

Project Scope

This project will install approximately 17,500 remote disconnect meters over the 2021 to 2025 time period. This will provide the capability to remotely turn power on and off at the service point. This will reduce expenses as it eliminates the requirement to send a meter technician to the premise to disconnect the meter as well as to later reconnect the meter when required. This will also eliminate the need to install power limiters based on timer functionality for non-payment during the winter months along with the associated expense of travelling to the premise.

Work Plan

The work plan involves installing the remote disconnect meters on some of the locations that are required to be sampled according to Measurement Canada, new installations, inside meter locations and defective meter replacements. There will be approximately 3500 meters installed per year.

Total Expenditure
2021: $501,000
2022: $501,000
2023: $501,000
2024: $501,000
2025: $501,000

Customer Impact
Remote disconnect meters reduce maintenance costs and technician time required to connect and disconnect meters, while providing efficient metering services for customers. The meters can also be used as part of the collections processes when funds have not been received for past usage. The meters can reduce the time required to have the disconnect or reconnect function performed which can increase customer satisfaction. E.g. For apartments where the power was turned off when the previous customer moved out, the disconnect meter can be used to turn power on quicker when the customer requests power. The remote disconnect meter can also be used with the scheduled remote batch capability to emulate a physical timer on a service during adverse weather conditions when disconnecting power is not desirable. The remote capability also provides enhanced safety for the meter technician if it is in a difficult to access or in a dangerous location, when a disconnect or reconnect function is required. The disconnect meters will have the normal verification periods as other meters as per Measurement Canada guidelines.

GENERAL PLANT

3.1 CUSTOMER SERVICE

3.1.1. NON CIS METER TO CASH ENHANCEMENTS & ELSTER EA-MS UPGRADE

3.1.1.1. Program Summary

Hydro Ottawa's Meter to Cash infrastructure is comprised of multiple critical metering systems responsible for collecting, processing and validating incoming meter data. Ensuring efficient and effective operations of these systems is essential to produce timely and accurate customer bills. These systems include Honeywell EA_MS, I-Tron MV90, Savage Data Systems and Triacta. Each of these systems will require upgrades and enhancements to maintain regulatory compliance, minimize risk and ensure successful business outcomes are achieved.

3.1.1.2. Program Description

3.1.1.2.1. Current Issues

- Aging metering applications nearing end-of-life and loss of vendor support
- Newer metering technology incompatible with current applications
- Unknowns of future regulatory obligations
- Increased demand and speed for meter data information
- Gaps in existing process and deficiencies in technology which must be addressed

3.1.1.2.2. Program Scope

Hydro Ottawa must keep current with technology of all Advanced Metering Infrastructure (AMI) systems used to bill our customers successfully. These critical applications must remain on a vendor supported platform along with reaping the benefits of additional features and enhancements inherent in the latest versions of these applications (see high level diagram below).

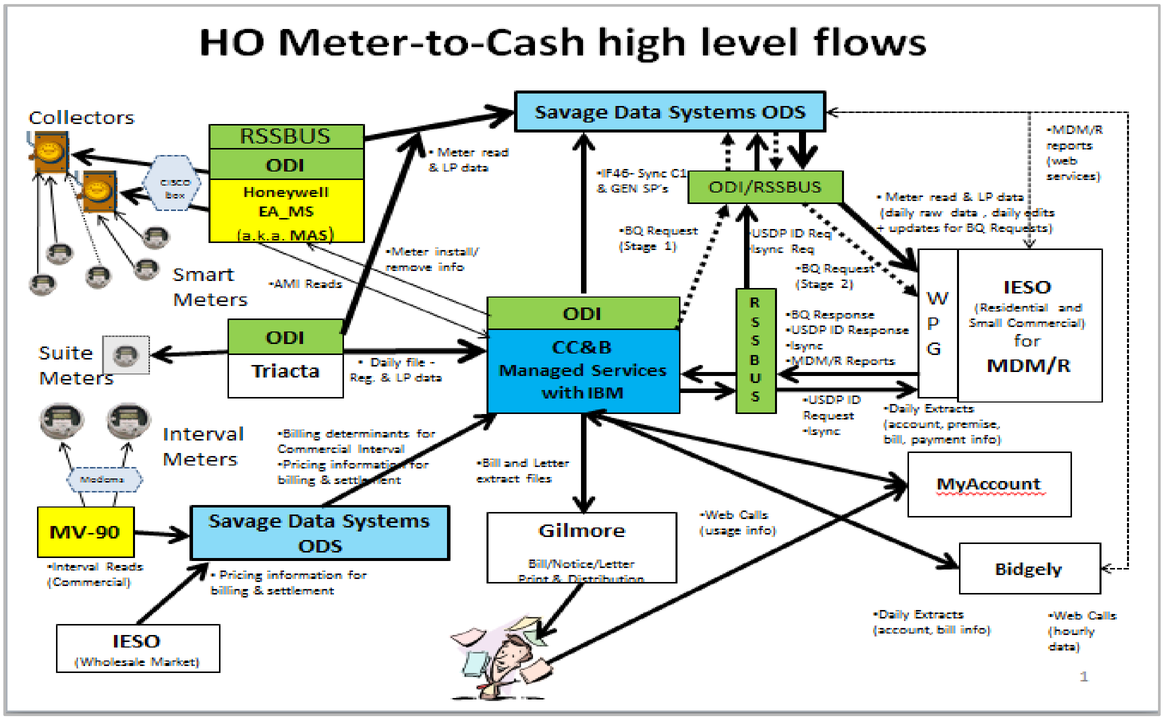
A major upgrade in 2021 is required for our AMI technology Honeywell EA_MS as well as a minor upgrade in 2025. Hydro Ottawa implemented EA_MS version 9.2 in Q4 2016 which is now considered End of Life technology as of Q2 2018 with the release of Honeywell's new platform Connexo NetSense 11.2. Moving to Connexo NetSense is a significant lift estimated at $1.3M in cost while the minor upgrade is estimated at $300K.

The MV90 Itron product is used to gather interval read data for our largest customers' meters. MV90xi was upgraded to version v5.0 early 2017. Hydro Ottawa is planning for two upgrades, one in 2021 and again in 2025.

Savage Data systems is a cloud solution and critical system in our Meter to Cash stream for all of Hydro Ottawa's rate class billings. Ongoing changes are anticipated to maintain Regulatory compliance as well as changes to critical interfaces with surrounding systems.

Funds will be used in the non-upgrade years to keep current with any changes regulatory requirements as well as continue to enhance Hydro Ottawa's operations by continuing to introduce automation to reduce internal workload and provide more insights to our operations group with more data analytics.

Figure 3.1 - Hydro Ottawa Meter-to-Cash High-Level Data Flows



3.1.1.2.3. Main and Secondary Drivers

The business drivers for this project are described in Table 3.1 below.

Table 3.1 - Business Driver

Business Driver	Description
Continue to enhance operational performance and productivity	Enhancements to improve regulatory compliance, cybersecurity, vendor support and business process improvements
Deliver on customer expectations – service quality and response	Maintaining critical Advanced Metering Infrastructure (AMI) to deliver quality service

3.1.1.2.4. Performance Targets and Objectives

Performing upgrades to our core non CIS meter to cash systems will meet the following objective:

- Ensure robust meter to cash systems that will position Hydro Ottawa to better leverage technologies and provide enhanced services to our customers.
- Enable Hydro Ottawa to purchase the latest meter technology that would only be compatible with the latest IT AMI infrastructure
- To maintain vendor support and improved cybersecurity by being on the most up to date platform
- To gain efficiencies with new technology, functionality including additional features in metering technology
- Re-engineered internal business processes to improve outcomes, productivity and efficiency
- Leverage new functionality and additional data in meters for analytics and application in distribution modeling and early outage detection.
- Maintain Regulatory compliance with all non CIS Meter to Cash system
- To strengthen Hydro Ottawa's position in the Ontario market by being on the same platform as other large distributors which would create synergies and encourage more collaboration

3.1.1.3. *Project Justification*

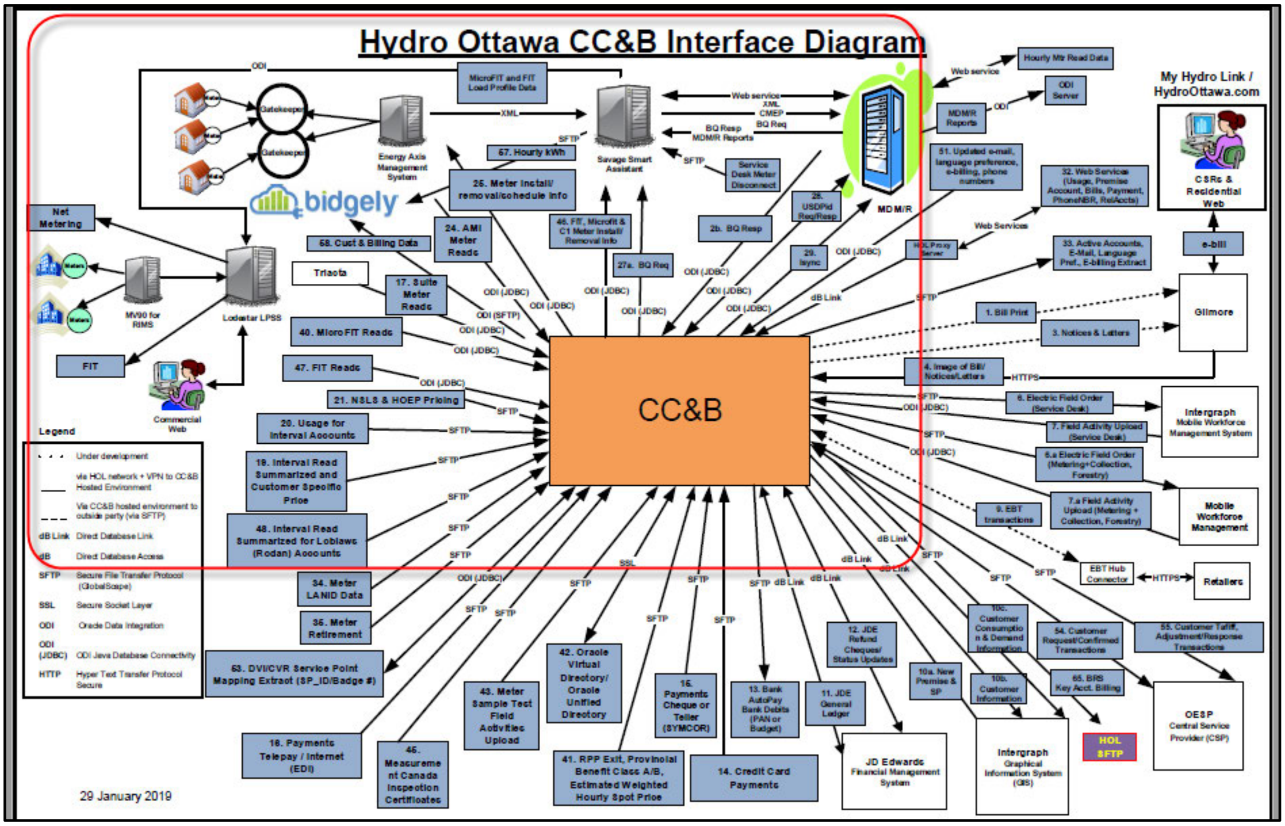
3.1.1.3.1. Alternatives Evaluation

Alternatives Considered

The non CIS Meter to Cash Enhancements application portfolio must evolve as the business evolves and as the vendor provides new software releases. Each application is part of an integrated application landscape and has implications upstream and downstream. Funds are required to effectively manage technology risk with our support partners and implement enhancements to achieve Hydro Ottawa business outcomes. Hydro Ottawa does not see an alternative in maintaining its critical AMI applications.

The outlined red box of the following interface diagram below depicts all of the upstream and downstream systems and interfaces that would be considered as part of these upgrades.

Figure 3.2 - Hydro Ottawa CC&B Interface Diagram



Evaluation Criteria

- Impact on OM&A: Additional fees for vendor support would be required as Hydro Ottawa would not be on the latest platforms
- Risk profile: due to not being on fully supported platforms. Critical business impact issues may take longer to resolve by the vendor. There are also potential security risks.
- Regulatory compliance: by being on the latest versions of these systems, Hydro Ottawa would not be exposed to not meeting regulatory compliance.
- Keeping up with Industry trends, metering technology
- Addressing customer future needs
- Perceived as innovative in the industry
- Vendor commitment towards future investments in the product lines
- Alignment with technology and ongoing stewardship

Preferred Alternative

An alternative to maintaining these AMI applications is not viable as this critical infrastructure is essential to provide accurate bills to our customer population.

3.1.1.3.2. Project Timing & Expenditure

Below lists the historical and future investments for the non CIS meter to cash systems:

- AMI technology EA_MS was upgraded from version 8.0 to version 9.2 in 2016
- MV90 was upgraded to version MV90xi version 5.0 in early 2017
- Corporate decision was made to eliminate Hydro Ottawa's on premise LPSS settlement system and replace all of its functions with Savage Data Systems. This project will be kicked off in Q3 2019 and will be live by Q2 2020.
- Perform multiple metering infrastructure upgrades in 2021 & 2025: Major Upgrade Honeywell EA_MS from version 9.2 of EA_MS to Connexo NetSence version X in 2021 (Estimated cost $1.3M) and a minor upgrade in 2025 (Estimated cost $300K). Upgrade MV90xi from version 5.0 to X in both 2021 & 2025 (both estimated at $100K). Maintain systems in the off upgrade years as other surrounding systems may change as well as remain Regulatory compliant.

The 2021-2025 upgrade approach is the result of key stakeholders input (Metering Operations, Meter Data Services, Billing & Customer Service, IM/IT) and is driven by the need to minimize risk while positioning the organization for future growth and innovation.

Table 3.2 - Meter To Cash Historical and Forecast Expenditures ($'000,000s)

	Historical					Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0.25	$0.13	$0.06	$0.17	$0.50	$1.5	$0.10	$0.10	$0.10	$0.50

3.1.1.3.3. Benefits

Table 3.3 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	• Ensure efficient and effective operations of non CIS meter to cash systems. These systems are all critical path systems used to accurately bill our customers. • Keeping these systems on the latest platforms will save the organization on costs required for potential special vendor patches. • Introduce new interfaces with enhanced features • Increased performance of these systems • Improved IT back end support and maintenance • New business processes introduces making internal workload more efficient • Remain regulatory compliant
Customer	• Lower risk of negative customer impacts such as not being able to read our meters • Ensure timely and accurate billing of our customers • Enhanced features and data from customer's meter which would feed into analytical tools that would provide customers with better usage information for decision making • Promote electricity conservation • Latest technology will allow Hydro Ottawa to invest in most up to date meters as they would be compatible
Safety	• Future versions will have enhanced safety features with handling of our physical meters.
Cyber-Security, Privacy	• Latest versions of these systems would provide Hydro Ottawa access to security patches and enhanced security
Coordination, Interoperability	• Strengthen LDC relationships using the same surrounding meter to cash systems such as Toronto Hydro, Alectra, Veridian, etc. Exchange of ideas and potential for sharing costs where there are synergies.
Economic Development	N/A
Environment	N/A

3.1.1.4. Prioritization

3.1.1.4.1. Consequences of Deferral

If the decision was to delay upgrades and maintenance of the non CIS meter to cash systems, the consequences/ risks would be the following:

- Honeywell EA_MS (responsible to collect meter read data from 330,000 customers) would be out of vendor support for an extended period of time, introducing major risk to billing our customers

- MV90xi (responsible to collect our interval meter read data) would be out of vendor support, introducing major risk to billing our large customers
- Hydro Ottawa would not be able to leverage new technology and additional features
- Hydro Ottawa would not be able to have the latest metering technology that would collect additional data for customer use
- Additional costs for emergency patches
- Risk of not being up to date with security patches
- Delaying internal efficiencies and automation

3.1.1.4.2. Priority

HIGH: This priority is set as maintaining these systems are critical to the success of Hydro Ottawa's timely and accurate billing of our full customer base.

3.1.1.5. Execution Path

3.1.1.5.1. Implementation Plan

Each individual change would be implemented using change management best practices.

3.1.1.5.2. Risks to Completion and Risk Mitigation Strategies

- Resource constraints: ensure alignment and commitment from the organization
- Dedicated project team: ensure the team solely focuses on this project and not in addition to operations
- Change management of new platform: ensure the project team focuses on preparing the organization for the changes

3.1.1.5.3. Timing Factors

- Honeywell EA_MS 9.2 out of vendor support in 2018- already at risk
- MV90xi version 5.0 will be out of vendor support in January 2021

3.1.1.5.4. Cost Factors

- Preliminary estimates were provided by the vendors that support these applications, i.e. Honeywell EA_MS, Itron, etc.
- Estimates for internal labour based on past projects
- Scope may increase due to some unknowns with the new Honeywell EA_MS platform
- Unknown Regulatory pressures could introduce additional un-anticipated development

3.1.1.6. Project Details and Justification

Table 3.4 - Non CIS Meter to Cash Enhancements

Project Name:	Non CIS Meter to Cash Enhancements
Capital Cost:	$2.3M
O&M:	N/A
Start Date:	January 2021
In-Service Date:	Enhancements will be realized at various points through the term
Investment Category:	General Plant
Main Driver:	Deliver on customer expectations
Secondary Driver(s):	Continue to enhance operational performance and productivity
Customer/Load Attachment	Enter Number of Customers/Load Attached
Project Scope	
Hydro Ottawa's Meter to Cash infrastructure is comprised of multiple critical metering systems responsible for collecting, processing and validating incoming meter data. Ensuring efficient and effective operations of these systems is essential to produce timely and accurate customer bills. These systems include Honeywell EA_MS, I-Tron MV90, Savage Data Systems and Triacta. Each of these systems will require upgrades and enhancements to maintain regulatory compliance, minimize risk and ensure successful business outcomes are achieved.	
Work Plan	
1. Assign a dedicated resources (Hydro Ottawa and/or contractors) 2. Assess requirements 3. Design/ upgrade/configure changes 4. Build/develop changes 5. Build/develop integrations changes 6. Data analysis 7. Data clean-up 8. Data transfer/migration 9. System functional testing 10. System integration testing 11. Training 12. User acceptance and regression testing 13. Deploy changes to production 14. Stabilization period	
Customer Impact	
Maintaining these systems are critical to the success of Hydro Ottawa's timely and accurate billing of our full customer base.	

3.1.2. CC&B ENHANCEMENTS

3.1.2.1. Program Summary

Oracle Customer Care & Billing (CC&B) is the system at Hydro Ottawa which provides billing of electricity revenue and serves as our main Customer Information System (CIS). It is large, complex and highly integrated across the organization; from our metering infrastructure, to provincial systems, and to our web and mobile applications. As the main CIS system, this application needs to be updated to accommodate Hydro Ottawa's customer service strategy. Funds are set aside each year to ensure CC&B is compliant with all current and future regulatory requirements while being enhanced to provide efficiencies to our internal staff and to provide value-add to our customers.

3.1.2.2. Program Description

3.1.2.2.1. Current Issues

Hydro Ottawa's CIS system will be upgraded to Version 2.7 in 2020. Once implemented and stabilized, there are continuous enhancements which will be required to maintain Regulatory Compliance, improve internal workload and align with our customer service strategy. Hydro Ottawa would also seek to position ourselves to take on new business opportunities such as those with affiliate companies.

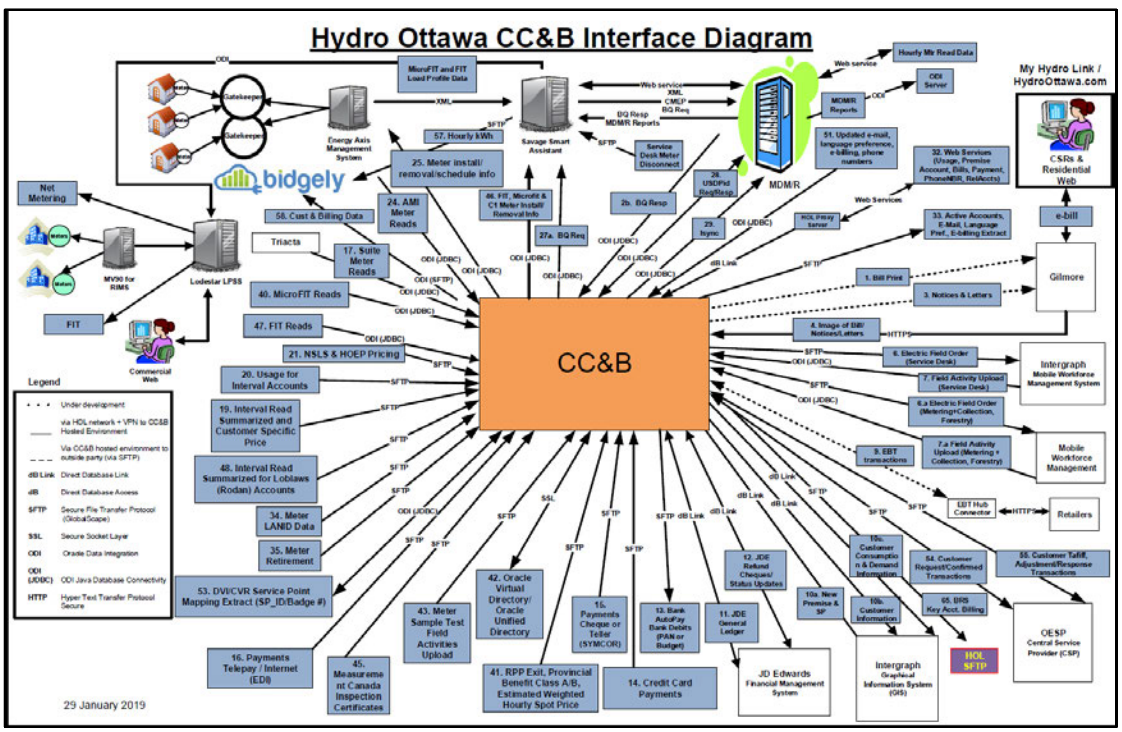
In the past, Regulatory enhancements that were delivered by Hydro Ottawa included Ontario Energy Support Program, Ontario's Fair Hydro Plan, automation of Net Metering, disconnect moratorium & SME license renewal (new parameters in the Isync), MDM/R Energy IP upgrade to name a few. We also delivered enhancements that benefited our customers such as Direct Deposit and Auto-dialer for collections activities. This maintenance is important and critical, not only as a licensed distributor but to be seen as a reputable and value-add utility to our customers.

3.1.2.2.2. Program Scope

- To perform Regulatory changes and maintain compliance. Some items on the horizon: Rate changes, new customer rate classes, IESO market renewal, customer service rules, green button, additional new services.

- To enhance CC&B and/or build new interfaces to work with other customer facing systems such as CRM, MyAccount Customer portal, IVR/telephony, mobile applications, to enrich customer knowledge and enhance 24/7 self-serve capabilities.
- To assist in streamlining and automation of existing business processes
- To modify CC&B to accommodate surrounding systems' upgrades and/or changes
- Leverage CC&B data to provide greater analytics capabilities to for improved insight and help define business strategies based on customer needs
- Ensure cyber-security precautions are in place
- Figure 3.3 below demonstrates the complexity of the interfaces inbound/outbound CC&B. Continuous maintenance due to the impacts of changing these surrounding systems will be required.

Figure 3.3 - Hydro Ottawa CC&B Interface Diagram



3.1.2.2.3. Main and Secondary Drivers

The main and secondary drivers for this project are described below:

- Maintain Regulatory compliance

- Position Hydro Ottawa to take on new business opportunities
- Re-engineer internal business processes to improve outcomes, productivity and efficiency
- Provide continuous customer service improvements, and increased customer satisfaction, offering customers with greater choice, control, convenience and communication options
- Keep up with changes in technology to stay at the forefront of evolving customer experience expectations.

3.1.2.2.4. Performance Targets and Objectives

Maintaining CC&B core application would meet the following objectives:

- Maintain our license as a distributor
- Maintain billing accuracy and timeliness
- Maintain effective and efficient management of customer accounts receivable
- Ensure we are positioned for prompt compliance to changing regulatory requirements
- Deliver on customer expectations for service quality and responsiveness
- Introduce automation to eliminate unnecessary manual work and utilise staff more efficiently – saving cost

3.1.2.3. Program Justification

3.1.2.3.1. Alternatives Evaluation

Alternatives Considered

In this case, there are no alternatives considered. Hydro Ottawa views this as a regular course of business operating as a utility in the Ontario Market. We must meet all Regulatory requirements while building a solid reputation with our customers and in the electricity industry.

Evaluation Criteria

Alternatives were evaluated considering the following criteria:

- Regulatory compliance
- Keeping up with Industry trends
- Addressing customer future needs

- Perceived as innovative in the industry
- Enhancing internal business processes, create efficiencies
- Alignment with technology and ongoing stewardship

Preferred Alternative

Based on the evaluation criteria, the preferred alternative is to invest in our CIS system to ensure continued regulatory compliance, enhance our product for customer satisfaction, energy conservation and introduce automation to better support the business.

3.1.2.4. Program Timing & Expenditure

Historically, Hydro Ottawa required funds on a yearly basis to continue to enhance our critical CIS system and maintain regulatory compliance. Below are the following initiatives and costs used to achieve them:

Regulatory:

- Ontario Energy Support Program
- Ontario's Fair Hydro Plan
- Automation of Net Metering
- Disconnect moratorium
- SME license renewal (new parameters in the Isync)
- MDM/R Energy IP upgrade

Enhancements:

- Direct Deposit functionality to allow customers the choice to have credits owed to them deposited directly into their bank accounts
- Auto-dialer for collections activities
- Auto-pay/Budget billing automation via online web
- Robust High/Low validation for all rate classes

In 2019, Hydro Ottawa initiated an upgrade to CC&B from version 2.3.1 to version 2.7. Below are some of the details relating to this project:

- Estimated to be a 13 month project- kicked off in April 2019, target production go-live May 2020
- Build in Divisional code functionality to allow faster implementation of future expansions
- Provides Operational Efficiencies:
    - o More efficient user navigation - Fewer mouse "clicks"
    - o 15% system performance improvement (per Oracle)
    - o Leverages base code where possible (minimizing customization)
    - o Eliminates the legacy Cobol system which is replaced by a standardized modern Java platform (opportunity to save costs) which is easier to support
    - o Integration capabilities are modern – allows faster speed to market
    - o Integration of customer preferences with CRM
    - o New configurable rate engine – allows easier and faster rate change implementation
    - o Out of Box data archival options using Information Lifecycle Management

In the future, funds will be required to continue the maintenance and upkeep of our core billing system. Some of the projects planned as part of our customer service include the following:

- Back-office Process Automation (RPA) requiring integration with CC&B
- New programs addressing specific customer segments such as Golden Age, Low income, key accounts
- Address increased requests for consolidated billing to ease customer effort in managing their bills
- Customer facing self-serve enhancements such as options in payment methods and due dates, pay plan programs, data analytics and processes such as service requests
- Ability to offer innovative rate plan options

Table 3.5 - CC&B Program ($'000,000s)

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0.27	$0.32	$0.20	$4.1	$4.4	$0.50	$0.50	$0.50	$0.50	$0.50

3.1.2.4.1. Benefits

The benefits of the CC&B enhancement program are summarized in Table 1.5 below.

Table 3.6 - Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	• Ensure efficient and effective operations of our CIS. This system has critical path features used to accurately bill our customers. • Introduce new interfaces with enhanced features • Increased performance of our CIS system • New business processes introduces making internal workload more efficient • Remain regulatory compliant
Customer	• Ensure timely and accurate billing of our customers • Enhanced features and data from customer's meter which would feed into analytical tools that would aide customers in usage decision making • Promote electricity conservation and education • Provide timely analytics to help inform customer and manage their energy costs
Cyber-Security, Privacy	• Alignment with Hydro Ottawa Cybersecurity program will ensure required disciplines are maintained into all aspects of the platform
Coordination, Interoperability	• Strengthen LDC relationships using the same CIS system such as Toronto Hydro & Alectra. Exchanging ideas and potential for sharing costs where there are synergies.

3.1.2.5. Prioritization

3.1.2.5.1. Consequences of Deferral

- Regulatory compliance at risk
- Inability to provide our customers exceptional service offerings risking customer satisfaction
- Reduced ability to streamline and automate processes
- System integration limitations
- Lose potential new business opportunities

3.1.2.5.2. Priority

HIGH: The priority is clear as maintaining this critical system is key to keeping our license as a distributor in the Ontario Market and furthering our customer service strategy.

3.1.2.6. Execution Path

3.1.2.6.1. Implementation Plan

These changes are treated as a program. They are a series of changes (all levels of effort) including regulatory changes that will be implemented as per their prescribed deadlines and/or based on customer and business needs.

3.1.2.6.2. Risks to Completion and Risk Mitigation Strategies

- Resource constraints: ensure alignment and commitment from the organization
- Volume of enhancements/efficiencies: the organization will need to prioritize based on customer and internal workforce impacts.

3.1.2.6.3. Timing Factors

Where the changes involve regulatory compliance, the deadlines would be set by the governed bodies; therefore the organization would need to shift in order for Hydro Ottawa to meet the prescribed timelines.

3.1.2.6.4. Cost Factors

- Controlled by our vendors, Hydro Ottawa would ensure fair and appropriate costs are allocated to each change
- Meeting regulatory requirements sometimes requires complex changes to our systems to accommodate. These can be costly to implement.

3.1.2.6.5. Other Factors

N/A

3.1.2.7. Project Details and Justification

The table below encompasses all changes required to our CIS system:

Table 3.7 - CC&B Enhancements Overview

Project Name:	CC&B Enhancements
Capital Cost:	2.5M
O&M:	N/A
Start Date:	Jan, 2021
In-Service Date:	Enhancements will be realized at various points over the term
Investment Category:	General Plant
Main Driver:	Operational Efficiency
Secondary Driver(s):	Customer Service Strategy
Customer/Load Attachment	
Project Scope	
• Maintain Regulatory Compliance • Improve internal workload • Align with our customer service strategy.	
Work Plan	
Each change implemented within this program will follow change management lifecycle: • Assigned resources • Design the solution with the affected stakeholder(s) • Build/Develop the solution • Unit testing to be completed by the vendor • User Acceptance testing by the assigned resources from IT and/or the business • Training and knowledge transfer • Deploy the production • Monitor	
Customer Impact	
• Re-engineer internal business processes to improve outcomes, productivity and efficiency • Continuous customer relationship improvements, providing customers with choices • To be seen as current and technically savvy by our customers	

3.1.3. SERVICE AUTOMATION

3.1.3.1. Program Summary

Hydro Ottawa is embarking on a Service Automation journey utilizing a digital platform in Customer Relationship Management (CRM) to enable a 360-degree view of customer activity across the organization. Our focus will center on Salesforce.com, recognized as an industry leader in connecting sales, service and marketing activities on a unified "mobile first" cloud platform. The purpose of this initiative is to provide a single, end-to-end picture of the customer's journey aggregated from across various channels, systems and data silos. By providing a unified view of all customer touchpoints, Hydro Ottawa will gain greater customer insight to deliver more personalized and engaging customer experiences, improve customer intelligence as well as achieve company performance objectives. This strategic approach will enable Hydro Ottawa to synchronously manage across the traditional customer-interfacing organizational boundaries, e.g., customer service, sales & marketing, field service, technical and operational support to achieve growth and success.

A significant portion of the project centers on Field Service Cloud (Scheduling and Dispatch of field crews). Hydro Ottawa is currently making use of an on-premise Field Service Management solution called Oracle MMW. This solution is nearing end of life and will no longer be supported by Oracle. Hydro Ottawa is seeking an enterprise grade field service management system which will improve the level of functionality and interoperability currently available, extend its use across the organization at a reasonable total cost of ownership over the next 5 to 10 years. Although Salesforce does offer a field service management solution (Field Service Lightning), it is a relatively new entrant to the industry and therefore lacks the maturity of some of its competitors. Hydro Ottawa will complete a fair evaluation of several offerings prior to selecting a solution to replace Oracle MWM.

3.1.3.2. Project/Program Description

3.1.3.2.1. Current Issues

Hydro Ottawa lacks centralized visibility of customer activity and interactions to enable improved insights, determine relevant solutions and drive better conversations. As a result, without a holistic view of the customer, key decision makers struggle to obtain accurate and timely information to drive their business. Due to customer data residing in multiple systems (islands), it is difficult to report, track and measure service levels or customer touchpoint improvements efficiently. Customer cases and service requests are managed in disparate systems which are not always visible to customer service and call center staff. Additionally, call center staff lack a knowledge management solution to help agents respond to customer inquiries quickly, with ease and increased quality. The key accounts team is currently working with spreadsheets and offline systems to manage their customer portfolio, which is both inefficient and error prone. Hydro Ottawa desires to innovate and launch further Customer Self Service, communication channels, emerging technology and mobile communications but does not possess a platform to enable this vision.

The Operations team requires a new Field Service Management solution to replace the current system nearing the end of life. The system today lacks performance management capabilities, impeding Hydro Ottawa's ability to analyze current and future work dynamics. Configurability of the system is limited and requires specialized support resources, restricting the adaptability of the system to support functional needs. The scheduling engine is able to manage the current workload, but has several limitations considered pain points for field resources. System capabilities are limited and do not fully support the functional needs in terms of work visualization and execution, and for communications with back office, other field resources, and with customers which require manual intervention.

3.1.3.2.2. Program/Project Scope

The scope of this journey is based on a multi-year strategy to improve service automation and iteratively build a 360-degree view of customer activity on a single unified platform. This will be a logical, phased approach that is customer-focused, adapts to change and encourages continuous improvement. The functional areas in scope include:

- ✔ Case management
- ✔ Omni channel and skills-based routing
- ✔ Correspondence tracking and email Integration
- ✔ Computer Telephony Integration
- ✔ Social Care
- ✔ Knowledge base and surveys
- ✔ Live agent chat / Chatbots

- ✔ Key account management
- ✔ Customer Segmentation
- ✔ Customer preference management
- ✔ Service desk
- ✔ Field service management
- ✔ Billing history and Energy Consumption
- ✔ Reporting, dashboards and KPIs
- ✔ Customer self service

Each of the identified areas above will require determination of business requirements, solution design, platform configuration, data conversion and integration to key business systems. The scope will include privacy and cybersecurity requirements into all aspects of solution design.

3.1.3.2.3. Main and Secondary Drivers

The business drivers for the Service Automation project are listed in Table 1.6 below.

Table 3.8 - Business Driver

Business Driver	Functional Area
Continue to enhance operational performance and productivity	Case management
	Omni channel and skills-based routing
	Correspondence tracking and email integration
	Knowledge base and surveys
	Field Service Management
Enhance / protect/ grow revenues	Key account management
	Customer segmentation
Deliver on customer expectations – service quality and response	Customer preference management
	Service desk
	Field Service Management
	Live agent chat / Chatbots
	Reporting, dashboards and KPI intelligence
Assist customers in managing their energy consumption and electricity costs	Billing history
	Energy consumption
	Customer self service
	Computer Telephony Integration

3.1.3.2.4. Performance Targets and Objectives

The performance objectives for the Service automation project are listed in Table 3.9 below.

Table 3.9 - Performance Objectives

Performance Objectives	
Strategy	Increase customer responsiveness and satisfaction
	Create customer loyalty and increase retention
	Gain operational efficiencies in account management
	Enhance corporate image and competitive advantage
Customer Relationship Management	Understand customer expectations and relationship management trends
	Create company-wide customer management
	Establish 'learning relationships' with customers
Operational Innovation	Provide service outside the traditional channels for 24x7x365
	Better internal communication
	Create data- and knowledge-sharing infrastructure
	Learn from customer data
Technology Innovation	Leverage cloud platform for Increased agility and quicker deployments
	Set the pace with personalized, proactive service
	Align cross-company touchpoints to present one face to the customer
	Coordinate across all customer contact channels

3.1.3.3. Project/Program Justification

3.1.3.3.1. Alternatives Evaluation

Alternatives Considered

Hydro Ottawa customer data resides in multiple disparate systems today which are owned and operated by distinct groups across the organization. These systems manage and support critical day-to-day functions necessary to deliver a quality service to customers. Hydro Ottawa recognizes that in order to unify its customer data, a digital platform will be required to act as a central hub. As a result, Hydro Ottawa sought leading independent research through Gartner Inc. to assist in the selection of a Customer Relationship Management (CRM) platform. Salesforce.com Inc. Service Cloud was selected as the preferred platform with alternatives such as Zendesk, Zoho, SugarCRM and Microsoft Dynamics 365 considered.

Evaluation Criteria

Hydro Ottawa evaluated Customer Relationship Management solutions based on the following criteria:

- ✔ Gartner research Pros and Cons
- ✔ Breadth of functionality
- ✔ Ease of use
- ✔ Ease of integration
- ✔ Cost
- ✔ Alignment with Energy and Utilities vertical
- ✔ Data privacy and Cybersecurity
- ✔ Vendor support
- ✔ Future Roadmap including AI

Preferred Alternative

Hydro Ottawa would consider Microsoft Dynamics 365 as a possible alternative to the Salesforce platform. The core feature sets for both sales and service automation are comparable in price, target business type, and capabilities. However, when looking beyond pure product features Hydro Ottawa feels Salesforce excels in the following:

- ✔ User experience
- ✔ Provides robust integration platform (flexible APIs)
- ✔ Richer toolsets and social media engagement
- ✔ Greater mobility
- ✔ Large eco-system to extend platform

3.1.3.3.2. Program Timing & Expenditure

Hydro Ottawa has never before implemented a Customer Relationship Management platform. This will be a net new addition to the application landscape with deployment based on the following roadmap and schedule:

Table 3.10 - Program Timing

Timeline	Deliverable	Description
2019	Service Desk	Launch Salesforce.com and leverage platform to be the central intake system for Electrical Service Requests eliminating a legacy in-house developed application which remains high risk today. Longer term, in-take will expand to include forestry, customer vault maintenance, telecom make ready requests, and more in future phases.
2020	Email & Web Integration	Migrate customer email and web form submissions into Salesforce case management eliminating the legacy process of managing multiple email inboxes through Microsoft Outlook. This will include skills routing, email response templates, KPI metrics and reporting.
	Live Agent Chat / Chatbots	Transition live agent chat to Salesforce solution and introduce chatbots to reduce the number of inquiries on key topics.
	Knowledge Base	Implement a Knowledge Base capability to arm Customer Service Agents with rich information enabling more consistent service, lower costs and quicker resolution times.
	Field Service Mgmt.	Begin implementation of field service management which includes scheduling and dispatch of field crews. This will replace a legacy application nearing the end of life. Evaluation and selection of a tool will take place in 2019 and early 2020.
2021	Field Services Cont'd	Complete implementation of field service management
2022	Customer Preference Mgmt.	Leverage Salesforce platform as a central hub to record customer communication preferences which may include language, email, sms, unsubscribe, bill and high usage alerts etc. Preferences will be cascaded across required business systems where the communication transaction is actually performed.

Timeline (Cont'd)	Deliverable (Cont'd)	Description (Cont'd)
2022	Key Accounts Mgmt.	Migrate away from managing Key Accounts on spreadsheets and embed process into Salesforce.com platform. The platform will be used for pro-active key account management strategies including setting targets, defining actions and tracking outcomes. Scope may include keeping track of all communication with account, improving visibility to account activity, building email tracking, workflow and notifications, setting up call and appointments along with enhanced reporting.
	Avaya CTI Integration	Integrate Avaya Computer Telephony to provide digital and voice routing and contextual based workflow information into Salesforce
	All Case Mgmt.	Migrate all remaining case management to Salesforce platform including Billing and Collection inquiries, Customer Outage, Design Engineering in-take, Forestry, Vault Maintenance service requests etc.
	Customer Segmentation	Hydro Ottawa will further improve its customer segmentation initiatives on the Salesforce platform. This will include determination of what data to gather, source system integration requirements, development of analysis methods and establishment of effective communication across company
	Surveys	Take advantage of native Salesforce surveys to collect feedback from customers for continuous improvement of Hydro Ottawa service activities
2023	Billing History & Energy Consumption	Expose select billing and energy consumption information into Salesforce to support Key Accounts program, digital campaigns, digital self-service and customer segmentation objectives.
	Enhanced Reporting	Further expand reporting and dashboard capabilities centered on performance and customer intelligence
2024	Campaigns	Execution of marketing campaigns centered on energy programs including consumption and behaviours, conservation opportunities etc.
	Social Care	Hydro Ottawa will integrate Salesforce platform with social media channels including Facebook, Twitter to further engage with its customer populace.
2025	Stabilization & General Enhancements	General enhancements to Salesforce.com for continuous improvement of Hydro Ottawa processes

Throughout this multi-year journey, Hydro Ottawa will investigate and develop customer self-service capabilities through integration of Salesforce with Hydroottawa.com website and mobile offerings.

Table 3.11 - Customer Relationship Management System Program Expenditure ($'000s)

	Historical					Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Service Manager Replacement				$191						
Customer Relationship Management					$141	$403	$302	$121	$101	$60
Field Service Management					$483	$907				

3.1.3.3.3. Benefit

The program benefits for the Service Automation program are listed in Table 1.10 below.

Table 3.12 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Reduce application footprint by collapsing a number of point systems into Salesforce (e.g. service desk, potentially field service mgmt., I-Sight, case mgmt., Reporting tools and offline systems). This will result in less systems, vendors, integrations and complexity. Launches a foundational platform on which to integrate other customer channels, touches and technology Harness Salesforce Mobile application enabling Customer Service staff to better collaborate and respond to customer activities in real time Substantially reduce manual effort and improve data accuracy through development of new integrations with key business systems. Successfully mitigate risk of aging Field Service Management platform nearing end of life and out of vendor support. Drive productivity improvements from a sophisticated, interoperable and flexible enterprise-level field service management solution in the operational context of electric utilities.

Benefits (Cont'd)	Description (Cont'd)
Customer	Leverage rich case mgmt. to drive centralized visibility of all customer in-take requests across the organization reducing cycle and resolution time Implement skills based routing rules to ensure the right people are engaged upfront for the right job Transition live agent chat channel to a more robust solution and introduce chatbots for self-serve and quicker turnaround on common questions. This will improve support and allow the business to scale. Establish a Knowledge Base capability to arm Agents with rich information enabling more consistent service, lower costs and quicker resolution times Take advantage of native survey capability to conduct surveys that are integrated into the Salesforce platform with live Customer data Integrate Avaya Computer Telephony system to bridge the gap between the phone (voice and data) and Salesforce platform for increased customer insights and intelligence. Enable workflows and new customer communications at appropriate stages of service progression e.g. payment received, appointment booked, reminders etc. to keep customers informed Drive pro-active Key Account Management improvements through Salesforce platform consolidating all relevant information, planning elements, customer interaction and success measurements to increase the quality of customer engagement and loyalty Tap into rich Salesforce eco-system to integrate social media channel engagement such as Facebook and Twitter to further consolidate single-view of communication channels Leverage Salesforce platform as a central hub to record customer communication preferences to improve personalization and customer choice. Expand Customer self-service capabilities through integration of Salesforce platform with Hydro Ottawa.com and mobile offerings Improve service request process by optimizing online web forms with pre-populated data to substantially reduce customer effort (data entry requirements) and increase data quality and accuracy Consolidate billing and energy consumption information into Salesforce to support Key Accounts program, digital campaigns, digital self-service and customer segregation objectives. Expand Customer segmentation opportunities with enhanced reporting and dashboard capabilities with SLA and KPI metrics embedded into processes for easy tracking and measuring of customer service activities Focus on the customer – leverage 360 view to enable insight into customer preferences, behaviour and attitudes to offering customers more personalized, relevant programs and solutions aligned to their needs, thereby improving the quality of service
Cyber-Security, Privacy	Salesforce platform and alignment with Hydro Ottawa Cybersecurity program will ensure required disciplines are built into all aspects of the solution Be better positioned to provide permission based secure access to customer data based on function or need

3.1.3.4. Prioritization

3.1.3.4.1. Consequences of Deferral

Nothing is more critical to Hydro Ottawa's success than the ability to deliver value to our customers. This is truer today than ever, as customers take on a more prominent role in shaping the electricity landscape. Customers are no longer just consumers of electricity, but also generators, sellers and managers of energy, equipped with unprecedented digital tools and a growing list of energy options. Hydro Ottawa recognizes this changing landscape and the need to increase focus on meeting customer needs, and creating a more effortless and engaging customer experience. Implementation of a digital Customer Relationship Management platform is viewed as a key component of this plan. Deferral of this journey would make it more difficult for Hydro Ottawa to achieve its Customer Service goals and performance objectives.

3.1.3.4.2. Priority

Obtaining a centralized view of customer activity is essential to any company. This journey is high priority as it will provide both a digital foundation to improve the customer experience and enable a "whole-of-company" customer management focus.

3.1.3.5. Execution Path

3.1.3.5.1. Implementation Plan

Please see section 1.3.3.2 which outlines the implementation plan and high level deliverables Hydro Ottawa is aiming to achieve each year.

3.1.3.5.2. Risks to Completion and Risk Mitigation Strategies

As with any technology deployment, not all requirements will be known upfront. Hydro Ottawa has met with key stakeholders and vendor contacts to discuss high level scope and provide conservative estimates that we feel are reflective of the work involved.

3.1.3.5.3. Timing Factor

Please see section 1.3.3.2 which outlines the implementation plan and high level deliverables Hydro Ottawa is aiming to achieve each year.

3.1.3.5.4. Cost Factors

Capital expenditures are based on estimates of internal labour and professional services to achieve scope. Operating expenditures are largely based on subscription services to the platform. Please see section 1.3.3.2 for additional details on cost.

3.1.3.5.5. Other Factors

N/A

3.1.3.6. Project Details and Justification

Table 3.13 - Service Automation Overview

Project Name:	Service Automation
Capital Cost:	$1.9M
O&M:	$3.2M (2021-2025)
Start Date:	January, 2021
In-Service Date:	Enhancements will be realized at various points through the term
Investment Category:	General Plant
Main Driver:	Deliver on customer expectations – service quality and response
Secondary Driver(s):	Continue to enhance operational performance and productivity
Customer/Load Attachment	
Project Scope	
Hydro Ottawa is embarking on a Service Automation journey utilizing a digital platform in Customer Relationship Management (CRM) to enable a 360-degree view of customer activity across the organization. Focus will center on Salesforce.com, recognized as an industry leader in connecting sales, service and marketing activities on a unified "mobile first" cloud platform.	
Work Plan	
The scope of this journey is based on a multi-year strategy to improve service automation and iteratively build a 360-degree view of customer activity on a single unified platform. This will be a logical, phased approach that is customer-focused, adapts to change and encourages continuous improvement. Please see section 3.2	
Customer Impact	
Please see section 2.4	

3.1.4. WEB MULTI-CHANNEL

3.1.4.1. Project Details and Justification

Table 3.14 - Web & Multi Channel Dev Overview

Project Name:	Web & Multi-Channel Dev
Project Number:	9202006923
Capital Cost:	$602K
O&M:	N/A
Start Date:	Q1 2020
In-Service Date:	Ongoing
Investment Category:	Customer Experience
Main Driver:	Customer Value
Secondary Driver(s):	Operational Efficiency
Customer/Load Attachment	All customers
Project Scope	
The Web & Multi-Channel Development initiatives will enhance existing and introduce new technology to allow Hydro Ottawa's customers to communicate and interact with the company on their channel of choice. The platforms encompassed in this project include email, telephone, Webchat, Chatbot, knowledge base, digital assistant, SMS and social media. This initiative is part of Hydro Ottawa's vision to move towards a more decentralized, customer centric and technologically advanced service, providing more value to its customers. Customers expect near real time feedback and interaction using their communication channel of choice. Hydro Ottawa will continue to monitor and interact with customers across these multiple channels.	
Priority	
This project is medium priority	
Work Plan	
The work plan involves the enhancement and introduction of a number of technology platforms. **MyAccount** MyAccount, Hydro Ottawa's web-based customer service portal will undergo a transformation. The existing service that accesses three different websites for billing, customer profile management and electricity usage will be consolidated into a single website. This integration will Improve the customer experience through a singular platform with a consistent look and feel and user experience. Operational savings will be realized through the adaptation to a single hosting footprint.	

Work Plan (Cont'd)

Hydro Ottawa's Mobile App

Hydro Ottawa's app allows customers to track their electricity usage and costs, to access their billing information, learn energy conservation tips, and to find out about current power outages. The app will be enhanced in order to continue to meet customer expectations for mobile interactions that are personal, self-serve and available 24-7. Hydro Ottawa intends to shift from a purely vendor managed application to a hybrid architecture. Customers will benefit from a more current and adaptable tool given the potential for more timely releases. Hydro Ottawa will benefit from the flexibility to work with any number of third parties for new and enhanced features.

Digital Assistant

Hydro Ottawa introduced a digital assistant smart speaker skill for both the Amazon Alexa and Google Home smart speaker platforms that answers the most common questions asked by its customers. Hydro Ottawa plans to create and maintain a digital assistant product roadmap to expand the skills and channels available to customers centered on engagement and self-service. Customers will continue to benefit from a growing channel that provides ease and convenience.

Self-Service Expansion/Automation

Hydro Ottawa will be exploring supporting technologies to expand self-service offerings for its customers. With the advent of AI, machine learning and work process automation technologies, operational cost savings can be realized throughout the organization. This endeavour will also increase customer value by providing additional 24/7 services.

Expand Communication Channels

Hydro Ottawa has plans to expand its customer service touchpoints through human connections and automated technologies. The enhancement of Webchat, and the introduction of Chatbot and automated attendants will provide Hydro Ottawa with a broader, scalable customer reach on a consistent basis.

Total Expenditure
2021: $120,000
2022: $120,000
2023: $120,000
2024: $120,000
2025: $120,000

Customer Impact

Hydro Ottawa is focused on identifying and implementing process improvements, automation, and incrementally offering new self-serve features for customers. These initiatives are designed to enhance customer service, to respond to growing customer expectations and to increase Hydro Ottawa's operational efficiency and effectiveness.

3.2. ENTERPRISE SOLUTIONS ENHANCEMENTS

3.2.1. ENTERPRISE SOLUTIONS ENHANCEMENTS

3.2.1.1. Program Summary

The Enterprise Solutions portfolio is responsible for the management of about 40 corporate business applications which include a mix of commercial-off-the-shelf, in-house developed and cloud based systems. Chief among these is our core JD Edwards ERP system which manages critical back-office functions in Finance, Supply Chain, Job Costing and Capital Asset Mgmt. Another large business system is Workday HCM providing core HR, payroll, compensation, benefits, performance, e-recruiting and employee self service. Each year, vendor professional services and internal labour are required to complete application upgrades, perform system enhancements, build and evolve integrations and launch new technology to deliver on Hydro Ottawa business outcomes. Enhancements are often driven from evolving legal and/or regulatory requirements, but also result from continuous improvement initiatives to deliver business value. This includes everything from improving daily operations, to process reengineering, rationalizing our technology, hardening systems and furthering the strategic objectives of Hydro Ottawa. The Information Technology organization has a strong mandate to remain “code current” where possible to remain compliant with vendor support and minimize potential of any cybersecurity vulnerabilities.

3.2.1.2. Program Description

3.2.1.2.1. Current Issues

Some of the current issues include:

- Legacy in-house developed systems where the original creator is no longer with the company which still requires maintenance and updates.
- Aging on-premise applications nearing end-of-life and loss of vendor support.
- Gaps in existing process and deficiencies in technology which must be addressed
- Interface and data quality issues resulting in incorrect data and or re-work cycles to correct
- On-boarding and off-boarding workflow of user accounts to business systems require evolution as more cloud systems are adopted

3.2.1.2.2.2 Program Scope

Technology costs are managed through Hydro Ottawa's IT governance process, which allows planners to look proactively at IT strategy, project expenditures, and service delivery, and align technology spending with business and corporate objectives. Senior business managers also provide guidance, direction and support to the decision-making for corporate technology decisions. Below represents the initiatives known at this time:

- Integrations including new and re-engineered
- JDE tools upgrade/Oracle patch updates
- Workday evolution and HR Technology
- Enhancements to Geotab and Fleetwave
- Barcoding Implementation
- Expansion of Preventative Maintenance program
- Upgrade of CopperLeaf C55 Asset Investment Planning system
- Automation of workflow
- Development of new JDE-Hubble reports
- Expansion of Adaptive Insights (budgeting tool)
- Implementation of Burdening process into JD Edwards
- Salesforces/Contract Billing order processing
- Implementation of Accounts Payable automated invoice creation
- JDE UI/Forms development
- Additional module/Features for ServiceNow
- Expansion of Service Automation platform
- Footprint expansion of ERP and Workday
- Data cleansing/purging
- New dashboard and reports for GeoTab
- Replacement of Fieldflex & Archibus system
- Contractor Onboarding system
- Decommissioning of Lenel system
- Decommissioning of Historical Paystub system
- Decommissioning of JDE 9.0

Many of these initiatives will require the assistance of professional services as the knowledge and expertise may not be available when needed or does not exist at all within Hydro Ottawa.

3.2.1.2.3. Main and Secondary Drivers

The main and secondary drivers for upgrading and enhancing the application within the Enterprise solutions portfolio are:

- Stable, well supported platforms
- Improve collaboration between systems
- Improve productivity
- Address system deficiencies/short comings (e.g. cybersecurity)
- Better analytics
- Maintain operational effectiveness
- Deliver on business commitments

3.2.1.2.4. Performance Targets and Objectives

Upgrading and enhancing applications within the Enterprise Solutions portfolio will support the following objectives:

- Maintain the viability of system
- Mitigate costly extended support, break-fix and emergency repairs
- Deliver on business outcomes
- Implement robust system integrations with data flow accuracy
- Improve cybersecurity and confidentiality of sensitive information
- Reduce legacy application footprint

3.2.1.3. Program Justification

3.2.1.3.1. Alternatives Evaluation

Alternatives Considered

The Enterprise Solutions application portfolio must evolve as the business evolves and as the vendor provides new software releases. Each application is part of an integrated application landscape and has implications upstream and downstream. Funds are required to effectively manage technology risk with our support partners and implement enhancements to achieve

Hydro Ottawa business outcomes. Hydro Ottawa does not see an alternative in maintaining its corporate business applications.

Evaluation Criteria

The evaluation criteria for the Enterprise System enhancements are:

- Price (labour rates)
- Vendor supportability
- Product Scalability
- Complexity of change
- Business alternative solutions

Preferred Alternative

An alternative is not really viable as all business applications do not stand still and must evolve as the business evolves.

3.2.1.3.2. Program Timing & Expenditure

Historic and future expenditures on the ERP enhancement program are summarized in Table 3.15.

Table 3.15 - Historical and Future ERP Enhancement Program Expenditures ($'000,000s)

	Historical					Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ERP System Enhancements	$0	$0.344	$0	$0.99	$0.679	$0.756	$0.896	$0.504	$0.378	$0.479
Copperleaf	$0	$0	$0	$0	$0.101	$0	$0.101	$0	$0	$0.101
Geotab & Fleetwave	$0	$0	$0	$0	$0.05	$0	$0	0.05	$0	$0

3.2.1.3.3. Benefits

Program benefits are summarized in Table 3.16 below.

Table 3.16 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	• Ensure efficient and effective operations of Hydro's Financial System • Keeping these systems on the latest version will save the organization on costs required for vendor engagement • Increase/maintain system performance • Improve/maintains system supportability • New business processes introduces making internal workload more efficient • Remain regulatory compliant • Drive opportunities for cost savings through leaner processes and in-platform planning and reporting
Customer	• Ensure timely and accurate transfer of data to/from systems and other future integrations • Reduction of manual data entry
Cyber-Security, Privacy	• Latest versions of these systems would provide Hydro Ottawa access to security patches and enhanced security
Environment	• Continued transition to cloud is environmentally friendly sharing hardware, minimizing energy and avoiding a localized install base

3.2.1.4. Prioritization

3.2.1.4.1. Consequences of Deferral

Without appropriate funding, there will be increased risk and an inability to adequately maintain and support our JD Edwards ERP, Workday HCM and portfolio of integrated applications resulting in the following:

- Delayed refresh of assets driving risks associated with S/W and H/W obsolescence;

- Negatively impact the ability of employees to support business outcomes;
- Decreased productivity due to prolonged applications/systems gaps;
- High unit cost of supporting and servicing applications;
- Limited vendor support; and
- Lack of IT security controls.

3.2.1.4.2. Priority

HIGH – Maintaining Hydro Ottawa's JD Edwards ERP, Workday HCM and supporting corporate applications are critical to the success of Hydro Ottawa operations.

3.2.1.5. Execution Path

3.2.1.5.1. Implementation Plan

3.2.1.5.2. Risks to Completion and Risk Mitigation Strategies

Competing priorities may impact the timely implementation of upgrades and enhancements. With executive support, stakeholder engagement, and careful planning and attention to schedule, this risk can be effectively managed.

3.2.1.5.3. Timing Factors

Initiatives will be staggered through the years based on client and resource availability.

3.2.1.5.4. Cost Factors

Cost factors for the Enterprise Solutions Enhancements project are:

- Estimates are based on existing vendor agreement and past projects/initiatives
- Unknown Regulatory pressures could introduce additional un-anticipated development
- Scope may increase due to new business requirements and vendor pressures

3.2.1.6. Project Details and Justification

Table 3.17 - Program Benefits

Project Name:	Enterprise Solutions Enhancements
Capital Cost:	3.3M
O&M:	
Start Date:	Q1, 2021
In-Service Date:	Enhancements will be realized at various points through the term
Investment Category:	General Plant
Main Driver:	Maintain operational effectiveness
Secondary Driver(s):	Deliver on business outcomes
Customer/Load Attachment	N/A
Project Scope	
Each year, vendor professional services and internal labour are required to complete application upgrades, perform system enhancements, build and evolve integrations and launch new technology to deliver on Hydro Ottawa business outcomes. Enhancements are often driven from evolving legal and/or regulatory requirements, but also result from continuous improvement initiatives to deliver business value. This includes everything from improving daily operations, to process reengineering, rationalizing our technology, hardening systems and furthering the strategic objectives of Hydro Ottawa.	
Work Plan	
1. Assign a dedicated resources (Hydro Ottawa and/or contractors) 2. Assess requirements 3. Design/ upgrade/configure changes 4. Build/develop changes 5. Build/develop integrations changes 6. Data analysis 7. Data clean-up 8. Data transfer/migration 9. System functional testing 10. System integration testing 11. Training 12. User acceptance and regression testing 13. Deploy changes to production 14. Stabilization period	
Customer Impact	
Corporate business applications are part of a broader application landscape and are used for critical back-office functions necessary to deliver invoices, reports and communication with our customers. They must be maintained to function correctly and efficiently.	

3.2.2. ERP PROGRAM

3.2.2.1. Program Summary

An effective Enterprise Resource Planning (ERP) solution is critical to the successful operation of Hydro Ottawa's ongoing business operations. Today, the organization relies heavily on JD Edwards ERP to support Finance, Supply Chain, Procurement, Job Costing and Capital Asset

Mgmt. business processes. The on-premise system, having gone live in 2018, will have reached the end of its useful life in 2023 requiring an upgrade across technology components. Leading independent research (Gartner Inc.) clearly shows that ERP is rapidly changing with cloud adoption, emerging technologies and evolving digital business requirements affecting the very definition of ERP. This has given rise to a number of next generation ERP cloud solutions in which to consider. With electric utilities facing significant disruption with innovations in energy storage, digital technology and continued emphasis on lower electricity costs, the need for increased business agility and adaptability to uncertainties in the coming years is paramount. While JD Edwards has generally served the company well, Hydro Ottawa intends to shift gears and migrate to a new cloud based platform to improve agility, operational efficiencies and eliminate the need to continually upgrade its ERP system every 5-7 years.

3.2.2.2. Program Description

3.2.2.2.1. Current Issues

JD Edwards has generally proven to be a dependable solution but has a number of shortcomings which continue to pose challenges for Hydro Ottawa. In alignment with the strategic direction, these challenges, combined with the availability of newer cloud-based ERP alternatives have culminated in a decision to move away from the current JD Edwards solution

- The user experience is not friendly and lags newer ERP offerings in the cloud. Significant training must be invested in employees to effectively use the system today.
- Professional Service support from local Canadian vendors remains challenging. There are very few local players available resulting in high lead times and expensive engagements.
- It remains difficult to recruit resources with JD Edwards expertise as the install base is declining and veteran resources command large salaries.
- Large technology upgrades are required every 5-7 years to maintain support and take advantage of new functionality. This requires expensive professional services and is time consuming.
- Infrastructure support costs are high and include sizeable hardware & hosting fees, require database support, patching, package build/deployment, security and access management.

- Due to product gaps, investment in alternative solutions for ERP Reporting, Job Cost Estimating, Segregation of Duties, Fleet Mgmt., and Forms Development have been required
- Oracle's product direction is predominantly focused on its newer cloud offerings (Oracle ERP Cloud) with little in the way of innovation on the JD Edwards platform.
- Hydro Ottawa is forced to pay 22% Software Maintenance Fees associated with JD Edwards to remain compliant with vendor support. This is high cost and low value.
- Integrations are difficult and require costly professional services and lead time to achieve
- IT resources spend too much time administering and maintaining the system instead of focusing on deriving business value from the system.

3.2.2.2.2. Program Scope

Hydro Ottawa has not yet determined which cloud-based ERP solution will best meet the needs of the business and will conduct a market scan to determine best-in-class technology. Workday HCM was successfully launched in 2018 covering the full spectrum of Human Capital Management on a cloud-based platform. Core financials, supply chain, job costing and preventative maintenance processes remain on JD Edwards and represent the functional scope of the ERP project. There are two approaches being given consideration:

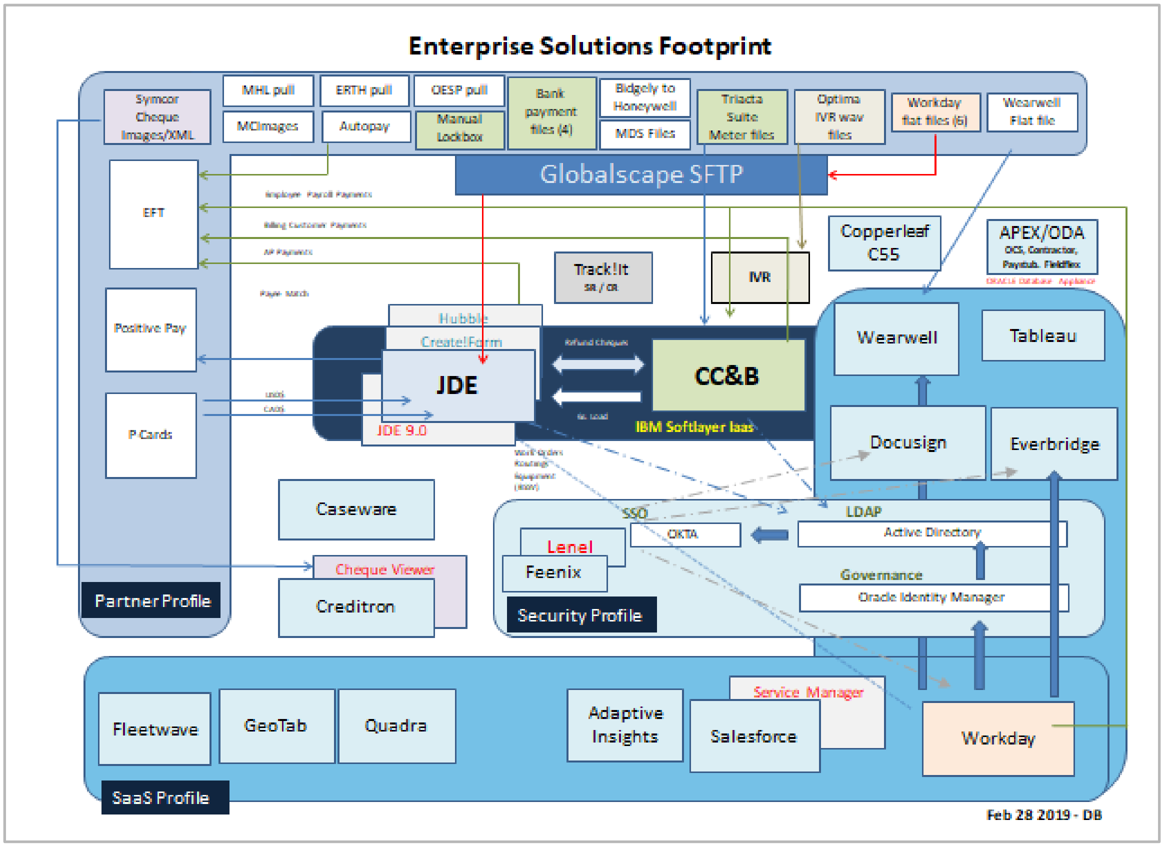
- Workday Financials for core Finance operations supplemented by an Enterprise Asset Management (EAM) platform for Supply Chain and Operations.

- OR -

- Selection of a Tier 1 Cloud ERP system with a similar functional footprint to JD Edwards

A combination of Gartner research, stakeholder consulting and vendor evaluations will assist in determining the course of action. JD Edwards is heavily integrated with the current application landscape with multiple interfaces to internal and external systems. This is depicted in Figure 3.4 below and identifies complexities that must be taken into account to ensure project success.

Figure 3.4 - Enterprise Solutions Footprint



3.2.2.2.3. *Main and Secondary Drivers*

The main driver for this project is to ensure efficient, effective ERP business outcomes are sustained for Hydro Ottawa's ongoing business operations in a manner that mitigates immediate and longer term risk. The industry is changing and Hydro Ottawa recognizes the need for increased business agility and adaptability to uncertainties in the coming years. The secondary driver centers on improving operational efficiencies including reduction of low-value activities and re-alignment of resources to better support Hydro Ottawa's growth strategy.

3.2.2.2.4. *Performance Targets and Objectives*

Migration of JD Edwards to a next generation cloud-based ERP will enable Hydro Ottawa to meet the performance targets and objectives in Table 3.18:

Table 3.18 - Performance Objectives

Performance Objectives	
Strategy	Improve business agility and adaptability
	Ability to focus on core competencies
	Lower ERP support costs
	Enable real-time business intelligence
Enterprise Resource Planning	Improve accessibility, mobility, and usability
	Boost productivity with customer proven best practices
	Faster time to value
	Continuous improvement
Technology Innovation	Remain current with the pace of innovation
	Rapid updates and upgrades
	Harness superior integration capabilities
	Improve security of data & disaster recovery
	Tap into rich ecosystem of vendor support

3.2.2.3. Program Justification

3.2.2.3.1. Alternatives Evaluation

Alternatives Considered

ERP systems are typically upgraded every 5-7 years as the solution is critical to the successful operation of Hydro Ottawa's ongoing business operations. Hydro Ottawa has not yet chosen its future ERP platform. One alternative being considered is to delay the future ERP Program and upgrade later. However this would:

- Delay the replacement of equipment past its current life-cycle expectancy
- Leave us with vendor software that will no longer be supported

- Reduce system reliability as failures will impact application uptime and overall system availability
- Drive additional sustainment costs, as vendors will charge their services at a premium rate to support end of life products.
- Increase the future migration cost significantly as there will be more data to migrate, more complexity and added risk as the business does not stand still.

Evaluation Criteria

Evaluation criteria will include:

- Sales execution & pricing
- Alignment to Electric Utility industry
- User experience
- Functionality features and adaptability capabilities out-of-the-box
- Data Security , data residency, disaster recovery capabilities
- Management reporting and analytics
- Future roadmap and innovation
- Integrations capabilities
- Vendor ecosystem of support

Preferred Alternative

Hydro Ottawa intends to select a cloud-based ERP platform in 2023 and that will be fully implemented by 2025, and prefers not to delay this transition because it would introduce additional risk, cost and constraints on future efficiency improvements

3.2.2.3.2. Program Timing & Expenditure

The outlined budget and scope in Table 3.19 is based on prior initiatives with comparable scope and size. These estimates are subject to change based on evolving information and will be greatly influenced by the chosen ERP approach and platform Hydro Ottawa elects to adopt.

The project has a high degree of complexity which stems from business transformation opportunities, refresh of technology, transition to cloud platforms, new user experience, integrations and the potential rollout of an Enterprise Asset Management system. Final costs will be determined following a competitive process, vendor selection and requirements analysis.

2023 – RFI/RFP, Vendor Selection, Requirements, Contract Negotiation

2024 – Design and Execution

2025 – Test, Go-Live and Hypercare

Table 2.3.19 - Historical and Future ERP Program ($’000,000s)

	Historical					Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure								$0.7	$6.2	$5.1

3.2.2.3.3. Benefits

Table 3.20 - Program Benefits

Benefits	Description
Strategy	• Positions organization with a modern ERP platform that can scale existing and future business efficiently and effectively • Improve IT resource utilization to focus on higher-value activities that are better aligned with Hydro Ottawa's growth strategy. • Digital transformation opportunity to improve processes including launch of native ERP mobile app and collaboration platform • Enables real-time reporting insights through multidimensional analysis and data visualization for a single source of truth across roles, reports, and analysis.
System Operation Efficiency and Cost Effectiveness	• Software as a service (SaaS) by its very nature incorporates customer-proven best practices into solutions to drive and extend business value • Automatic upgrades are the antidote for the long and expensive upgrade cycle that Hydro Ottawa has been subject too while maintaining an on premise ERP system • Simplifies the Hydro Ottawa application landscape by collapsing point systems and closing product gaps that exist today. • Offers robust API and integration capabilities between ERP modules and surrounding systems which are both easier and cheaper to implement. • Unlocks access to emerging technology embedded within cloud ERP such as robotic process automation, machine learning, natural language processing for increased productivity • Reduces hosting and infrastructure support costs some of which include unplanned environment refreshes, patching, DBA work, tools upgrades etc. • Streamlined vendor support with standard SLAs and a large partner ecosystem to tap for professional services and support • Drive opportunities for cost savings through leaner processes and in-platform planning and reporting

Benefits (Cont'd)	Description (Cont'd)
Customer	● Increase operational effectiveness through simplified user interfaces, superior performance and standardized processes. ● Enables rapid implementation of new functionality immediately and at a lower cost than experienced on JD Edwards today. ● Improve Enterprise Asset Management strategy to drive greater visibility and understanding of an asset's life and health from initial design to planning its production and retirement. ● Ability to harness new innovations quicker since all customers share the same software version/functionality; ● Increased productivity by virtue of a mobile app and collaboration technologies inherent with cloud-based ERP adoption ● Improved 24x7 service and support
Cyber-Security, Privacy	● Superior cybersecurity practices and technology capabilities which are fully auditable and standardized as part of the cloud offering to protect against threats and secure sensitive information.

3.2.2.4. Prioritization

3.2.2.4.1. Consequences of Deferral

Should the project be deferred Hydro Ottawa would continue to rely on existing systems that are past their recommended useful life, which introduces risk and increases the future cost of migration substantially. Additionally, Hydro Ottawa would continue absorbing many of the current challenges / pain points previously identified.

3.2.2.4.2. Priority

This project is seen as a high priority based on risk to critical ERP business outcomes for a Utility which is facing significant disruption in the coming years.

3.2.2.5. Execution Path

3.2.2.5.1. Implementation Plan

The JDE program will follow implementation/migration best practices for change and project management. Please see section 3.2.

3.2.2.5.2. Risks to Completion and Risk Mitigation Strategies

Risk to completion include resource availability of key subject matter experts, strains to desired business outcomes caused by adherence to out-of-the-box approach, potential extended timeline and/or scope creep. These risks will be mitigated through involvement of Hydro Ottawa's executive management team in the steering committee to reinforce expectations, independent project management oversight, strict scope containment through change management process that restricts approvals to essential items only, and internal resource reassignments for full-time dedicated participation in the project along with empowerment to make decisions.

3.2.2.5.3. Timing Factors

To avoid the risk of having to do another expensive on premise ERP upgrade and being out of vendor support, the recommended project timeline will target 2023-2025 timeline

3.2.2.5.4. Cost Factors

Final cost of the project will be determined by selected solution(s) and negotiated contract with vendors.

3.2.2.5.5. Other Factors

N/A

3.2.2.6. Project Details and Justification

Table 3.21 - ERP Program Overview

Project Name:	ERP Program
Capital Cost:	$12.0M (One-time Implementation)
O&M:	$1.6M (2024-2025)
Start Date:	Q1, 2023
In-Service Date:	Q4, 2025
Investment Category:	General Plant
Main Driver:	• Implement a new cloud base ERP Solutions • Provide a solid support system as the as the foundational platform that will position Hydro Ottawa to better leverage other technologies and provide enhanced services to our customers
Secondary Driver(s):	N/A
Customer/Load Attachment	N/A
Project Scope	
Hydro Ottawa will select a replacement cloud-based ERP system, leveraging next generation technology to provide a more cost-effective, flexible and agile solution to deliver successful ERP business outcomes over the long term. We will reduce our IT infrastructure and avoid procuring, installing, maintaining, and managing addition JD Edwards infrastructure services and support in-house along with the associated capital investments and staffing required.	
Work Plan	
1. Assign a dedicated project team (Hydro Ottawa and contractors) 2. Assess upgrade requirements 3. Design upgrade changes 4. Build/develop upgrades changes 5. Build/develop integrations changes 6. Data transfer/migration 7. System functional testing 8. System integration testing 9. Training 10. User acceptance and regression testing 11. Deploy changes to production 12. Stabilization period	
Customer Impact	
Provide Hydro Ottawa with a more effective framework to address evolving business needs and customer expectations in a more timely and efficient manner by utilizing a cloud base solution and not have to build, support, maintain any custom applications and/or infrastructure	

3.3. FLEET REPLACEMENT

3.3.1. FLEET REPLACEMENT PROJECT

Details can be found in Attachment 2-1-1(G) Fleet Report.

3.4. IT LIFE CYCLE AND ONGOING ENHANCEMENTS

3.4.1. IT LIFE CYCLE AND ONGOING ENHANCEMENTS

3.4.1.1. Program Summary

The following program is centered on IT Infrastructure assets which are subject to lifecycle management to ensure assets are monitored and managed in a systemised approach. This enables the corporation to ensure productivity and efficiency in the operations of its IT assets and that these assets remain available and reliable to support the business functions and operations of the organization. As well, this program enables Hydro Ottawa to take advantage of upgraded and newer robust technologies, hardware and software, to support IT infrastructure with increased operational efficiencies and effectiveness.

3.4.1.2. Program Description

3.4.1.2.1. Current Issues

The IT Asset Lifecycle Management Program ensures equipment that is reaching end of life or usefulness are identified and replaced on an established schedule. This prevents unscheduled outages, which impact business operations negatively, by systematically scheduling systems and equipment for replacement proactively.

Ongoing Enhancements are positively impacted with the upgrade or replacement of aging equipment as well as the introduction of new technologies that are leveraged to increase the efficiency and effectiveness of IT operations.

3.4.1.2.2. Program Scope

IT Assets Lifecycle Management and Operational Enhancements have been identified in the following areas:

- PC/Peripheral Replacement Pr
- Server Expansion/Replacement P
- Network Switch Upgrades
- Network Security
- Technology Recovery
- Tape Capacity Upgrade

- Network File Storage Expansion
- Network Monitoring Tools
- CMM - New PCs,Per,Soft
- Server Virtualization
- Voice Infrastructure Upgrade
- ThinClient/DesktopVirtualization
- Disaster Recovery & Enhancement
- Wireless Device Independence
- Test Lab & Enhancements
- Video Conferencing
- Windows 10 Rollout
- Office 2010 Rollout
- Service Now
- Database Technology
- Meeting Room Replace
- Network Firewalls

Through proactive and systematic replacement of identified end-of-life IT assets, Hydro Ottawa will continue to ensure the dependable, reliable and secured operations of these assets critical to support the various business units throughout the organization. Operational enhancements will benefit IT operations in its augmented, effective and efficient delivery of informatics services. End users will directly benefit from these enhancements with newer and more productive technology. Some examples of this include quicker delivery of applications via thin client/desktop virtualization, more office tools, operating system upgrades and video conferencing

3.4.1.2.3. Main and Secondary Drivers

The main driver of this program is to ensure the availability and access of IT infrastructure assets and systems with minimal to no interruption by supporting the 24/7 operational requirements demanded by the business units at Hydro Ottawa and its affiliates.

3.4.1.2.4. Performance Targets and Objectives

The IT Asset Lifecycle Management and Operation Enhancements program will ensure that Hydro Ottawa business units continue to have access to reliable, dependable and secure IT infrastructure while also supporting the organization's delivery of:

- Customer Value – supporting infrastructure, systems and messaging systems such as email that are customer facing.
- Organizational Effectiveness – supporting infrastructure and systems that support internal staff members.
- Corporate Citizenship – supporting infrastructure and services provided by IT Operations to support business units in their delivery of Hydro Ottawa services within the service territory.
- Financial Strength – effective and efficient use of IT assets and systems used to support the delivery of IT services to the organization.

3.4.1.3. Program Justification

3.4.1.3.1. Alternatives Evaluation

Alternatives Considered

IT Operations continually evaluates alternatives available to the delivery of IT services through ongoing evaluation of new technologies and services that would effectively and efficiently support the environment. These technologies and solutions are identified and evaluated as IT Operations identifies hardware, systems and technologies it supports through the IT Asset Lifecycle Management program. This, for example, may include: virtualization of applications, upgrading the servers' operating system, upgrading a messaging platform such as Exchange, upgrading or replacing a service desk application such as Track-It! with a cloud based solution, desktop virtualization eliminating the need for high-end client devices etc.

Evaluation Criteria

Efficiencies gained and cost reductions are analysed through a cost benefit analysis, including ongoing support requirements and associated costs. Solutions that are identified as beneficial will be reviewed further and when identified as beneficial will be selected and implemented as an alternative.

Preferred Alternative

IT Operations continually evaluates alternatives available to the delivery of IT services through ongoing evaluation of new technologies and services that would effectively and efficiently support the environment. These technologies and solutions are identified and evaluated as IT Operations identifies hardware, systems and technologies it supports through the IT Asset Lifecycle Management Program. This, for example, may include: virtualization of applications, upgrading the server's operating system, upgrading a messaging platform such as Exchange, upgrading or replacing a service desk application such as Track-It! with a cloud based solution, desktop virtualization eliminating the need for agnostic or high-end client devices, etc.

Cost benefit analysis will be leveraged to determine which alternatives are acceptable to support the IT environment on an ongoing day to day operation.

3.4.1.4. Program Timing & Expenditure

This program will be implemented over a 5-year period as outlined in Table 3.22. During each period potential alternatives and industry opportunities are explored for cost and maintenance reductions.

Future expenditures, where opportunities are available, will be reduced.

Minimization of costs for these programs are supported and controlled by significant cost benefit analysis required for ongoing operations support of these solutions, including cost avoidance and ensuring the best value is acquired through competitive RFP and RFI requested proposals through Hydro Ottawa's procurement group.

Table 3.22 - Historical and Future IT Life Cycle Program ($'000,000s)

	Historical					Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$0.8	$0.7	$1.9	$0.7	$1.2	$1.7	$1.2	$1.0	$0.8	$1.5

3.4.1.4.1. Benefits

Benefits of this program are summarized in Table 3.23 below.

Table 3.23 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	Maintain reliable and efficient systems and hardware required to deliver IT services throughout the organization by minimizing downtime and unexpected failures. Ability to monitor systems and infrastructure proactively to taking evasive action when necessary to prevent failure of IT infrastructure components.
Customer	Ensure efficient, effective and secure access to IT systems that are utilized by business units throughout the organization which are used by these business units to support our external and internal Hydro Ottawa customers.
Safety	N/A
Cyber-Security, Privacy	By leveraging and following security policies, processes and procedures to proactively monitor, protect and report IT systems and services utilizing best in bread approaches to IT security for all infrastructure components and systems.
Coordination, Interoperability	Ensure that technologies acquired and supported by IT Operations adhere to best of breed technologies so that flexibility may be exercised efficiently and securely when leveraging IT components with internal and external resources.
Economic Development	N/A
Environment	Virtualization of IT systems has in the last decade been a high priority for Hydro Ottawa and continues to be forefront for the acquisition and support of IT infrastructure and solutions. This extends from network switches, servers and to the desktop. Virtualization enables Hydro Ottawa to decrease its carbon footprint through the reduction of equipment e.g. hardware, required to support the infrastructure, as well as the reduction in power required to maintain the operations and cooling of equipment.

3.4.1.5. Prioritization

3.4.1.5.1. Consequences of Deferral

Should Hydro Ottawa delay the established cycle of asset management would result in system failures, infrastructure failures and unscheduled outages causing: non-compliance from a cyber security perspective, loss of data, operational delays and associated costs to the business units, as well loss of business units' perception of dependable, reliable and secured IT infrastructure and support.

Operational enhancements delays could result in missed opportunities for savings, data loss, and difficulties in providing ongoing support to outdated/unsupported systems, e.g.: O/S; applications; support tools, etc.

3.4.1.5.1. Priority

The priority of these programs varies and are rated from High to Medium

Dependable, reliable and secure access to IT infrastructure and systems must remain uncompromised. Priority in maintaining an established IT Asset Lifecycle Management program will ensure the organization will meet its operational established targets and ensure the delivery of reliable services to its customers.

Operational benefits will be obtained by augmenting tools that are utilized to monitor, manage and proactively maintain the entire IT infrastructure and will ensure ongoing reliable infrastructure operations.

All other IT initiatives by business units require a solid and reliable IT infrastructure foundation.

3.4.1.6. Execution Path

3.4.1.6.1. Implementation Plan

As noted, these programs are operational focused and span a number of years and provide ongoing support to Hydro Ottawa IT business unit users.

3.4.1.6.2. Risks to Completion and Risk Mitigation Strategies

Resources and changing priorities may impact Hydro Ottawa from completing initiatives as planned. The demand of IT Operational resources may be required to be redirected to other immediate operational priorities that are deemed to be urgent in nature or possible changes in operational priorities as demanded by the organization. Most delays can be mitigated with the reassignment of resources or reprioritization of listed programs/initiatives.

3.4.1.6.3. Timing Factors

Changes in operational, other projects dependent on IT operational resources, and corporate priorities could impact the timing and delivery of program services identified.

3.4.1.6.4. Cost Factors

Potential final cost factors include requirements for IT infrastructure services that may be defined by business units and/or additional requirements not originally identified in the IT project roadmap.

3.4.1.6.5. Other Factors

Other factors may include identified requirements of business units as it relates to IT infrastructure and support.

3.4.1.7. Project Details and Justification

Table 3.24 - IT Asset Management Lifecycle and Ongoing Enhancements Overview

Project Name:	*IT Asset Management Lifecycle and Ongoing Enhancements*
Capital Cost:	$6.2M
O&M:	*N/A*
Start Date:	January 2021 – December 2025
In-Service Date:	Various dates
Investment Category:	*General Plant*
Main Driver:	*Operational Efficiency*
Secondary Driver(s):	*Reliability*
Customer/Load Attachment	*N/A*
Project Scope	
Various initiatives to support IT Operations in its support of the organization as it relates to the management and operational support of IT infrastructure required by the business units.	
Work Plan	
Each initiative will have its own work plan defined in the period in which the initiative will be executed.	
Customer Impact	
This program will provide internal business units with the required IT assets to effectively support and meet their customer objectives expected from Hydro Ottawa customers.	

3.4.2. CYBERSECURITY ENHANCEMENT

3.4.2.1. Program Summary

As noted elsewhere in this Application, Hydro Ottawa is continuing to execute on its strategy of providing greater choice, convenience, control, and self-serve capability to its customers. An inherent aspect of this expansion of customer services is increased use and reliance on digital solutions, many of which are connected to the utility's corporate information technology ("IT") networks. Accordingly, an essential element of these initiatives is integrating effective cybersecurity controls that will safeguard the utilization of these technologies and applications for both the customer and company alike. This project consists of the capital and operational expenditures that are necessary to ensure such integration.

3.4.2.2. Program Description

3.4.2.2.1. Current Issues

The increasing sophistication and frequency of cyberattacks is one of the most significant business and operational risks facing the electricity sector in Ontario. The recognition of this fact has been reflected in several important provincial policy and regulatory developments in recent years, which have included actions directed specifically at local distribution companies ("LDCs").

For example, Ontario's *2017 Long-Term Energy Plan* ("LTEP") acknowledges cybersecurity as being "increasingly important in protecting critical infrastructure, such as the province's electricity system." What's more, the LTEP characterizes cybersecurity as "an operational necessity for the distribution sector," which encompasses "both the protection of customer-specific information held by LDCs and the protection of distribution-level system operations."[1]

Subsequent to the issuance of the LTEP, the Ontario Energy Board ("OEB") finalized amendments to the *Distribution System Code* ("DSC") in March 2018. The new provisions in the DSC require LDCs to report to the OEB on an annual basis regarding their level of cybersecurity readiness and capability, relative to the requirements, best practices, and expectations set forth in the industry-developed *Ontario Cyber Security Framework* ("Framework"). In its notice to affected parties regarding the adoption of these Code amendments, the OEB stated the following:

[1] Ministry of Energy, *Ontario's Long-Term Energy Plan 2017: Delivering Fairness and Choice* (2017), page 84.

> *"Application of the Framework by licensed transmitters and distributors will provide a method to assess existing capability against industry recommended best practices. The OEB expects this approach to provide a consistent reference point to assess licensed distributors' and transmitters' cyber security risk and capability. Licensed transmitters and distributors will be better informed as they work to incorporate cyber security into the enterprise risk management decision making, and investment planning that will ultimately form part of their business plans and their transmission and distribution system plans (as applicable)."*[2]

Moreover, the 2019 Revenue Requirement Submission of the Independent Electricity System Operator ("IESO") to the OEB was anchored in the IESO's 2019-2021 Business Plan, which had received approval from the Minister of Energy, Northern Development and Mines prior to submittal of the filing. Enhancements of its cybersecurity program were identified by the IESO as a major priority, in order to address the increasing complexity and growing threat of cyberattacks. What's more, the possible occurrence of a significant cybersecurity event that disrupts reliable grid operations was formally designated in the IESO's corporate risk register as one of the key risks facing the organization.[3]

The provincial policy and regulatory posture with respect to cybersecurity is matched and affirmed by a complementary layer of policy action at the federal level. In 2018, the Government of Canada released its *National Cyber Security Strategy* which, among other things, cautioned that "[s]ome cyber systems – such as electricity grids, communications networks, or financial institutions – are so important that any disruption could have serious consequences for public safety and national security."[4] The accompanying *National Cyber Security Action Plan* places immense emphasis on enhanced collaboration with the energy sector, with the aim of strengthening the unique expertise and capacity that is essential to bolstering defenses against advanced cyber threats.[5]

As the foregoing discussion illustrates, the public policy landscape in which Hydro Ottawa operates is one in which expectations and requirements have amplified considerably in recent

[2] Ontario Energy Board, *Notice of Amendments to Codes*, EB-2016-0032 (March 15, 2018).
[3] Independent Electricity System Operator, *2019 Revenue Requirement Submission*, EB-2019-0002 (January 28, 2019), Exhibit A-2-2, Page 23 of 27.
[4] Public Safety Canada, *National Cyber Security Strategy: Canada's Vision for Security and Prosperity in the Digital Age* (2018), page 18.
[5] Public Safety Canada, *National Cyber Security Action Plan: 2019-2024* (2019), pages 6-7.

years with regards to the steps that owners and operators of critical infrastructure – especially electricity infrastructure – must undertake to safeguard their assets against cybersecurity risks.

Against the backdrop of a policy landscape in which requirements and expectations are becoming more numerous and rigorous, Hydro Ottawa is in an advantageous position of having been an early adopter and industry leader amongst its Ontario LDC peers, as it relates to the implementation of best practices and cybersecurity protections.

Since 2012, the utility has had a formal cybersecurity program in place in which an annual roadmap of deliverables is defined and executed. For the first several years, the program was anchored in the ISO 27000 series of standards governing information security. Beginning in 2016, Hydro Ottawa started to implement core components of the cybersecurity framework developed by the U.S. National Institute of Standards and Technology ("NIST"). The decision to begin adhering to the NIST framework was based, in part, upon the results of a third-party maturity assessment commissioned by Hydro Ottawa, which underscored a broader shift taking place across the North American electric utility industry in adoption of the NIST framework. The industry-developed Framework in Ontario borrows heavily from the NIST structure, meaning that Hydro Ottawa occupied a vanguard position amongst Ontario distributors in terms of capability and readiness as new DSC provisions relating to cybersecurity and the Framework were taking effect in 2018. In addition to NIST implementation, other major cybersecurity initiatives at the utility in recent years have included assessments of program maturity, gaps, and privacy protections; the establishment of incident response and managed security services from external third-party experts; and regular penetration testing of corporate and operational networks and network segmentation.

Furthermore, for several years Hydro Ottawa has been a regular participant in, and contributor to, key forums inside and outside of Ontario for the advancement of cybersecurity knowledge and protection in the electricity sector. These include initiatives at the IESO, such as their Cyber Security Forum and cyber intelligence-sharing partnership with the Canadian Centre for Cybersecurity[6], as well as the biennial "GridEx" security exercise organized by the North American Electric Reliability Corporation ("NERC"), which is the largest such exercise of its kind

[6] http://www.ieso.ca/en/Powering-Tomorrow/Data/IESO-opens-the-door-to-sector-wide-cybersecurity-offensive.

and draws participation from thousands of participants from hundreds of utilities across the continent.[7]

Finally, it merits observation that, as the electricity distributor to the capital city of a G7 country, Hydro Ottawa conducts its business activity in a unique operating environment. Many of its customers, especially in the institutional sector, have distinct service needs which can only be met by a distribution system that is modern, reliable, safe, and secure.

To ensure that Hydro Ottawa can continue to fulfill its regulatory obligations and maintain best-in-class cybersecurity protections in a manner that is proportionate to its business and risk profile, it is imperative that the utility be able to sustain investments in a robust cybersecurity program which deploys a combination of controls focused on people, processes, technologies, and governance.

3.4.2.2.2. Project Scope

This project represents a natural extension and maturation of Hydro Ottawa's existing cybersecurity program, and is necessary to maintain compliance with OEB requirements and conformance with evolving best practices, including those that are captured within the cybersecurity Framework for electricity distributors in Ontario.

As the cybersecurity threat landscape continues to evolve and expand, Hydro Ottawa needs to ensure that its cybersecurity program is adequately resourced and able to perform core functions with limited downtime and exposure. It is imperative for Hydro Ottawa to concentrate significant attention on its corporate IT infrastructure, in light of the utility's approach to cybersecurity protection and network segmentation. Seeing as most operational technology ("OT") networks are closed, secure networks, the utility's corporate IT networks represent the point of entry and attack through which any cybersecurity intrusion will likely occur. Internet access for the IT networks is essential, as most services require internet connectivity (e.g. email, website, payroll, outage management, etc…) Malicious actors typically target an end-user's corporate IT network in order to pivot into the OT network. Robust defenses for the IT network are therefore a must.

[7] https://www.nerc.com/pa/CI/CIPOutreach/Pages/GridEx.aspx.

3.4.2.2.3. Main and Secondary Drivers

As noted above, in step with regulatory mandates and public policy requirements, it is imperative for Hydro Ottawa's cybersecurity program to be adequately resourced and to fulfill the basic functions expected of critical electricity infrastructure owners and operators in relation to cybersecurity (i.e. identify, protect, detect, respond, and recover). In light of the present state of readiness and capability at Hydro Ottawa, the progression of industry best practices, the evolution of external threats and risks, and the need to safeguard system reliability, targeted investments in enhancing the overall cybersecurity posture of the utility's IT networks are warranted.

3.4.2.2.4. Performance Targets and Objectives

Hydro Ottawa has a well-established, defense in-depth cybersecurity program in place that consists of a blend of technical and administrative controls combining people, governance, process, and technology. This defense in-depth program needs to continuously evolve to ensure that its safeguards are sufficiently robust to mitigate the ever-expanding threat landscape.

Hydro Ottawa employs technology solutions at various levels, including at the application and network segments. Anti-Virus used to be a core technology solution but the current model has become primitive and antiquated. It has been replaced with newer technology that employs artificial intelligence capabilities and is able to detect anomalous behaviour by observing traffic patterns. This is simply one control in a series of many controls and safeguards that an organization requires.

A defense in-depth approach remains the *de facto* approach to ensuring proper cybersecurity controls are in place. Nevertheless, a review of the current technology stack is needed to ensure this approach is able to succeed in the new technology landscape. For example:

- Solutions are increasingly being migrated to the cloud, as the need for Software-as-a-Service and Infrastructure-as-a-Service solutions magnifies.
- There is a need to ensure that strict requirements are in place, adhered to, and continuously audited (i.e. formal risk assessments for certain agreements).

- Regulatory and compliance obligations continue to multiply, especially in relation to privacy protections.
- There is a need for Hydro Ottawa's privacy and data protection practices to continue to mature, including in relation to organizational governance.
- More formal risk management and assessment practices are required throughout the utility as well as from third parties.
- Growing areas of focus include insider threat management and data loss protection.

An overriding, fundamental objective of this project is securing Hydro Ottawa's distribution system against a cyberattack that could result in a widespread, prolonged power outage.

3.4.2.3. Program Justification

3.4.2.3.1. Alternatives Evaluation

Alternatives Considered

Do Nothing

This option is not considered viable, as it would introduce a severe risk into Hydro Ottawa's cybersecurity program and protections.

Evaluation Criteria

N/A

Preferred Alternative

N/A

3.4.2.3.2. Program Timing & Expenditure

Historical expenditures in cybersecurity enhancements within the General Plant category are identified in Table 3.25 below (alongside proposed expenditures for the 2021-2025 period). Noteworthy cybersecurity projects undertaken by Hydro Ottawa during the 2016-2020 rate term include the following:

- Implementation of real-time network traffic analysis solution that incorporates artificial intelligence in order to monitor traffic patterns for known detections against behaviours that match active incidents;

- Adoption of fully-managed intelligent security incident and event management solution that incorporates next generation Security-as-a-Service capabilities, including identifying and classifying assets accordingly;
- Cultivation of Advanced Vulnerability Management capabilities that examine the entire utility and differentiate between high-risk applications and services;
- Deployment of Enterprise Patch Management capabilities which ensure that patches are applied to critical assets and high-risk applications are patched within Hydro Ottawa's threshold;
- Hardening of endpoints and access points in order to risk-mitigate the attack surface;
- Incorporation of next-generation technologies to replace and augment current capabilities to mitigate advanced and changing threats;
- Implementation of risk management solutions that measure Hydro Ottawa's resilience and provide a maturity score; and
- Automation and integration of solutions for the purposes of creating more actionable data.

Over the past five years, Hydro Ottawa has exercised discipline in controlling costs and managing approved sending for its cybersecurity program. The program is on track to be within budget for the 2016-2020 rate term, with no overspend.

With respect to future expenditures, these are likewise shown in Table 3.25 below. Cybersecurity enhancement Initiatives that are planned over the course of 2021-2025 as part of this project include the following: data loss prevention mechanisms; governance and privacy obligations stemming from the Ontario Framework and provincial and federal requirements for the protection of personal information; adoption of cloud-based solutions; continued convergence between OT and IT systems; cybersecurity and privacy awareness training for employees; full orchestration of cybersecurity workflows to improve business efficiencies; and modernization of cybersecurity safeguards.

Table 3.25 - Cybersecurity Enhancement Capital Expenditures ($'000s)

	Historical			Bridge		Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
TOTAL	$316.9	$142.4	$142.4	$78.2	$302.3	$302.3	$201.5	$201.5	$201.5	$201.5

With respect to operational expenditures that will be required to support implementation of this project, the associated technology is shifting from a traditional perpetual license model to a subscription-based model. Accordingly, annual subscription costs of $135K have been budgeted for the project.

Table 3.26 - Cybersecurity Subscription Budget ($'000s)

	Historical			Bridge		Test				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Expenditure	$0	$0	$75	$148	$136	$136	$136	$136	$136	$136

3.4.2.3.3. Benefits

Program benefits are summarized in Table 3.27 below.

Table 3.27 - Program Benefits

Benefits	Description
System Operation, Efficiency and Cost Effectiveness	Prevent cyber attacks from occurring. Ensuring risk is minimized
Customer	Prevent cyber attacks from occurring. Ensuring risk is minimized Ensure customer data is properly protected and the possibility of information loss is minimized.
Safety	Prevent cyber attacks from occurring. Ensuring risk is minimized
Cyber-Security, Privacy	Prevent cyber attacks from occurring. Ensuring risk is minimized
Coordination, Interoperability	N/A
Economic Development	N/A
Environment	N/A

3.4.2.4. Prioritization

3.4.2.4.1. Consequences of Deferral

Hydro Ottawa believes that an appropriate means for evaluating and interpreting the consequences of deferring this project is to examine the cost impacts associated with a worst possible outcome – namely, a successful cyber attack. As shown in Table 3.28 below, an outage lasting four hours, affecting approximately 3,000 customers, and involving only one substation would cause economic impacts of $1.8M. A 12-hour outage involving all 88 substations would adversely impact all customers in Hydro Ottawa's service territory and would potentially incur economic damages of almost $240M.

Table 3.28 - Economic Impacts of Cyber Attack

Calculation Based on DSP	
SAIDI (Baseline Value	1.58
Total Customers - Residential Class	303,571
Total Customers - Small & Mixed Commercial	27,177
Total Customers - Large Class	1,029
Total Customers Served	**331,777**
Average load not served during outage / Customer	3 kW
Average Value of Service (VOS) ($ per Minute of Outage)	**$1.00**
Number of Substations	88

Outage Information	Single Station	Nested Stations	Whole City	Duration	
Substations	1	2	88	**Minutes**	**Hours**
Customers	3,770	7,540	331,777		
Total Economic Impact	$904,846.36	$1,809,692.73	$79,626,480.00	240	4
	$1,357,269.55	$2,714,539.09	$119,439,720.00	360	6
	$1,809,692.73	$3,619,384.45	$159,252,960.00	480	8
	$2,714,539.09	$5,429,078.18	$238,879,440.00	720	12

3.4.2.4.2. Priority

- Hydro Ottawa's cybersecurity program defines a yearly roadmap based on priorities, gaps, risks, and budget, and will prioritize this and other projects accordingly.
- This project's priority status is high, seeing as it is a multi-year project, with 2021 representing the largest share of annual capital expenditures for the Test Years.

3.4.2.5. Execution Path

3.4.2.5.1. Implementation Plan

Implementation will consist of identifying and evaluating cyber risks that target Hydro Ottawa infrastructure, business functions, and employees, and ensuring that the required levels of control are present in order to identify, detect, protect, respond, and recover from cyber threats.

The evolution and modernization of the current cybersecurity program will require continuous examination of the technology stack (including technical and administrative controls), oversight of people, processes, and technology to ensure that risks are addressed within an acceptable timeframe, and fulfillment of requirements arising from the Ontario Framework, provincial and federal privacy regulations, and other sources.

3.4.2.5.2. Risks to Completion and Risk Mitigation Strategies

For risk mitigation purposes, it is imperative that this project be completed during the 2021-2025 rate period.

3.4.2.5.3. Timing Factors

Execution of this project could be delayed by such factors as the introduction of new risks into Hydro Ottawa's cybersecurity risk landscape, constraints on resources, and availability of competencies and skill sets that will be required for project delivery.

3.4.2.5.4. Cost Factors

One of the biggest risks to Hydro Ottawa's cybersecurity program is resource constraints and associated costs. Obtaining skilled personnel with the requisite expertise on cybersecurity remains challenging. A co-sourcing model will help complement the skill set required to efficiently and effectively execute on the utility's cybersecurity program, including this project.

3.4.2.5.5. Other Factors

N/A

3.4.2.6. Renewable Energy Generation (if applicable)

N/A

3.4.2.7. Leave-To-Construct (if applicable)

N/A

3.4.2.8. Project Details and Justification

Table 3.29 - Cybersecurity - Enterprise Program Overview

Project Name:	Cybersecurity – Enterprise Program
Capital Cost:	$1.1M (2021-2025)
O&M:	$0.7M (2021-2025)
Start Date:	2021
In-Service Date:	2022-2025
Investment Category:	General Plant - IT Life Cycle - Cybersecurity
Main Driver:	Reduce cybersecurity risks in IT environment
Secondary Driver(s):	N/A
Customer/Load Attachment	All customers
Project Scope	
Implement adequate cybersecurity safeguards (including the ability to identify, protect, detect, respond, and recover from cyber attacks) for all corporate IT infrastructure and business applications.	
Work Plan	
Continue to evaluate cyber risks that target Hydro Ottawa infrastructure, business functions, and employees, and ensure that the required level of cybersecurity controls are present in order to identify, detect, protect, respond, and recover from cyber threats.	
Customer Impact	
It is imperative to ensure that Hydro Ottawa practices due diligence in protecting customer information and providing essential services without interruption. A cyber attack that could disrupt the business or result in a breach of customer information would result in a range of sub-optimal outcomes for the utility and customers alike.	

3.5. INFORMATION SERVICES AND TECHNOLOGY

3.5.1. Data Management & Integrations

3.5.1.1. Program Summary

Hydro Ottawa will embark on a number of next generation technology initiatives to increase productivity, gain operational efficiencies and enhance the customer experience. Many of these initiatives center on improving the management of “data” which is recognized as a key asset to the company. Currently, a large amount of time is spent on curating data vs. analyzing data. A multi-year data strategy will commence to identify business requirements and a platform needed to serve both the internal and external needs of the company. This will culminate in the adoption of an information management platform, data-warehouses, data lakes and analytical platforms to serve the various domains. Hydro Ottawa will embrace platforms that will employ Artificial intelligence and Machine Learning to predict bills, inform customers of outages, deliver visibility into repairs in their areas, track a truck to a service call, order services and get quotes on line. The advent of Robotics will enable the automation and augmentation of the customer experience through the use of Bots such as Chat bots, Bots that will process customer moves and Bots which could assist with the billing process. As Hydro Ottawa continues transitioning to systems in the cloud, Lifecycle management and integration technologies will be required to facilitate seamless data exchange and entitlement with the appropriate security and controls in place.

3.5.1.2. Program Description

3.5.1.2.1. Current Issues

Some of the current issues include:

- A number of business systems are not integrated today or rely on legacy technologies that lack the robustness of a modern integration platform
- Interface and data quality issues resulting in incorrect data and or re-work cycles to correct
- The company lacks a digital platform to efficiently collaborate, govern and manage unstructured data as part of the information management program.
- Hydro Ottawa does not have a data warehouse which makes reporting across systems difficult and inefficient.
- Business intelligence is lacking across the company due to gaps in technology, governance and resources.
- The transition to cloud is driving the need for a modern Lifecycle management system to manage the onboarding and offboarding of employees in a timely and secure manner.
- A number of business tasks are manual in nature today but could be eliminated with the emergence of artificial intelligence and robotics.
- The total cost of ownership of Oracle systems is very high today and Hydro Ottawa would like to reduce this significantly through the use of engineered systems

3.5.1.2.2. Program Scope

Technology costs are managed through Hydro Ottawa IT governance process, which allows planners to look proactively at IT strategy, project expenditures, and service delivery, and align technology spending with business and corporate objectives. Senior business managers also provide guidance, direction and support to the decision-making for corporate technology decisions. Below represents the initiatives known at this time:

- Data Warehousing and Analytics
- Integrations
- Oracle Consol Appliance (Engineered Systems)
- Lifecycle Mgmt.
- Artificial Intelligence
- Information Mgmt. Platform Deployment
- Blockchain
- Robotic Process Automation

Many of these initiatives will require the assistance of professional services as the knowledge and expertise may not be available when needed or does not exist at all within Hydro Ottawa.

3.5.1.2.3. Main and Secondary Drivers

- Improve productivity
- Maintain operational effectiveness
- Deliver on business commitments

3.5.1.2.3. Performance Targets and Objectives

Upgrading and enhancing applications within the Enterprise Solutions portfolio will support the following objectives:

- Maintain the viability of system
- Mitigate costly extended support, break-fix and emergency repairs
- Deliver on business outcomes
- Implement robust system integrations with data flow accuracy
- Improve cybersecurity and confidentiality of sensitive information

- Reduce legacy application footprint

3.5.1.3. Program Justification

3.5.1.3.1. Alternatives Evaluation

Alternatives Considered

Each initiative above is necessary to address shortcomings that exist today be it replacement of legacy technology and/or addressing a technology gap for which Hydro Ottawa has no in-house solution. Hydro Ottawa will source potential technology solutions based on business requirements for each of the technology initiatives which best meet the needs of the business. This will take into account the evaluation criteria as identified below.

Evaluation Criteria

- Price (labour rates)
- Vendor supportability
- Product Scalability
- Complexity of change
- Business alternative solutions

Preferred Alternative

A preferred alternative is not known at this time.

3.5.1.3.2. Program Timing & Expenditure

Program expenditures are summarized in Table 3.29 below.

Table 3.29 - Historical and Future Data Management & Integrations Program ($'000s)

	Historical					Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure	$46	$0	$30	$35	$961	$894	$519	$578	$303	$857

3.5.1.3.3. Benefits

Program benefits are summarized in Table 5.2 below.

Table 3.30 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	• Improved system integrations and data quality • Better collaboration • Reduction in paper • Increase operational intelligence • Increase/maintain system performance • Improve/maintain system supportability • Drive opportunities for cost savings through leaner processes and in-platform planning and reporting
Customer	• Ensure timely and accurate transfer of data to/from systems and other future integrations • Reduction of manual data entry • Increased customer intelligence and insights
Cyber-Security, Privacy	• Latest versions of these systems would provide Hydro Ottawa access to security patches and enhanced security • Improved on-boarding and off-boarding of employees • Improved security and controls on company data
Environment	• Continued transition to cloud is environmentally friendly sharing hardware, minimizing energy and avoiding a localized install base

3.5.1.4. Prioritization

3.5.1.4.1. Consequences of Deferral

Without appropriate funding, managing expanding company data and integration requirements will be difficult. Additionally, we will fall behind in the adoption of next generation technologies.

- Delayed refresh of assets driving risks associated with S/W and H/W obsolescence
- Negatively impact the ability of employees to support business outcomes
- Decreased productivity due to prolonged applications/systems gaps;
- High unit cost of supporting and servicing applications;
- Limited vendor support
- Lack of IT security controls;

3.5.1.4.2. Priority

HIGH – Successful companies are those which are data driven and Hydro Ottawa is no exception. We lack sufficient technology today to manage the transmission and lifecycle of data, which is an extensive key asset to the company.

3.5.1.5. Execution Path

3.5.1.5.1. Implementation Plan

3.5.1.5.2. Risks to Completion and Risk Mitigation Strategies

Competing priorities may impact the timely implementation of initiatives. With executive support, stakeholder engagement, and careful planning and attention to schedule, this risk can be effectively managed.

3.5.1.5.3. Timing Factors

Initiatives will be staggered through the years based on client and resource availability.

3.5.1.5.4. Cost Factors

- Estimates are based on existing vendor agreements, past projects/initiatives and published pricing as of the time of this writing
- Unknown Regulatory pressures could introduce additional un-anticipated development
- Scope may increase due to new business requirements and vendor pressures

3.5.1.6. Project Details and Justification

Table 3.31 - New Technology Initiatives

Project Name:	New Technology Initiatives
Capital Cost:	$3.2M
O&M:	$0.5M (2021-2025)
Start Date:	Q1, 2021
In-Service Date:	Enhancements will be realized at various points through the term
Investment Category:	General Plant
Main Driver:	Maintain operational effectiveness
Secondary Driver(s):	Deliver on business outcomes
Customer/Load Attachment	N/A

Project Scope

Hydro Ottawa will embark on a number of next generation technology initiatives to increase productivity, gain operational efficiencies and enhance the customer experience. Many of these initiatives center on improving the management of "data" which is recognized as a key asset to the company.

- Data Warehousing and Analytics
- Integrations
- Oracle Console Appliance (Engineered Systems)
- Lifecycle Mgmt.
- Artificial Intelligence
- Information Mgmt. Platform Deployment
- Blockchain
- Robotic Process Automation

Work Plan

1. Assign a dedicated resources (Hydro Ottawa and/or contractors)
2. Assess requirements
3. Design/ upgrade/configure changes
4. Build/develop changes
5. Build/develop integrations changes
6. Data analysis
7. Data clean-up
8. Data transfer/migration
9. System functional testing
10. System integration testing
11. Training
12. User acceptance and regression testing
13. Deploy changes to production
14. Stabilization period

Customer Impact

Hydro Ottawa will improve the management and transmission of data using analytics and artificial intelligence. This will yield greater insights and business intelligence to improve customer engagement such as predicting bills, informing customers of outages, enabling conversation through chat-bots and offering online services which correspond to customer needs and energy consumption habits.

3.6. OPERATION INITIATIVES

3.6.1. FIELD SERVICE MANAGEMENT

3.6.1.1. Program Justification

Table 3.32 - Field Service Management Overview

Project Name:	Field Service Management
Project Number:	Project Number
Capital Cost:	$907k
O&M:	Refer to O&M in Section 1.3.6 Service Automation
Start Date:	2020
In-Service Date:	2021
Investment Category:	General Plant
Main Driver:	Risk of Failure
Secondary Driver(s):	Enhance operational performance and productivity, Deliver on customer expectations
Customer/Load Attachment	N/A
Project Scope	
As detailed in Material Investment Plan GP 1.3 Service Automation, this project is to fund the replacement of the on premise Mobile Workforce Management (MWM) System with a cloud based system. The anticipated benefits include improved system configurability, enhanced mobile functionality, robust performance management, reporting and dashboard capabilities, an enhanced customer experience and operational efficiencies	
Priority	
Hydro Ottawa went live with the first phase of MWM in December of 2016. Within a year of go-live, the vendor acquired a cloud based solution from a competing company and announced that it would no longer be investing in the existing MWM product and would be eliminating support at some point in the future. Hydro Ottawa has upwards of 40 crews using the system that are at risk of a significant reduction in productivity should we have an extended outage or catastrophic failure on this system that is nearing end of life. A new cloud based field service management system will also permit Hydro Ottawa to expand the use of the tool across additional work groups to further enhance operational performance and productivity.	
Work Plan	
Hydro Ottawa will be completing a review and evaluation of several products in the field service management space prior to selecting a solution for implementation. Work is to begin in early 2020, with a target of beginning implementation prior to the end of the year. The new solution will be fully implemented in 2021.	
Customer Impact	
New cloud based field service management systems offer increased functionality aimed at improving the customer experience. Some of these include self-serve appointment booking, “where’s my tech” location services, and work flows and new customer communications at various levels of service progression. This type of customer focused functionality will be part of the evaluation criteria for a new system.	

3.6.2. AMI ANALYTICS AND INTEGRATION ENABLEMENT

3.6.2.1. Program Summary

The majority of Hydro Ottawa metering assets will be fully depreciated in year 2023. As a result, Hydro Ottawa conducted a review of the current state architecture including existing metering assets and associated Advanced Metering Infrastructure (AMI). Hydro Ottawa retained Black and Veatch to conduct the study and assist in the development of an AMI strategic roadmap. The aim of this study was to provide insight into the potential features, advantages and shortfalls of Hydro Ottawa's current metering state along with a view of potential use cases based on currently available and emerging technologies. The study identified three primary obstacles that are limiting Hydro Ottawa from expanding the usefulness of the AMI system, summarized as follows:

1. Obstacles in extracting available data via the current AMI network either due to bandwidth/latency limitations or backhaul connectivity limitations (dial up modems)

2. Obstacles in developing additional enhancements to downstream system to enhance their potential use of AMI data that may already be available

3. Obstacles borne from core metering and/or data capabilities of the sealed electric meters currently in the field.

This project serves as a means of tackling the second obstacle in the list, with the goal of developing enhancements to further leverage use of AMI data across the organization.

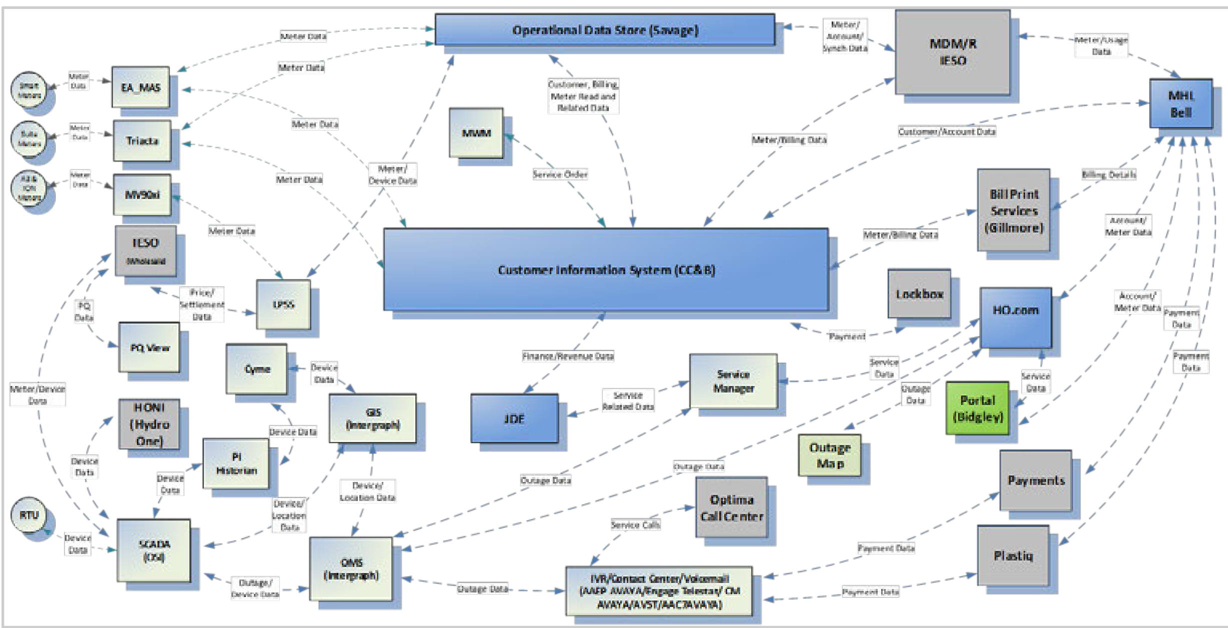
3.6.2.2. Program Description

3.6.2.2.1. Current Issues

Since the adoption of smart metering technologies in 2006, Hydro Ottawa has undertaken significant investments to leverage AMI data as a means of driving operational efficiencies and improving the accuracy of our bills. As we migrate our meter data communication back-haul to an "always-on" technology, we will be in a position to extend the use of this data to further improve operational efficiencies, accuracy of reporting and our customer's experience.

As demonstrated in Figure 3.6, Hydro Ottawa's current IT architecture does not include any specific platform to provide detailed analytics of our AMI data nor does the HoneyWell/Elster head-end (EA_MS) currently integrate with systems aside from our meter data management platform (Savage) and Customer Care & Billing system (CC&B). Furthermore, as we migrate towards an “always-on” cellular communication back-haul of AMI data, the amount of data available to internal stakeholders will vastly increase in size. In order to fully leverage the available data, we will need to invest in data storage, analytics and integration solutions.

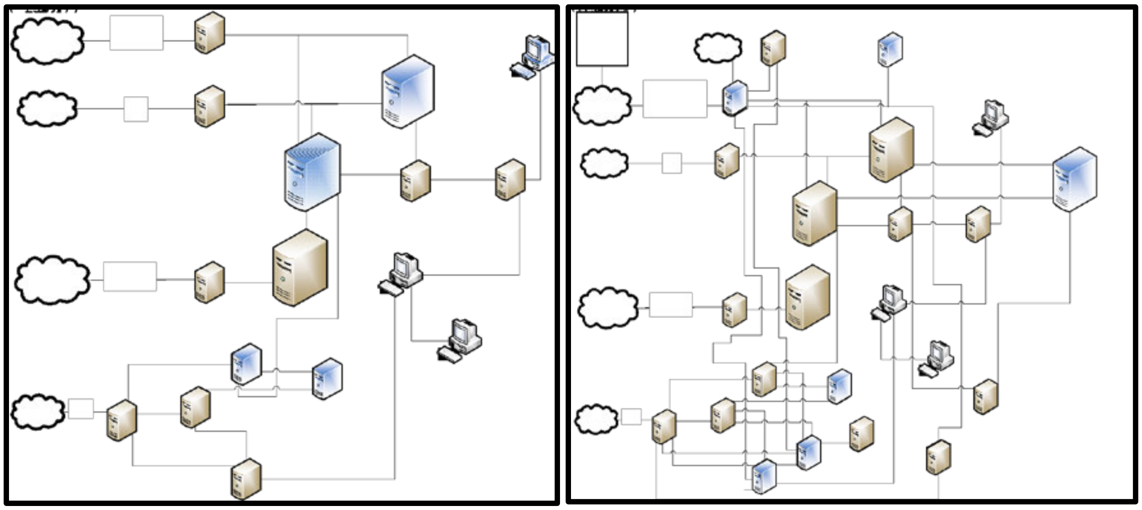
Figure 3.6 - Hydro Ottawa Current State System



3.6.2.2.2. Program Scope

This project will involve the selection, configuration, data conversion and integration of a cloud based data analytics platform, whereby Hydro Ottawa will source analytics solutions vendors to supply the underlying platform. The platform will be procured to include the rules engines, configuration and programming tools and the selected vendor will be required to demonstrate proven use cases by other utilities. Hydro Ottawa will be seeking solutions which make use of next generation technology such as machine learning and artificial intelligence capabilities. Also included in this project will be the integration of new and existing systems as well as the development of an internal portal to make data and analysis abilities accessible to users consuming this information. The image on the left in Figure 3.7 below depicts the current state and integration of existing systems and the image on the right depicts the future systems integration required to fully leverage AMI data.

Figure 3.7 - Current and Future Planned Systems and Integrations



3.6.2.2.3. Main and Secondary Drivers

The primary driver of this project is to generate operational efficiencies and productivity improvements across the organization. Hydro Ottawa stakeholders will have greater access to AMI data and the ability to take advantage of all functionality from the existing metering population. This will be accomplished through the installation of an advanced data analytics platform, development of a data warehouse and portal, and through the support of integrations to new and existing systems. These advancements will allow users to:

- Access additional features in metering technology as meters are upgraded in the field;
- Re-engineer internal business processes to improve outcomes, productivity and efficiency; and
- Leverage new functionality and additional data in meters for analytics and other applications across the landscape e.g. distribution modeling and early outage detection.

Improvements in data quality and evidence based decision making will enable Hydro Ottawa to provide a higher quality of its customers.

3.6.2.2.4. Performance Targets and Objectives

The following represents the targets and objectives of this journey:

- Enable enhancements to Hydro Ottawa's customers experience through implementation of advanced data analytics. Examples of enhancements to be enabled are:
  - Data analytics required to enable bill forecasting
  - Power restoration alerts integrated with bill forecasting to eliminate the perception that customers will be billed during outages
  - Data analytics to perform load disaggregation, to estimate customer utilization by appliance.
  - Data analytics required to enable Pre-pay programs and rates
  - Data analytics for customer usage profiling for integration into CSR portal
- Leverage existing AMI data to improve operational efficiencies within asset planning, regulatory, finance, meter data services, billing, collections and metering field operations. A non-comprehensive summary of examples include
  - Enhanced automated troubleshooting and field service dispatching leveraging AMI alerts and exceptions through advanced data analytics
  - Automation of the Move-In/Move-Out process leveraging remote disconnect meters and integration with CRM
  - Improved accuracy and reduction of labour in rate design, cost of service, revenue forecasting, unbilled estimates and loss allocations
  - System integration of historical AMI data to enable load forecasting and modeling, transformer loading analysis and distribution modeling
- Additional integrations to be considered include
  - Providing threshold alerts and alarms to DMS for system troubleshooting
  - Data integrations with DERMS module for advanced forecasting and modeling
  - Pre-establishing system architecture requirements to enable multi-platform data integration and analytics (e.g. water, thermal, streetlights)
- Continue to develop a more nimble system architecture, allowing our systems to be flexible and adaptable to a continually changing regulatory landscape

3.6.2.3. Program Justification

3.6.2.3.1. Alternatives Evaluation

Alternatives Considered

Hydro Ottawa's current IT architecture does NOT include any specific platform to provide the detailed AMI analytics that will be required. In Black and Veatch's Technology Roadmap and AMI Strategy Summary Report, they presented three potential approaches for solving the existing data analytics gap. Specifically, the three approaches that Hydro Ottawa may consider include:

❖ Option 1 - Platform or use case enabled application

- The analytics "platform" approach is a build-it-yourself strategy. In this approach, Hydro Ottawa would architect the databases, the dashboards, the extracts, and the algorithms to analyze the data based on their own use case definitions and process automation descriptions. This approach should only be undertaken by organizations that are very adept at complex database architecture designs, with strong in-house data science and analytical capabilities, and expert data presentment skills.
- This approach is based on sourcing an analytics solution from a vendor who can provide not only their own underlying "platform" but also the rules engines, configuration and programming tools, and (most importantly) implemented use cases from other utilities. This would be the preferred approach for utilities with well-defined use case targets which should be the case at Hydro Ottawa based on the opportunities assessments.

❖ Option 2 - MDMS or Head End System module alternative

- Many of the top tier MDMS vendors offer data analytics modules as add-on applications to their MDMS solutions. Based on whether the current MDMS vendor (Savage) can provide data analytics applications, leveraging their data analytics solution may provide an opportunity for more efficient access to data analytics and reduced implementation risk.
- Several of the top tier AMI vendors offer data analytics modules as options for their AMI system head end application. Based on the long-term AMI solution vendor of choice, this may become a viable option for Hydro Ottawa to consider.

- ❖ Option 3 - Full service/SaaS or DBRT
  - Full Service and Software as a Service (SaaS) vendors provide not only the platform, the application, the use cases, but also the data scientist and professional services to develop new use cases and data tests as Hydro Ottawa's needs evolve. Specifically, Oracle provides this capability via their prior acquisition of DataRaker, which is offered as a hosted service.
  - Design, Build, Run, Transfer (DBRT) strategies leverage application suppliers and consultants to develop and configure the platform and application, develop and implement the initial use cases, integrate the use cases into automated business processes, help run the new automated processes with Hydro Ottawa, and finally transfer the platform, application, and the developed use cases over to Hydro Ottawa for long term operation and support.

Hence, the first step in preparing for the data analytics release and the solution selection process for Hydro Ottawa will be a diligent identification and prioritization of the desired use cases that Hydro Ottawa believes will drive value from expanded AMI data availability. Many of these are readily identifiable from the AMI Opportunities Matrix.

Evaluation Criteria

The following criteria shall be used in evaluating the potential alternatives of the Advanced AMI Data Usage project:

- Support Desired Business Opportunities: The proposed solution shall provide a clear lineage to enable the use cases prioritized by the internal stakeholders or the initiatives identified by the Smart Energy Steering Committee
- Return on Investment: The proposed solution shall clearly align to a qualitative financially justifiable reduction in operating and maintenance expense and/or qualitative increase in reliability or customer experience in relation to the capital expenditure requirements.

- Resourcing Requirements: The internal resourcing requirements of the proposed solution shall consider the availability of resources to complete the project when combined with other projects also included in the 2021-2025 roadmap
- Mitigate Long Term Risk: With the potential of a significant shift in the regulatory framework currently governing the LDCs along with the IESO's upcoming Market Renewal, the proposed solution shall be capable of being architected in such a way so as to enable integration of new types of devices and data analytic use cases.

Preferred Alternative

The preferred alternative is Option #1 – A platform or use case enabled application.

The methodology of the Black & Veatch study included conducting stakeholder engagement sessions, reviewing functionality of the existing meter population, reviewing Hydro Ottawa's current AMI system architecture and conducting a review of the benefits of alternative technologies. The primary result of the study was the conclusion that the majority of AMI data use cases are achievable with the existing meter population. The remainder of the high priority use cases are enabled upon transitioning to a cellular, "always-on" technology for meter data back-haul. Additionally, Hydro Ottawa believes Option #1 is the most cost effective approach.

3.6.2.3.2. Program Timing & Expenditure

The investment on this project will be aligned to the enablement of features through the communications infrastructure upgrade, the planned EA_MS head-end upgrade and the desired year of implementation by key stakeholders. Table 3.33 illustrates the breakdown of capital expenditure by year and was developed in alignment of the aforementioned drivers. Hydro Ottawa's focus has centered on high priority use cases.

Table 3.33 - AMI Program ($'000s)

Year	Cost	Use Case	High Level Execution Needs	Key Business Drivers
2021-2022	$800	Improved Cost of service analysis	AMI data to data warehouse, automate reporting by integrating AMI data to system model, develop internal dashboard and reports	Reduced OM&A (labour), Improved accuracy
		More accurate earnings & budget forecasting	AMI data to data warehouse, automate reporting by integrating AMI data to system model, develop internal dashboard and reports	Reduced OM&A (labour), Improved accuracy
		Improved real and apparent loss allocation	AMI data to data warehouse, automate reporting by integrating AMI data to system model, develop internal dashboard and reports	Reduced OM&A (labour), Improved accuracy of loss allocation
		Improved Distribution Modeling and Calibration	Port hourly interval data (VEEd) to CYME	Improved accuracy of modeling and forecasting, future proof for increased penetration of DER
		Automate meter data anomaly process (low/no consumption, low voltage, high consumption, missing segments)	Analytics and machine learning to review AMI data to discover and validate anomalies. Automatically dispatch field crews as required.	Reduce unbilled revenue, Reduce OM&A (labour) for manual intervention
2022	$350	Reduction in Meter Operations field orders for "move-in / move-out" by using remote disconnects / reconnect functionality.	Program to automatically disconnect/reconnect services at MIMO. Automatically dispatch field crews as required. Connect with CRM for call agents to schedule. Remote disconnect required on service	Reduced OM&A (labour), Improved customer service, reduce unbilled revenue
		Analytics of exceptions and alerts to reduce field visits and internal labour	Analytics and machine learning to analyze meter alerts and exceptions. Automatically dispatch field crews as required.	Reduce OM&A (labour), Reduce unbilled revenue
		Aggregation of Load at Virtual Nodes for Distribution System Analysis, Transformer / Device Load Analysis and Equipment Sizing	Port hourly interval data (VEEd) to CYME	Transformer loading validation, future proof for increased penetration of DERs
		Improve AMI Alert and Exception Management by back end systems. (Reduce billing issues)	Analytics and machine learning to automatically find billing exceptions earlier in the process. Automatically dispatch field crews as required.	Reduce total number of billing exceptions, Reduce OM&A (labour) for manual intervention

Year (Cont'd)	Cost (Cont'd)	Use Case (Cont'd)	High Level Execution Needs (Cont'd)	Key Business Drivers (Cont'd)
2022	$350	Automation of capacity reserve charge	Analytics to determine whether a customer should be charged capacity reserve. Upgrades to CC&B to enable new charge	Regulatory
		Disaggregation of Load / Appliance Monitoring (using appliance profiles)	Analytics to enable load disaggregation, integration with customer portal and CRM, automated statistics and reporting	Improved customer service, enabler for future potential revenue
		Improved accuracy and reduced labour in rate design	AMI data to data warehouse, automate reporting by integrating AMI data to system model, develop internal dashboard and reports	Reduced OM&A (labour) improved accuracy
		Reduced unaccounted for usage and field labor due to improved identification of lost or orphan (a.k.a. data nodes) meters	Analytics and machine learning of AMI exceptions Automatically dispatch field crews as required.	Reduced OM&A (labour), Reduce billing exceptions
2025+		Prepayment Programs / Rates	Discovery of requirements to enable required during 2020/2021 years	Improved customer experience

The actual timing of the above use cases will be subject to analytics platform capabilities, resource availability, status of dependency projects to enable required features etc.

Table 3.34 - AMI Program Expenditure ($'000,000s)

	Historical					Future				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Expenditure						$0.51	$1.04			

3.6.2.3.3. Benefits

Program benefits are summarized in Table 3.35 below.

Table 3.35 - Program Benefits

Benefits	Description
System Operation Efficiency and Cost Effectiveness	• Evidence based decision making • New business processes introduced making internal workload more efficient • Improved data quality and automations • Remain regulatory compliant
Customer	• Improved timeliness and accuracy of billing of our customers • Enhanced features and data from customer's meter which would feed into analytical tools that would aide customers in usage decision making • Promote electricity conservation • Latest technology will allow Hydro Ottawa to invest in most up to date meters as they would be compatible
Safety	• Future versions will have enhanced safety features with handling of our physical meters.
Cyber-Security, Privacy	• Latest versions of these systems would provide Hydro Ottawa access to security patches and enhanced security
Economic Development	• Enhanced system integrations will set the foundation for future conservation initiatives, pre-pay programs, virtual net metering, EV chargers, complex load settlement, etc.
Environment	• A primary benefit of the data analytics and machine learning will be a reduction in field visits and truck rolls thereby reduction carbon footprint

3.6.2.4. Prioritization

3.6.2.4.1. Consequences of Deferral

If the decision was to delay the enablement of AMI Analytics & Integrations:

- Use cases identified by stakeholders in the above table would not be achievable, leaving significant OM&A reduction potential and inefficiencies un-addressed
- Lack of system integrations would inhibit future long term use cases not included in this project

MED: The priority is set as medium. Enablement of AMI data analytics and system integrations will not only enhance the customer's experience and reduce operating costs, but also ensure Hydro Ottawa has developed the foundation necessary to accommodate the impending complexity of metering as DERs and EVs become more mainstream. .

3.6.2.5. Execution Path

3.6.2.5.1. Implementation Plan

Each individual change would be implemented using project disciplines and change management best practices.

3.6.2.5.2. Risks to Completion and Risk Mitigation Strategies

- Resource constraints: ensure alignment and commitment from the organization
- Dedicated project team: ensure the team solely focuses on this project and not in addition to operations
- Change management of new platform: ensure the project team focuses on preparing the organization for the changes

3.6.2.5.3. Timing Factors

- Metering backhaul communications upgrade planned for 2021/2022

3.6.2.5.4. Cost Factors

- Firm estimates not yet received
- Estimates for internal labour is based on past projects
- Scope may increase due to some unknowns of availability and features of vendors
- Unknown Regulatory pressures could introduce additional un-anticipated development

3.6.2.6. Project Details and Justification

Table 3.36 - Program Benefits

Project Name:	AMI Analytics & Integrations Enablement
Capital Cost:	$1.6M
O&M:	$1.0M (2021-2025)
Start Date:	January 2021
In-Service Date:	Enhancements will be realized at various points through the term
Investment Category:	CAPEX – General Plant
Main Driver:	Operational Efficiencies and Productivity Improvements
Secondary Driver(s):	Improve the quality of Customer Service
Customer/Load Attachment	
Project Scope	
This journey involves the adoption of a cloud based data analytics platform to enable greater insights of AMI data across the organization. Included in this project will be the integration of new and existing systems as well as the development of an internal portal to make data and analysis abilities accessible to users consuming this information. A number of high priority use cases have been identified to improve operational efficiencies and productivity, in addition to improving the quality of Customer Service.	
Work Plan	
1. Resourcing (Hydro Ottawa and/or contractors) 2. Assess requirements 3. Design/configure 4. Build/develop 6. Data conversion 9. Testing (Unit/Functional/Integration) 11. Training 12. User acceptance and regression testing 13. Deployment 14. Stabilization	
Customer Impact	
Improvements in data quality and evidence based decision making will enable Hydro Ottawa to provide a higher quality of service to the customer populace.	

3.6.3. GT SOFTWARE CUSTOMIZATION

3.6.3.1. Project Details and Justification

Table 3.37 - Program Benefits

Project Name:	GT Software Customization
Project Number:	9202003770
Capital Cost:	$1.76M in 2021-2025
O&M:	N/A
Start Date:	1-Jan-2021
In-Service Date:	On-Going
Investment Category:	General Plant
Main Driver:	Improved Performance
Secondary Driver(s):	Reliability
Customer/Load Attachment	ALL Customers
Project Scope	
This project includes software and services from new and existing vendors to enhance, modify, improve, and customize the tools and systems that operate Hydro Ottawa's grid. Primarily, these Software Systems operate for the benefit of the Hydro Ottawa System Operations team. The Grid Technology Systems routinely need minor enhancements and adjustments in response to requests from the users and changes in other platforms (that interconnect with Grid Technology Systems). These changes routinely fall outside of the scope and schedule of the major upgrade investments and therefore require small, limited scope engagement with internal and vendor staff. It is therefore necessary to carry a budget for these annual minor enhancements	
Priority	
Medium – This investment represents an annual re-investment into the customization of Hydro Ottawa's Control room and control software based on the needs and requirements of System Operations.	
Work Plan	
This project operates as an annual investment program in the software systems and tools. Therefore, the work carried out each year is determined through consultation and planning efforts in partnership with System Operations and IT staff.	
Customer Impact	
This investment will enhance the efficiency and performance of system operators in the control room through improvement of the tools and software they use. This includes: SCADA, Distribution Management, and Outage Management systems.	

3.6.4. COPPERLEAF UPGRADE

3.6.4.1. Program Details and Justification

Table 3.38 - Copperleaf Upgrade Overview

Project Name:	*Copperleaf Upgrade*
Capital Cost:	$201,532 (outlined in ERP Enhancements MIP)
O&M:	*N/A*
Start Date:	*2022*
In-Service Date:	*Ongoing*
Investment Category:	*General Plant*
Main Driver:	*Operational Efficiency*
Secondary Driver(s):	*Support business outcomes*
Customer/Load Attachment	*N/A*
Project Scope	
Hydro Ottawa will upgrade its Asset Investment Planning system to remain current with vendor support and take advantage of new functionality. Additionally, new valuation models will be configured to aid in the decision making process.	
Priority	
This is medium priority	
Work Plan	
The work will involve vendor professional services working alongside Finance, Operations and IT to ensure a seamless upgrade and enhancement of valuation models.	
Customer Impact	
This activity will aid Hydro Ottawa planners to make appropriate and data driven investment decisions on all company assets.	

3.6.5. GEOTAB AND FLEETWAVE

3.6.5.1. Program Details and Justification

Table 3.39 - Geotab and Fleetwave Overview

Project Name:	Geotab and Fleetwave
Project Number:	9202014335
Capital Cost:	$50,383 (outlined in ERP Enhancements MIP)
O&M:	N/A
Start Date:	2023
In-Service Date:	In-Service Date
Investment Category:	General Plant
Main Driver:	Operational Efficiency
Secondary Driver(s):	Support business outcomes
Customer/Load Attachment	N/A
Project Scope	
Hydro Ottawa will enhance Fleetwave and Geotab systems which are responsible for managing and maintaining fleet assets and telemetry of trucks in the field. Additionally, investment will be made to enhance reporting and integration capabilities with downstream systems.	
Priority	
Medium - We need to plug some of the gaps that exist within these systems today to eliminate the need for manual reconciliation efforts.	
Work Plan	
The work will involve a mix of integration and reporting enhancements and will be spearheaded by IT, Finance and Operational resources.	
Customer Impact	
The enhancements will allow Hydro Ottawa to further optimize fleet assets for improved productivity	

FLEET REPLACEMENT PROGRAM

1. INTRODUCTION

Hydro Ottawa relies on a diverse fleet of 234 vehicles and 44 other units of transportation equipment to support its operations, maintenance and administration ("OM&A") and capital work programs. Vehicles are an essential component of providing efficient and reliable service to customers through the timely restoration of power, ensuring efficient construction and maintenance of the distribution system, and safeguarding both worker and public safety.

Hydro Ottawa's service territory is comprised of 662 km^2 of rural service area and 454 km^2 of urban service area. This size and mix of territory requires a variety of fleet equipment that can support maintenance and construction activities in a diverse overhead and underground distribution line operating environment.

The utility's Fleet Services Unit ("Fleet") is responsible for both the maintenance and capital replacements for fleet vehicles. Fleet, in conjunction with the various distribution operations work groups, determines the demand for vehicles based on the planned OM&A and capital work programs. Based on an ongoing assessment of asset condition, Fleet makes maintenance decisions throughout a vehicle's lifecycle and recommends replacement when and if needed. Deterioration of fleet assets can negatively impact utility performance in areas such as reliability, productivity, and safety.

A summary of the number and net book value of Hydro Ottawa's fleet assets is provided in Table 1 below.

Table 1 – Number of Hydro Ottawa Fleet Vehicles and Net Book Value per Vehicle Category (as of September 30, 2019)

Vehicle Category	# of Units	Net Book Value ($'000s)
Light Duty Vehicles	146	$2,035
Medium Duty Vehicles	26	$1,011
Heavy Duty Vehicles	62	$7,957
Other	44	$647
TOTAL	**278**	**$11,650**

Descriptions of vehicles in the above categories are as follows:

- Light Duty Vehicles – pick-up trucks, vans, and small cars for supervisor and inspection staff transport. These vehicles are used for work such as trouble calls, crew and material transport, metering, collections, design, and safety inspection.
- Medium Duty Vehicles – step vans and walk through body trucks which are used as workshops for underground splicing and station maintenance; dump trucks used for transporting compaction materials for pole line work; and flatbed trucks for transporting cable and transformers.
- Heavy Duty Vehicles – consist of bucket trucks, diggers, and cranes, which are used for performing overhead and underground line work, drilling and installing poles, and lifting heavy transformers. This category also includes several track machines, including a backyard bucket/digger and a backyard transformer transporter.
- Other – includes pole trailers, flat deck trailers, underground pulling equipment, and forklifts (indoor and outdoor) for material handling.

2. FLEET MANAGEMENT PRACTICES

Fleet is responsible for the procurement, maintenance, and disposal of vehicles and equipment needed to support Hydro Ottawa's functional and operational needs. Fleet's primary objective is to manage its assets to the lowest overall lifecycle cost, while ensuring asset reliability and employee and public safety.

A key objective is that capital investments be made at a level and pace that allows overall costs to be minimized. An optimally timed vehicle replacement strategy also helps to ensure that the appropriate number of vehicles are available to support system maintenance and capital investment plans.

Hydro Ottawa's fleet replacement practices are governed by the Corporate Policy on *"Fleet"* and the Corporate Procedure on *"Acquisition and Decommission of Fleet Assets."* The utility has a multi-year capital plan to effectively manage and replace its fleet assets. The objectives of the fleet replacement plan are as follows:

- **Safety:** Provision of safe, reliable, and efficient vehicles and equipment to meet operational requirements.
- **Regulatory:** Compliance with all applicable legislation and regulations, as well as accepted industry norms and practices. For example, Fleet must perform annual vehicle inspections to make sure vehicles are compliant with its Commercial Vehicle Operators Registration.
- **Financial:** Management of assets to the lowest overall lifecycle cost, while ensuring asset reliability and employee and public safety.
- **Environmental:** Environmental considerations from the point of procurement through the life of the vehicle. This includes consideration of fuel economy, exhaust emissions, route optimization, reducing idle time (through education of vehicle operators), and reviewing environmentally friendly options where feasible.

Hydro Ottawa's fleet replacement plan reviews all current vehicles and proposes future replacement dates and cost. The replacement plan is based on a vehicle by vehicle assessment weighing the following criteria:

- Vehicle age
- Mileage
- Engine hours
- Power take off (“PTO”) hours
- Operating and maintenance costs
- Repair history
- Availability of repair parts
- Overall internal mechanic assessment of vehicle condition, and
- Utilization

As a result of these evaluations, vehicles may be retained longer due to being in better than average condition, while others may be replaced earlier due to being in poorer condition. Of note, Ottawa is subject to extremely hot and humid summers and harsh and cold winters. This has a direct effect on the life expectancy of engines and hydraulic equipment as well as on road conditions. Reactive repairs increase during the harsh months and vehicle condition can sometimes deteriorate ahead of projected schedules. Hydro Ottawa factors in conditions such as these, along with specific vehicle condition assessments, in order to determine which vehicles should be replaced and the appropriate year of replacement.

Table 2 provides information on the quantitative fleet vehicle replacement criteria. (Note that the quantitative criteria is Age **or** Km **or** Engine Hours). Only one of these criteria has to be met in order to trigger consideration of a proposed replacement. In many cases, because of the nature of work performed by a specific vehicle, the Km and Engine Hours metrics are not reached prior to the Age criteria being met.

Table 2 – Quantitative Vehicle Replacement Criteria

Vehicle Description	Age	Age (2016-2020 Application)	Km	Engine Hours	PTO Hours
Light Duty					
Automobile (All types)	10	7	150,000	4,000	N/A
Pick-up Trucks (All types)	10	7-8	100,000	5,000	N/A
Vans (Compact)	8	7	150,000	5,000	N/A
Vans (Cargo)	8	8	150,000	6,000	N/A
Medium Duty					
Vans (StepSide/Cube/ Walk-through Body)	12	10	150,000	8,000	N/A
Trucks (Dump)	12	10	125,000	6,000	N/A
Trucks (Stake / Flatbed)	15	10	150,000	8,000	N/A
Heavy Duty					
Trucks (Bucket, Radial Boom Derrick (“RBD”) and Line - includes track units)	12	12	200,000	10,000	5,000
Trucks (Knuckle Boom / Crane includes track units)	15	15	200,000	10,000	5,000
Other					
Forklifts (Inside and Outside)	15	15	N/A	10,000	N/A
Trailers (Pole, Utility, Pulling, Reel)	15	12	N/A	N/A	N/A

Since Hydro Ottawa filed its previous rebasing application, several of the replacement age criteria have increased.[1] Fleet is able to extend the replacement age of some vehicle types due to a number of improvements such as use of improved synthetic oil products, undercoating, live view of vehicle performance (and driver behaviour), and engine code failure information for timely diagnosis and repairs. It should be noted that Hydro Ottawa’s replacement age criteria is consistent with, or is greater than, that of industry peers in Ontario.

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

3. FLEET CAPITAL EXPENDITURES – HISTORICAL AND BRIDGE YEARS

Table 3 summarizes Hydro Ottawa's actual and projected capital expenditures on fleet during the 2016-2020 Custom Incentive Rate-Setting ("Custom IR") period.

Table 3 – Summary of 2016-2020 Actual and Projected Fleet Capital Expenditures vs. OEB-Approved Levels ($'000s)

	Historical			Bridge		Total 2016-2020
	2016	**2017**	**2018**	**2019**	**2020**	
Actual or Projected Capital Expenditures	$2,619	$1,584	$1,195	$583	$1,632	**$7,613**
OEB Approved Levels (EB-2015-0004)	$1,455	$1,209	$1,452	$1,480	$1,876	**$7,472**
Variance Over / (Under)	*$1,164*	*$375*	*$(257)*	*$(897)*	*$(244)*	*$141*
% Variance Over / (Under)	*80%*	*31%*	*(18)%*	*(61)%*	*(13)%*	*2%*

The fleet capital expenditure program was actively managed by the utility. Due to acquisition timing differences and re-prioritizations, actual expenditures differed from planned levels on an annual basis. However, over the full five-year Custom IR period, fleet expenditures are expected to only slightly exceed the OEB-approved level of $7.5M (i.e. by $141K or 2%).

Table 4 below provides further breakdown by vehicle category and number of units over the 2016-2020 period.

Table 4 – Summary of 2016-2020 Actual and Projected Fleet Capital Expenditures and Number of Units by Vehicle Category vs. OEB-Approved Levels ($'000s)

Vehicle Category	2016-2020 # Units	2016-2020 Cap. Ex.	2016-2020 # Units Planned	2016-2020 OEB-Approved Cap. Ex.	Variance # Units	Variance
Light Duty	30	$1,093	28	$991	2	$102
Medium Duty	7	$854	4	$329	3	$526
Heavy Duty	18	$5,298	17	$5,379	1	$(81)
Other	4	$368	11	$773	(7)	$(405)
TOTAL	**59**	**$7,613**	**60**	**$7,472**	**(1)**	**$141**

Over the course of the 2016-2020 Custom IR period, a number of trade-offs were made to address vehicles in poor condition. As such, some of the other units were deferred and Medium Duty vehicles were replaced instead.

4. 2021-2025 FLEET CAPITAL EXPENDITURES

As the 2021-2025 rate period approaches, Hydro Ottawa currently owns many vehicles that are either already beyond their planned life, or will be beyond their planned life during the upcoming rate term.

As a general rule, the average age of the fleet by each major category should be approximately half of the vehicle replacement ages shown in Table 2 above. This helps to ensure a balanced fleet, reduces dependence on obsolete parts, and provides for a smoother annual replacement cycle.

To illustrate, if a simple example of 10 vehicles in a fleet is assumed, and all of them are in the same category with a replacement age of 10 years, the ideal vehicle age profile would be the following:

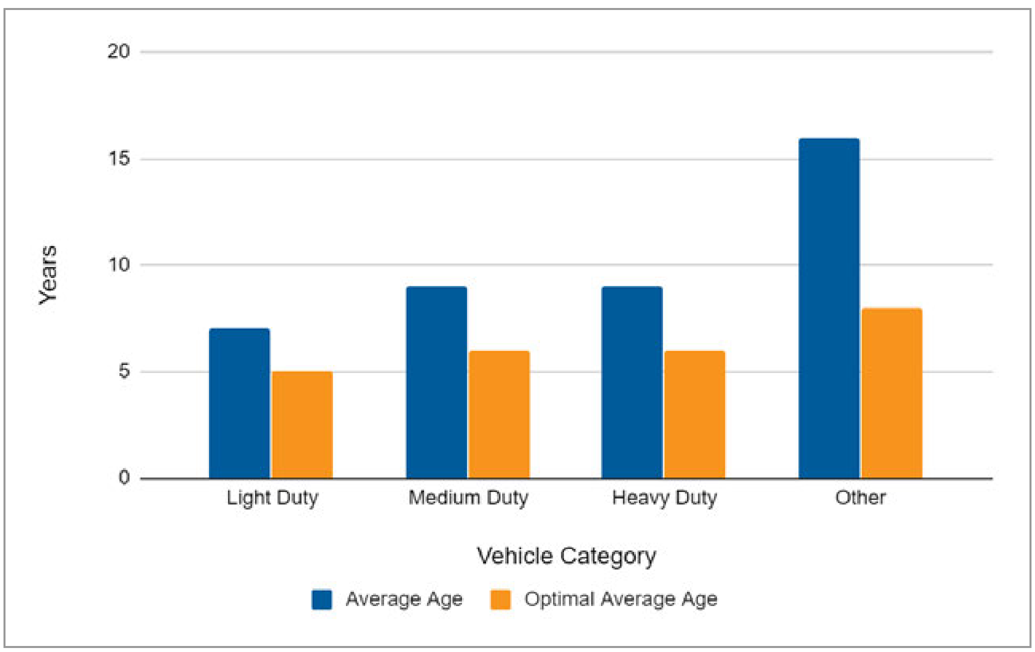
- Vehicle 1 at 9.5 years old

- Vehicle 2 at 8.5 years old
- Vehicle 3 at 7.5 years old
- (…etc., etc.…)
- Vehicle 9 at 1.5 years old
- Vehicle 10 at 0.5 years old

This would provide for an average age of five years old for the entire fleet of 10 vehicles (i.e. one-half or 50% of the replacement age).

As noted below in Figure 1, Hydro Ottawa's actual average fleet age is above this "Optimal Average Age" threshold in all categories.

Figure 1 – Average Age of Hydro Ottawa Fleet Vehicles vs. Optimal Average Age by Vehicle Category[2]



[2] The information presented in this Figure includes all units in Hydro Ottawa's fleet (i.e. 287 in total).

As a vehicle ages, higher operating expenses due to increasing levels of reactive repairs are incurred. The capital replacement program helps to ensure that investments are made at the appropriate level and timing in order to optimize asset maintenance, repair, and capital costs. An appropriately timed vehicle replacement strategy also helps to ensure that the right number of vehicles are available to support system maintenance and capital investment plans.

Hydro Ottawa has identified the need to significantly re-invest in Fleet assets, as many vehicles have reached or exceeded the end of their operational service life. These vehicles are subject to increased maintenance and repair expenditures, deteriorating chassis and engine performance, and potentially pose a health and safety hazard to the public and employees. Based on the criteria and process outlined in section 2 above, Hydro Ottawa has developed a vehicle replacement strategy. The associated number of vehicles and cost are summarized in Table 5.

Table 5 – Proposed 2021-2025 Fleet Capital Expenditures by Vehicle Category ($'000s)

Vehicle Category	2021		2022		2023		2024		2025		Total	
	# of units	$	# of units	$	# of units	$	# of units	$	# of units	$	# of units	$
Light Duty	26	$1,319	17	$1,130	17	$932	17	$910	0	$0	77	$4,291
Medium Duty	9	$1,671	5	$797	0	$0	0	$0	0	$0	14	$2,468
Heavy Duty	8	$3,191	8	$2,599	3	$1,173	2	$771	2	$2,008	23	$9,742
Other	1	$164	0	$0	1	$115	0	$0	0	$0	2	$279
TOTAL	**44**	**$6,345**	**30**	**$4,526**	**21**	**$2,220**	**19**	**$1,681**	**2**	**$2,008**	**116**	**$16,780**

Over the 2021-2025 rate period, a total of 116 vehicles at a cost of $16.8M are planned to be purchased in order to replace vehicles at the end of their useful lives. A summary of the gross and net book value of the vehicles planned for replacement is provided in Table 6 below. As of September 30, 2019, these vehicles are 76% depreciated and will continue to further depreciate until their scheduled replacement.

Table 6 – Gross and Net Book Value per Vehicle Category (as of September 30, 2019) of Fleet Vehicles Planned for Replacement in 2021-2025 ($'000s)

Vehicle Description	# of Units	Gross Book Value	Net Book Value
Light Duty Vehicles	77	$2,689	$1,541
Medium Duty Vehicles	14	$1,449	$199
Heavy Duty Vehicles	23	$7,255	$1,541
Other	2	$100	$25
TOTAL	**116**	**$11,493**	**$2,732**

As part of the customer engagement conducted in support of the development of this Application, Hydro Ottawa asked customers a question regarding vehicle replacement and provided three response options from which to choose.[3] A significant majority of customers (83% of respondents) indicated that they would prefer Hydro Ottawa to "[m]ake investments in the fleet on a vehicle-by-vehicle basis weighing age, kilometers driven, engine hours, repair history, availability of parts and internal mechanic assessments of the general vehicle condition."

This customer preference is consistent with - and supports the appropriateness of - the fleet management practices and basis of vehicle replacement that Hydro Ottawa has followed and is set to employ over the 2021-2025 rate term.

Hydro Ottawa's lifecycle approach to fleet replacement initially identified capital funding needs in the range of $22.7M-$26.1M (for 185-210 vehicles) over the 2021-2025 period. The higher end of the range was based strictly on the replacement age criteria in Table 2 above; the lower end was based on a combination of age and an assessment of individual vehicle historical performance and asset condition. Through extensive review and reprioritization to identify high priority essential replacement vehicles, reductions were made from the initial replacement range to arrive at the funding level being requested in this Application. Furthermore, efforts were made to "smooth" out expenditure levels over the course of 2021-2025. However, despite these

[3] Please see Exhibit 1-2-2: Customer Engagement on the 2021-2025 Application for more information.

efforts, based on a detailed review of asset condition and needs, a higher number of replacements are required in the earlier years of the 2021-2025 period.

Table 7 outlines how fleet capital expenditures in 2016-2020 are set to fall below historical levels. The table also shows the increase in the upcoming 2021-2025 rate period in order to catch-up on asset replacement and maintain an appropriate level of fleet condition. Efforts were made to smooth the associated replacement expenditures to the extent possible, while still being mindful of replacement criteria, safety, environmental impacts, and reliability.

Table 7 – Comparison of Fleet Capital Expenditures from Previous Five-Year Rate Periods to Proposed 2021-2025 Replacement ($'000s)

	2011-2015 Actual Capital Expenditures	2016-2020 Actual / Projected Capital Expenditures	2021-2025 Proposed Capital Expenditures
TOTAL	**$10,048**	**$7,613**	**$16,780**

It is important to note that the number of vehicles being replaced in the 2021-2025 period will be the same as the number removed, meaning there will be no net growth in fleet vehicle assets. However, unit replacement costs are higher due to automotive/truck sector cost escalations. With respect to the annual trend in expenditures, 2021 has a higher level of capital expenditures on vehicle replacement than average due to the need to urgently replace critical assets. Many of these assets are significantly beyond their expected life and replacement has already been delayed. However, it is no longer possible to delay any further.

Of Hydro Ottawa's current fleet of 278 vehicles and equipment, 250 (90%) will be at or beyond their replacement criteria age in the 2021-2025 period. Of these 250 unis, 112 (45%) are planned to be replaced. An additional four vehicles (for a total of 116) that do not meet the replacement age criteria are also planned to be replaced for reasons such as engine hours and kilometers exceeding replacement criteria levels, vehicle damage, and poor operating condition.

These four units are specifically identified and discussed in this section under Medium Duty Vehicles (Units #1013 and #1014) and Heavy Duty Vehicles (Units #1201 and #1202).

The following sub-section provides details on planned capital expenditures by year and by vehicle type. Vehicle purchases are made in accordance with standard Hydro Ottawa procurement policies and procedures (see Attachment 4-2-2(A): Procurement Policy).

4.1. LIGHT DUTY VEHICLES PLANNED FOR REPLACEMENT IN 2021-2025

Based on an assessment following the methodology outlined in section 2 above, 77 Light Duty vehicles are planned for replacement over the 2021-2025 period, as summarized in Table 8.

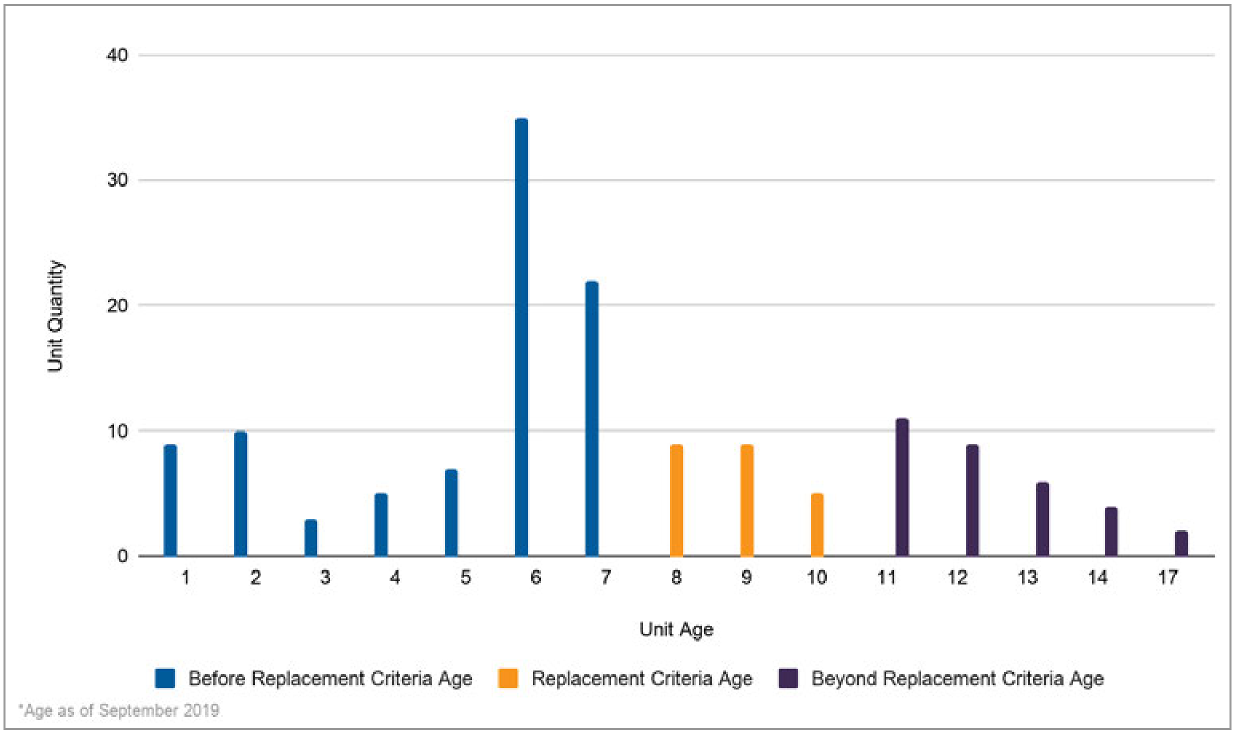
Table 8 – Light Duty Vehicles Planned for Replacement in 2021-2025 ($'000s)

	2021	2022	2023	2024	2025	Total
# Units	26	17	17	17	0	77
Capital Expenditure	$1,319	$1,130	$932	$910	$0	$4,291

All of the light duty vehicles identified will exceed the replacement criteria ages noted in Table 2 above and are either in poor condition or expected to be in poor condition by the time the replacement year arrives.

Figure 2 below indicates the age distribution of Light Duty vehicles and the number beyond their replacement criteria age, as of September 2019.

Figure 2 – Age of Light Duty Fleet Assets



4.2. MEDIUM DUTY VEHICLES PLANNED FOR REPLACEMENT IN 2021-2025

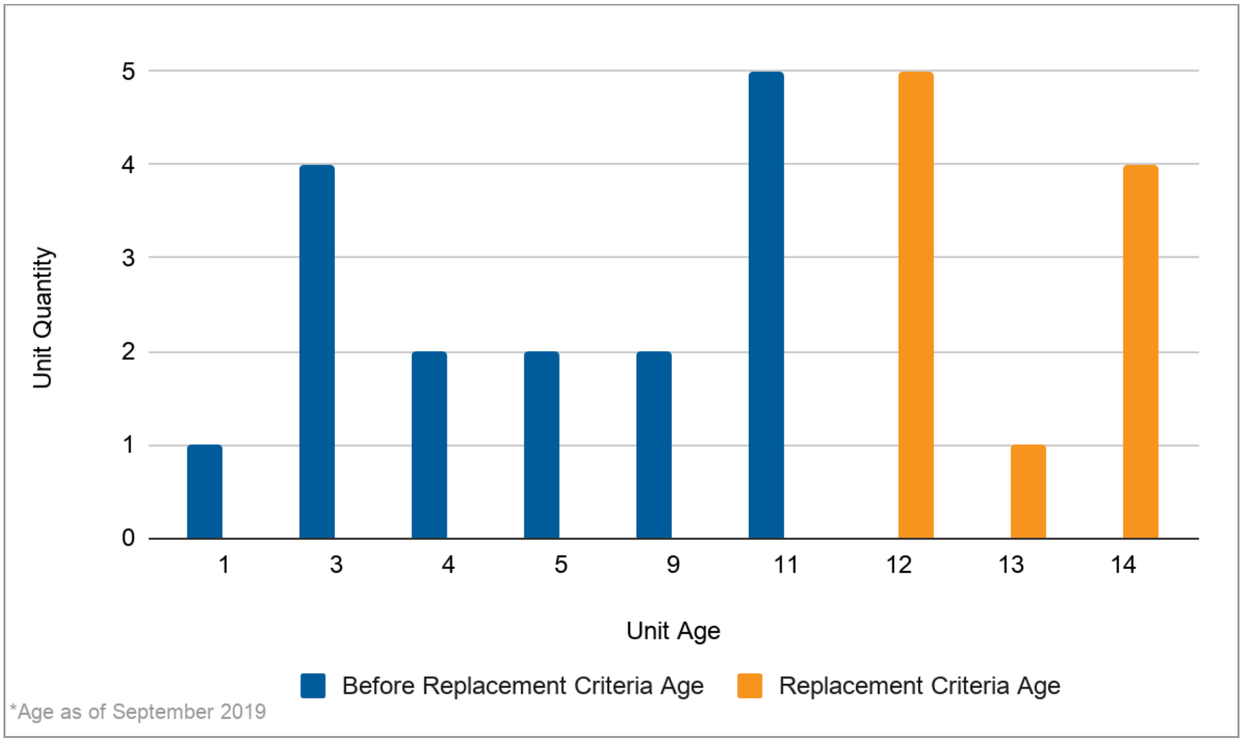
Table 9 summarizes the plan for replacement of Medium Duty vehicles over the upcoming five-year rate term.

Table 9 – Medium Duty Vehicles Planned for Replacement in 2021-2025 ($'000s)

	2021	2022	2023	2024	2025	Total
# Units	9	5	0	0	0	14
Capital Expenditure	$1,671	$797	$0	$0	$0	$2,468

Figure 3 below indicates the age distribution of Medium Duty vehicles. As of September 30, 2019, all vehicles are within the replacement age criteria. However, over the 2021-2025 period, 15 vehicles will exceed this range.

Figure 3 – Age of Medium Duty Fleet Assets



A significant portion of the Medium Duty vehicle replacement plan is due to operational and reliability issues with a specific type of van – the “Workhorse Step Van.” These vehicles are at, or will be, beyond their useful life during the 2021-2025 rate term and further maintenance is difficult due to the lack of available parts. Due to the poor performance history of the Workhorse Step Vans, the replacement plan is to change the vehicle manufacturer from Workhorse to Freightliner for the cab and chassis. This will reduce maintenance and downtime because of improved accessibility to parts and materials. The change to Freightliner vehicles is the main reason for the two-year increase in replacement age criteria for this category, as shown in Table 2 above. The Freightliner vehicles are expected to have a longer service life on account of more robust diesel engines, frames, braking, suspension, transmission, and powertrain. They are also designed for higher mileage. The Workhorse Step Van replacements identified below use the new 12-year age for Freightliner Step Vans as the useful life comparison. However, if the previous planned Workhorse Step Van 10-year useful life was used, two years should be added to the information pertaining to beyond useful life.

Table 10 below outlines planned replacement of medium duty vehicles in 2021.

1 **Table 10 – Medium Duty Vehicle Planned Replacements in 2021**

Vehicle	Unit #	Year Acquired	Details and Rationale for Replacement
Step/Cube Van	2612	2006	• In 2021, will be three years beyond its useful life • Workhorse Step Van with a hybrid battery system - parts are becoming obsolete • Repair costs and associated downtime is increasing beyond acceptable levels
Step/Cube Van	2720	2008	• In 2021, will be one year beyond its useful life • Forecasted engine hours are expected to exceed the standard life cycle amount by close to 2,000 hours • Workhorse Step Van - parts are becoming obsolete • Repair costs and associated downtime is increasing beyond acceptable levels
Step/Cube Van	2715	2008	• In 2021, will be one year beyond its useful life • Forecasted engine hours are expected to exceed the lifecycle amount by close to 2,000 hours • Workhorse Step Van - parts are becoming obsolete • Repair costs and associated downtime is increasing beyond acceptable levels
Step/Cube Van	2717	2008	• In 2021, will be one year beyond its useful life • Workhorse Step Van - parts are becoming obsolete • Repair costs and associated downtime is increasing beyond acceptable levels
Step/Cube Van	2902	2009	• In 2021, will be at the end of its useful life • Workhorse Step Van - parts are becoming obsolete • Repair costs and associated downtime is increasing beyond acceptable levels
Step/Cube Van	2818	2009	• In 2021, will be at the end of its useful life • Workhorse Step Van - parts are becoming obsolete • Repair costs and associated downtime is increasing beyond acceptable levels
Step/Cube Van	2823	2009	• In 2021, will be at the end of its useful life • Workhorse Step Van - parts are becoming obsolete • Repair costs and associated downtime is increasing beyond acceptable levels.
Step/Cube Van	2821	2009	• In 2021, will be at the end of its useful life • Workhorse Step Van - parts are becoming obsolete • Repair costs and associated downtime is increasing beyond acceptable levels.
Step/Cube Van	2817	2009	• In 2021, will be at the end of its useful life • Workhorse Step Van - parts are becoming obsolete • Repair costs and associated downtime is increasing beyond acceptable levels

Table 11 outlines planned replacements of medium duty vehicles in 2022.

Table 11 – Medium Duty Vehicle Planned Replacements in 2022

Vehicle	Unit #	Year Acquired	Details and Rationale for Replacement
Step/Cube Van	2604	2006	• In 2022, will be four years beyond its useful life • Workhorse Step Van - parts are becoming difficult to source in Canada, which is leading to unacceptable downtime - some parts are already not available
Step/Cube Van	2639	2006	• In 2022, will be four years beyond its useful life • Workhorse Step Van - parts are becoming difficult to source in Canada, which is leading to unacceptable downtime - some parts are already not available
Step/Cube Van	2713	2008	• In 2022, will be two years beyond its useful life • Forecasted engine hours are expected to exceed the lifecycle amount by over 3,000 hours, which for this style is significantly above expectations • Workhorse Step Van - parts are becoming difficult to source in Canada, which is leading to unacceptable downtime - some parts are already not available
Dump Truck	1014	2011	• In 2022, will be one year earlier than its intended useful life • Multi-user vehicle and primarily operates in rough terrain and on construction sites for filling pole holes with compaction materials • Suspension and body damage on this unit • Expected to be in very poor condition by 2022
Dump Truck	1013	2011	• In 2022, will be one year earlier than its intended useful life • Multi-user vehicle and primarily used in rough terrain and on construction sites for filling pole holes with compaction materials • Suspension and body damage on this unit • Expected to be in very poor condition by 2022

4.3. HEAVY DUTY VEHICLES PLANNED FOR REPLACEMENT IN 2021-2025

Table 12 summarizes the plan for replacement of Heavy Duty vehicles during the upcoming five-year rate term.

Table 12 – Heavy Duty Vehicles Planned for Replacement in 2021-2025 ($'000s)

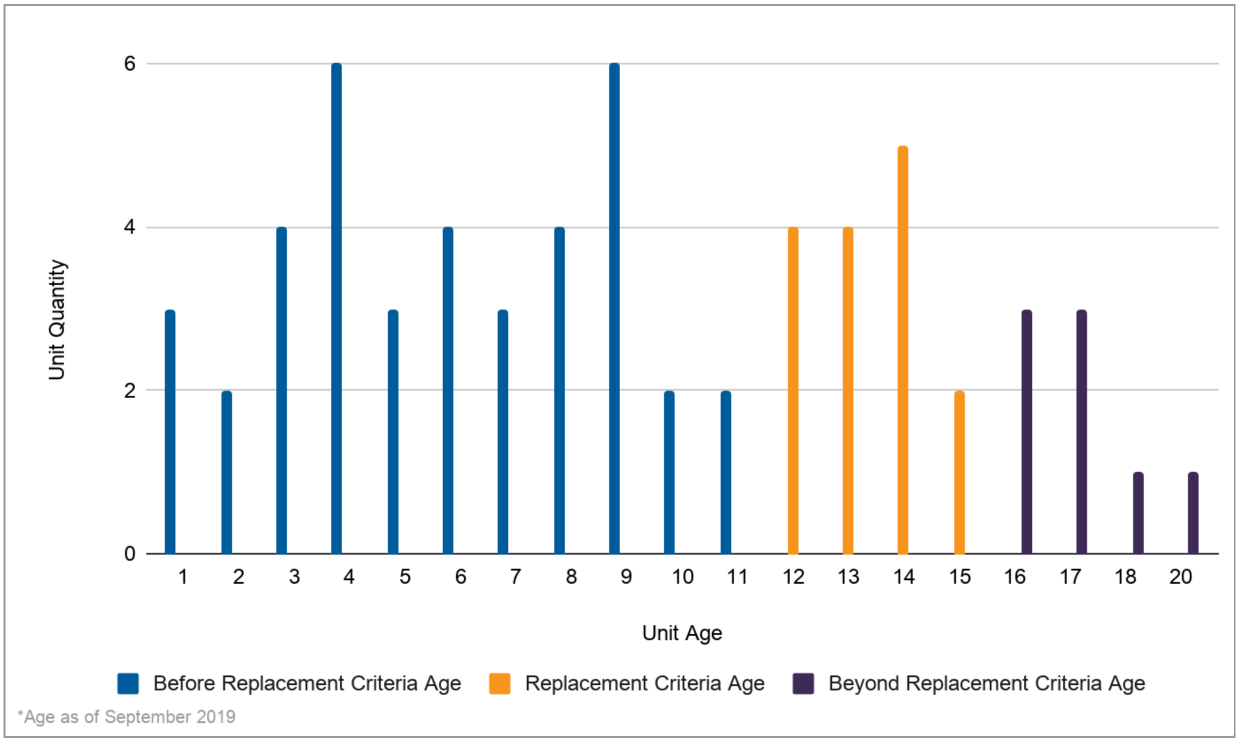
	2021	2022	2023	2024	2025	Total
# Units	8	8	3	2	2	23
Capital Expenditure	$3,191	$2,599	$1,173	$771	$2,008	$9,742

It should be noted that for equipment such as Heavy Duty Vehicles which have longer order lead times there is often a need to provide vehicle chassis deposits and make progress payments at certain stages in the unit build. These payments are recorded as capital expenditures in the year made, whereas the number of units replaced reflects the year of vehicle delivery and capitalization.

Figure 4 below indicates the age distribution of Heavy Duty vehicles and the number beyond their replacement criteria age, as of September 2019.

1 **Figure 4 – Age of Heavy Duty Fleet Assets**

2



3

4 Table 13 outlines planned replacements of heavy duty vehicles in 2021.

5

1 **Table 13 – Heavy Duty Vehicle Planned Replacements in 2021**

Vehicle	Unit #	Year Acquired	Details and Rationale for Replacement
Medium-sized Bucket Truck	2403	2004	• In 2021, will be five years beyond its intended useful life • Engine hours are forecasted to exceed the 10,000 hours replacement criteria in Table 2 above by almost 4,000 hours • With both age and engine hours exceeding thresholds, this unit presents potential stability concerns and thus requires replacement in 2021
Large Bucket Truck with Jib Winch	2531	2006	• In 2021, will be three years beyond its intended useful life • Unit's underside is starting to flake, the boom has been refurbished once, the sub-frame is cracking and has been welded, and hydraulics are slow • Overall, the vehicle requires significant downtime for repairs since many parts are not available in Canada • The boom/bucket structure is an Amador model built in 1987 and refurbished in 2005 - Amador has been out of business for close to 15 years - as a result, parts are increasingly difficult to find
Large RBD Line Truck	2610	2007	• In 2021, will be two years beyond its intended useful life • Engine hours are forecasted to exceed the 10,000 hours replacement criteria in Table 2 above by over 3,000 hours • The boom is showing signs of wear and approaching outer limits of acceptability • Boom aerial inspections are becoming difficult to pass
Large Bucket Truck	2613	2007	• In 2021, will be two years beyond its intended useful life • Engine hours are forecasted to exceed the 10,000 hours replacement criteria by 3,000 hours • The boom and hydraulic pressures have been running on outer limits • Boom aerial inspections are becoming difficult to pass
Medium/Small RBD Line Truck	2705	2008	• In 2021 will be one year beyond its intended useful life • Unit is in poor condition, the deck floor will need major work to keep safe, and repairs to keep this unit on the road continue to escalate
Medium Bucket Truck	2803	2008	• In 2021, will be on year beyond its intended useful life • Engine hours are forecasted to exceed the 10,000 hours replacement criteria by over 3,500 hours • There have been increasing costs on this unit in recent years to repair the emissions system and additional maintenance work is still required • The boom is in poor condition and guards require replacement once again • Aerial inspections are becoming difficult to pass
Large Bucket Truck	2609	2007	• In 2021, will be two years beyond its intended useful life • Engine hours are forecasted to exceed the 10,000 hours replacement criteria by close to 3,000 hours • The boom is showing signs of deterioration • High repair costs
Small Bucket Truck	1201	2012	• In 2021, will be three years before its intended useful life • Total kilometres are forecasted to exceed the 200,000km replacement criteria by over 10,000km • Engine hours are forecasted to exceed the 10,000 hours replacement criteria by 2,000 hours • The boom has reliability problems and a high number of breakdowns • This is a 24/7 usage vehicle, and it is not unusual that km and engine hours exceed the replacement criteria ahead of the age criteria

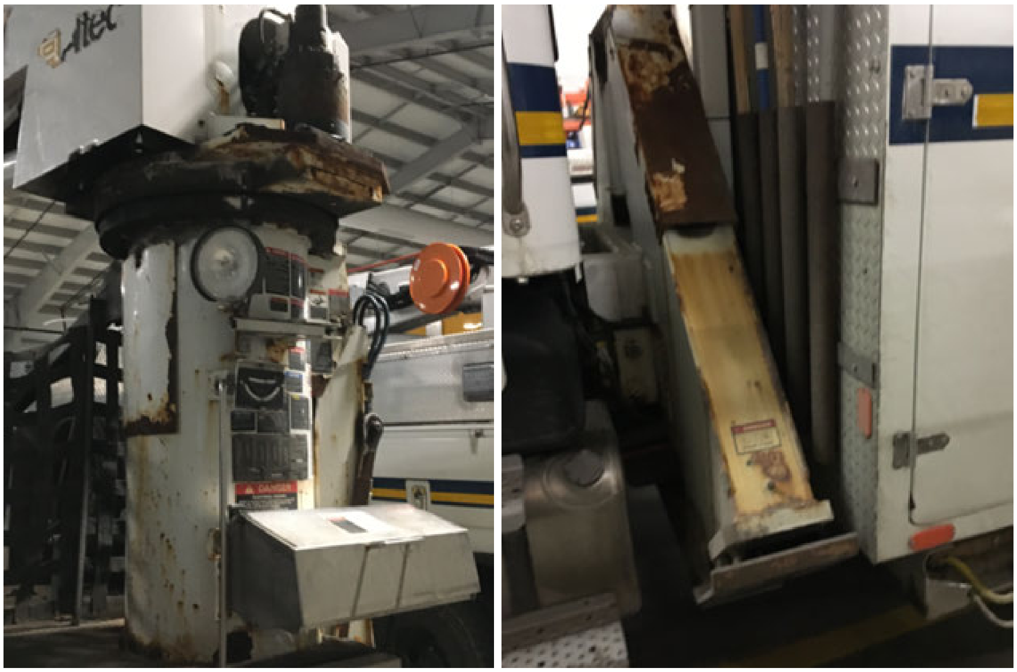
Figure 5 – Unit #2403 with Outrigger Structural Deterioration

Table 14 below outlines planned replacement of heavy duty vehicles in 2022.

Table 14 – Heavy Duty Vehicle Planned Replacements in 2022

Vehicle	Unit #	Year Acquired	Details and Rationale for Replacement
Large RBD Line Truck	2532	2005	• In 2022, will be five years beyond its intended useful life • Standard transmission is problematic in a multi-user environment • Boom capacity is a problem for lifting in rural areas, while the truck generally too large to service the downtown core
Large Bucket Truck	2605	2006	• In 2022, will be four years beyond its intended useful life • Engine hours are forecasted to exceed the 10,000 hours replacement criteria by 2500 hours • Boom tip is showing rust deterioration and structural weakening • Rising repair costs
Medium bucket Truck	2706	2008	• In 2022, will be two years beyond its intended useful life • Engine hours are forecasted to exceed the 10,000 hour replacement criteria by 4,400 hours • Boom limits are becoming excessive for inspection sign-off • Rising repair costs
Large Bucket Truck with Bare Hand Jib Winch	2901	2009	• In 2022, will be one year beyond its intended useful life • Unit has high repair costs and extremely long downtime, as some parts need to be manufactured based on original engineered drawings • Repair welding of outrigger frames and elevator gussets has been performed • Boom/bucket structure is an Amador model built in 1994 and refurbished in 2009 - Amador has been out of business for close to 15 years - as a result, parts are difficult to obtain
Large Bucket Truck	2815	2009	• In 2022, will be one year beyond its intended useful life • Engine hours are forecasted to exceed the 10,000 hours replacement criteria by 3,000 hours • Wear and tear on the truck and boom • Emission system is nearing its replacement interval • Rising repair costs
Large RBD Line Truck	2911	2010	• In 2022, will be in line with its intended useful life • Unit does not meet current business needs • Low capacity digger that cannot meet lifting expectations - there is no further ability to increase lift capacity without exceeding safety limits
Medium-sized Bucket Truck	1105	2010	• In 2022, will be in line with its intended useful life • Hybrid unit - hybrid repairs become difficult to manage when the unit is kept beyond its useful life due to the advancements in technology • Boom will require boom tip guard replacement in the near future
Small Bucket Truck	1202	2012	• In 2022, will be two years before its intended useful life • Engine hours are forecasted to exceed the 10,000 hours replacement criteria by 2,000 hours • Emission-related repairs have been high • Being a 24/7 vehicle, it is not unusual that total kilometres and engine hours exceed the replacement criteria ahead of age criteria

Figure 6 – Unit #2532 with Outrigger Structural Deterioration and Pedestal Corrosion[4]



[4] The deficiencies captured in this picture present potential stability and safety concerns.

Figure 7 – Unit #2605 with Rust Deterioration on Boom

Table 15 outlines planned replacements of heavy duty vehicles in 2023.

Table 15 – Heavy Duty Vehicle Planned Replacements in 2023

Vehicle	Unit #	Year Acquired	Details and Rationale for Replacement
Medium/Small RBD Line Truck	1010	2011	• In 2023, will be in line with its intended useful life • Unit does not meet current and anticipated business needs due to limited lifting capacity
Large Bucket Truck with Bare Hand Jib Winch	1008	2011	• In 2023, will be in line with its intended useful life • Unit has high repair costs and extremely long downtime, as some parts are manufactured based on original engineered drawings • Parts are becoming scarce or obsolete • Boom/bucket structure is an Amador model built in 1995 and refurbished in 2010 - Amador has been out of business for close to 15 years - as a result, parts are difficult to find • This is Hydro Ottawa's only fiber-optic controlled boom and it will no longer be supported by the vendor
Large Bucket Truck	1012	2011	• In 2023, will be in line with its intended useful life • Boom and hydraulic pressures have been running on outer limits • Boom aerial inspections are becoming difficult to pass • Rising repair costs

Table 16 outlines planned replacements of heavy duty vehicles in 2024.

Table 16 – Heavy Duty Vehicle Planned Replacements in 2024

Vehicle	Unit #	Year Acquired	Details and Rationale for Replacement
Medium/Small RBD Line Truck	1011	2011	• In 2024, will be one year beyond its intended useful life • Unit was specified for multi-use pooling, however, not all functions are used regularly, with some functions having become inoperative and seized from underuse • Replacement vehicle will have functionality in line with business needs
Large RBD Line Truck	1009	2011	• In 2024, will be one year beyond its intended useful life • Unit does not meet anticipated business needs due to limited lifting capacity

Table 17 outlines planned replacements of heavy duty vehicles in 2025.

Table 17 – Heavy Duty Vehicle Planned Replacements in 2025

Vehicle	Unit #	Year Acquired	Details and Rationale for Replacement
Flatbed Truck with Crane	2201	2002	• In 2025, will be eight years beyond its intended useful life • Unit is expected to be in extremely poor condition by 2025 • With respect to the crane portion of this unit, parts will be difficult to source on account of the unit's age (i.e. 20+ years)
Large Bucket Truck	1210	2013	• In 2025, will be in line with its intended useful life • Deteriorating state of the boom, vehicle age, rising repair costs

4.4. OTHER UNITS AND EQUIPMENT PLANNED FOR REPLACEMENT IN 2021-2025

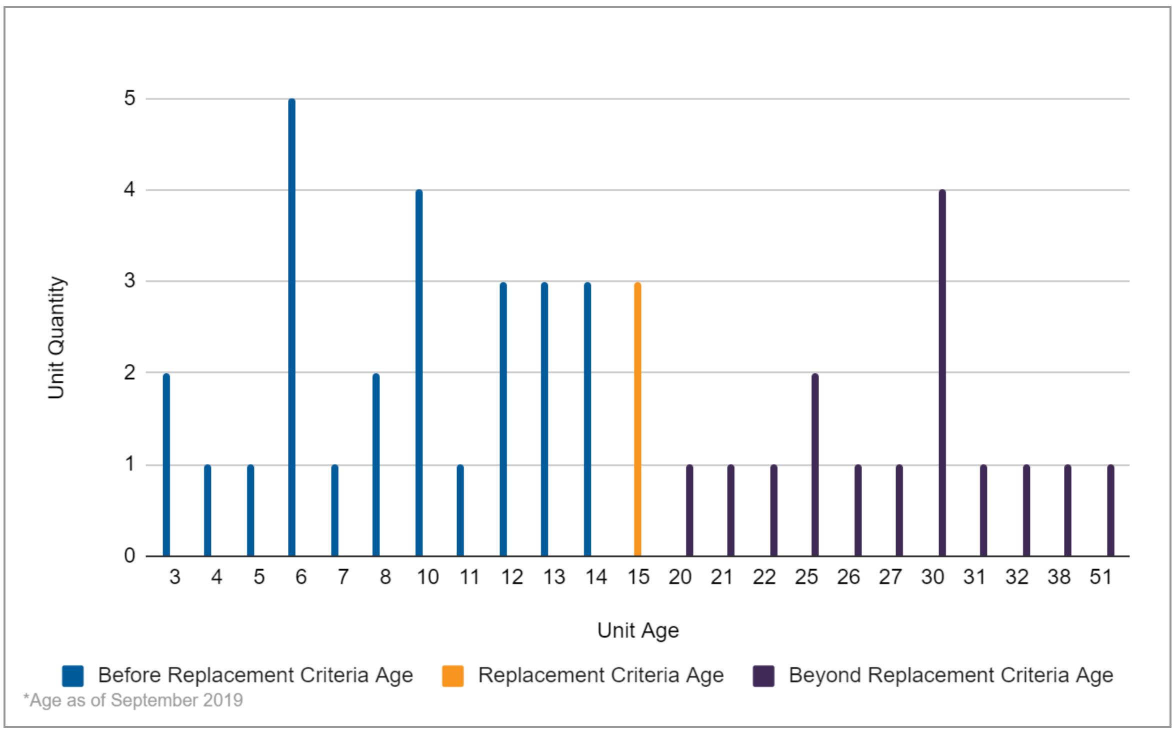
Table 18 summarizes the plan for replacement of other vehicles during the upcoming five-year rate term.

Table 18 – Other Units and Equipment Planned for Replacement in 2021-2025 ($'000s)

	2021	2022	2023	2024	2025	Total
# Units	1	0	1	0	0	2
Capital Expenditure	$164	$0	$115	$0	$0	$279

Figure 8 below indicates the age distribution of other units and equipment and the number beyond their replacement criteria age, as of September 2019.

Figure 8 – Age of Other Fleet Assets



The following other units and equipment are planned for replacement during the 2021-2025 rate term:

Table 19 – Other Units and Equipment: 2021-2025 Planned Replacements

Equipment	Unit #	Year Acquired	Detail and Rationale for Replacement
Forklift	8878	1988	• Proposed replacement in 2021, which will render it 33 years old at that time and 18 years beyond its planned replacement age • Life of this forklift continues to be extended, however there are increasing reliability and maintenance issues
Line Tensioner	9586 T-12	1990	• Proposed replacement in 2023, which will render it 33 years old at the time of replacement and 18 years beyond planned replacement age • The life of this equipment continues to be extended, however there are increasing reliability and maintenance issues

5. VEHICLE PROCUREMENT

Hydro Ottawa's vehicle procurement process is based on the utility's Procurement Policy (see Attachment 4-2-2(A): Procurement Policy).

Once vehicle capital replacement needs are established, an open tender is issued through the Procurement group. Hydro Ottawa is not tied to any particular supplier, which provides the utility with market flexibility and the opportunity to secure the most favourable pricing and terms. Furthermore, the development of standard fleet specifications by job profile for eight vehicle models has allowed for a more efficient procurement process and resulting fleet uniformity. These standards include, but are not limited to, lifting capacity, cab design, turning radius, jib configuration, boom height, and boom reach.

Some vehicles have long procurement lead times of up to 18 months. Lead times vary by type of vehicle due to the vehicle demand and potential issues in obtaining the necessary specifications for these vehicles.

A risk associated with long lead time is that the condition of current vehicles can deteriorate within the waiting period for the new vehicles. This, along with accidents and unexpected breakdowns, may impact Hydro Ottawa's ability to meet work program requirements. This risk is pro-actively managed through the lifecycle replacement strategy, which factors in vehicle lead time as part of the replacement timing.

Approximate lead times for vehicle procurement are presented in Table 20 below.

Table 20 – Average Vehicle Lead Time

Vehicle Class	Approximate Order Lead TIme
Light Duty Vehicles	Less than 6 months
Medium Duty Vehicles	11 - 12 months
Heavy Duty Vehicles	18 months or more
Other	Less than 6 months

Hydro Ottawa also considers environmental implications in the procurement process. Decisions are influenced by factors such as fuel efficiency and versatility. A versatility example includes year-round tires that save maintenance, down-time, and cost.

6. COMPARISON WITH OTHER LDCs

In order to provide a general indication of the size and age of Hydro Ottawa's fleet in comparison with other local distribution companies ("LDCs"), this section provides a comparison with Alectra Utilities Inc. ("Alectra") and Toronto Hydro-Electric System Limited ("THESL"), which have also sought approval for fleet capital through the Custom IR process. Comparative information was drawn from publicly available information in the OEB's annual *Yearbook of Electricity Distributors* ("yearbook"), and also from information filed in recent rate application proceedings involving the respective LDCs.[5]

[5] Alectra Utilities Inc., *2020 Electricity Distribution Rate Application*, EB-2019-0018 (May 28, 2019); Toronto Hydro-Electric System Limited, *2020-2024 Custom Incentive Rate-setting Distribution Rate Application*, EB-2018-0165 (August 15, 2018).

Information to fully benchmark fleet metrics across LDCs was not available and it is thus recognized that the following information, while it may be generally indicative, does not constitute a comprehensive benchmarking analysis. Rather, it is intended to provide a general indication that Hydro Ottawa's fleet size and replacement practices are in a reasonable range when compared to the utility's large municipally-owned LDC peers in Ontario.

On balance, Hydro Ottawa's fleet size compares favourably to Alectra and THESL, as shown in Tables 21, 22, and 23 below.

Table 21 – Comparative Fleet Metrics: Hydro Ottawa vs. Alectra & THESL

Fleet Metrics	Alectra	THESL	Hydro Ottawa
# of Customers per Sq. km. of Service Area	542	1,226	300
% of Vehicles Proposed for Replacement Over Applicable Distribution Rate Period (excluding Other)	51%	54%	49%
# vehicles per 1,000 Customers	1.71	1.58	1.43
# Total Service Area km. served per vehicle	3.16	1.29	4.77
% of Transportation Equipment Depreciated (USofA #1930)	n/a	69%	87%

The following observations can be derived from the foregoing comparative fleet metrics:

- Hydro Ottawa's customers are more dispersed than those of its comparators (i.e. the utility must travel further to serve customers).
- Hydro Ottawa has requested a slightly lower level of fleet replacement than its comparators did in their respective rate proceedings (49%).
- Hydro Ottawa has fewer vehicles to serve customers than its comparators do (1.43 per 1,000 customers).
- Hydro Ottawa has more service territory to cover for OM&A and Capital work that must be supported by Fleet (4.77 km per vehicle).

- Hydro Ottawa's fleet has depreciated more (i.e. is older) than that of THESL (87% depreciation).

With respect to the average age of vehicles in Table 22 below, Hydro Ottawa's Medium Duty and Light Duty vehicles have a higher average age than both those of Toronto Hydro and the peer group consisting of LDCs in the OEB's yearbook. Hydro Ottawa Light Duty vehicles have a higher average age (7.0 years) than those belonging to THESL, and a lower average age than that of the LDC peer group. However, it should be noted that the optimal average age of a pool of Light Duty vehicles is five years, as per Figure 1 above.

Table 22 – Average Age of Vehicles (# of Years)

Vehicle Category	THESL	Ontario MEU Peer Group	Hydro Ottawa
Light Duty	5.8	7.6	7
Medium Duty	6.1	5.8	9
Heavy Duty	7.6	7.1	9
Other (Trailer, Forklift, etc…)	11.8	n/a	16

Table 23 compares Hydro Ottawa's replacement age criteria to those of THESL and Alectra, based on information from their recent rate filings. Of note, the range of replacement ages based on technical and operating assessments is consistent amongst the three LDCs. An exception is in the "Other" category, which consists primarily of Trailers. Hydro Ottawa is experiencing a longer than planned replacement age for these assets (see Figure 6 above for details).

Table 23 – Comparison of LDC Fleet Replacement Age Criteria

Vehicle Category	Hydro Ottawa # Years	THESL # Years	Alectra # Years
Light Duty	8-10	7-10	7-10
Medium Duty	12-15	8-15	10-12
Heavy Duty	12-15	10-16	10-15
Other (e.g Trailers)	15	20	15

The above comparative information is provided as a “reasonableness check” and indicator that the vehicle replacement requested by Hydro Ottawa is not out of step with the approaches utilized by other LDCs or with industry norms. Hydro Ottawa acknowledges that these comparisons are limited due to the lack of available information and are not definitive on a standalone basis. Nevertheless, Hydro Ottawa believes that a sufficient basis exists for this information to be taken into consideration as part of the overall evidence provided in this Attachment.

7. FLEET MAINTENANCE PROGRAM

Hydro Ottawa operates a repair centre to maintain a large majority of its fleet. Preventative scheduled maintenance on the entire fleet is conducted on a regular basis. Maintenance schedules are implemented per manufacturer recommendations, unless Fleet determines the usage pattern (heavy or light) warrants a different maintenance schedule.

Hydro Ottawa regularly inspects aerial equipment on a six-month basis. In addition, the utility monitors mileage and engine hours, which may trigger an earlier inspection. On Light Duty equipment, Hydro Ottawa performs regular scheduled maintenance every six months or 6,000 km.

Hydro Ottawa provides extensive training to staff technicians in order to achieve the qualifications necessary to sign\-off on inspection documents related to the safe operation of aerial units in proximity of high voltage power lines.

The utility uses high quality synthetic oils allowing vehicle service intervals to be extended to semi-annual compared to the previous quarterly intervals. This results in reduced impact on the environment and fewer trips to the garage for service.

Hydro Ottawa continuously works on ways and methods to extend the useful lives of vehicles. As an example, Fleet is currently extending manufacturer undercoating by reapplying every two years with model dates of 2013 and beyond.

7.1. FLEET MANAGEMENT SYSTEM

In order to increase fleet efficiencies, Hydro Ottawa purchased a fleet management software system, FleetWave. FleetWave is a web-based enterprise fleet management software solution. It provides comprehensive fleet management for the utility's fleet operations, including the following:

- Asset Tracking and Management including Capital Replacement Planning;
- Preventative Maintenance Scheduling;
- Workshop Management (Workflow Planning, Scheduling, Job Assignment);
- Work Order Management;
- Warranty, Recalls & Campaigns;
- Operating Cost Management (Fuel, Licences, Permits, etc.);
- Inventory Management (parts supply system);
- Risk Management (MVA, Safety, Ministry of Transportation Compliance, Records, etc.); and
- Technician Records and Training Plan.

Hydro Ottawa's FleetWave system keeps an up-to-date record of previous vehicle maintenance, as well as future maintenance appointments. FleetWave provides notification of vehicles that require maintenance in the next 30, 60, and 90 days. This provides Fleet and the operators the opportunity to schedule work accordingly. In turn, this helps to ensure that Hydro Ottawa is efficient with repairs, resulting in improved vehicle performance and decreased vehicle down time.

A recent improvement to FleetWave was an integration with GeoTab (see section below for details). This communication between systems allows for a more efficient and proactive approach to maintenance. GeoTab communicates real-time kilometer and engine hours to FleetWave to help ensure maintenance is completed within the specified mileage parameters. Drivers can also record defects in GeoTab which can be transmitted directly to a repair list in FleetWave, so that they are in queue waiting for the next scheduled repair.

FleetWave provides up to date and accurate information on kilometers, PTO hours and engine hours to help effectively manage maintenance schedules.

7.2. GEOTAB

Hydro Ottawa uses a Global Positioning System ("GPS") tracking system called GeoTab. Besides providing vehicle location in real-time, the system also collects data while the vehicle is running.This data includes routes, idling time, kilometers traveled, excessive accelerating/braking, speeding, and operation information.

The benefits of the GeoTab system include the following:

- Tracking vehicle idle time
- Monitoring vehicle utilization
- Recording garage downtime
- Tracking repair time
- Dashboard tracking of fleet statistics for management
- Accident review and reconstruction
- Monitoring driver behaviour
- Obtaining information on engine faults in real-time

The GeoTab system is new and gaining traction to monitor, track, and improve vehicle utilization and idle time. The system also provides information on how a vehicle is being used on the road, which helps to improve driver performance and reduce the wear and tear on the vehicle. Fleet and operations are currently looking to create driver scorecards from GeoTab to view and promote positive driver behaviour. This dashboard can highlight items such as excessive idling, harsh acceleration, harsh cornering, harsh braking, speeding, and seatbelt use. The driver scorecard will help reduce risk and improve fuel economy and public safety.

8. UTILIZATION

Hydro Ottawa intends to leverage the Geotab GPS units in each of the vehicles to analyze the utilization of all types and classes of vehicles to identify opportunities to rationalize, where appropriate. Utilization statistics are difficult to develop as many different factors have to be considered, such as 24/7 operations vs. daily operations, trucks with low kilometres but with high boom hours, and transport of crews and materials to job sites. Many trucking companies use km driven as the primary utilization statistic. However, Hydro Ottawa's operations are not directly comparable.

Hydro Ottawa recently moved to new facilities at 2711 Hunt Club Rd. and 201 Dibblee Rd., consolidating various departments into centralized locations.[6] With the new operation centres, Hydro Ottawa is able to be more strategic with the location of fleet vehicles in relation to the work being performed and there is reduced travel time being logged to and from job sites.

Each vehicle is associated with a particular group or position. The intention is to improve utilization of specialized construction vehicles through sharing of those resources amongst work groups. The initiative will also include an analysis of the usage patterns of pick-ups, vans, and cars to determine where low-utilization vehicles can be removed from service or re-deployed to replace older vehicles in the fleet that may have higher maintenance and operational costs. The

[6] For additional information on these facilities, please see Attachment 2-1-1(A): New Administrative Office and Operations Facilities.

utility's current objective is a reduction of at least six vehicles, representing approximately 2% of the fleet.

9. INNOVATIONS

Hydro Ottawa has embraced a culture of change within the workplace, focusing on investing and leveraging new technologies for the fleet. A few examples of such technologies are listed below.

9.1. MINI BUCKET TRUCKS, DIGGERS AND MATERIAL CARRIERS

Hydro Ottawa has successfully implemented the use of "backyard" bucket trucks. Track-mounted and designed for work in narrow, difficult-to-access areas such as residential backyards, these miniature units make digging, setting utility poles, restoring power, and maintaining power lines both safer and more efficient. This is all achieved while not causing damage to the homeowner's landscape. Photographs of these vehicles are provided in Figure 9.

Figure 9 – Track Machines

(From Left to Right: Mini-Bucket, Digger, and Material Carrier)

9.2. 60 Foot Elevator Trucks

Elevator trucks are extended reach bucket trucks that have enabled Hydro Ottawa's Power Line Technicians to utilize a regular sized truck to reach heights/lengths that would normally require a larger truck to complete the work. The normal 60 ft boom is attached to an elevator. For regular height work, the boom operates no differently than others. However, when extended reach or heights are required, the elevator portion raises the entire boom to allow for a 70 ft working height. Figure 10 shows this truck in operation.

Figure 10 – 60 Foot Elevator Trucks

9.3. MOBILE OFFICE VEHICLES

Mobile office vehicles allow employees to continue working when they are on the road and to make fewer return trips to the office. This increases employee efficiency and helps Hydro Ottawa to save fuel and to respond to more customers in a more timely manner. Figure 11 below illustrates the interior of a mobile office.

Figure 11 – Mobile Office Vehicle Interior

10. GREENING THE FLEET

Hydro Ottawa believes in social responsibility and values environmental consciousness.

There is currently low market availability of hybrid vehicles. However, Hydro Ottawa keeps up to date on possible hybrid options for lighter vehicles such as pick-up trucks. The utility's fleet currently contains the following low-emitting or non-emitting vehicles and equipment:

- 2 Chevy Volts
- 2 Hybrid cars
- 1 Hybrid bucket truck
- 17-20 devices with battery technology
- 14 flex-fuel vehicles
- 10 aerial devices converted to biopure biodegradable oil (i..e. non-toxic and metal free)

Hydro Ottawa is committed to the acquisition of vehicles with hybrid technology where there is an operational and financial business case for doing so.

Auxiliary hybrid units have been installed to run all accessories, except for air conditioning, using an inverter and auxiliary batteries. It is no longer necessary for a vehicle to be kept running at a job site, thus reducing idling time and saving fuel. The batteries charge when the vehicle is on the road and when plugged in at night.

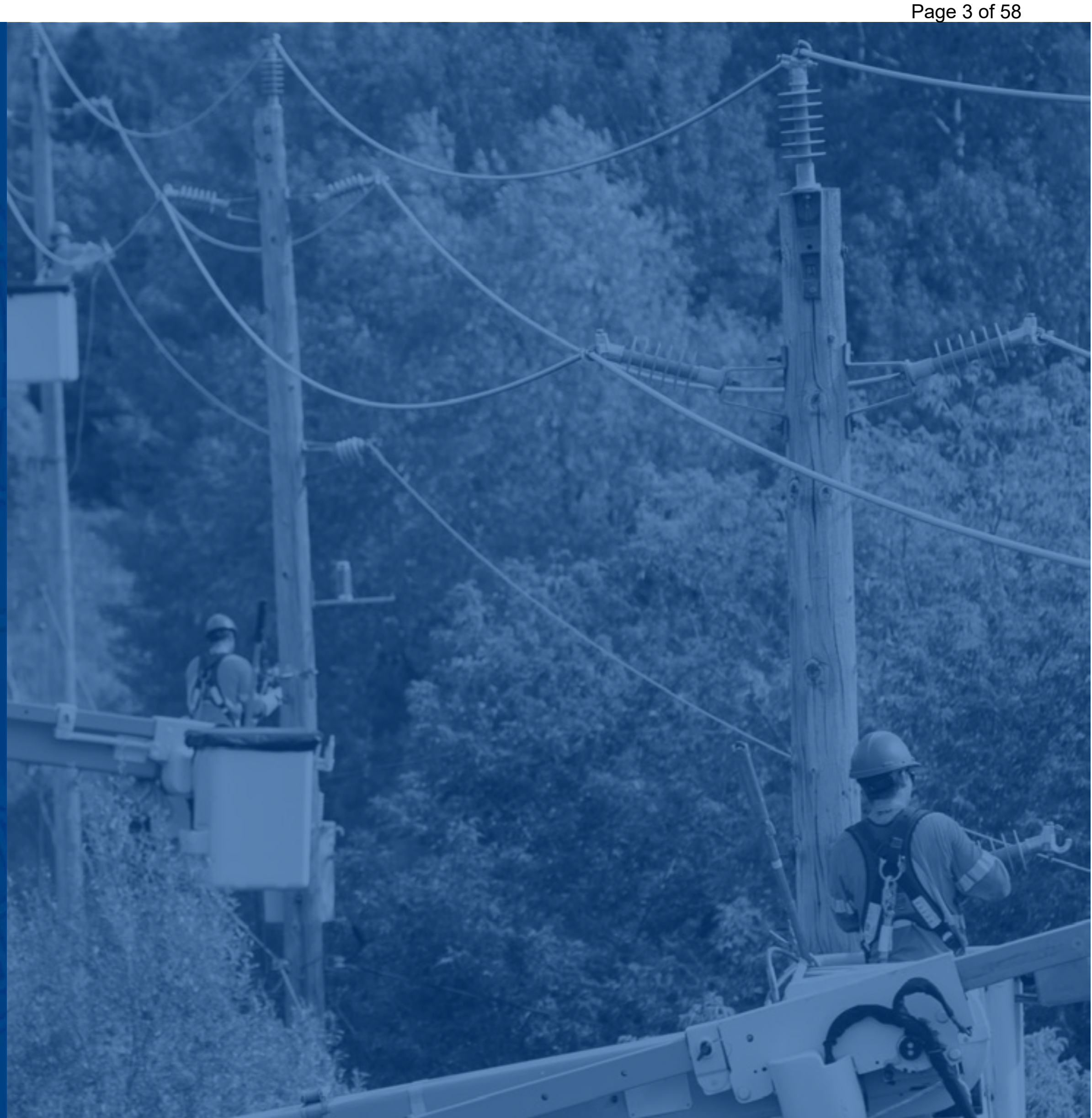
	TITLE:	
	Specification	
RECOMMENDED: **S. Hawthorne, P.Eng.**	NO:	REV:
APPROVED: **G. Paradis, P.Eng.**	**IAS0003**	**1**
REV. DATE: **2020-01-14**		

Strategic Asset Management Plan

See Hydro Ottawa's Intranet site for the latest revisions

REVISION SHEET

Revision	Description of Change	Date	Initial
0	Original Document	2018-11-30	cm/lj
1	Scope & General Update	2020-01-14	sh/gp



Strategic Asset Management Plan

Contents

1. Introduction

1.1. Overview

Hydro Ottawa Limited (Hydro Ottawa) is a regulated electrical distribution company and subsidiary of Hydro Ottawa Holding Inc. which is wholly owned by the City of Ottawa. The scope of the Strategic Asset Management Plan (SAMP) encompasses Hydro Ottawa's asset management activities associated with distribution and station assets ("distribution assets") as described in section 4.2. The SAMP describes the objectives of Hydro Ottawa's asset management practices and how they align with and translate from the corporate objectives. It also describes Hydro Ottawa's business drivers; asset management principles and strategies; roles and responsibilities; and the strategy of the Asset Management System (AMS) that lead to the development of the various *Asset Management Plans* (AMPs).

In order to continually improve, Hydro Ottawa is aligning the asset management processes and practices with the ISO 55001 standard. This ensures that strategic asset decision-making processes achieve a balanced weighting of cost, risk and asset performance that meet or exceed service level expectations of customers; comply with the terms of applicable acts, licences and codes; improve asset value and resource efficiency; and minimize health, safety and environmental impacts.

The purpose of the SAMP is to provide "documented information that specifies how organizational objectives are to be converted into asset management objectives, the approach for developing AMPs, and the role of the AMS in supporting the achievement of asset management objectives" (ISO 55000 3.3.2). The SAMP sets a clear framework and overarching strategy of the AMS. The SAMP describes the Asset Management Policy's principles (described in Section 4.3) which are implemented through the AMS. Additionally, the SAMP sets strategies to achieve the asset management objectives and describes how these objectives support the corporate strategic objectives set out in Hydro Ottawa's Strategic Direction 2016-2020, shown in Figure 1-1 below. Finally, the SAMP provides the guiding input for the development of AMPs.

Figure 1-1: Hydro Ottawa's Corporate Strategic Objectives

1.2. Structure of the Document

SAMP Section	*Description*
Section 2 – References	Describes the relevant reference material associated with the SAMP
Section 3 – Business Context	Describes the operating environment for Hydro Ottawa to provide context for the subsequent sections; describes stakeholder expectations to provide line of sight from the corporate strategic objectives to the asset management objectives, as well as roles and responsibilities
Section 4 – Asset Management System (AMS) Framework	Describes Hydro Ottawa's AMS model and key elements; describes the asset management objectives and subsequent asset management measures
Section 5 – Business Drivers	Describes the business drivers to which Hydro Ottawa must respond
Section 6 – Asset Management Strategies	Describes the asset management strategies and initiatives that ensure Hydro Ottawa's asset management objectives are met
Section 7 – Asset Information	Describes the importance of asset information, the attributes required and the software used to manage the information
Section 8 – AMS Risk Review	Describes Hydro Ottawa's risk and opportunity review process specific to the AMS to document appropriate actions
Section 9 – Financial Accounting for Assets	Describes how Hydro Ottawa manages financial information on distribution assets and the associated accounting practices
Section 10 – Performance Monitoring and Continuous Improvement	Describes the importance of performance measures at Hydro Ottawa in driving continuous improvement to achieve the asset management objectives
Section 11 - Implementation	Describes Hydro Ottawa's communication and review processes for the SAMP

2. References[1]

Hydro Ottawa – *Strategic Direction*
Hydro Ottawa – IAS-0001 – *Asset Management Policy*
Hydro Ottawa – *Asset Management Plans*
Hydro Ottawa – IAP0022 – *Asset Management System Risk Procedure*
Hydro Ottawa – IAP0021 – *AMS Communication Plan*
Hydro Ottawa – IAP0025 – *Continual Improvement Plan*
Hydro Ottawa – ESS0008 – *Equipment Approval Process*
Hydro Ottawa – POL-Fi-003 – *Procurement Policy*
Hydro Ottawa – PRO-Fi-013 – *Contract Procurement Process*
Hydro Ottawa – ESG0001 – *Construction Verification Program (CVP)*
Hydro Ottawa – POL-Fi-009 – *Internal Controls over Financial Reporting*
Hydro Ottawa – POL-Fi-013 – *Capitalization Policy*
Hydro Ottawa – GEG0001 – *Asset Health Index Guideline*
Hydro Ottawa – GRG0002 – *Feeder Performance Analysis*[2]
Hydro Ottawa – TBC – *Project Evaluation Procedure*[3]
Hydro Ottawa – TBC – *Project Prioritization Procedure*[4]
Hydro Ottawa – ECG0008 – *Distribution System Voltage and Power Quality Guideline*
Hydro Ottawa – GDS0008 – *Substation Protection Design Guide*
Hydro Ottawa – DFS0007 – *Control and Retention of Tech Based Docs and SWM*
Hydro Ottawa – POL-IM-001 – *Information Management Policy*
Hydro Ottawa – *Records Classification and Retention V9.1*
Ontario Energy Board – *Distribution System Code*
British Standards Institution – ISO55001 – *Asset Management – Management System*
British Standards Institution – ISO14001 – *Environmental Management System*
British Standards Institution – 18001 – *Occupational Health and Safety Assessment Series*
Institute of Asset Management – *an Anatomy*
International Accounting Standards Board – *International Financial Reporting Standards*
Ontario Regulation 22/04 – *Electrical Distribution Safety*
Ontario Ministry of Energy – *Climate Change Action Plan*
Ontario Ministry of Energy – *Ontario Green Energy Act*
Independent Electricity System Operator – *Ontario Planning Outlook*
Government of Canada – SOR/2008-273 – *PCB Regulations*
METSCO Energy Solutions – *Asset Health & Risk Assessment Method R1*

[1] Most recent revisions of the referenced documents are to be used
[2] Document in progress
[3] Document in progress
[4] Document in progress

3. Business Context

3.1. Hydro Ottawa Background

Hydro Ottawa is an electricity distribution company serving customers in the City of Ottawa and the Village of Casselman in eastern Ontario, Canada. Hydro Ottawa owns, plans for, builds, operates and maintains an electrical system comprised of transformers, switchgears, poles, conductor, cables, meters and other related distribution assets within a service area of 1,116 km^2 shown below in Figure 3-1. These assets consistently deliver safe and reliable electrical services to approximately 335,320 customers[5].

Hydro Ottawa's asset management initiatives ensure the effectiveness of the assets in meeting its current operating requirements. The initiatives also ensure that the assets are managed in order to provide value in supporting future requirements based on forecasted population growth, forecasted electrical demand and shifting climate trends These requirements are addressed in a manner which maximizes value through balancing the aspects of cost, risk and performance in order to continue to satisfy the needs and expectations of customers and stakeholders.

Hydro Ottawa's Electrical System[5]

- Connections to 335,320 customers
- 1,116 km^2 service area
- 83 owned/co-owned substations

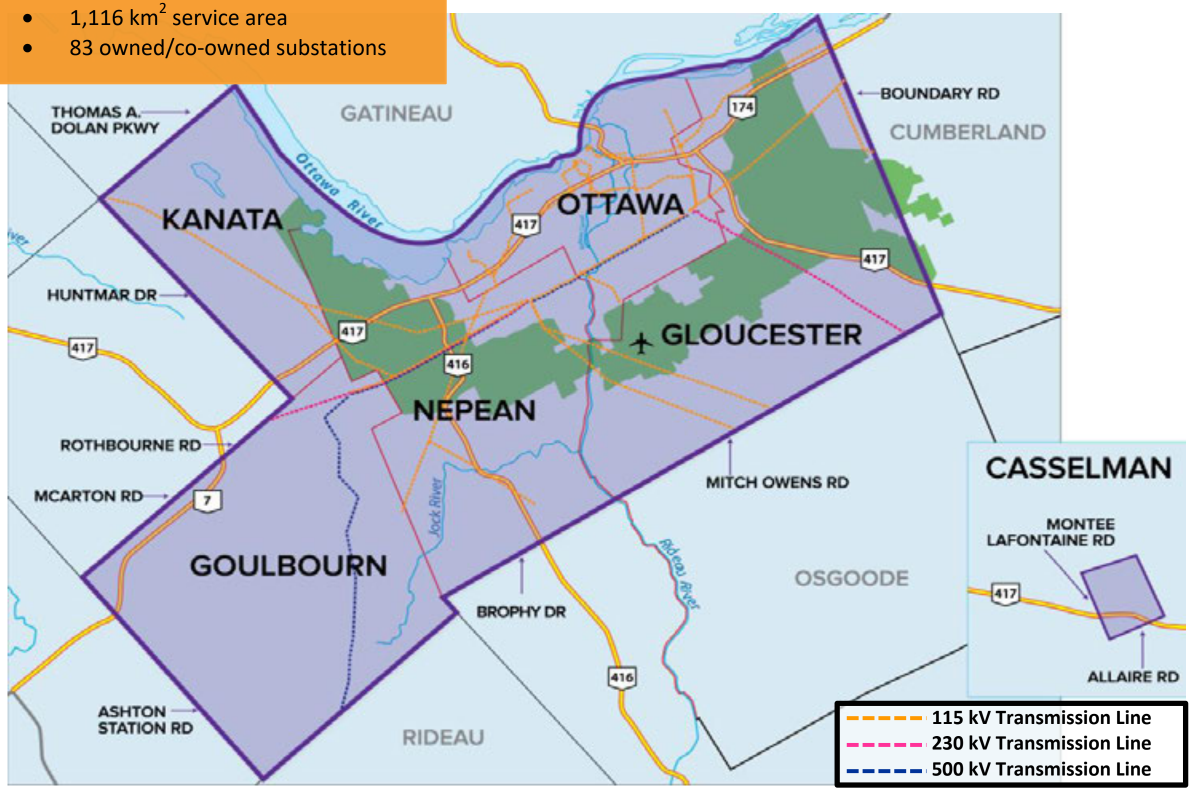


Figure 3-1: Hydro Ottawa's Service Area

[5] Information as of 2018-12-31

3.2. Stakeholder Consideration

Hydro Ottawa takes the interests of all stakeholders into account, including employees, customers, suppliers, shareholders and the communities and environment in which we operate. These commitments are described in Table 3-1 below.

Table 3-1: Stakeholder Commitment

Stakeholder	*Commitment*
Customers	Hydro Ottawa is committed to delivering value across the entire customer experience through an honest and fair relationship and by providing reliable, responsive and innovative products and services in compliance with legislated rights and standards for access, safety, health and environmental protection.
Employees	Hydro Ottawa is committed to maintaining a safe, secure and healthy work environment, hiring and retaining the best-qualified people enriched by diversity and characterized by open communication, trust and fair treatment.
Suppliers and Contractors	Hydro Ottawa is committed to having an honest and fair relationship with suppliers and contractors and to purchase equipment, supplies and services on the basis of merit. Hydro Ottawa pays suppliers and contractors in accordance with agreed terms, encourages an adoption of responsible business practices and requires the adherence to the Occupational Health & Safety Act.
Community and the Environment	Hydro Ottawa is committed to being a responsible corporate citizen and to contributing towards making the communities in which we operate better places to live and do business. Hydro Ottawa is sensitive to the community's needs and dedicated to the protection and preservation of the environment.
Shareholder	Hydro Ottawa is committed to protecting the shareholder's investment and managing risk effectively. Hydro Ottawa communicates all matters material to the organization in addition to establishing and maintaining leading governance practices.
Regulators	Hydro Ottawa is committed to complying with the regulations and guidance as provided by the OEB, and other government authorities which govern its operations.

3.3. Hydro Ottawa Assets

Hydro Ottawa currently recognizes distribution assets and related asset management activities within the scope of the AMS. The major asset classes within the distribution system are shown in Table 3-2. Hydro Ottawa's in-scope distribution assets have a net book value of $794,211,000[6].

Table 3-2: Hydro Ottawa Major Class Distribution Assets[1]

Asset Type	*Population*
Station Transformers	167
Station Breakers	1,105
Poles	48,514
Load Break Switches	194
Line Reclosers	52
Pole mounted Transformers	15,670
Distribution Cables (PILC)	367 km
Distribution Cables (XLPE/TRXLPE)	2,578 km
Distribution Cables (EPR)	123 km
Distribution Overhead Conductor	2,745 km
Underground Transformers Vault Transformers	20,468
Underground Switchgear	508
Vault Switchgear	468
Cable Chambers	3,878

[1] Information as of 2018-12-31

3.4. Roles and Responsibilities

Asset management activities within the AMS are to be completed by the designated roles. The various roles within the AMS and their responsibilities are defined below.

Executive Management Team: Shall be members of top management within Hydro Ottawa consisting of the President and Chief Executive Officer, Chief Financial Officer, Chief Electricity Distribution Officer, Chief Customer Officer, Chief Human Resources Officer, Chief Information and Technology Officer, Chief Energy and Infrastructure Officer, and Chief Electricity Generation Officer.

Asset Owner: Shall be the Chief Electricity Distribution Officer or competent delegate. The Asset Owner is responsible for supporting the AMS and providing top level visibility, as well as making high-level strategic decisions and approvals such as approving asset management objectives.

Asset Manager: Shall be the Director, Distribution Engineering and Asset Management supported by the Director, Distribution Construction and Maintenance and the Director, System Operations and Grid Automation, or competent delegate(s). The Asset Manager is responsible for the operation and continual improvement of the AMS, making strategic decisions such as determining the balance of asset cost, risk and performance to meet the asset management objectives. In addition, the Asset Manager shall:

- Maintain the asset management objectives within the AMS;
- Approve and prioritize specific asset management strategies;
- Ensure there is sufficient support, resources and an engaged and competent workforce to deliver the AMS; and
- Review, monitor and report performance of the AMS to the Asset Owner and other members of the Executive Management Team.

Asset Service Provider: Shall be Manager-level staff and below within roles associated with asset management activities. Asset Service Provider’s responsibilities include:

- Defining and managing the strategies, standards, operational planning, maintenance planning, and capital planning of Hydro Ottawa’s assets; and
- Efficiently implementing the operational plans, maintenance plans and capital works plans for Hydro Ottawa assets.

Asset Management Council: Shall include representatives from across the organization and provide governance of the AMS as defined in Section **Error! Reference source not found.**

Business Support: Additional groups and sections responsible for enabling asset management objectives and the success of the AMS.

4. Asset Management System (AMS) Framework

The ISO 55001 standard describes an AMS as being "used by the organization to direct, coordinate and control asset management activities". Hydro Ottawa uses the ISO 55001 framework, shown in Figure 4-1 below, to describe the AMS. This framework details how the elements work together and how they align with Hydro Ottawa's corporate strategic objectives and commitment to stakeholders. Following this model allows Hydro Ottawa to efficiently deliver asset management activities, thereby supporting the achievement of the asset management objectives. Hydro Ottawa's application of the AMS elements is further explained throughout this section.

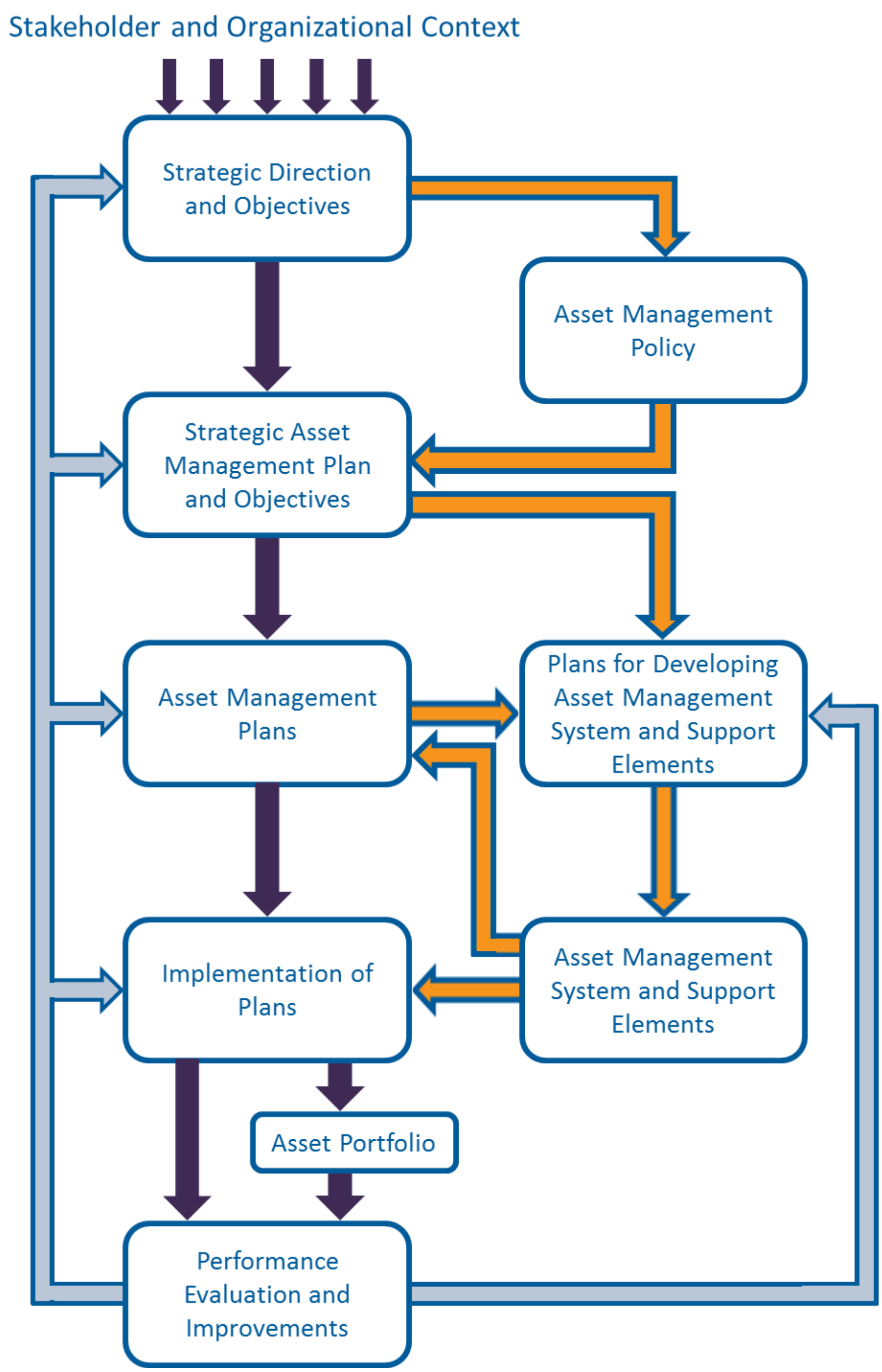


Figure 4-1: Asset Management System Key Elements (Source: Based on BSI, ISO 55000)

4.1. Strategic Direction and Objectives

In 2016, Hydro Ottawa updated the organizational strategic direction for the period of 2016-2020 refreshing the corporate strategy previously set in 2012. Hydro Ottawa's Strategic Direction provides an overview of business strategy and financial projections over this period. The strategic direction informs all stakeholders of the trends shaping the business environment and how the company intends to respond to them. It sets out a balanced program for strong performance in existing operations, coupled with sustainable and profitable business growth, while being customer-centric, financially responsible, and responsive to a changing environment.

The strategic direction sets out four (4) organizational objectives: Customer Value, Financial Strength, Organizational Effectiveness and Corporate Citizenship, shown in Figure 4-2 below. These objectives are used to develop the Asset Management Policy and are the pillars around which the AMS is focused, shaping the asset management objectives and the outcomes by which the risk and performance of the AMS is evaluated.

Figure 4-2: Hydro Ottawa's Corporate Strategic Objectives

CUSTOMER VALUE

We will deliver value across the entire customer experience

- by providing reliable, responsive and innovative services at competitive rates

FINANCIAL STRENGTH

We will create sustainable growth in our business and our earnings

- by improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people

CORPORATE CITIZENSHIP

We will contribute to the well-being of the community

- by acting at all times as a responsible and engaged corporate citizen

ORGANIZATIONAL EFFECTIVENESS

We will achieve performance excellence

- by cultivating a culture of innovation and continuous improvement

4.2. Scope of the Asset Management System (AMS)

The scope of Hydro Ottawa's AMS follows the framework shown in the AMS model outlined in Figure 4-1 and is used to direct, coordinate and control Hydro Ottawa's asset management activities.

Hydro Ottawa's AMS encompasses Hydro Ottawa's distribution and station assets ("distribution assets"). Specifically, the distribution assets covered by Hydro Ottawa's AMS have been categorized by the following asset classes:

- Station Transformers;
- Station Switchgear & Breakers;
- Station Batteries, Protection & Control Equipment;
- Poles, Fixtures & Primary Overhead Conductors;
- Overhead Switches;
- Overhead Transformers;
- Civil Structures;
- Underground Primary Cables;
- Distribution Underground Transformers;
- Distribution Underground Primary Switchgear;
- Vault Transformers;
- Telecommunications; and
- Metering.

The following assets are not included in Hydro Ottawa's AMS:

- Fleet;
- Office Buildings; and
- Information Technology equipment not directly used in concert with any of the in scope asset classes.

The AMS scope is used to build the Asset Management Policy IAS0001 and is integral in the development of the asset management objectives and measures.

4.3. Asset Management Policy

The Asset Management Policy IAS0001 describes the "intentions and direction of an organization as formally expressed by its top management" (ISO 55000 3.1.18). Its purpose is to provide stakeholders with the principles and high-level direction which Hydro Ottawa applies to asset management practices to achieve the organizational and asset management objectives. These principles, shown in Table 4-1, guide the approach used for implementation of this SAMP and the AMS. The Asset Management Policy is:

- developed through alignment with Hydro Ottawa's Strategic Direction and the organizational objectives;
- reviewed and endorsed by top-level management, demonstrating Hydro Ottawa's commitment to asset management;
- approved by the President & Chief Executive Officer of Hydro Ottawa, and the Chief Electricity Distribution Officer; and
- reviewed annually by the Asset Manager and updated as required to ensure that it is relevant, accurate and complete.

Table 4-1: Asset Management Principles

Principle	*Description*
Lifecycle Approach	Consider the complete lifecycle of assets to develop investment plans that are sustainable and economically efficient.
Customer Engagement	Thoroughly consider customers' expectations in developing plans that maximize the value delivered to customers and stakeholders.

Principle	*Description*
System Performance	Achieve performance excellence through asset decisions based upon optimized consideration of costs, risks and benefits to attain asset management objectives.
Efficient Project Delivery	Execute effective plans efficiently, on time and on budget.
Demand Management	Create and support sustainable growth in grid accessibility to accommodate additional customer services (load and generation) while maintaining or improving levels of service.
Risk Management	Use high-quality and timely data and information to make the best risk-based decisions about assets, balancing the needs of shareholders and customers.
Systematic	Make consistent and transparent decisions based on facts and detailed data analysis.
Data Analysis	Utilize asset investment planning and management tools to analyze and report information on asset performance, quality of service and cost, to support risk management, decision-making and continuous improvement.
Employee Competency	Provide employees with the necessary training, tools and technologies to implement the SAMP while supporting organizational knowledge transfer through targeted development programs.
Compliance	Comply with all legal, regulatory and environmental requirements.
Sustainable	Continually review and improve the effectiveness of the AMS.

4.4. Strategic Asset Management Plan (SAMP) and Objectives

The purpose of the SAMP is to provide "documented information that specifies how organizational objectives are to be converted into asset management objectives, the approach for developing AMPs, and the role of the AMS in supporting achievement of the asset management objectives" (ISO 55000 3.3.2). The SAMP's objective is to set the framework and overarching strategy of the AMS. The SAMP describes:

- the Asset Management Policy's principles which are implemented throughout the AMS;
- the strategies to achieve the asset management objectives;
- how these objectives are converted from the corporate strategic objectives shown in Figure 1-1; and
- the guiding input for the development of AMPs.

Hydro Ottawa's asset management objectives are developed using the principles in the Asset Management Policy and are aligned to the objectives set out in Hydro Ottawa's Corporate Strategic Direction. These objectives take into consideration stakeholder expectations, business drivers and the requirement to comply with relevant legislation, codes, licences and technical standards. Using these inputs, Hydro Ottawa has developed five (5) asset management objectives, described in Table 4-2. A hierarchy of the alignment and associated asset management measures is shown in Figure 4-3 and expanded in Appendix B. The asset management measures describe the desired goals for each of the five objectives and the high level strategy by which it will be achieved. The ability to achieve these measures determines the success of their corresponding objectives. Section 6 describes the asset management strategies to achieve the asset management goals and objectives. The SAMP and the asset management objectives and measures are continuously monitored with a detailed review and update occurring in line with Hydro Ottawa's Strategic Direction by the Asset Manager. This ensures that the SAMP and objectives are relevant and accurate with respect to Hydro Ottawa's strategic objectives.

Table 4-2: Asset Management Objectives

Asset Management Objective	*Description*
Levels of Service	To maintain and enhance leading performance of the distribution system through improving electrical service and alignment with customers' expectations
Asset Value	To maximize the realization of value from distribution system assets over their entire lifecycle through managing risks and opportunities
Resource Efficiency	To maximize economic efficiency by minimizing costs associated with maintaining and operating the distribution system
Health, Safety & Environment	To minimize employee and public health and safety risks and environmental risks from distribution system activities
Compliance	To maintain compliance with all internal and external requirements while managing the distribution system

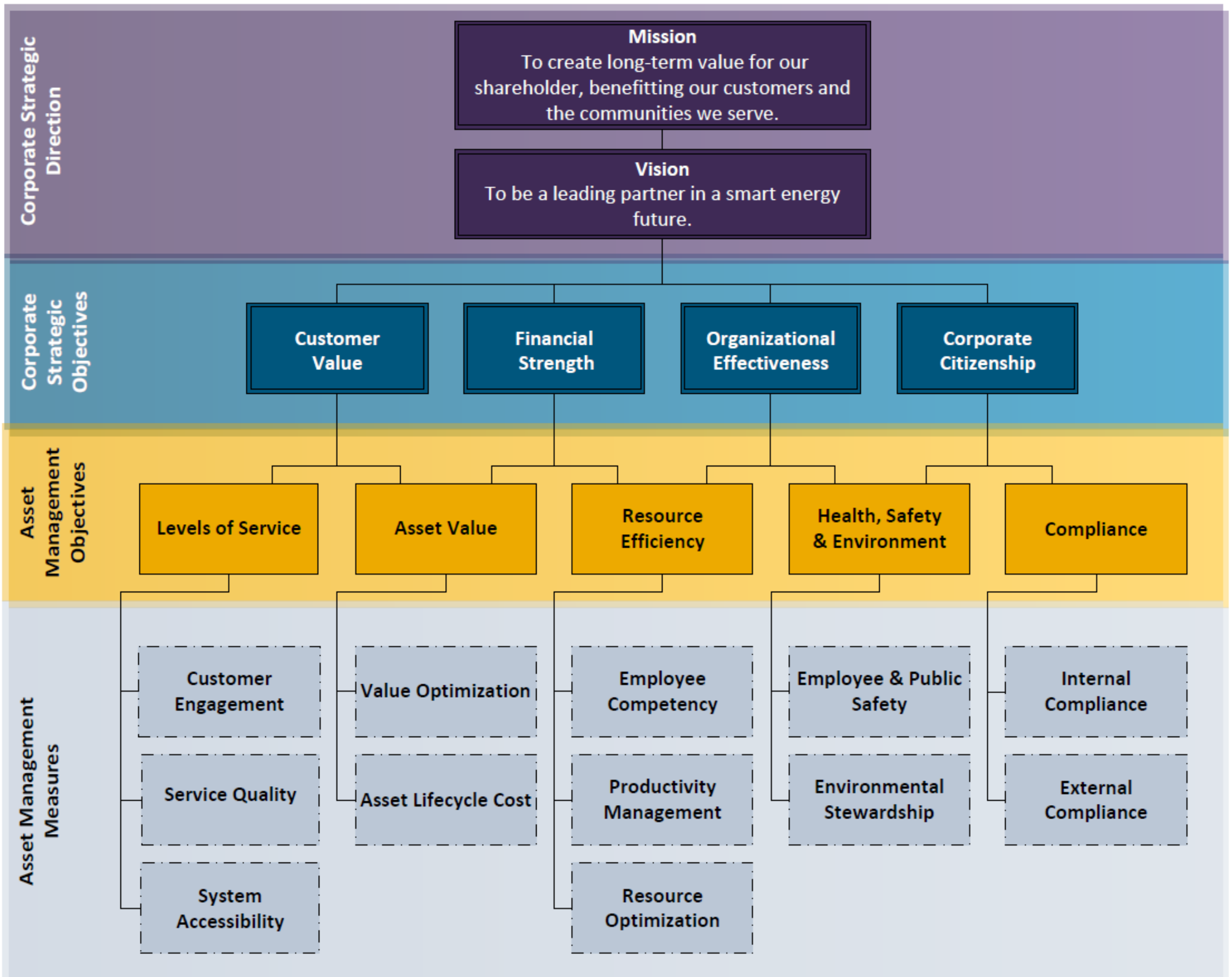


Figure 4-3: Asset Management Objectives and Measures

4.5. Asset Management Plans (AMPs)

The AMPs describe “documented information that specifies the activities, resources and timescales required for an individual asset, or a grouping of assets, to achieve the organisation’s asset management objectives” (ISO 55000 3.3.3). Hydro Ottawa’s AMPs:

- utilize the guiding strategies within the SAMP and are aligned with the Asset Management Policy and its principles;
- account for relevant obligations outside the AMS such as environmental or regulatory compliance;
- describe how Hydro Ottawa manages both discrete and groups of assets and systems, as well as the associated asset management activities in order to achieve the asset management objectives;
- describe a multi-year strategy for discrete and groups of assets and systems and the resources required; and
- define the technical and asset level guidelines for budget development.

Hydro Ottawa’s AMPs are reviewed annually by the Asset Manager and updated as required to ensure that they are relevant, accurate and complete and remain aligned with the asset management objectives.

4.6. Support Elements

In addition to the above documents, Hydro Ottawa has developed numerous policies, procedures, work methods, guidelines and standards to support a comprehensive AMS.

4.7. Implementation of Plans

The implementation of the AMPs is carried out by the Asset Service Providers following the activities described within the respective AMP. The AMPs' execution utilizes the principles set forth in the Asset Management Policy and the strategies set out in the SAMP discussed in Section 6.

4.8. Performance Evaluation and Improvements

The evaluation of performance is carried out as defined in Section 0.

5. Business Drivers

Hydro Ottawa has numerous business drivers, both internal and external, which influence its asset management practices. Below is a list of the major drivers which are recurring topics surrounding asset management affecting Hydro Ottawa. These drivers are measured as described in this section as described by the KPIs referenced in Section 0.

5.1. Customer Expectations

As a company that provides an essential service to the public, nothing is more critical to Hydro Ottawa's success than the ability to reliably deliver electric service that provides value to its customers. Hydro Ottawa recognizes that maintaining the trust and confidence of customers and stakeholders is essential to the company's asset management objectives. We are committed to understanding and responding to the needs of our customers, particularly during these times of change within the electricity sector. The fundamentals of customer value in the electricity business have long been considered to be quality and cost — delivering a reliable service while operating efficiently and effectively to keep rates competitive. Additionally, our customers are increasingly becoming engaged and seeking information to become more knowledgeable regarding their energy usage, the source of the energy (renewable vs. non-renewable) and how they can control their electricity costs. Hydro Ottawa continues to operate with its customer's interests in mind, and actively encourages their participation in helping the company shape how it will deliver electricity services in the future, such as through the items described in section 6.1

For example, Hydro Ottawa engages customers using market research surveys to determine service satisfaction. These surveys help Hydro Ottawa understand its customer's expectations relative to Ontario and national comparators. In 2018, a customer satisfaction survey was conducted. Figure 5-1 shows the satisfaction of Hydro Ottawa's customers compared to both the national and provincial satisfaction results. Overall, Hydro Ottawa's customers have indicated high levels of satisfaction with their service, on par with the national average and above the provincial average. Hydro Ottawa uses the results of customer surveys to help maintain a high level of customer satisfaction through ongoing customer engagement and service excellence.

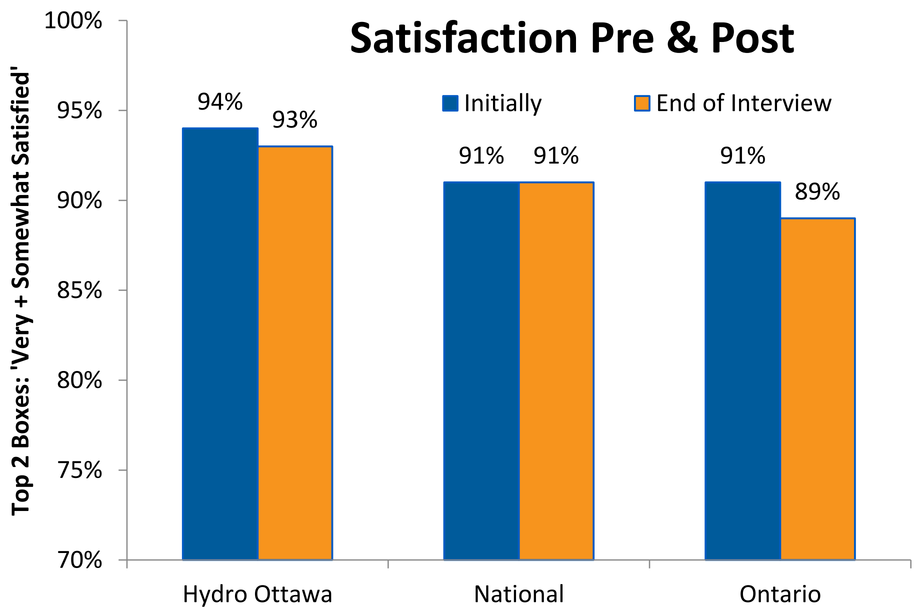
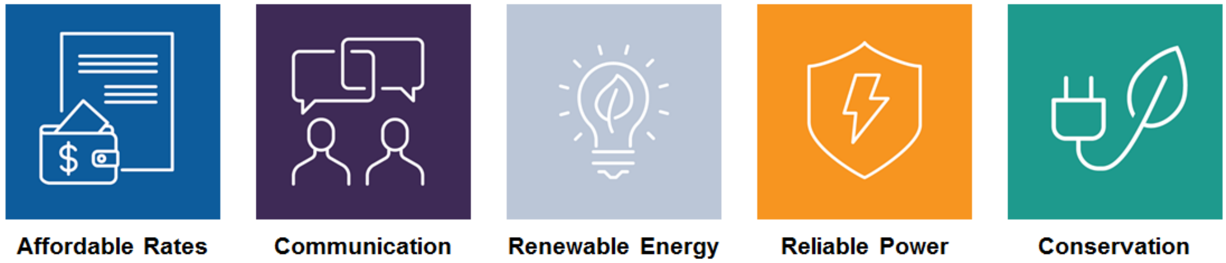


Figure 5-1: Customer Satisfaction Survey Results 2017

In addition to satisfaction, the survey invited customers to identify their top priorities. In order from most to least significant, the following priorities indicate what customers value most.



Use of survey results is an integral part of Hydro Ottawa's approach to drive service improvements and help shape planning decisions. The following sections describe the metrics and systems Hydro Ottawa uses to measure asset performance and determine when investment decisions are needed to meet the goals and objectives outlined in Section 4.4.

5.2. Service Quality

Reliability

Customers increasingly rely on electricity for the successful operation of their businesses and their day-to-day lives. Customer satisfaction levels have proven to be greatly impacted by the service quality and availability of Hydro Ottawa's distribution system. Hydro Ottawa's historical reliability performances for both System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) are shown in Figure 5-2. While vast improvement in Hydro Ottawa's reliability for controlled events has been seen compared to historical performance, both SAIFI and SAIDI have not shown further improvement in recent years. Considerations of new ways to improve reliability are vital in order to meet customer expectations.

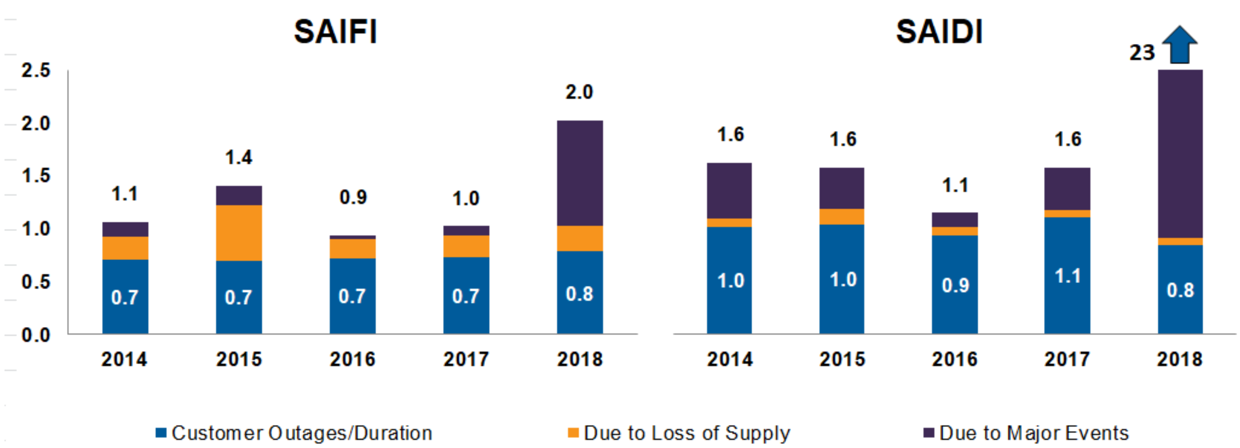


Figure 5-2: Reliability Statistics

Hydro Ottawa service reliability has increasingly been impacted negatively over the past decade by weather events, characterized by the Major Event reliability contribution seen in Figure 5-2. Extreme weather events include, but are not limited to high wind events, freezing rain, temperature and precipitation extremes, as well as complex events such as tornadoes. In response to these events, and forecasted changes in weather patterns attributed to climate change, Hydro Ottawa has undertaken a Climate Vulnerability Risk Assessment (CVRA). Hydro Ottawa has subsequently developed an adaptation plan as part of its distribution planning activities further information on these studies can be found in section 6.2.2.4

5.3. Asset Condition

Understanding the existing condition of Hydro Ottawa's assets is critical in determining whether the assets can and will continue to meet customers' service quality expectations and achieve the company's asset management objectives. In 2015, Hydro Ottawa engaged a third-party service provider with expertise in the utility industry to support the establishment of comprehensive asset inspection methods. These inspection methods provide insight into the condition of the assets and support the creation of condition scores based on several factors respective to the asset class. The results of the inspections are used to perform Asset Condition Assessments (ACAs) where a health index score is calculated from the results. The inspection methods and ACAs are further explained in asset specific AMPs.

Hydro Ottawa applies the developed ACA inspection methods using internal and external resources to inspect distribution system assets. Hydro Ottawa has and will continue to perform detailed inspections on the entire set of distribution assets listed in Section 4 and incorporate ACA-compliant inspections into its statements of work for testing, inspection and maintenance programs. The results of these inspections for Hydro Ottawa's total distribution assets and major asset categories appear in Figure 5-3. Additionally, Figure 5-3 demonstrates the state of Hydro Ottawa's major asset classes with respect to remaining operating life. Using failure probability curves, the expected operating life is determined for respective assets within each asset class. Hydro Ottawa uses a 2% probability of failure to determine the expected operating life of overhead and underground distribution assets and a 1.5% probability of failure for station assets due to the increased consequence of asset failure.

Figure 5-3: Asset Condition and Age Demographics[7]

[7] Information as of December 31, 2018

5.4. System Capacity

In order to continue to offer service to new customers and respond to increased demand for existing customers, Hydro Ottawa requires an electrical system with adequate supply and delivery capability for both load and Energy Resource Facility (ERF) customers.

Load Customers

The Integrated Regional Resource Planning (IRRP) process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria (ORTAC), and develops integrated solutions to address any capacity needs that are identified. Candidate solutions include: conservation, demand management, distributed generation, large scale generation, transmission, and distribution. The IRRP outlines several transmission and distribution stations that will exceed their capacity limitations within the near, medium, and long term. HOL also contributes to the IRRP by identifying feasibility limitations within the planning area that may not be known to the IRRP working group (i.e. Greenbelt, rivers, highways, etc). The IRRP is designed to address arising capacity needs of the regional utilities, and to identify cost effective and viable solutions. The working group, which consists of the IESO, HOL, Hydro One Network Inc., and Hydro One Distribution, holds several meetings throughout the year to discuss progress on the study.

Over the last 10 years, Hydro Ottawa's system demand levels have remained stable, with a summer peak between 1400 MW and 1600 MW, however load is expected to grow over the next 20 years as shown in Figure 5-4. Factors driving this growth are the increasing redevelopment of rural areas into suburban/urban communities, the implementation of the City of Ottawa's Light Rail Transit system and the continued intensification of existing urban areas. Based on the IRRP assessment completed in 2017, Hydro Ottawa expects the system to see, on average, a 2% average annual growth over the next 20 years. This forecast does not include future conservation programs or unplanned ERF connections. Hydro Ottawa also applies a high-demand scenario forecast based on extreme weather events (such as high summer temperature) known as the 1-in-10-year forecast in capacity planning decisions.

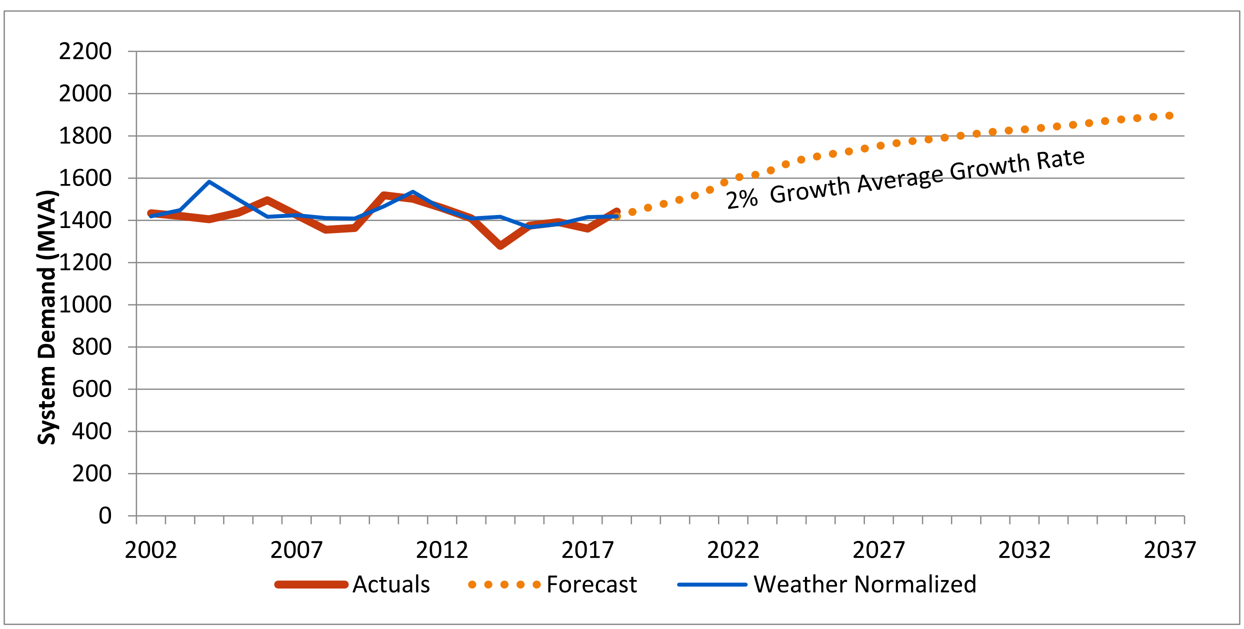


Figure 5-4: Forecasted Demand Growth

Energy Resource Facility Customers

Since the inception of the Feed-in-Tariff (FIT) and microFIT programs by the Ontario Ministry of Energy through the *Ontario Green Energy Act*, Hydro Ottawa has experienced an increase in ERF connections. At the end of 2017, Hydro Ottawa had a total of 883 ERFs connected to the system. Hydro Ottawa anticipates ERF connections to continue to increase with the Net Metering Program replacing the FIT and microFIT programs which ended in 2016. In addition, commercial customers continue to evaluate the economics of load displacement generation to reduce their electricity demand. Figure 5-5 shows the ERF connections and installed capacity over the last five (5) years. The average number of connections decreased between 2016 and 2018 primarily as a conclusion of the FIT and MicroFIT programs. Hydro Ottawa continually reviews technical limitations of the distribution system and evaluates options to reduce constraints that limit its ability to connect future ERFs.

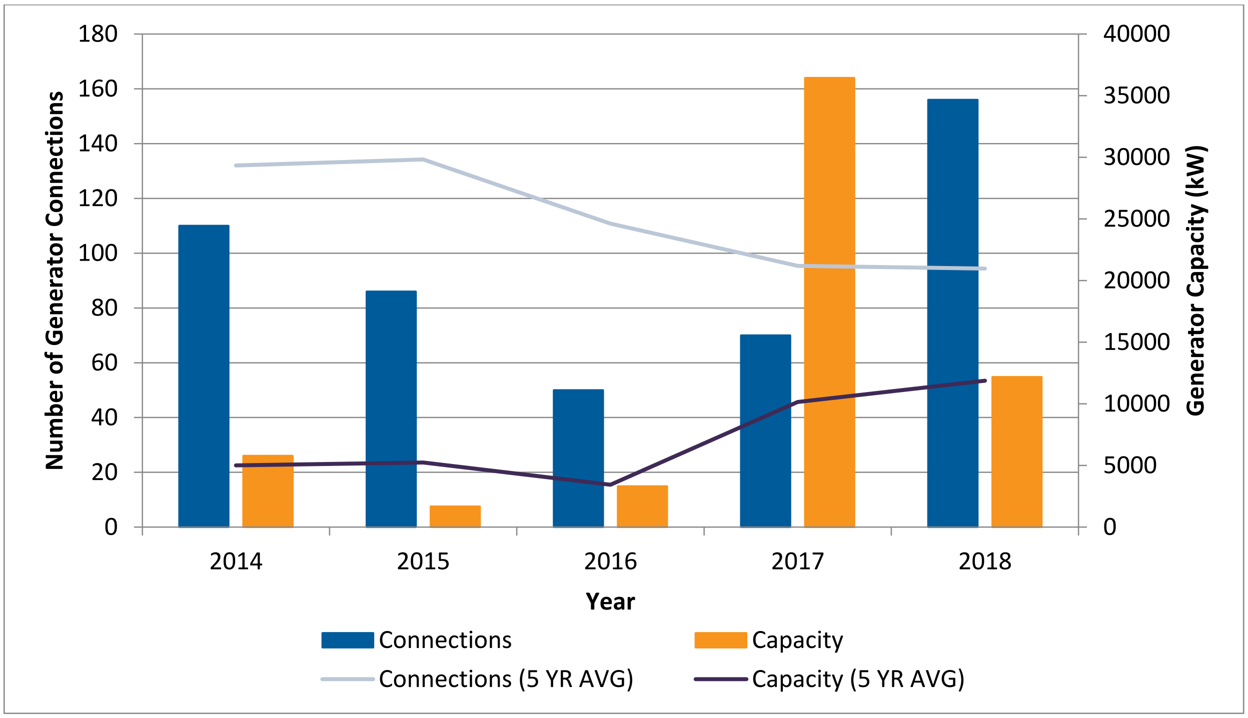


Figure 5-5: ERF Connections[8]

5.5. Financial Considerations

A central challenge facing Hydro Ottawa is the need to invest in the replacement and modernization of degrading assets without putting upward pressure on customer rates. Hydro Ottawa is committed to ensuring customer value is a primary consideration throughout all business practices, and continues to focus on increasing value for money through embedding continuous improvement initiatives across the organization. Specifically, within its asset management processes, Hydro Ottawa strives to reduce costs through the achievement of operational efficiencies by improving productivity and reducing asset lifecycle costs. These processes and resulting strategies are described in section 6.

[8] 2017 saw a single customer connection of 29,350 kW. While connections of this size may occur in the future, it is not anticipated to be a trend

5.6. Resources

A highly-skilled, properly-trained and knowledgeable workforce is essential to the continued success and effectiveness of Hydro Ottawa's asset management program. Like other utilities, Hydro Ottawa faces challenging workforce demographics that require a comprehensive talent management strategy aimed at anticipating future workforce needs. In addition, Hydro Ottawa's workforce planning must ensure that proper training is provided as new technologies emerge and are adopted, such as smart systems, and advanced distribution management systems. Hydro Ottawa expects a loss of 4,784 cumulative years of trades and technical experience between 2016 and 2026. To meet this challenge, Hydro Ottawa has increased its focus on workforce renewal by attracting and developing young workers to facilitate the effective transfer of knowledge and skills from our veteran workforce. Work plans and specific skill requirements continue to be reviewed to ensure the resources meet our workforce needs. These actions will enable Hydro Ottawa to continue successfully executing asset management plans.

In addition, Hydro Ottawa has built and maintains a community of competent external contractors trained and equipped to enhance and supplement its internal resources. Centralizing the oversight of these contractors by the Program and Contractor Management group drives alignment and efficiency of Hydro Ottawa's resource allocation. This mix of resources provides Hydro Ottawa the flexibility to respond to changing and growing customer and asset investment needs.

6. Asset Management Strategies

Hydro Ottawa has made a strategic decision to incorporate the ISO 55001 standard into its asset management activities in order to continue improving its asset management activities and reinforce its commitment to adopt industry best practices. To ensure the AMS is comprehensive, Hydro Ottawa has established an Asset Management Council (AMC) to create, review and comment on the various components which make up the AMS. The AMC includes employees from the various asset management related areas to ensure thorough expertise. The AMC monitors and updates the AMS as required to ensure that it is relevant, accurate and complete.

The SAMP sets out Hydro Ottawa's strategies in order to achieve the asset management objectives. The strategies draw from the top-level corporate objectives defined in Hydro Ottawa's Strategic Direction and the guiding principles defined in the Asset Management Policy, ultimately delivering the asset activity plans in the AMPs. Hydro Ottawa's asset management objectives will be accomplished through the strategies and initiatives related to asset management measures described below.

6.1. Levels of Service Strategy

6.1.1. Customer Engagement

Customer value is at the center of Hydro Ottawa's corporate strategic objectives. As the customer's role and place within the electricity system evolves, successful utilities will be those that recognize that customers are not all the same, and therefore, will adapt and tailor their service delivery options to the specific needs of individual customers. Additionally, customers are looking for increased communication with Hydro Ottawa as they seek to become more involved in defining their energy options and footprint. Hydro Ottawa aims to improve customer engagement and empower customers and industry partners through consultations, utilizing their feedback to shape the corporate strategic direction and inform the company's planning, design and construction processes. Below are highlighted initiatives Hydro Ottawa undertakes to deliver customer engagement.

Customer Consultations on Projects

Hydro Ottawa employees regularly consult with customers regarding asset upgrades such as cable, pole or distribution transformer replacement projects that may impact their property or neighbourhoods. The consultation process begins with informing customers who may be impacted of pending work through various methods of communication, followed by an open-house meeting aimed at creating an open, two-way dialog. During the open houses, Hydro Ottawa staff informs customers of the scope, schedule and the general process to be undertaken to perform the work. It is also a venue for customers to provide feedback and voice any concerns that staff is able to address. This is an excellent forum to gain additional information on the particulars of the neighbourhood; and general geographic, aesthetic concerns or insights that Hydro Ottawa can take into consideration. Through this process, Hydro Ottawa is increasingly looking to customers to help shape plans, right down to the level of local construction projects.

The open house strategy was developed based on feedback received from our customers and it has proven to support and enable productive and successful projects for both Hydro Ottawa and its customers. Hydro Ottawa believes that strong and open communication is essential to maintain an open dialog with our customers. Notably, our customers have commented that they appreciate the consultation sessions and the forum to provide an opportunity to air their concerns. They also value that Hydro Ottawa informs them of project needs and expected impacts on levels of service, and that customers have the opportunity to offer their feedback incorporated into the design and scheduling decisions. Hydro Ottawa continues to review projects, and the impacts which they may have on customers and communities, and to ensure open houses are initiated and scheduled appropriately.

Customer Satisfaction Feedback

Hydro Ottawa's Customer Service group conducts an annual survey to obtain feedback from customers regarding Hydro Ottawa's service. As part of the survey, customers are asked to identify their level of satisfaction with Hydro Ottawa's performance and their top priorities on how service can be improved. Hydro Ottawa utilizes their input and priorities its inform the strategic direction. Where these priorities relate to asset management activities, the asset management objectives and strategies take these priorities into consideration to ensure delivery of customer value and satisfaction. Additionally, customer priorities are considered in distribution project evaluation as described in the *Project Evaluation Procedure.* Hydro Ottawa continues to engage customers and adapt survey questions as necessary in order to receive timely and relevant information to provide service which results in positive customer satisfaction.

In 2020, Hydro Ottawa will initiate a new forum to obtain customer satisfaction feedback. Along with the customer open houses, Hydro Ottawa will conduct customer satisfaction surveys after the open houses and following the completion of projects within their neighbourhoods. The post-open house customer survey will focus on the customer's satisfaction with the proactive communication and project information. The post-construction customer survey will focus on areas including customer communication, electricity service quality, ability to accommodate the customer and overall satisfaction. The results will allow Hydro Ottawa to better understand areas of strengths as well as areas that can be improved with respect to customer engagement and planning and construction processes.

Third Party Education

Hydro Ottawa undertakes a significant amount of work with third parties for proposed projects such as new electrical services and equipment relocations. These third parties include developers, contractors, consultants, the City of Ottawa and other utilities. To facilitate proactive engagement and strengthen relationships with parties whom Hydro Ottawa works with on a daily basis, Hydro Ottawa's Distribution Design section provides informational presentations. These presentations include a review of Hydro Ottawa's processes, standards and conditions which apply to the scope of work to be completed by each party. Additionally, feedback is requested and evaluated to ensure processes are efficient and reasonable for both Hydro Ottawa and third parties.

6.1.2. Service Quality

Hydro Ottawa aims to deliver electric power in a form which meets customers' needs by providing reliable service and mitigating power quality issues which affect customer service. When gaps in service quality are identified, Hydro Ottawa takes appropriate actions by developing of solutions that balance performance, risk and cost. Below are highlighted initiatives that Hydro Ottawa undertakes to deliver reliable and quality electric service to our customers.

Worst Performing Feeder Analysis

Hydro Ottawa tracks and analyzes reliability performance for the distribution system as a whole and for each of our distribution system feeders. The feeders are reviewed using performance metrics and benchmarks defined in GRG0002 – *Feeder Performance Analysis* procedure. The analysis prioritizes feeder performance based on their reliability impact for further review in order to identify trends and create planned investments to improve reliability. Hydro Ottawa's worst feeder analysis aims to reduce recurring outages affecting the same customers and communities.

Reliability Council

Hydro Ottawa formed a Reliability Council in 2014 to bring continued focus on system and customer reliability. Comprised of stakeholders across the organization, the purpose of this council is to maintain a culture of reliability and drive change from a diverse set of perspectives to deliver effective solutions. The council meets monthly to review system performance and operational issues. The focus of these meetings and discussions is Hydro Ottawa's Five (5)-Year Reliability Roadmap, which identifies steps and actions to achieve the council's objectives. This document is updated annually, and incorporates past performance objectives and sets a direction moving forward based on feedback from meeting participants.

Smart Energy Steering Committee

Hydro Ottawa formed a Smart Energy Steering Committee in 2017 to bring continued focus on the application of technology to develop a smarter grid and deliver innovative customer solutions. This initiative also aligns with Hydro Ottawa's goal of moving towards and enabling an intelligent energy future. The Smart Energy Steering Committee is cross-functional and provides leadership, oversight, coordination and direction to Hydro Ottawa's Smart Energy Initiatives. The purpose of the committee is to develop and deliver on the Smart Energy Roadmap, which identifies initiatives to achieve Hydro Ottawa's smart energy objectives. These objectives are:

1) Develop enhanced grid reliability and service offerings to enable the provision of a 100% reliable electrical service offering;
2) Position Hydro Ottawa as the provider of proactive and innovative energy solutions that align with our customers' needs, preferences and objectives; and
3) Expand current value and revenue streams, building on core areas of strength through the provision of electricity and related services.

Power Quality Monitoring

Hydro Ottawa strives to meet industry standards by providing customers with appropriate levels of service power quality. Hydro Ottawa has set power quality requirements for its distribution system as outlined in ECG0008 – *Distribution System Voltage and Power Quality Guideline*. When power quality limits are not met, typically through notification by a customer, Hydro Ottawa actively responds, using monitoring devices to collect data and determine the underlying cause. A report and recommendation(s) are then created and executed to rectify the issue if caused by Hydro Ottawa's distribution system.

Hydro Ottawa strives to proactively identify power quality issues and appropriate mitigation prior to and in advance of customer notifications. Hydro Ottawa utilizes power quality measurement devices and software at substations, and an expanding fleet of ION meters at customer locations. The information available at these locations allows Hydro Ottawa to have more visibility into the distributions system's ability to continuously deliver high power quality service to its customers.

Vegetation Management

Hydro Ottawa manages the vegetation that encroaches on our distribution lines and equipment. The Hydro Ottawa service area is currently divided into regions for vegetation management: 12 suburban areas which are trimmed on a three (3)-year cycle and 16 core areas which are trimmed on a two (2)-year cycle. Additionally, accelerated vegetation management is targeted to specified areas with faster-growth tree species. These activities strive to ensure public safety and improve system reliability, especially for tree-related outages during storms or adverse weather events. Hydro Ottawa is also currently piloting a "fee for vegetation management service" for customers who would like Hydro Ottawa to trim or remove trees on their property outside of the company's Right-of-Way. In many instances, the trees are within the fall radius of electrical lines and removal provides additional protection against outages and damage to Hydro Ottawa or customer equipment.

Testing, Inspection, and Maintenance Programs

HOL's planned testing, inspection, and maintenance programs are it's primary means of collecting condition data used to calculate the health index of assets and to identify corrective actions to ensure continued reliable operation as described in Section 6.2.

HOL's planned programs can be divided into three groups:

1. **Predictive**: assessing the condition of the asset
2. **Preventative**: maintaining the condition of the asset
3. **Corrective**: improving the condition of the asset

Predictive programs collect technical details, testing, and inspection data used to identify assets in need of corrective action while determining the asset's overall condition. These programs use a combination of inspection techniques depending on the asset type being considered and identification of failure mode(s) that pose an increased risk to safety, reliability or the environment. The deployment of communications equipment and sensors on certain new or upgraded assets provides Hydro Ottawa the ability to monitor the condition of its assets and to collect operational data in real time, thereby reducing or eliminating the use of predictive programs to obtain asset data. Furthermore, ongoing monitoring supports Hydro Ottawa' eventual transition from time-based to condition based maintenance.

6.1.3. System Accessibility

Hydro Ottawa seeks to maximize system accessibility by reducing connection constraints for new customers, whether these customers are consuming electricity (load customer connections) or producing electricity (ERF connections). Where gaps in system accessibility are identified, Hydro Ottawa undertakes appropriate actions by developing solutions that balance performance, risk and cost. Below are initiatives that Hydro Ottawa undertakes to streamline system accessibility.

Load Customer Connections

Hydro Ottawa performs regular assessments of available sources of supply or alternative solutions for new customers. Annually, a comprehensive load-study is completed for Hydro Ottawa's distribution system. The study forecasts future system demand based on historical trends, existing planned developments and longer-term plans provided by municipalities, developers and provincial policy. In addition, Hydro Ottawa plans and designs its system to account for a potential for a severe weather year by developing both one-in-one (1-in-1) and one-in-ten (1-in-10) year forecasts. The load assessment determines the capability of the distribution system to maintain adequate electricity supply to customers under worst case or one-in-ten conditions. Additionally, Hydro Ottawa works with industry stakeholders on the IRRP for the Ottawa area to address electricity needs at substations connected to Hydro One Network Inc.'s (HONI) transmission system. Hydro Ottawa continues to improve load forecasting methods by reviewing regulatory and legislation changes which may impact electrical growth in the future.

Increasingly, customers are seeking greater support and advice from Hydro Ottawa for new technologies such as electric vehicles and ERFs. Hydro Ottawa reviews these requests to determine solutions which meet customer's requirements, while maintaining the electrical grid's integrity, safety and adherence to good utility practices. To facilitate these connections Hydro Ottawa continually evaluates and updates internal interconnection and design standards to best enable the integration of customer-owned technologies such as behind-the-meter generation or ERF.

Enable Energy Resource Facility (ERF) Connections

Hydro Ottawa evaluates and coordinates the connection of ERFs on the electrical system, working with both HONI and the IESO as required. Hydro Ottawa determines and communicates requirements for ERF interconnection to avoid negative impacts to the distribution system. This includes requirements for control and monitoring when required to ensure Hydro Ottawa is able to evaluate the impact of ERFs and their contribution to offsetting the system's peak demand for forecasting. Currently, there are three (3) substations which are restricted from connecting new ERFs due to technical limitations. These restricted substations are HONI's Slater TS (short circuit limited), Lisgar TS (thermally limited) and Hydro Ottawa's Ellwood MTS (short circuit limited). Hydro Ottawa continues to evaluate these constraints, working with HONI as needed, to determine solutions to reduce or eliminate the constraints.

Additionally, as an increasing number of customers seek to connect to the system and incorporate new technologies, Hydro Ottawa strives to ensure connections can be made while maintaining the electrical grid's integrity, safety and adherence to good utility practices. Hydro Ottawa's *Project Prioritization Procedure* identifies projects that increase the opportunity for ERF connections. When considering system renewal, Hydro Ottawa rebuilds communication, protection and infrastructure which can enable interconnection of larger ERFs.

6.2. Asset Value Strategy

6.2.1. Value Optimization

Hydro Ottawa aims to maximize asset value by determining optimal asset replacements and balancing capital and O&M solutions; it achieves this goal by comparing costs and benefits and mitigating risks of candidate solutions. Below are highlighted initiatives Hydro Ottawa undertakes to maximize asset and project value.

Asset Program Replacement

Hydro Ottawa seeks to proactively replace assets to 'levelize' the replacement costs and resource requirements over the assets' operating life. Specific assets are then prioritized based on their condition as determined through the ACA, using detailed inspections and the methodology described in GEG0001 – *Asset Health Index Guideline*. Proactive replacements avoid years of increased asset failures and achieve the delivery of the asset management objectives. Starting in 2020, Hydro Ottawa intends to use the asset investment planning and management software tool, C55, to evaluate the large inventory of in-service distribution assets in order to forecast replacement needs. The asset analytics module of C55 provides a long-term view to analyze replacement options, utilizing an asset's age, existing condition, future condition degradation and risk profile to provide optimal replacement rates. This approach allows Hydro Ottawa to predict years when asset failures are expected to significantly increase, potentially causing uneven years of high replacement costs, constrained labour resources and decreased levels of service reliability.

Project Optimization

Hydro Ottawa's investment decision-making process utilizes the asset investment planning and management software tool C55 to evaluate and optimize projects and to create a plan that balances performance, risk and cost. The Asset Planning section utilizes asset information discussed in Section 6.2.2 and system information to determine improvements through capital, operation and maintenance solutions. When a need is identified, multiple alternatives such as corrective maintenance, replacement or no action are created, analyzed and evaluated in order to achieve the desired asset management objectives and performance targets.

Hydro Ottawa considers several key factors in the determination of the optimal balance of investments across the asset portfolio. These include asset condition, lifecycle cost, labour resources, risks and benefits. Hydro Ottawa uses value measures to define risks and benefits/opportunities. Potential risks include deficiencies to health and safety, system capacity, environment stewardship, compliance and increasing financial costs. Potential benefits include improving system reliability and program efficiencies, using technical innovation, enabling distributed generation and reducing financial cost.

The agreed-upon asset decision-making method and criteria allow for optimal trade-offs between benefits (performance), risks and costs. The scoring methodology used in the prioritization process is further explained in the Hydro Ottawa *Project Prioritization Procedure*. Additionally, the *Project Prioritization Procedure* describes the methodology for consistent decision-making which allows for unbiased results. It also defines the review of the investment decision-making methodology and value measures to ensure they are applicable to stakeholder's values.

The finalized program and portfolio of projects are annually approved by the Manager, Asset Planning after being reviewed and approved by internal stakeholders. Once accepted by Hydro Ottawa's Executive Management Team, the portfolio of multi-year plans and their respective budgets are submitted for approval to Hydro Ottawa's regulator, the OEB, as part of the regulatory rate application process. The resulting program-level solutions from the Capital Expenditure Plan, such as pole replacements, are documented in their respective AMPs.

6.2.2. Asset Lifecycle Cost

Hydro Ottawa aims to reduce the total life-cycle cost of assets by managing the distribution system in a fiscally responsible manner through efficient planning, procurement, design and deployment of programs and projects over the asset's lifecycle.

Hydro Ottawa asset lifecycles go through four (4) major stages as shown in Figure 6-1 below. As an asset progresses through its lifecycle, numerous stakeholders throughout Hydro Ottawa are involved. The effective and efficient coordinated activities amongst these groups and sections are required to reduce the total cost of assets and to ensure that the maximum value is achieved. Below are highlighted initiatives Hydro Ottawa undertakes to maximize asset value by managing asset lifecycle cost.

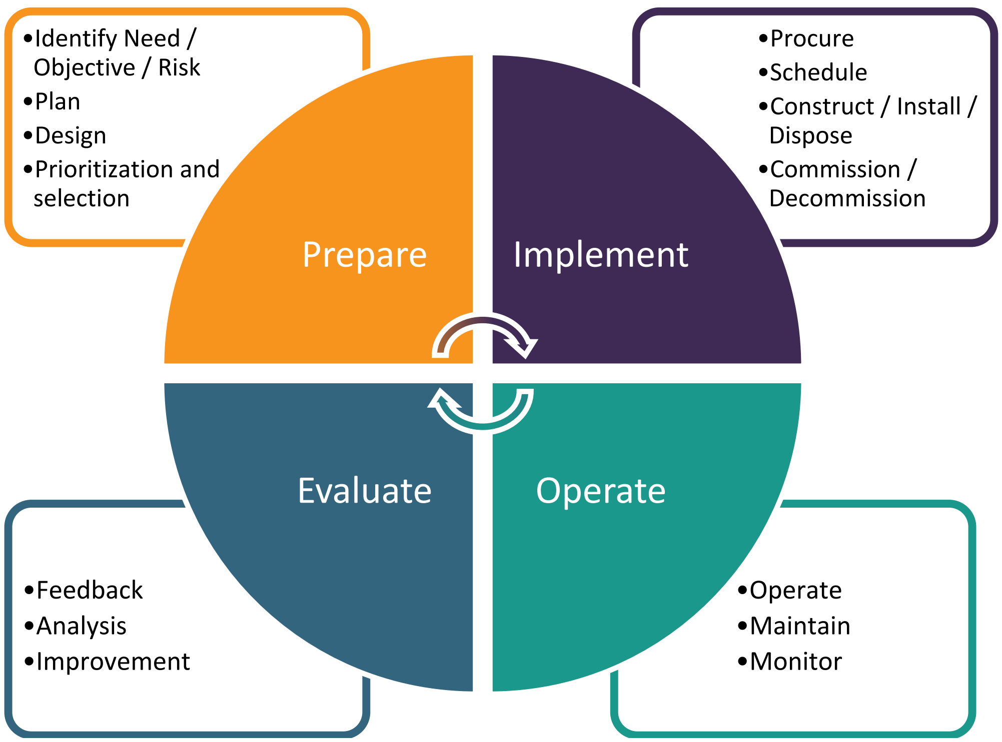


Figure 6-1: Asset Lifecycle Stages

6.2.2.1. Prepare Stage

Multiple Solution Evaluation

Hydro Ottawa completes and evaluates a range of potential solutions to improve the distribution system and deliver on asset management objectives. These alternatives can include do nothing, like-for-like replacement, upgrades, repair or corrective maintenance activities. Additionally, the use of new technology is a key consideration to improve the capability of existing assets and take advantage of advancing their performance. An important step when evaluating new technology is the Equipment Approval Committee, which engages stakeholders form across the company to evaluate new equipment prior to introduction into the distribution system. This process allows Hydro Ottawa to proactively improve the installation process for new types of equipment, and prevents unintended scenarios where individualized pieces of equipment are installed that could result in higher maintenance and repair costs. Project alternatives are documented, evaluated and prioritized in C55 to ensure the balancing of benefits, risks and cost.

Guidelines, Standards and Specifications

Hydro Ottawa has established numerous guidelines, standards and specifications for asset management related activities. These documents guide staff to ensure the consistent management, design, construction, maintenance and operation of the distribution system, and to continually deliver safe, cost effective, reliable electric service. Hydro Ottawa has developed and continues to develop specifications and standards utilizing industry best practices to identify solutions appropriate to the characteristics and historical context of the distribution system. Hydro Ottawa's Distribution Policies and Standards section or delegated personnel develop these documents through stakeholder engagement and due diligence.

Third Party Collaboration

Hydro Ottawa engages with third parties such as telecommunication companies and the City of Ottawa to to better coordinate similar activities and timelines for construction work within our service area. Collaboration with third parties allows for reduced costs through cost agreements for shared work such as excavation and traffic management plans between the parties. To aide in understanding the various construction activities occurring in the service area, Hydro Ottawa actively participates in the Utility Coordinating Committee (UCC) and uses Envista, a map-based coordination tool for utilities working in the right-of-way, to share plans with other parties and learn what activities they are undertaking. Additionally, Hydro Ottawa collaborates with HONI through ongoing communication of planned substation work to ensure the proposed solution works for both parties.

Project Prioritization

Refer to section 6.2.1.

6.2.2.2. Implement Stage

Material Standardization

Hydro Ottawa ensures that equipment used in the construction or repair of the distribution system has been internally approved. Hydro Ottawa follows the working procedure ESS0008 — *Equipment Approval Process* to evaluate equipment on numerous factors including safety, functionality, reliability and affordability. To effectively accomplish this objective, as well as to better manage equipment stock, Hydro Ottawa endeavors to standardize equipment used throughout its distribution system. This generally includes purchasing assets based on approved internal specifications and strategic partnerships with manufacturers and vendors. This strategy also improves asset value by limiting the accompanying standards, which may be asset-specific and increasing general knowledge and familiarity of Hydro Ottawa employees with the equipment.

First-in-First-out (FIFO)

Hydro Ottawa's Supply Chain section strives to increase asset value by minimizing an asset's financial depreciation while being stored in inventory. This is achieved through a FIFO approach in which the goal is for the oldest asset procured to be used for the first job requiring it. This approach encompasses both emergency spare and planned project assets, ensuring that all assets are effectively used. Best results are achieved when efficiently managing higher cost, long lead time assets such as distribution transformers and switchgear, each of which are tracked by serial number, as well as, by date of manufacture.

Request for Proposals (RFP)

Hydro Ottawa issues RFPs for stock inventory, non-stock material and services. The RFP process allows for increases in asset value by promoting competition among vendors, with bid evaluations based upon multiple criteria including cost, quality, adherence to specifications, industry experience and knowledge. These processes are described in POL-Fi-003 – *Procurement Policy* and the PRO-Fi-013 – *Contract Procurement Process*. Hydro Ottawa's Supply Chain section works with project managers on specific jobs to review the RFPs and evaluate the proposals before ultimately awarding a contract agreement to the vendor to ensure the selected vendor provides Hydro Ottawa with the most value.

Resource Scheduling

Refer to section 6.3.

6.2.2.3. Operate Stage

System Normalization

Hydro Ottawa's System Operations section continuously strives to ensure that the distribution system is operating in an optimal state. The distribution system has been designed and configured using best and prudent engineering practices in order to provide a safe and reliable supply of electricity to customers while minimizing system losses and maintaining effective operational control. However, due to factors such as planned work, unplanned outages and defective equipment, the distribution system is often in an abnormal state, such as feeder reconfiguration. The condition is recorded by System Operations on live operating maps using electronic pins which describe the reason behind the abnormality. As work is completed, returning the system to the normal state is given priority and the electronic pins are removed. Annually, System Operations reviews all system abnormalities and works with stakeholders to ensure jobs are being completed to return the system to an optimal state.

24/7 Staff

Hydro Ottawa's System Operations unit works on shifts to ensure there are employees available 24/7. In addition on-call employees are available outside of regular hours to assist with emergencies if required, which allows for timely responses to abnormal system conditions such as power outages occurring after normal work hours. Furthermore, the 24/7 staff supports the completion of distribution system re-configuration to allow for maintenance and construction work. This includes small construction projects, operating switches in the distribution system to set up future planned work and isolating customers upon request to complete maintenance and construction activities.

Protection/Remote Operability Strategies

Hydro Ottawa's protection philosophy standard follows a fuse saving strategy as described in GDS0008 – *Substation Protection Design Guide*. By using a fuse saving method, temporary faults such as tree contacts will not result in a sustained outage to customers and Hydro Ottawa does not have to redirect resources from planned work to the outage location for system switching and restoration work. Hydro Ottawa also implements remote operable devices in key locations which can be controlled by the System Operations section through its Supervisory Control and Data Acquisition (SCADA) system. Operating these devices remotely reduces outage durations and operational costs by eliminating the need to send a crew to physically operate the equipment.

Reliability-Centered Maintenance

Hydro Ottawa has reviewed, considered and integrated concepts of Reliability-Centered Maintenance (RCM) strategy for its distribution assets. Moving forward, Hydro Ottawa looks to continue adopting best practices and plans to implement RCM. Traditionally, time-based preventative maintenance cycles have been used by Hydro Ottawa. Although effective, time based maintenance can create inefficiencies and the inability to prioritize higher risk interventions. Hydro Ottawa now prioritizes reactive maintenance activities based on the condition of its assets rather than via time-based schedules. By utilizing asset condition data to drive maintenance activities, Hydro Ottawa expects increases in cost effectiveness, reliability and a greater understanding of the level of risk of equipment that the organization is managing.

6.2.2.4. Evaluate Stage

Climate Impact Study

Hydro Ottawa constantly looks to identify opportunities and threats to its electrical distribution assets to ensure they are able to continue to deliver value throughout their lifecycle. In order to further improve upon existing asset management practices, Hydro Ottawa undertook a distribution system climate vulnerability risk assessment (CVRA) and developed a Climate Change Adaptation Plan with an external consultant. The CVRA was used to evaluate potential impacts and risks to the Hydro Ottawa electrical distribution system and supporting infrastructure as a result of changing climate and extreme weather events. This assessment process followed the Canadian Electricity Association's guide on adaptation to climate change, and Engineers Canada's Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. This assessment methodology conforms to the International Organization for Standardization (ISO) 31000 Risk Management Standard, to identify relevant climate parameters and infrastructure responses, and assign risk ratings to each response to relevant climate considerations. The process involved the systematic review of historical climate information and the projection of the nature, severity and probability of future climate changes and events. The assessment of climatic changes was used to establish the exposure of infrastructure systems to these climate events. The impact of a particular damaging or disruptive climate event was then quantified and used to calculate the risk for a particular climate-infrastructure interaction. This process was repeated for all applicable infrastructure elements to produce an electrical distribution infrastructure climate risk profile.

The CRVA followed the following methodology:

1. Identification of climate events (e.g. temperature, precipitation, winds) and their threshold values above which infrastructure performance would be affected and projecting the probability of occurrence of the climate hazards in the future (i.e. 2050s).
2. Assignment of a probability score for each climate event based on climate data. This involved converting the projected probability of occurrence of future climate parameters into the five-point rating scale used in Hydro Ottawa's Asset Management System Risk Procedures.
3. Assignment of a severity rating for the impact of climate events on each element of the distribution system considered in the assessment. Impacts on the infrastructure were assessed for various performance criteria. This part of the assessment was completed through a staff workshop.
4. Calculation of the risk for each infrastructure element was performed.
5. Using Hydro Ottawa's Asset Management System Risk Table, medium, high and very high risks to infrastructure and operations were identified.

The adaptive capacity – the ability of a system to respond which takes into consideration factors like, age, design setting, etc.– of the infrastructure elements were taken into account during the risk assessment stage.

This study identified a number of risks, which will be considered in the management of Hydro Ottawa's assets moving forward. 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 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.

Key adaptations which have been incorporated into Hydro Ottawa's 2021-2025 Asset plans and Distribution system plans include: planning for climate, increased system resilience, and increased operational capability.

Planning for climate, in response to a changing climate Hydro Ottawa formalize the incorporation of climate into its planning systems, to ensure risks and adaptation remain current as climate trends and science evolve. Hydro Ottawa will continue to perform post-event analysis to identify lessons learned.

Further, Hydro Ottawa will ensure future climate resilience is considered in all decision making practices, and establish recurring process to evaluate vulnerability risks to ensure long term sustainability of its current investments.

Increased system resilience, will focus on sustaining and introducing practices to mitigate damage during severe wind and ice events. Hydro Ottawa will evaluate and implement where feasible augmentations to its vegetation management practices to mitigate the impact of extreme weather. Building on the success of Storm hardening, and revised vegetation management practices implemented in 2014/2015, Hydro Ottawa will work with the City of Ottawa and the Village of Casselman to explore feasibility to expand trimming to include heritage trees, and trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability.

Renewal of aged and decayed overhead infrastructure to withstand climatic forces from storm events is key to resilience over the long term for the system. Most notably Pole Renewal programs support the development of this resilience. Hydro Ottawa will augment the impact of these renewal investments, over the 2021-2025 period through the development of new anti-cascade standards, and risk based application guides to further mitigate damage in high risk installations when damage does occur. Hydro Ottawa will continue to invest in appropriate technologies to augment its response to outages when weather events due cause interruption. These include system capacity investments to maintain sufficient operational capacity and redundancy, as well as, automation investments, to enable remote and automatic, isolation and restoration of faulted system components.

Asset Condition Assessment (ACA)

Asset Condition Assessments (ACAs) are critical in determining the condition and probability of failure of Hydro Ottawa's distribution assets, and are an input to the determination of end-of-life of discrete assets or combined asset classes as described in Section 5.3.

As Hydro Ottawa increasingly moves to condition-based decision making, the requirement for data collection has become more important. Hydro Ottawa continues to inspect distribution assets per regulation and inspection procedures, collecting information required for each asset's ACA. This analysis is used to support the capital and maintenance plans required for the continued maintenance and enhanced performance of the distribution system in a cost effective manner. Hydro Ottawa continues to gather the required information for all assets where ACAs are conducted. Further details can be found in the respective AMPs.

Corrective Actions

Hydro Ottawa performs inspections and verifications of both equipment and construction work to ensure that they meet the associated standards and specifications. This ensures the continuity of grid integrity and safety, as well as ensuring the assets are procured and constructed in such a manner to provide value over their intended operating life. Hydro Ottawa follows developed procedures to correct non-compliance issues discovered through inspection. Hydro Ottawa's ESS0008 – *Equipment Approval Process* ensures that any equipment received is inspected and verified to ensure compliance without defect. Additionally, Hydro Ottawa's ESG0001 – *Construction Verification Program* working procedure details inspections to confirm that construction was built in accordance with the associated plan, work instruction or standard designs. Should there be non-conformance with either process, the procedures specify the steps that are followed to resolve and document the actions taken. This working procedure is in compliance with Ontario Regulation 22/04 which stipulates laws for inspection and approval of construction in distribution systems.

Single Asset Repository

Hydro Ottawa uses a Geographic Information System (GIS) to collect and track information for its distribution assets. Using a single asset repository allows for a 'single source of the truth' as well as a centralized system for employees to obtain and utilize asset data. Along with electrical connection and geographic location, the GIS system captures asset-specific information such as nameplate data and installation year, as well as photos and inspection records for specific assets. Hydro Ottawa's GIS and Distribution Records unit continually updates this information for newly constructed assets and for updates or corrections to existing information by Hydro Ottawa employees authorized to access and update GIS records.

6.3. Resource Efficiency Strategy

6.3.1. Employee Competency

Hydro Ottawa aims to ensure employees are aware, competent and empowered by providing requisite and appropriate education, training and experience. A highly-skilled, properly-trained and knowledgeable workforce is essential to Hydro Ottawa's continued success. Below are highlighted initiatives Hydro Ottawa undertakes to ensure employee competency.

Asset Management System Awareness

Hydro Ottawa ensures that all employees, particularly persons doing work associated with distribution asset management, are aware of the AMS through various communication media from people leaders and through Hydro Ottawa's intranet as defined by IAP0021 – *AMS Communication Plan*. This provides employees with understanding of the relevant business and asset management objectives, their contribution to the effectiveness of the AMS and implications of non-conformance with the AMS requirements.

Workforce Training

Hydro Ottawa's asset management activities rely on the knowledge, skills and education of numerous groups throughout Hydro Ottawa. Training is achieved through formal education and "on-the-job" learning. Additionally, internal and external training courses, attendance at industry conferences and technical presentations, and memberships in professional associations enable employees to keep up-to-date on new technologies and practices to enhance their existing skills. The following accreditations and professional designations may be required depending on the employee's role and their requirement to demonstrate the achievement of knowledge essential to their position:

- Journeyperson certification
- Ontario Association of Certified Engineering Technicians and Technologists certification
- Professional Engineer licensure
- Project Management Professional certification
- Chartered Professional Accountant certification
- Supply Chain Management Professional certification

Hydro Ottawa's training and development program delivers courses in three (3) categories:

1) Safety and Trades Training: Provides re-certification courses and continual skill upgrading to ensure staff remain competent and safe;
2) Professional Development Offerings: Delivers programs that focus on innovation and productivity, technical and business skills;
3) Management and Leadership Development: Continued training on skills required to succeed as a people leader at Hydro Ottawa.

In-house training and development is offered through Hydro Ottawa's Organizational Development Group within its Human Resources Division, which provides course offerings specific to an employee's roles and duties. Additionally, Hydro Ottawa's Training Council creates a platform where issues that impact training and development on a corporate level can be reviewed and discussed on an ongoing basis.

Technical and Trades Development

Hydro Ottawa continues to be a proud partner with Algonquin College in the delivery of a two (2)-year Powerline Technician Diploma Program. This partnership allows Hydro Ottawa to provide training for future Powerline Maintainer and Power Cable Apprentices while identifying ideal candidates for post-graduation hiring. Furthermore, Hydro Ottawa is also pleased to be a partner with Algonquin College to provide a Training Delivery Agent (TDA) which allows Hydro Ottawa to deliver the annual in-class and practical training required for Power Line Technician Apprenticeships. The program has completed its second year, providing training for Apprentices in their first and second years of apprenticeships. By 2020, Hydro Ottawa will be administering training for Power Line Technicians of all levels and be the sole TDA provider in Eastern Ontario. In addition, Hydro Ottawa is actively exploring opportunities to further develop this partnership through the establishment of a co-op program for Certified Engineering Technicians and Technologists as well as further trades development in roles which involve staff responsible for asset management activities. Hydro Ottawa also offers an Engineering Intern Training and Development Program to enable engineering graduates to learn from professional engineers while obtaining the necessary experience and training to obtain professional designation.

Working Groups

Hydro Ottawa participates in and supports numerous external and internal councils, committees and working groups. Hydro Ottawa actively encourages its employees to be involved with these groups, as they allow for the collaboration of industry experts on topics pertinent to our business. External groups allow Hydro Ottawa employees to both learn and teach others on the best practices in the industry and where trends and changes are expected. Internal groups allow for cross-discipline and divisional collaboration to ensure all stakeholders' input is gained. Appendix B shows the councils, committees and working groups in which Hydro Ottawa participates that affect asset management activities.

6.3.2. Productivity Management

Hydro Ottawa focuses on maximizing the efficiency and effectiveness of the work force by increasing productivity at every opportunity. This includes ongoing efforts to improve the efficiency of our capital work, reduce operating costs and maximize the productivity of our workforce. Hydro Ottawa strives to cultivate a culture of innovation and continuous improvement, focusing on three outcomes in particular: (1) a safe and healthy work environment; (2) an engaged, aligned and prepared workforce; and (3) efficient and effective operations that enhance the customer experience. The ability to engage employees from different functions and disciplines to work closely together is essential to the success of asset management at Hydro Ottawa. Below are highlighted initiatives Hydro Ottawa undertakes to maximize asset management related productivity.

SCADA

Hydro Ottawa is currently in the process of replacing both the hardware and software components of its SCADA system. The Grid Technology section is undertaking this upgrade due to end-of-life equipment and obsolescence of both software and hardware components. SCADA is an integral part of many functions at Hydro Ottawa, and the new SCADA system will provide a foundation for applications which drive productivity process efficiency such as an Advanced Distribution Management System (ADMS). An ADMS will provide system operators with increased analysis capability and distribution system awareness. Further, the new system includes a pre-production environment that allows for improved testing during activities such as the commissioning of new SCADA points.

Telecommunication Master Plan

Hydro Ottawa is currently executing a Telecommunication Master Plan project. This initiative involves the installation of high-speed communications at Hydro Ottawa substations. Specifically, 75 substations will be connected to a core wide area network comprised of high capacity fiber optic cables. The remaining 14 substations will be connected by radio systems creating a field area network. Additional fiber connections will include Hydro Ottawa's work centers. This project provides a range of benefits to Hydro Ottawa, including increased productivity through the new communication to substations, which will allow for remote operation and monitoring of the distribution system. Such tasks will include programming protection relays and analysing recorded information.

Mobile Workforce Management

Hydro Ottawa has implemented a Mobile Workforce Management (MWM) tool to schedule and dispatch field crews to complete high volume, short cycle work such as metering, collections, new service connections, inspections and service truck work. The tool effectively schedules and optimizes travel routes to increase productivity of staff and ensure Hydro Ottawa meets or exceeds customers' expectations. This also reduces time spent on scheduling which can be used for higher value work activities. The MWM tool will continue to provide increased productivity as it is expanded to further work groups and include maintenance and longer cycle projects.

Service Manager Upgrade

Hydro Ottawa has upgraded to the Service Manager software used for organizing customer-requested work. The new tool will increase productivity by reducing the volume of manual work required through smart integrations with other software applications currently used and our website for online service requests.

6.3.3. Resource Optimization

Hydro Ottawa endeavors to deliver optimized resources for its asset management activities through the use of both internal and external workers. This achieves increased asset value by minimizing labour costs on specific work activities and maximizing the volume of work which is completed efficiently. Below are highlighted initiatives Hydro Ottawa undertakes to maximize asset and project value.

Workforce Planning Strategy

Hydro Ottawa continues to focus on maintaining a qualified workforce by attracting and developing young workers and by planning and facilitating an effective transfer of knowledge and skills to these workers from our more experienced workforce. Hydro Ottawa's comprehensive Talent Management Strategy is aimed at anticipating and meeting talent needs through planning, talent attraction and acquisition, effective deployment of resources, and performance management and development. Hydro Ottawa has established the Workforce Planning Core Planning Team, which brings together a cross-functional group of managers and directors to determine the workforce needs for required trades and technical roles/positions for both the short and long term. This is completed by reviewing the labour demand needed to accomplish operational and business requirements, and labour supply including employee competency, retirements/retirement eligibility and internal movements. This analysis determines the best combination of internal resources, new hires, utilization of overtime and use of contracted services.

Mutual Aid

Hydro Ottawa is a volunteering member of the North Atlantic Mutual Assistance Group, comprised of utilities across northeast Canada and the United States. This group delivers not-for-profit assistance to each other during times of crisis or emergencies when an act, such as a severe weather event, exceeds the capabilities of a utility to reasonably restore or maintain electrical service to customers. Hydro Ottawa's involvement has allowed for numerous supporting events to assist various partnered utilities and allows for the ability to request support from other utilities, optimizing the available resources to manage the electrical system, should it be necessary.

Crew Size Optimization

Hydro Ottawa has reviewed the utilization of internal resources used for construction and maintenance activities on the distribution system. Based on the scope of work typically completed, these resources have been organized into large and medium construction crews and reliability crews. This restructuring allows for effective deployment of resources based on the work requirement, improving productivity in completing the activities. Table 6-1 describes the restructuring of crews, the respective resources and the scope of work.

Table 6-1: Optimized Crew Description

Crew Type	Labour Resources	Scope of Work
Large Construction Crew	Distribution Operation Supervisor 6-8 Power Line Technicians	Large-scale system renewal or system service work (e.g. replacement of 30-100 poles)
Medium Construction Crew	4-5 Power Line Technicians	Medium-scale system renewal, system service and demand work (e.g. asset relocation)
Reliability Crew	3-4 Power Line Technicians	Small-scale system renewal, system service, damage to plant and reliability work (e.g. replacement of end-of-life assets)

Each type of crew has specific advantages: Larger crews lead to more diverse skills which are beneficial when dealing with the increased number of tasks and providing the required problem solving on large, complex projects. They also utilize more equipment efficiently which leads to decreased project timelines, reducing planned outages, project set up and travel costs and the number of traffic interruptions. Smaller crews are more flexible and mobile for completing a large number of smaller projects. The decrease in size allows for work to be completed in areas with space limitations, reduces the impact of public disruption, increases work coverage in the service area and allows Hydro Ottawa to economically complete small work request projects from third parties.

Hydro Ottawa reviews program requirements and delivery to ensure crew structure and resource allocation remains optimal. As requirements and initiatives change, crew structure and personnel assignment are modified to best align with the needs.

Weekend Blitz

Hydro Ottawa occasionally optimizes the use of its internal and external resources to complete large-scale construction projects during weekends, often requiring road closures. This is executed after thorough, collaborative planning to ensure the adequate resources and required third parties are available and that city and other regulatory permits can be obtained. This construction method can be internally driven or requested by third parties such as developers to meet their timelines. While there are increased labour costs associated with this strategy due to over time, many factors provide offsetting value such as:

- A safer work environment with no distractions due to closure of roads
- Expedited project timelines due to efficiencies from large commitment of resources
- Reduction in daily traffic setup and traffic management
- Reduction in daily power outages which may be required
- Reduction in customer impact, specifically to commercial customers who are closed on weekends
- The ability to efficiently complete off-road work when weather permits
- Minimized disruption to other work groups which require the resources for daily tasks
- Minimized environmental impact

Hydro Ottawa continues to evaluate projects which can benefit from this construction method.

Geotab

Hydro Ottawa has implemented Geotab global positioning system software on vehicles used to support asset management activities. While primarily used by Hydro Ottawa's Fleet section, Geotab provides real-time monitoring of where vehicles and crews are located. This provides Hydro Ottawa supervisory personnel with increased situational awareness and resource optimization by dispatching the nearest crews with the proper equipment and skills during outages, storm events or distress calls. Additionally, the increased situational awareness allows for efficient site visits by knowing exactly where crews are, and support using recorded data in the event of customer complaints.

Standing Offers

A significant amount of work completed on Hydro Ottawa's distribution system is repeatable and consistent, such as drilling a pole hole. In consideration of limited resources and equipment, as well as crew scheduling commitments for higher priority work, it is more economical for contractors to be engaged to complete this work. Hydro Ottawa secures this specialized labour via a competitive procurement process known as a Request for Standing Offers (RFSO). Standing Offers allow Hydro Ottawa to engage multiple contractors for work on an "as needed" basis at fixed rates over a 2-3 year agreement period. Vendors are evaluated on multiple criteria including health and safety, technical capabilities, utility customer references and pricing.

6.4. Health, Safety and Environment Strategy

6.4.1. Employee and Public Safety

Hydro Ottawa aims to eliminate or mitigate all existing and potential risks to employee and public safety. To achieve this, Hydro Ottawa has established an Environment and Occupational Health and Safety management system which complies with British Standard 18001 – *Occupational Health and Safety Assessment Series*. The management system dictates the strategies, policies and procedures required to promote safe work practices and prevent injuries. Below are highlighted initiatives Hydro Ottawa undertakes to ensure employee and public safety.

Material & Construction Standards and Standard Work Methods

As described in section 6.2.2.1, Hydro Ottawa's Distribution Policies and Standards section establishes equipment specifications, construction/installation standards and standard work methods based on internal and industry standards, codes and best practices. Equipment specifications follow ESS0008 – *Equipment Approval Process* to ensure equipment procured and utilized in the distribution system is safe for employees and the public. Construction standards and standard work methods are designed to provide Hydro Ottawa staff and external contractors with engineered methods for the work that they carry out to ensure safety is maintained. Additionally, through the training and apprentice programs described in section 6.3.1, Hydro Ottawa ensures employees are given hands-on training and experience with safe work practices.

Operation Instructional Videos

Hydro Ottawa has developed training aids for operations staff on how to safely and correctly operate devices on the distribution system. Hydro Ottawa's distribution system was built over decades as the City of Ottawa expanded and electric utility systems were amalgamated, resulting in the collection of various types of equipment from numerous manufacturers and differences in design practices as technology evolved. Staff may be required to operate equipment that is uncommon in the system and therefore may be unfamiliar with the proper operating techniques. Accordingly, Hydro Ottawa has developed video operational aids which can be viewed as a refresher to address this issue.

Public Safety Awareness

Hydro Ottawa strives to increase customer and public awareness of the safety measures associated with our distribution assets. Annually, Hydro Ottawa representatives present safety information to numerous elementary schools within our service area. These presentations are informative and dynamic, tailored to students in two groups: (1) kindergarten to grade 4, and (2) grade 5 to grade 8. Hydro Ottawa has also developed a series of animated videos to provide safety messages to the public. While oriented towards children, the videos culminate with a safety quiz requiring the assistance of an adult, thus reaching a larger audience. These resources are communicated on Hydro Ottawa's external web site and through social media. Hydro Ottawa continues to increase its outreach in educating the public about electrical safety.

Building Permit Approval

Hydro Ottawa works with the City of Ottawa to provide proactive comments to requesters, primarily developers, on construction or demolition plans. These comments center on the proximity of distribution assets to the planned development site. Hydro Ottawa has several standards which dictate the allowable space required to ensure public safety. The City of Ottawa has worked with Hydro Ottawa to extend this proactive approach to other permitting activities such as pool installations. Being proactive allows Hydro Ottawa to ensure safety measures are being followed and allows the developer to modify their project, if required, which reduces potential unforeseen costs.

6.4.2. Environmental Stewardship

Hydro Ottawa undertakes efforts to minimize its environmental footprint by reducing the release of controlled or environmentally damaging substances. To achieve this objective, Hydro Ottawa has established an Environment and Occupational Health and Safety management system which complies with ISO 14001 – *Environmental Management*. The management system dictates the strategies, policies and procedures required to promote environmental protection and pollution prevention in balance with socio-economic needs. Below is a highlighted initiative Hydro Ottawa undertakes to ensure environmental stewardship.

Polychlorinated Biphenyl (PCB) Replacement

Federal Regulation SOR 2008-273 – *PCB Regulations* dictates requirements to replace equipment with oil containing PCBs by various dates depending on the PCB concentration. While the regulatory obligations has timelines as far out as 2025 (for pole mounted transformers), Hydro Ottawa has elected to take an accelerated approach to remove the transformers from service. This strategy ensured the removal of the risk that any oil leaked by these transformers would release PCB to the environment.

Infrared Scanning and Oil Spill Remediation

HOL reports to the Ministry of the Environment on the volume of oil spilled and the cost of remediation. HOL performs routine inspection programs on oil filled equipment and actively manages replacements to mitigate the environmental impact of oil spills making use of infrared scanning. Further detail can be found in the AMPs.

6.5. Compliance Strategy

6.5.1. Internal Compliance

Hydro Ottawa aims to ensure internal requirements are met by adhering to internally approved policies, procedures, standards and controls. Below are highlighted initiatives Hydro Ottawa undertakes to ensure internal compliance.

Internal Audit

Hydro Ottawa recognizes the importance of independent audits to ensure that procedures are adequate, are being complied with and to assess and improve the effectiveness of the AMS with respect to the ISO 55001 standard. Hydro Ottawa’s internal audit procedures cover the examination and evaluation of all AMS elements on an annual basis, with the exception of years where an external audit on the AMS is completed. Corrective activities are carried out to resolve gaps and to support continuous improvement. Hydro Ottawa’s Internal Audit and Risk Management section is consulted to ensure consistent best practices are applied.

Project Tracking

Hydro Ottawa has established control measures to actively monitor and regulate the completion of capital and maintenance activities with respect to distribution assets. Project risks are assessed by the responsible stakeholders and presented on a monthly basis to managers and directors responsible for asset management. The desired asset management objectives are achieved by reviewing and balancing the risks identified with proposed solutions prior to selecting a specific plan or work activity.

6.5.2. External Compliance

Hydro Ottawa strives to maintain status as a distributor in good standing and preserve our distribution license by complying with all applicable regulations, laws, standards and acts. Hydro Ottawa's Regulatory Affairs group works with the required stakeholders to ensure alignment and compliance with the OEB. Below are highlighted initiatives Hydro Ottawa undertakes to ensure external compliance.

External Audit

Hydro Ottawa recognizes the importance of independent audits to ensure that procedures are adequate, verify that the procedures are being complied with and to assess and improve the effectiveness of the AMS with respect to the ISO 55001 standard. Hydro Ottawa's external audit will cover the examination and evaluation of all AMS elements. Correction activities will be carried out to resolve gaps and continually improve. External audits will be completed as required and every three (3) years minimally should Hydro Ottawa seek certification.

Additionally, Hydro Ottawa undergoes an annual external audit to ensure compliance with Ontario Regulation 22/04 – *Electrical Distribution Safety* with the Electrical Safety Authority. This audit is coordinated by the Occupational and Public Safety section with numerous stakeholder involvements across asset management activities. This audit ensures the adherence to requirements of Ontario Regulation 22/04 – *Electrical Distribution Safety*, as well as identifies recommendation to be actioned to support continued improvement.

Financial Spend and Capitalization Tracking

Hydro Ottawa has established control measures to actively monitor and regulate spending activities with respect to its distribution assets. Hydro Ottawa's Finance group provides spending summary reports to Hydro Ottawa's Executive Management Team on a monthly basis. These reports describe spending targets, variations and the reasons behind any variations. The spending reports are also provided to the required stakeholders to ensure the information is communicated to all relevant parties. Additionally, a financial change request process has been established for capital spending adjustments. This allows for the appropriate monitoring and approvals to be given to projects when a variance from the original budget is requested. Hydro Ottawa's Asset Planning section works with stakeholders to determine whether projects need to be deferred or advanced throughout the year to meet the spending targets.

Hydro Ottawa also monitors the ongoing capitalization of assets (capital additions) to ensure values are within designated targets. These assets are tracked monthly by the Finance group and presented to Executive Management Team. They are also presented to the Board of Directors, along with the financial spending, and to relevant stakeholders on a quarterly basis.

7. Asset Information

Asset information and the use of this information to drive and improve business processes and decision making are essential to maximize asset value. This is achieved through analysis, management and the optimization of assets for the benefit of our customers and stakeholders. The use of information is also required to deliver on the principles set out in the Asset Management Policy. In order to ensure that asset information provides value, Hydro Ottawa's desired attributes for information are set out in Table 7-1.

Table 7-1: Hydro Ottawa Information Attributes

Information Attribute	*Description*
Timely	Information must be present for effective decision making. Legacy information can easily become outdated when needed and lack of information or details that can result in delayed decisions and missed opportunities. Hydro Ottawa regularly updates asset information through close-out of work records, inspections and monitoring technology to ensure its timeliness. Should information be required that is not scheduled it will be provided promptly to allow for timely decision making.
Reliable	The quality of decision making relies on the quality of the information used. Inadequate or inaccurate information generally results in less optimal decisions. Therefore, Hydro Ottawa strives to ensure information is accurate and reliable to ensure the best decisions are made.
Accessible	Hydro Ottawa endeavors to make information readily accessible and obtainable to those who require it for their work or in order to make information-driven decisions. This is accomplished through publishing information in available software applications, and Hydro Ottawa's intranet and Hydro Ottawa's servers.
Cost Effective	In order to maximize value, Hydro Ottawa ensures that the collection of information is completed at a reasonable cost. This includes reviewing internal and external resources to collect the information as well as the frequency at which the information is gathered.

Hydro Ottawa utilizes a number of software systems and databases to manage workflows and provide information to support the operation of the AMS, and to store information on the asset base. The software systems and how they interface is seen in Figure 7-1. Their use with respect to asset management processes is described in Appendix D. While numerous software systems are used, information on Hydro Ottawa's assets is primarily resides within the GIS, which acts as a single asset repository, asset connectivity model and asset geospatial record. By making this information, asset locations, demographics and inspection records available in a single location, Hydro Ottawa strives to improve the accessibility of asset data for those who rely on it.

The expectations and requirements for the creation and life-cycle management of Hydro Ottawa's documents, as well as the responsibilities, authorities and inter-relationships are outlined in POL-IM-001 – *Information Management Policy*. Additionally, Hydro Ottawa has established the classification and retention of documented information through the *"Records Classification and Retention V9.1"* guideline and DFS0007 – *Control and Retention of Tech Based Docs and SWM*, detailing the different retention periods for various pieces of information throughout the company based on importance, legal and regulatory requirements. IAS0002 – *Asset Management System Manual* supplements the existing processes with a focus on asset management documented information.

Hydro Ottawa's Information Management section is currently leading the transformation of Hydro Ottawa's information processes. This includes digitizing documents to increase accessibility, removing duplicate and outdated information and re-organizing the classification structure while investigating new technology solutions. The changes implemented through the information management strategy will improve existing Hydro Ottawa processes.

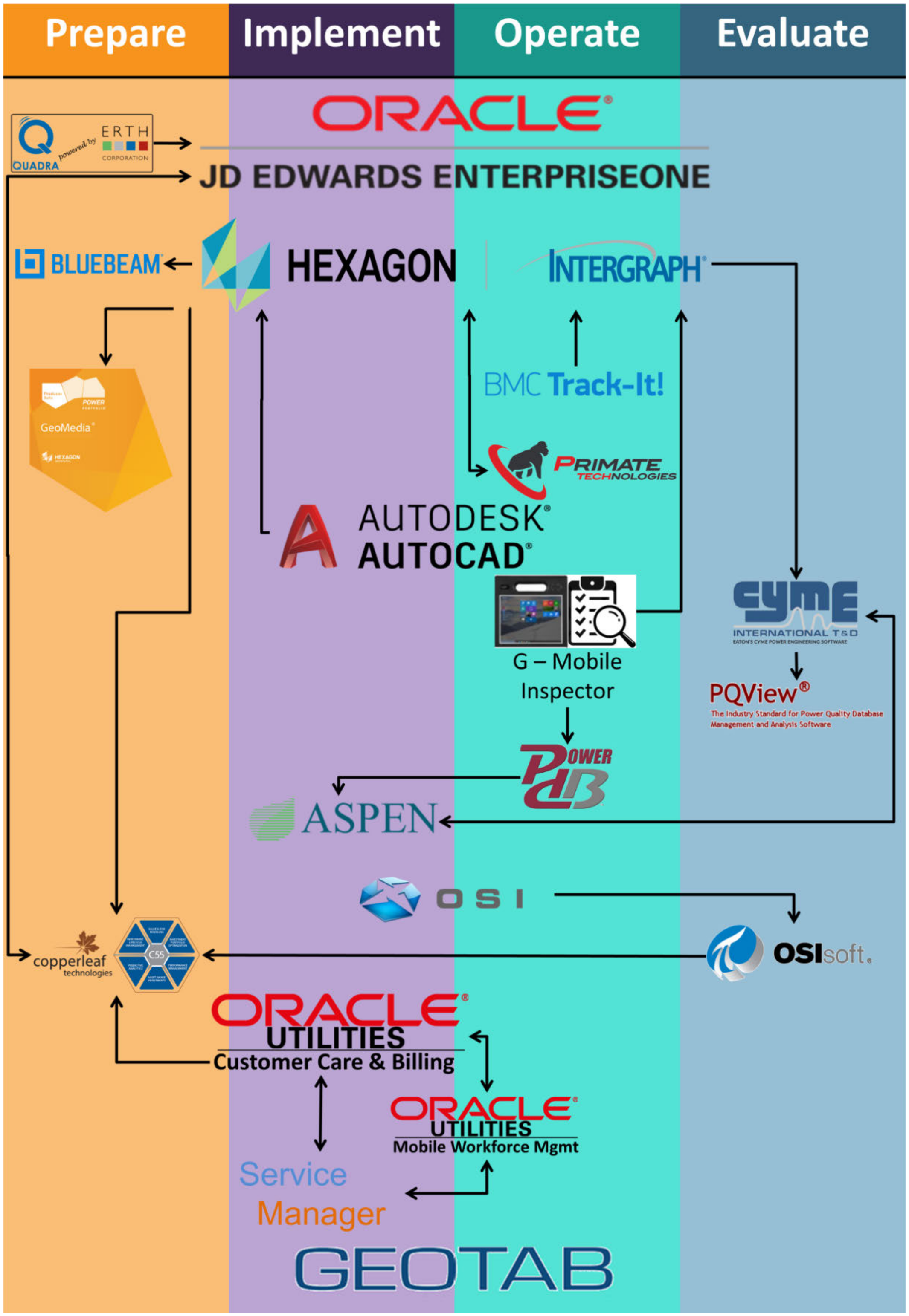


Figure 7-1: Asset Management System Information Software

8. AMS Risk Review

At the strategic level, Hydro Ottawa has developed an Enterprise Risk Management (ERM) framework which is used to identify and make decisions regarding actions to address strategic risks and opportunities.

At an operational level, Hydro Ottawa has developed a risk management process (IAP0022 – *AMS Risk Procedure*) to undertake actions to address risks and opportunities in accordance with the scope of the AMS.

The identification of risks and opportunities affecting the operations and performance of asset management at Hydro Ottawa are established, implemented and maintained through the use of Risk Register in IAP0022 – *Asset Management System Risk Procedure*. The Register is reviewed quarterly by the AMC, and takes into consideration the context of the organization and stakeholder's needs to determine the risks and opportunities that need to be addressed to:

- Ensure the AMS can achieve its intended result(s);
- Enhance desirable effects;
- Prevent or reduce undesirable effects; and,
- Achieve continual improvement.

The Asset Manager leads the review of the Register of Risks and Opportunities quarterly and decides on any actions to address the listed risks and opportunities. This includes how to integrate and implement the actions in the AMS processes and evaluate the effectiveness of actions taken. The actions taken to address risks and opportunities are proportionate to the potential impact on the conformity of asset management practices.

9. Financial Accounting for Assets

The source of financial accounting information for Hydro Ottawa's distribution assets is Oracle's JD Edwards EnterpriseOne (JDE) system. Data from JDE is used in a number of databases and spreadsheets for analysis within the Asset Management organization. Hydro Ottawa's financial accounting on assets follows corporate policy POL-Fi-009 – *Internal Controls over Financial Reporting*. Hydro Ottawa follows the International Accounting Standards Board's (IASB) *International Financial Reporting Standards* (IFRS) for financial reporting for the entire distribution asset base.

Hydro Ottawa utilizes the JDE financial system to record distribution assets as pooled or discrete for the purposes of capitalization, accounting and reporting. Typically, distribution assets are capitalized as pooled while station assets are capitalized as discrete investments. Depending on the situation, a pooled asset class may be broken out into discrete asset components for more visibility and tracking. Hydro Ottawa's corporate policy POL-Fi-013 – *Capitalization Policy* defines the criteria used with respect to the capitalization of distribution assets. The financial system stores the recognized/capitalized assets, asset depreciation and the de-recognition of assets. The difference between the initial cost of the asset and the accumulated depreciation is reported as the net book value. Depreciation of Hydro Ottawa's assets is completed over the lesser period of their expected life or the expected period of future benefit if recorded to be different. The method of pooled or discrete asset classes and their expected useful life are shown in Table 9-1 below.

Table 9-1: Financial Accounting for Distribution Assets

Asset	***IFRS Life (years)***	***Capitalization Method***
Station Equipment >50kV Other	25	Pooled
Station Switchgear >50kV	40	Discrete
Station Transformers >50kV	45	Discrete
Station Equipment <50kV Other	25	Pooled
Station Switchgear <50kV	40	Discrete
Station Transformers <50kV	45	Discrete
SCADA RTU, Relays, Communication Equipment	15	Pooled
U/G Polymer Insulated Cable	35	Pooled
U/G Switchgear & Reclosers	25	Pooled
Vault Switchgear & Reclosers	30	Pooled
U/G PILC Cable	60	Pooled
U/G Conduit & Cable Chambers	40	Pooled
Line Transformers O/H & U/G	35	Pooled
Line Transformers Vault	35	Pooled
O/H Insulators & Conductors	45	Pooled
O/H Switchgear & Reclosers	25	Pooled
Poles, Towers, Fixtures	45	Pooled
Services	45	Pooled

Asset	IFRS Life (years)	Capitalization Method
Telecommunications	8	Pooled
Metering	15	Pooled

10. Performance Monitoring and Continuous Improvement

Hydro Ottawa creates and monitors a number of key performance indicators (KPIs) to inform and continually improve the AMPs and business decisions. Hydro Ottawa has a variety of metrics used to measure performance of assets and asset management activities and reports on several of these KPIs based on regulatory requirements to the OEB through the Reporting and Record Keeping Requirements.

Hydro Ottawa has introduced a new framework of internal KPIs, found in IAP0025 – *Continual Improvement Plan* to support the SAMP. These KPIs amend the existing measures and will monitor performance outcomes and trends aligned with Hydro Ottawa's asset management objectives. The KPIs will also support the review of asset management strategies and associated activities including processes in order to deliver on the business objectives.

Performance monitoring and reporting enables fact-based decision-making in line with the Asset Management Policy's principles. Hydro Ottawa uses the information provided through the KPIs to drive continuous improvements within the various groups and sections which make up asset management, as well as enhance processes, asset management and business strategy planning. Such continuous improvements are also informed by assessing the applicability of industry best practice developments and through stakeholder feedback on existing processes and systems. In addition, IAP0022 – *AMS Risk Procedure* is used to address fundamental risks and opportunities with Hydro Ottawa's AMS. Changes to these processes and systems are recorded through updates to the respective AMS documentation.

11. Implementation

11.1. Communication and Usage of the SAMP

The SAMP is delivered to internal and external stakeholders, as appropriate, following the process defined in IAP0021 – *Asset Management System Communication Plan*. It shall be accessible, transparent and open for sharing. In particular, the Asset Owner, Asset Managers and Asset Service Providers shall communicate Hydro Ottawa's asset management objectives and the importance of the AMS to all employees, customers, suppliers, contractors and other stakeholders. Communication shall be two-way by being open to receiving information which could improve the AMS.

The SAMP is linked to Hydro Ottawa's Strategic Direction, the Asset Management Policy, the various AMPs and other AMS documents as outlined in Section 4. The SAMP is primarily used by staff and stakeholders involved in asset management at Hydro Ottawa as a guide to the strategies used to deliver Hydro Ottawa's asset management objectives. In addition, the SAMP is used to inform appropriate asset management components within the regulatory submission.

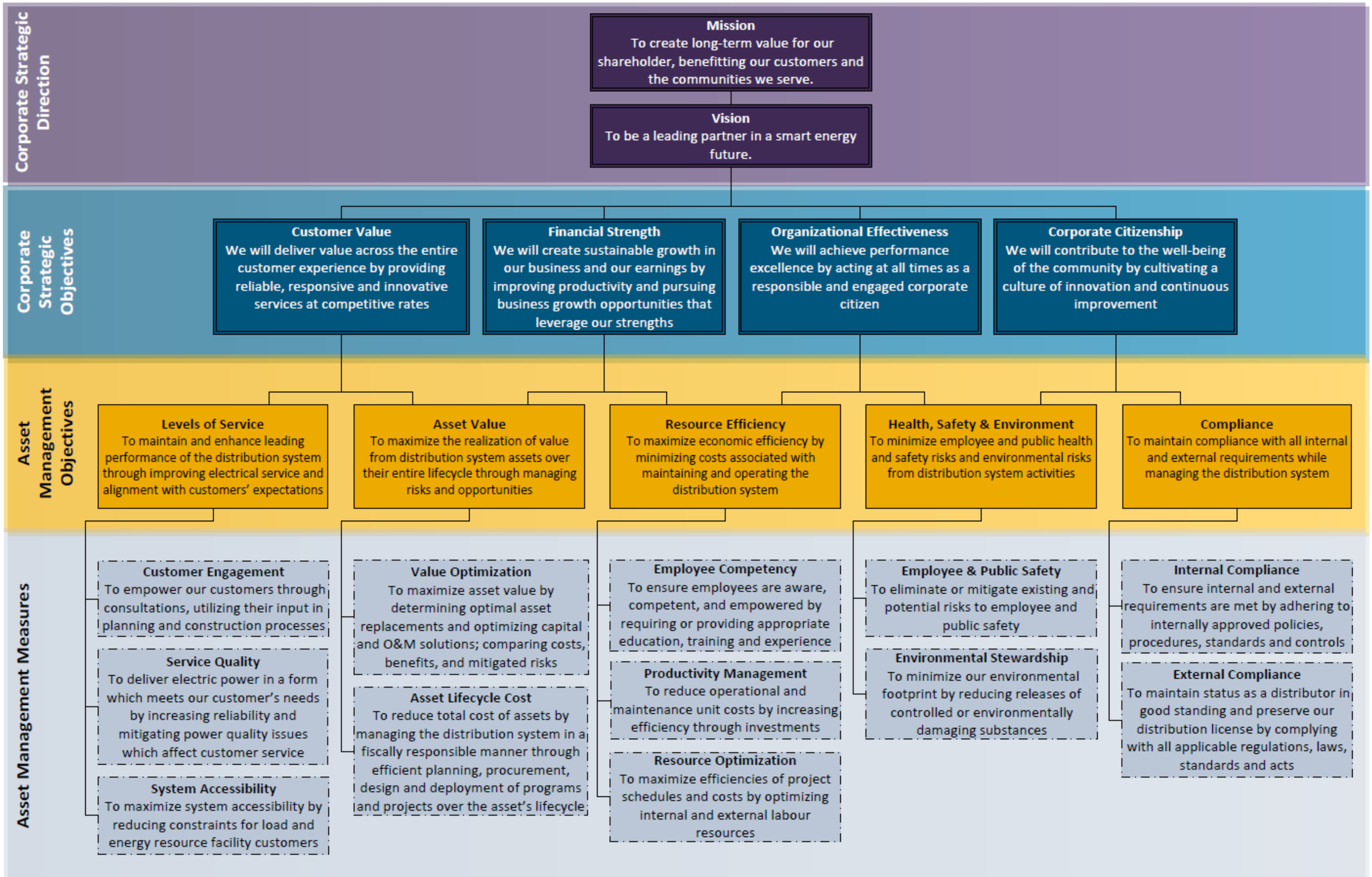
11.2. Review of the SAMP

The SAMP is reviewed with each revision of Hydro Ottawa's Strategic Direction and is updated as required by the Asset Manager and approved by the Asset Owner. It may also be updated and approved to accommodate changes to Hydro Ottawa's business environment and design or operating practices (e.g. changes in regulatory requirements, government policy, etc.). Individual AMS documents are reviewed and updated more frequently, dependent on the scope of the document and review schedules as stated in the respective document.

Appendix A Acronyms

ACA	Asset Condition Assessment
ADMS	Advanced Distribution Management System
AMC	Asset Management Council
AMP	Asset Management Plan
AMS	Asset Management System
BSI	British Standards Institution
DSC	Distribution System Code
EPR	Ethylene Propylene Rubber
ERF	Energy Resource Facility
ERM	Enterprise Risk Management
FIFO	First-in-First-out
FIT	Feed-in-Tariff
GIS	Geographic Information System
HOEP	Hourly Ontario Energy Price
HONI	Hydro One Network Inc.
IRRP	Integrated Regional Resource Planning
IAM	Institute of Asset Management
IASB	International Accounting Standards Board
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
ISO	International Organization for Standardization
KPI	Key Performance Indication
LoS	Loss of Supply
MicroFIT	Micro Feed-in-Tariff
MWM	Mobile Workforce Management
O/H	Overhead
OEB	Ontario Energy Board
OPO	Ontario Planning Outlook
PAS	Publicly Available Specification
PCB	Polychlorinated Biphenyl
PILC	Paper Insulated Lead Cable
RCM	Reliability-Centered Maintenance
RES	Renewable Energy Supply Contract
RESOP	Renewable Energy Standard Offer Program
RFP	Request for Proposal
RMS	Root Mean Square
RTU	Remote Terminal Units
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SARFI	System Average Root Mean Square (RMS) Variation Frequency Index
SCADA	Supervisory Control And Data Acquisition
SF6	Sulfur Hexafluoride
TDA	Training Delivery Agent
TRXLPE	Tree Retardant-Cross-Linked Polyethylene
U/G	Underground
UCC	Utility Coordinating Committee
XLPE	Cross-Linked Polyethylene

Appendix B Asset Management Objectives



Appendix C Asset Management Working Groups

External Councils, *Committees and Working Groups*	*Description*
Building Better and Smart Suburbs Working Group	Comprised of City of Ottawa departments, utilities, public consultation and other third parties, this group is focused on developing solutions for current suburban developmental issues by implementing initiatives that help improve urban design and support land efficiency and functionality in new suburban subdivisions. This includes reviewing distribution asset locations and construction methods.
CEA – Service Continuity Committee	Comprised of mostly Canadian electrical utilities, this group focuses on reliability service improvement. Members discuss reliability statistics and data, and issues such as outage classification and best practices used to improve reliability.
CEA – Operations Technology & Telecom Committee	Comprised of mostly Canadian electrical utilities, this committee ensures that electric utilities have access to the radio frequency spectrum through advocacy to Government related radio groups such as the CRTC. Additionally, the committee provides a forum to share lessons learned, investigate, technologies for developing secure networks, and to produce CEA codes relative to telecommunications for electric utilities.
CEATI – Distribution Lifecycle Asset Management	This working group helps utilities make informed decisions regarding asset management by sharing best practices and processes and collaborating with various industry experts in the distribution field. It aims to achieve the desired value of assets by improving and balancing aspects, such as performance, risk and cost.
CEATI – Power Quality & Advanced Technology	This working group helps utilities stay up-to-date regarding changes in utility power systems by creating a forum for member utilities. The group focuses on four (4) main aspects which are Customer Power Quality, Power Quality Monitoring and Data Analysis, Power Quality Impacts of DER Integration and Transmission Power Quality.
CEATI – Protection & Control Task Force	This working group helps find solutions for issues related to protection and control by bringing together industry professionals through networking opportunities. This helps utilities with application, optimization and the innovative use of protection and control technologies in their power systems.
CEATI – Station Asset Management	This group aims to improve the life cycle management of station equipment and apparatus by bringing together industry parties to conduct research in the field of electrical substations. This helps utilities in their future stations' developments by identifying ways to reduce costs and use new technologies.
Climate Change Action Plan	This five (5)-year plan fights climate change, reduces greenhouse gas pollution and helps in transitioning to a low-carbon economy. It aims to work with people, industries and organizations for a low-carbon future. Also, it intends to find cost-effective and low-carbon sources of energy for providing electricity and to implement energy conservation programs that reduce emissions.

External Councils, *Committees and Working Groups*	*Description*
Electrical Contractors Association Ontario Focus group	This association represents approximately 100 companies in Ottawa who conduct, maintain and service electrical installations. The association aims to advance various skills in the industry and promote a high standard of skill and competence for electrical contractors by collaborating with the government and industry leaders.
Energy Evolution Working Group	The Energy Evolution is a renewable energy transition plan, led by the City of Ottawa with input from businesses and industry experts. Its goal is to increase Ottawa's renewable energy power consumption. Phase 1 focuses on energy supply and demand by implementing several actions in the next three (3) years. These actions include reducing energy production through fossil fuels and implementing a net-metering framework for renewable energy through Hydro Ottawa.
Greater Ottawa Home Builders Association	The association represents builders, renovators, designers, trade contractors, suppliers and financial institutions who are involved in the residential construction industry. The association aims to inform the public about the local housing market, provide consumers with excellent service, support their members, and further develop the housing industry.
Regional Planning & Cost Allocation Working Group	The group works under the OEB and with the IESO and HONI to ease the implementation of regional planning and regional infrastructure plans and to align the cost responsibility provisions for load customers in the OEB's Transmission System Code and Distribution System Code.
Utility Coordinating Committee (UCC)	This group ensures safe and efficient coordination of construction and maintenance projects within the City of Ottawa's roadways. Through the forum of the UCC, City representatives and utility company representatives meet regularly to discuss common design and construction challenges, share innovative information and co-ordinate project-related matters.
UCC Subcommittee – 4 party trench	This subcommittee is made up of City of Ottawa representatives and utility company representatives who discuss the use of a single trench to house all utilities. This group also develops standards to ensure proper clearances and responsibilities to enable the single trench. A single trench allows for cost efficient installation and servicing.
UCC Subcommittee – Road Cross section	This subcommittee is made up of City of Ottawa representatives and utility company representatives who discuss and coordinate utility locations within proposed standard City of Ottawa road cross sections. This ensures adequate clearances are maintained and allow for work to be effectively completed on assets.

Internal Councils, *Committees and Working Groups*	*Description*
Contractor Onboarding Working Group	The contractor onboarding working group reviews Hydro Ottawa's internal documentation and process for onboarding new contractors working for Hydro Ottawa. This ensures the contractors have a comprehensive understanding of Hydro Ottawa practices, work standards and expectations.
Designer/GIS Working Group	The designer/GIS working group reviews issues with respect to communication or processes between the two units due to the integral relationship. In addition to improvements, forecasted issues are raised to create solutions before problems develop.
Equipment Administration Committee	The equipment administration committee works to ensure that received equipment meets Hydro Ottawa specification through the review of test reports. The committee improves processes in order to drive efficiency for the stakeholders.
Equipment Approval Committee	The equipment approval committee works to suggest, evaluate, and approve new assets to be used within Hydro Ottawa's distribution system. With the involvement of relevant stakeholders across the organization, the committee will evaluate and suggest action for new assets, from implementation, to trials to not using said equipment.
Grounding and Bonding Working Group	The grounding and bonding working group reviewed existing Hydro Ottawa practices against industry best practices. With the involvement of relevant stakeholders, this working group developed new processes and standards to ensure safe and consistent asset installations.
ISO55000 Asset Management Council	The asset management council creates, reviews and comments on the various components which make up the AMS. The council includes employees from the various asset management related areas to ensure thorough knowledge. The AMC will monitor and update the AMS as required to ensure that it is relevant, accurate and complete.
Joint Health and Safety Committee	This committee identifies actual and/or potential hazards and makes recommendations regarding the evaluation and control of these hazards. This includes hazards working with distribution assets. Additionally, the committee will routinely review and promote ongoing worker safety and training programs.
Kanban Working Group	The kanban working group reviews the material stocked in kanban with the required stakeholders. The group's goal is to minimize the overall amount of material stocked while maximizing stocking of the right material.
Project Coach Committee	The project coach committee reviews existing project management practices at Hydro Ottawa with industry standards. The committee improves the internal processes and workflows through revisions due to stakeholder feedback and changes to existing processes and software. Additionally, the committee provides periodic training to internal stakeholders.

Internal Councils, *Committees and Working Groups*	*Description*
Protection & Control Committee	The protection & control committee reviews Hydro Ottawa's standards and processes with the required stakeholders. The goal is to improve internal knowledge, review internal standards against industry best practices and make processes more efficient.
Reliability Council	Refer to Section 6.1.2.
SCADA User Group	The SCADA user group was established to ensure regular monthly meetings are held between the Grid Technology, Stations, and System Operations teams responsible for the ongoing operation of the SCADA system. This is to ensure the development of system standards and best practices, as well as to address any current system issues that require a fix or change. The meetings also offer an opportunity for the stakeholders to meet on a regular basis to confer about items relating to current and upcoming SCADA projects that impact all parties.
Smart Energy Steering Committee	Refer to Section 6.1.2.
Standards Committee – Fiber	This standard's committee reviews, maintains and updates design, maintenance, construction and material specification technical standards with respect to telecommunication assets.
Standards Committee – Overhead	This standard's committee reviews, maintains and updates design, maintenance, construction and material specification technical standards with respect to overhead assets.
Standards Committee – Stations	This standard's committee reviews, maintains and updates design, maintenance, construction and material specification technical standards with respect to station assets.
Standards Committee – Underground	This standard's committee reviews, maintains and updates design, maintenance, construction and material specification technical standards with respect to underground assets.
Station Maintenance Committee	The station maintenance committee supports and improves station maintenance and inspection activities to increase system reliability, optimize maintenance cost and improve replacement planning. This is accomplished by providing a collaborative space for the development of procedures, work methods and processes and providing a venue for maintenance activity/equipment concerns to be reviewed and addressed.
Strategic Workforce Planning	Refer to Section 6.3.3.
Underground Cable Forecasting Working Group	The underground cable forecasting working group reviews equipment ordering and forecasting to ensure efficient material management. Internal stakeholders' needs and processes are reviewed and improved before reaching out to external vendors.

Appendix D Information Software

Software	*Description*
Aspen	A repository of data and settings on relays, circuit breakers, transformers, current transformers, potential transformers and communication equipment. Aspen is used by Hydro Ottawa to store information related to station assets and SCADA devices. Additionally, workflows are used within the tool to track activities related to approving and changing protection settings.
Autodesk – Autocad	Produces 2D documentation and drawings with a comprehensive set of drawing, editing, and annotation tools. Autocad is used by Hydro Ottawa for completing design drawings for distribution projects and creating system single line diagrams.
BMC – Track-It!	A software solution which allows automatic delegating, tracking, closing and data collection for various tasks within departments. Hydro Ottawa uses BMC's Track-It! to manage requests to the GIS & Distribution Records unit with respect to updating asset records and completing the integration of project records.
Copperleaf – C55	An asset investment planning and management tool with decision analytics solutions that leverage operational, financial and asset data to empower organizations to make investment decisions that deliver the highest business value. C55 is used by Hydro Ottawa as a project repository, where projects are created, valued and prioritized. Additionally, C55 is used for creating and approving project change requests and analyzing assets based on condition and risk.
CYME	A suite of tools which allow for planning and operational studies of the distribution system. Hydro Ottawa uses the following modules: **CYMDIST** – distribution system modelling, load flow and fault analyses. **CYMTCC** – development and review of protection devices. **CYMECAP** – determining loading ampacity and temperature effects on electrical conductors.
Geotab	Geotab is a web-based fleet management software which allows companies to see vehicle and driver information in one place and use it to make quicker, better-informed decisions. Hydro Ottawa uses Geotab to improve situational awareness and resource optimization by dispatching crews to outages and calls based on location and skill.
Hexagon – Geomedia	Hexagon's GeoMedia software is a flexible and dynamic GIS package for creating, updating, managing and analyzing valuable geospatial information. Hydro Ottawa uses GeoMedia to develop geospatial maps of assets and projects to improve the understanding of scope. This tool is also used for querying asset information.
Hexagon – Intergraph	Hexagon's Intergraph G/Technology software enables a definitive source of reliable, location-based information describing asset networks and their connectivity. Hydro Ottawa uses this software as the single asset repository. Along with electrical connection and geographic location, the system houses asset specific information such as nameplate and installation year, as well as asset photos and inspection information.

Software	Description
G-Mobile Inspector Software	G-Mobile Inspector is a custom built software solution to integrate asset inspection information with Hexagon's Intergraph G/Technology software. Custom forms are created and inspectors use tablets to enter asset specific information used to determine the asset's condition and drive maintenance or capital work. This information is then stored in the asset repository, connected to the respective asset, and able to be queried.
Open Systems International	Open Systems International's SCADA platform is feature-rich and flexible, providing real-time monitoring and control applications for various real-time processes. As the single enterprise SCADA platform, Hydro Ottawa uses this software to monitor the distribution network and substation, controlling devices connected through the network as required.
Open Systems International Soft – PI System	Software with the ability to collect, analyze, visualize and share large amounts of high-fidelity, time-series data from multiple sources to people and systems across all operations. PI System is used by Hydro Ottawa to review data recorded by monitoring devices connected through SCADA. This data is used in planning system load capacity and anomaly event investigations.
Oracle – Customer Care & Billing	A modern customer information system that is designed to meet the needs of utilities now and into the future. It is a complete billing and customer care application that handles every aspect of the customer lifecycle, from service connection to payments processing and everything in between. Hydro Ottawa uses this tool to bill customers, aid in scheduling work and review loading information.
Oracle – JD Edwards EnterpriseOne	An integrated applications suite of comprehensive enterprise resource planning software that combines business value, standards-based technology and deep industry experience into a business solution. EnterpriseOne is used by Hydro Ottawa for financial and resource information and stock material management.
Oracle – Mobile Workforce Management	A software solution which provides fully integrated real time, best-of-breed planning, scheduling, dispatch and mobile communications. Mobile Workforce Management is used by Hydro Ottawa to optimize the scheduling and deployment of internal field workers.
Power DB	A database with formatted test forms for data entry and reporting. Power DB is used by Hydro Ottawa for station maintenance where equipment inspections are recorded.
PQ View	A multi-component software system for building and analyzing databases of power quality and energy measurements. Its components build measurement databases, write summary reports, compute power quality indices, view waveforms and RMS samples, and trend steady-state quantities. PQ View is used by Hydro Ottawa for analyzing power quality events on the distribution system.
Primate Technologies	Visualization software product for control room environments collaborating with geographic maps to lead to improved situational awareness and operational awareness for control room operators, dispatchers and staff. Hydro Ottawa uses Primate Technologies for system operations maps showing live configurations with detailed notes and equipment pins.

Software	*Description*
Quadra – ERTH	Quadra is a powerful and feature-rich web-based estimating, purchase automation and job management tool that streamlines your bid-to-invoice life cycle. ERTH is used by Hydro Ottawa to complete project estimations using preconfigured assemblies of parts lists and material costs for specific job scopes.
Revu – Bluebeam	An award-winning PDF creation, editing, markup and collaboration technology designed for architecture, engineering and construction workflows. Bluebeam is used by Hydro Ottawa to create and comment on project drawings between several groups.
Service Manager	A Hydro Ottawa-built APEX-based application which is used to store documents and complete work flows for the processes involving scheduling asset work with customers.

Stantec

Distribution System Climate Risk and Vulnerability Assessment

Final Report

November 11, 2019

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(signature)

Nicole Flanagan, P.Eng.

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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.

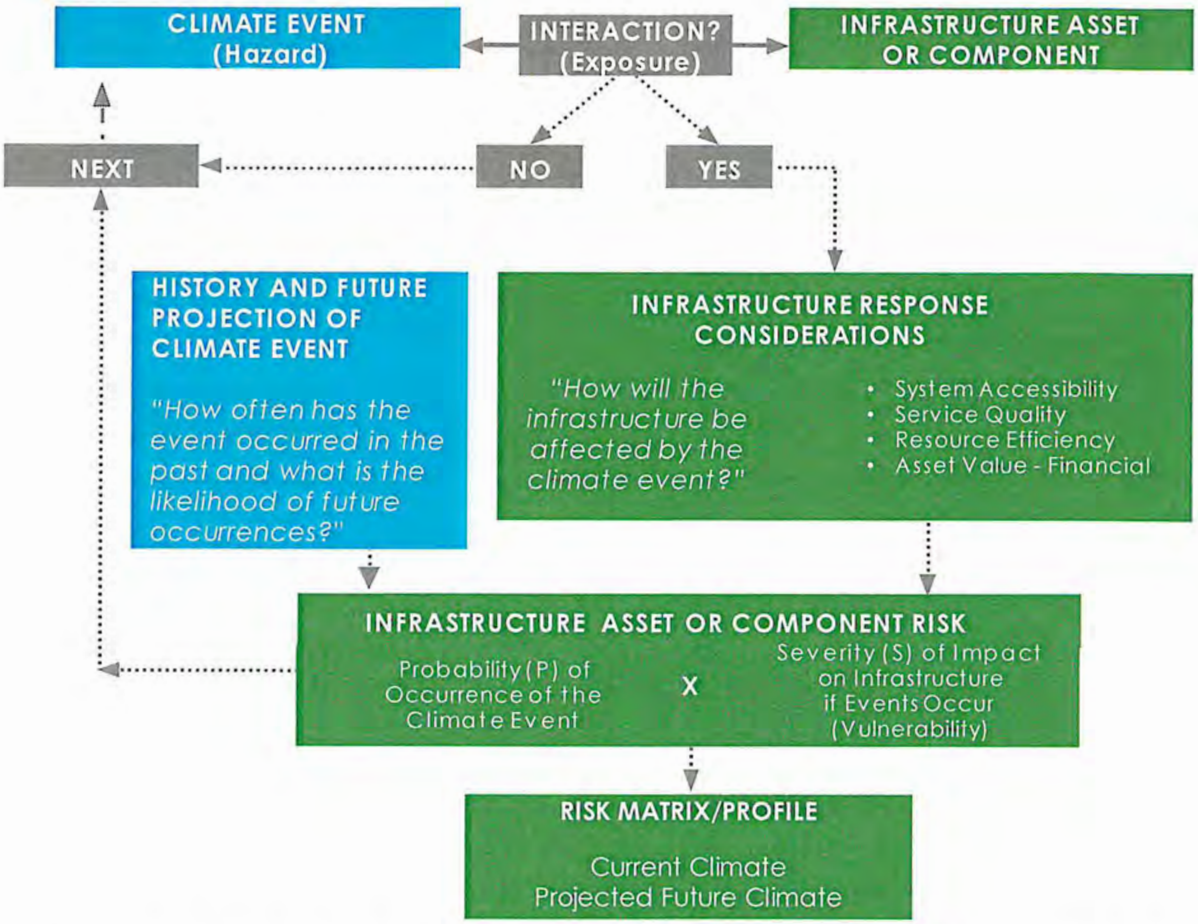
The procedures used to perform this analysis, and the associated analytical results, are detailed in the report. Climate analyses in this study use projections for the "business-as-usual" Representative Concentration Pathway emissions scenario – RCP8.5 – and for the 2050s (2041-2070).

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.

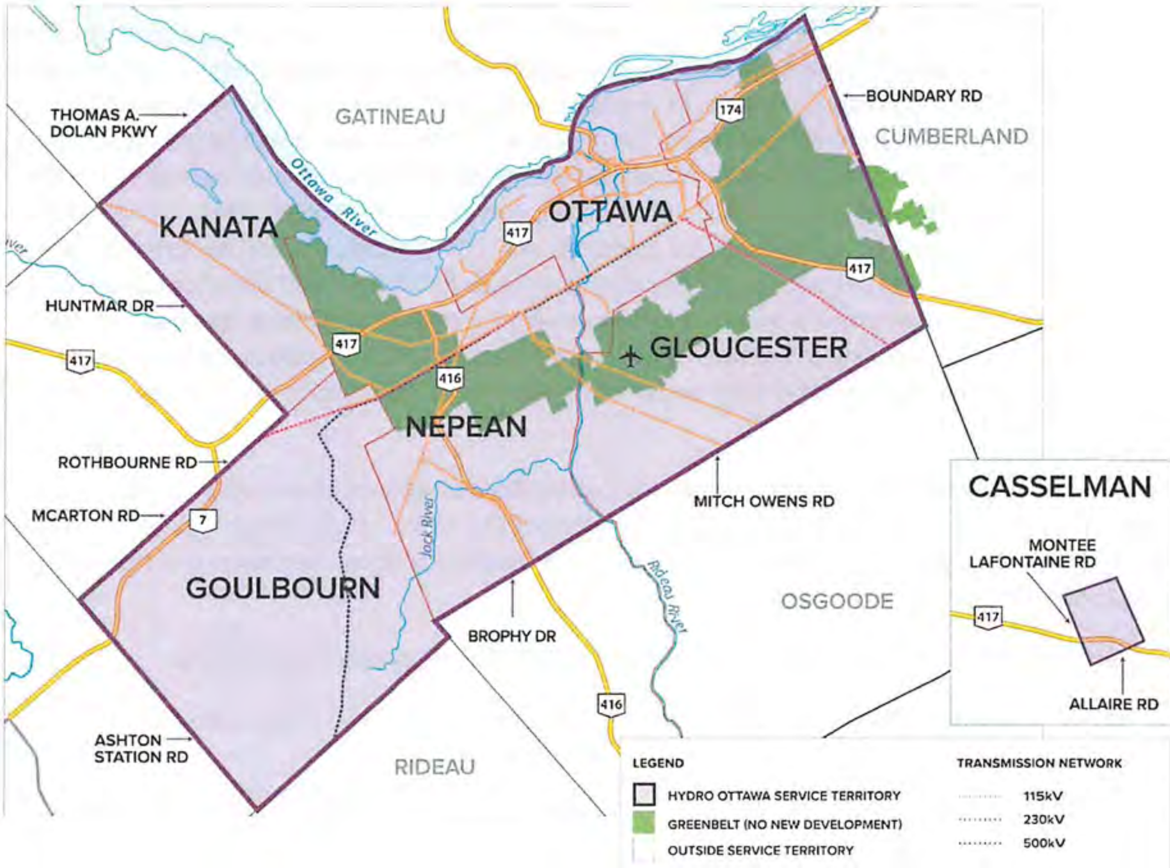

Figure 1 Map of Hydro Ottawa Service Territory[1]

[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).

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DISTRIBUTION SYSTEM CLIMATE RISK AND VULNERABILITY ASSESSMENT

Methodology
November 11, 2019

Risks / Opportunities		Impact: Insignificant (1)	Minor (4)	Moderate (9)	Extensive (16)	Significant (25)
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	System Accessibility	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	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	Resource	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	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	Corporate Brand	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
		Insignificant	Minor	Moderate	Extensive	Significant

Likelihood: Probability			Insignificant	Minor	Moderate	Extensive	Significant
(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

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.

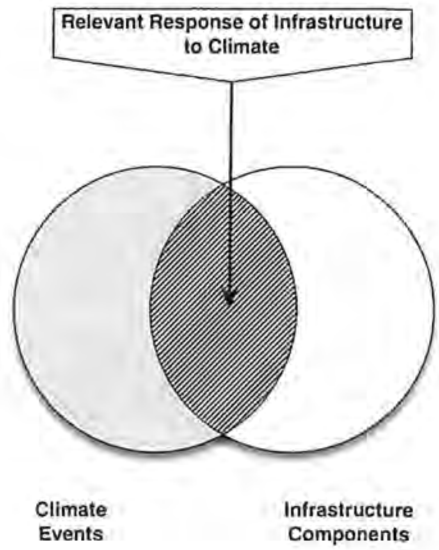

Figure 3 Diagram representing the interaction between climate events and infrastructure components

This CRVA did not include the optional Step 4 – Engineering Analysis of the PIEVC Protocol (this step is recommended when the team needs a more in-depth analysis of the particular infrastructure-climate interaction where the team feels additional climate or engineering data is needed). The use of the Triple Bottom Line module was not part of this assignment, although risk mitigation and adaptation measures were developed and provided in a separate report.

The methodology of the Protocol includes five key steps to ensure the assessment is consistent and rigorous. The five key steps are:

1. Project Definition;
2. Data Gathering and Sufficiency;
3. Risk Assessment;
4. Engineering Analysis (optional as necessity and resources permit); and,
5. Recommendations and Conclusions.

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.

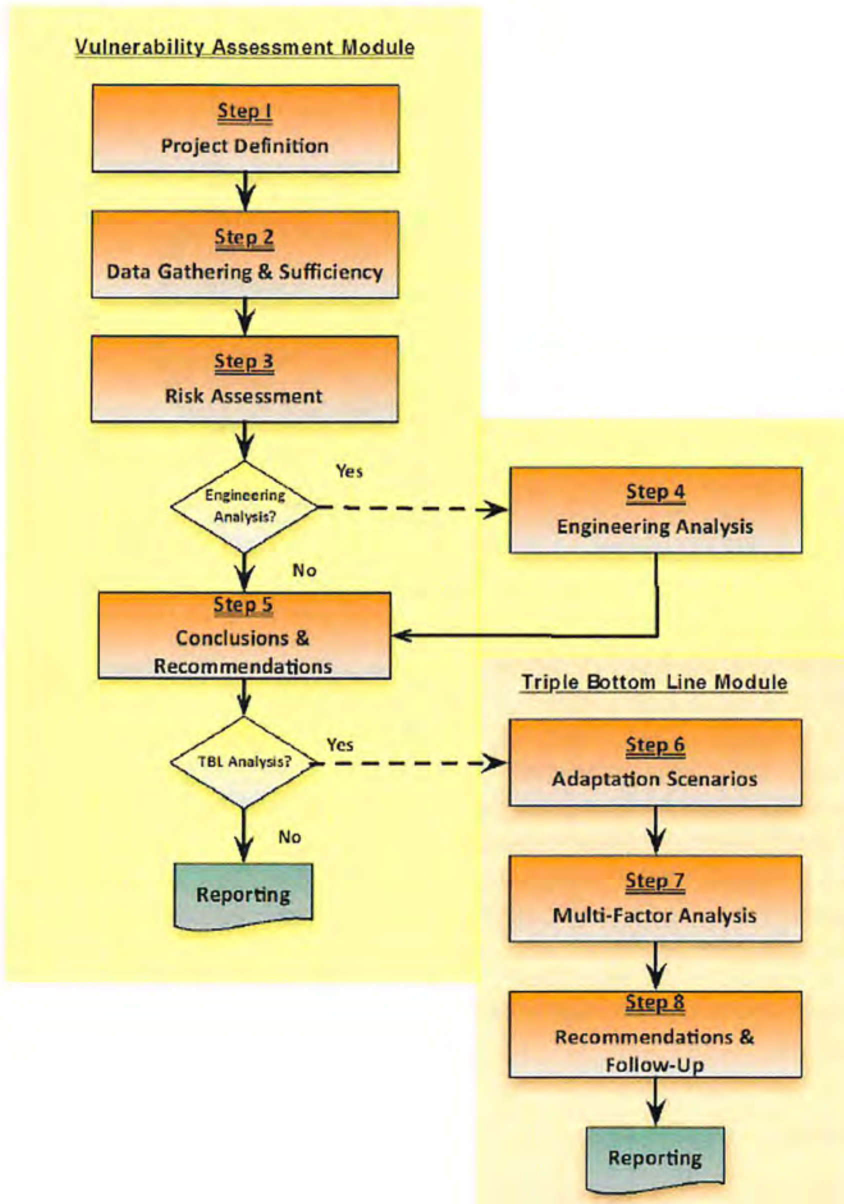

Figure 4 Flow Chart Illustrating the PIEVC Protocol Process

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).

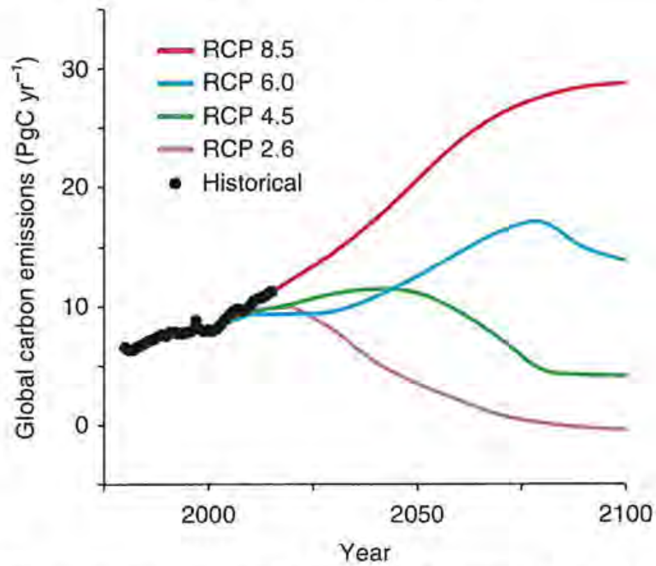

Figure 5 Historical CO_2 emissions for 1980-2017 and projected emissions trajectories until 2100 for the four Representative Concentration Pathway (RCP) scenarios. Current global emission trends have very closely followed the "business-as-usual" RCP8.5 scenario trajectory. Figure from Smith and Myers, 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).

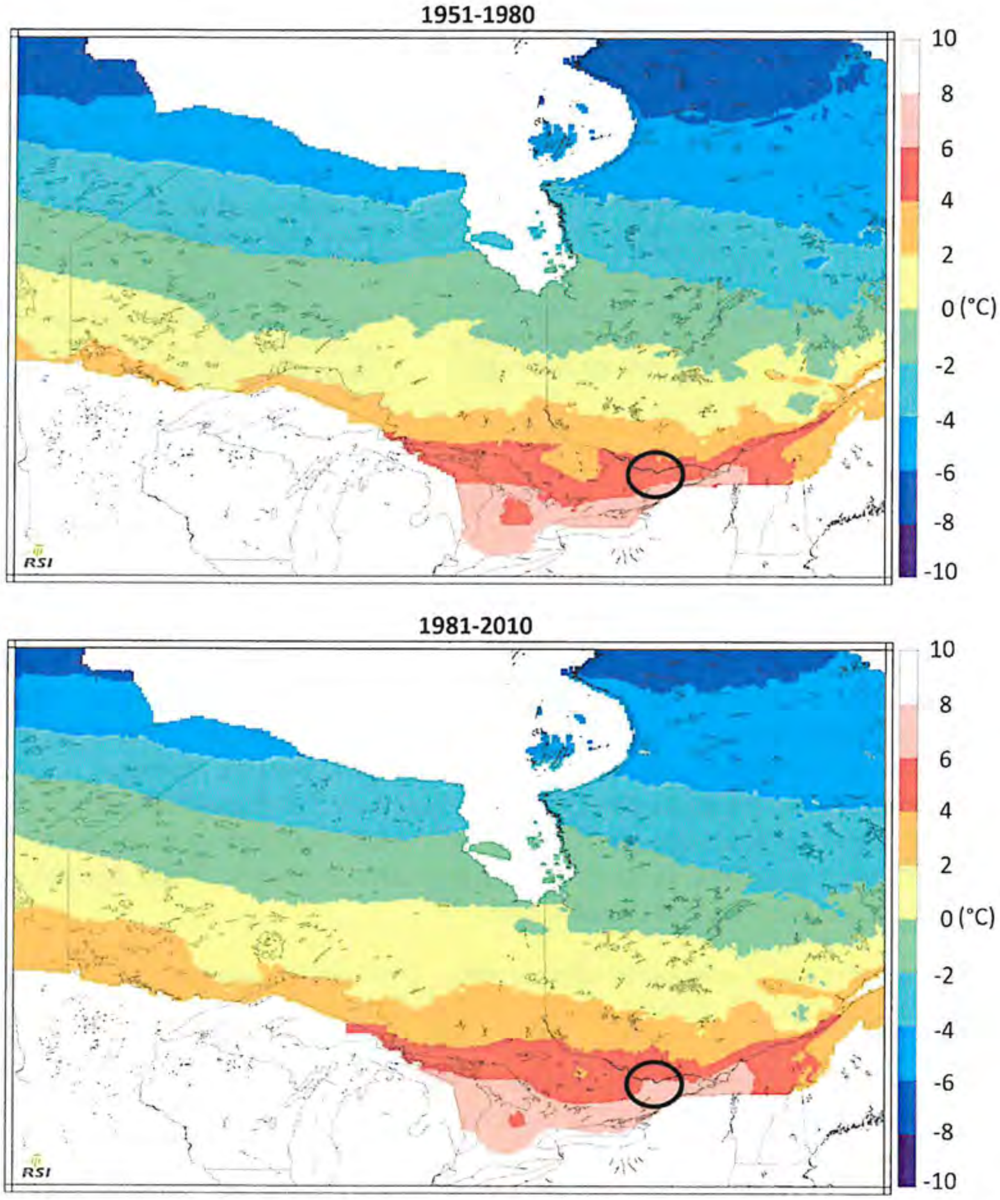

Figure 6 Observed annual mean (2m) air temperature over the 1951-1980 (upper) and1981-2010 (lower) periods. The change in mean annual temperature can be inferred from comparison of the plots (i.e. the difference in the colouration), with observed increases in temperature throughout Southern Ontario. 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.)

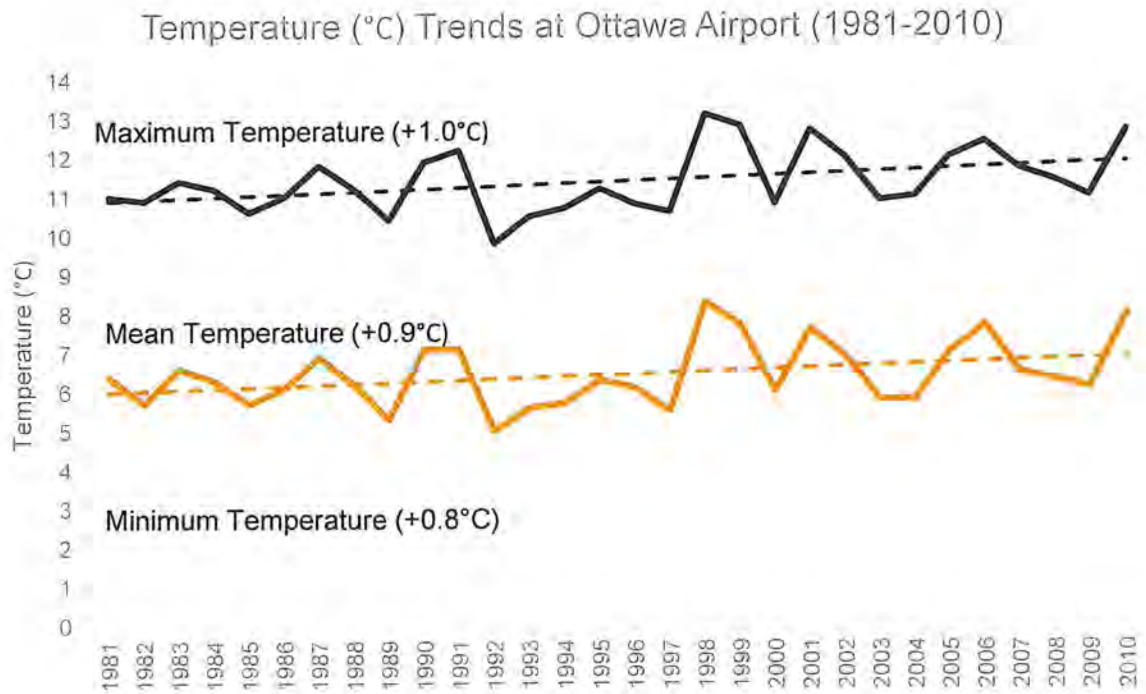

Figure 7 1981-2010 Annual Mean, Maximum, and Minimum Temperature Data and Trends at Ottawa Airport

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.

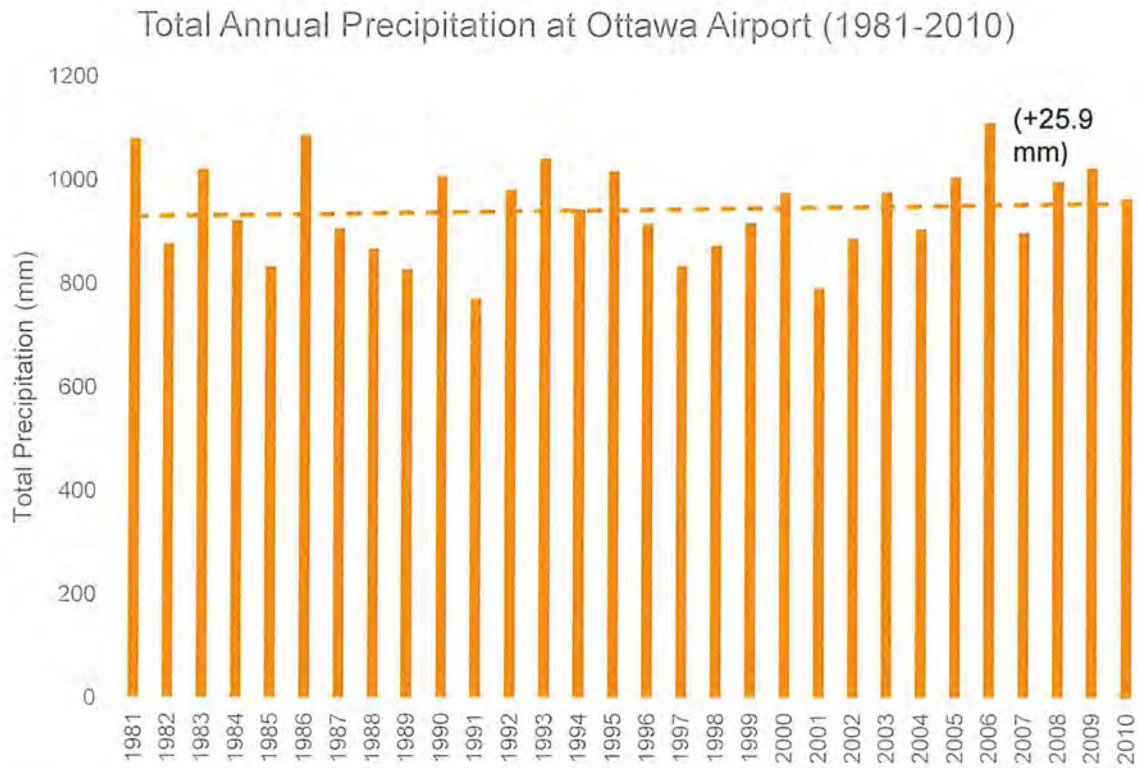

Figure 8 1981-2010 Total Annual Precipitation Data and Trend at Ottawa Airport

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.

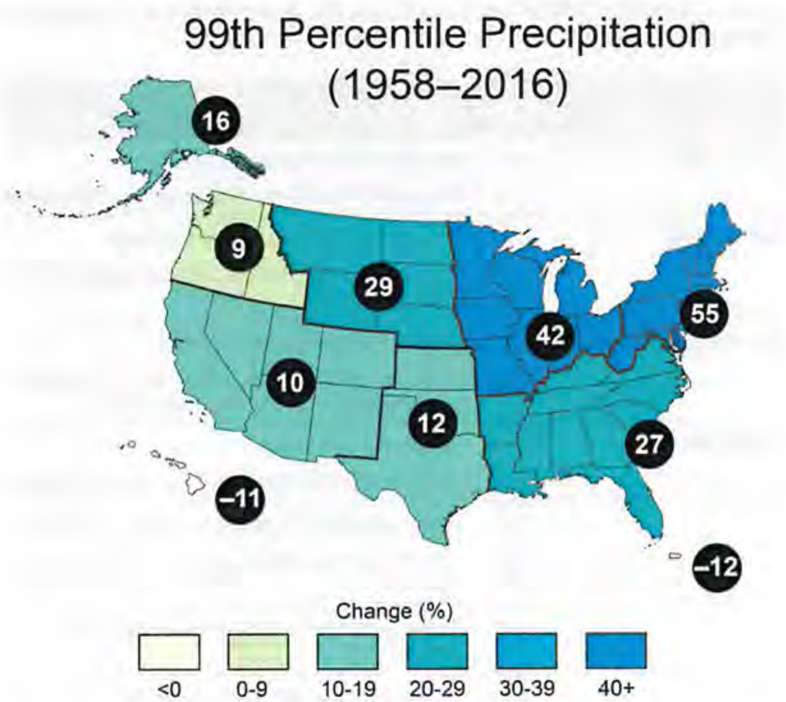

Figure 9 Percent increases in the amount of precipitation falling in daily events that exceed the 99th percentile of all days with precipitation (i.e. the total precipitation falling in the top [heaviest] 1% of daily precipitation events) in the United States, 1958-2012, calculated from daily precipitation 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.

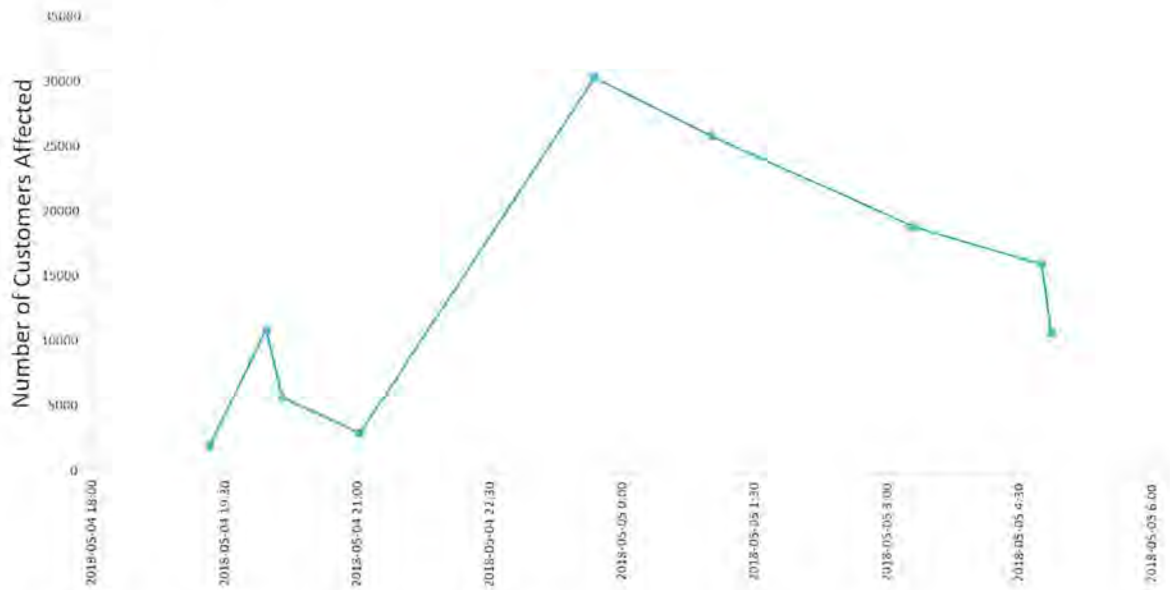

Figure 11 Timeline describing number of customers affected during May 4, 2018 windstorm. Note small peak of ~11,000 between 7:30 and 8:00 PM EDT, followed by much larger peak of >30,000 later in the evening. Total number of customers affected based on outages reported by Hydro Ottawa's Twitter account.

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).

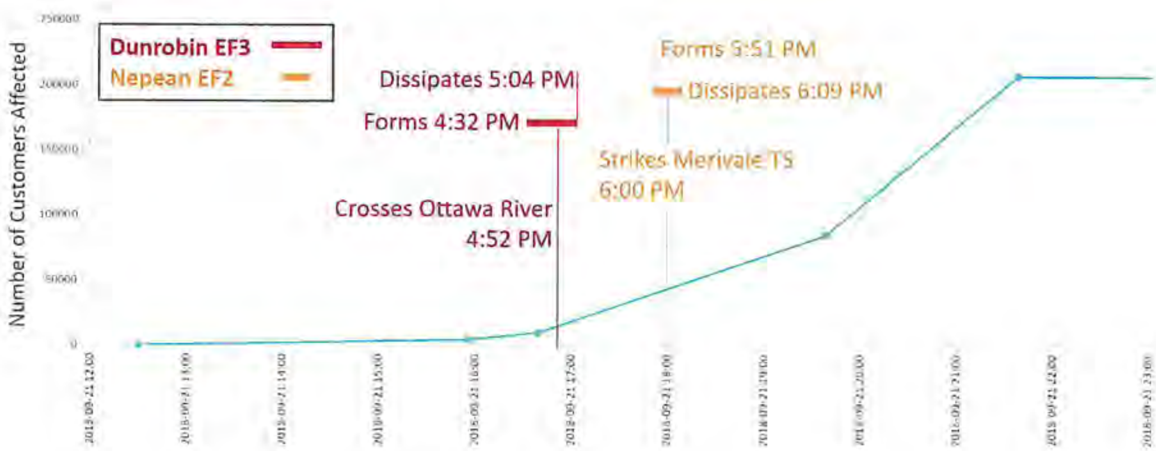

Figure 12 Timeline comparing the total number of reported customers affected versus the occurrence of the Kinburn-Dunrobin-Gatineau tornado (red) and the Nepean-South Ottawa tornado (orange). Outage totals are based on those reported by Hydro Ottawa's Twitter account and the final total based on post-event 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

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

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

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

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.

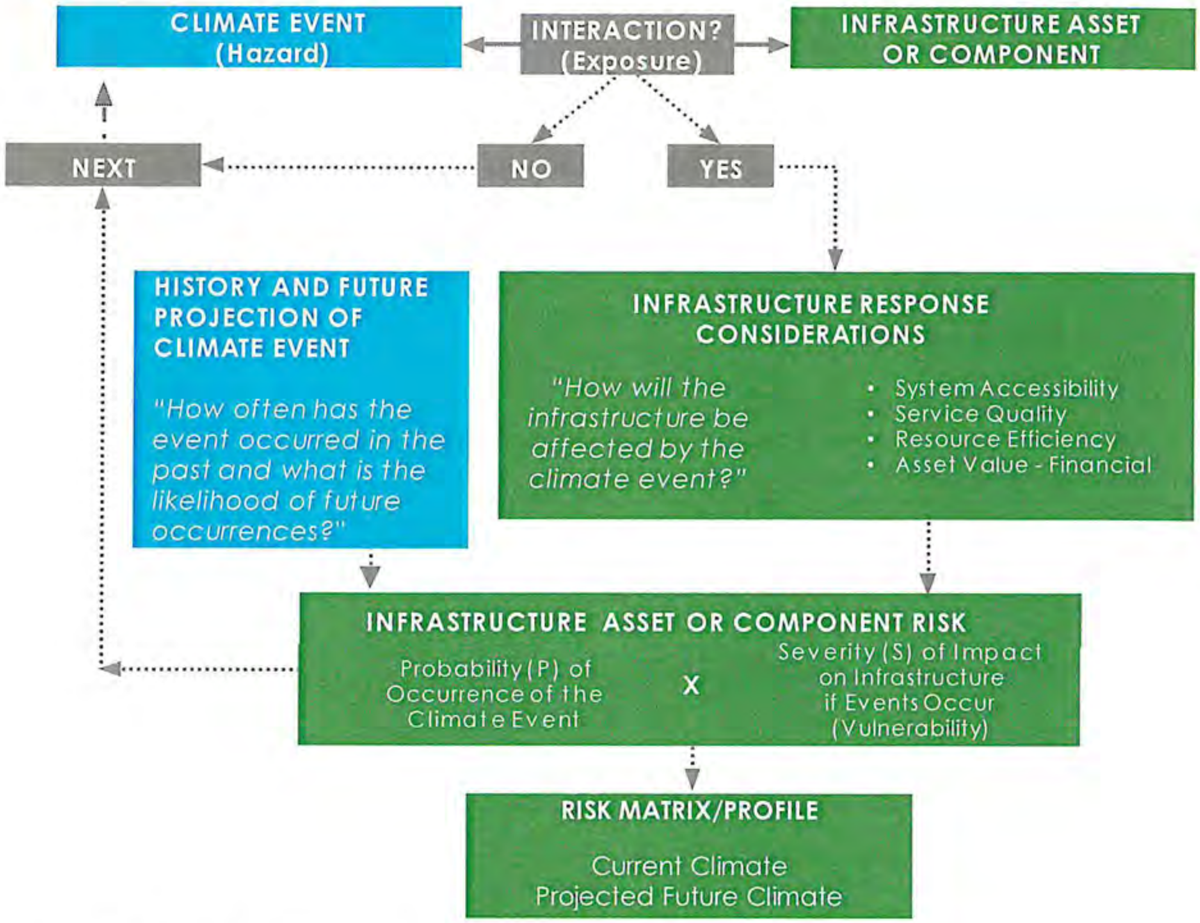

Figure 13 Flow Chart Descripting Risk Evaluation Process

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: Current Climate	Risk Rating: Future Climate	Asset Performance Affected	Impacts	Result / Consequence
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

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

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

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

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

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

Contents

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.

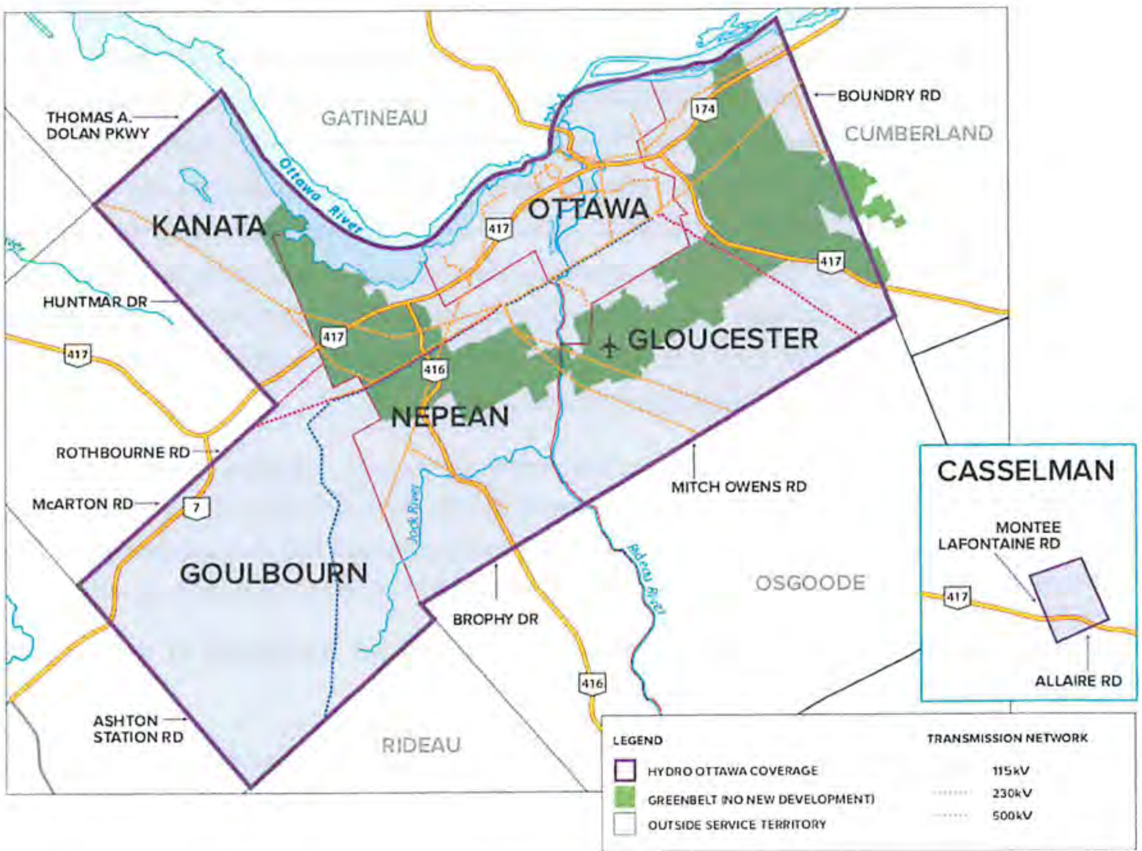

Figure 1: Map of the Hydro Ottawa service area in the City of Ottawa and Village of Casselman regions. Areas shaded in purple represent the Hydro Ottawa service area, while those shaded in blue are outside of its jurisdiction. The Ottawa Macdonald-Cartier International Airport, located in the Gloucester 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**).

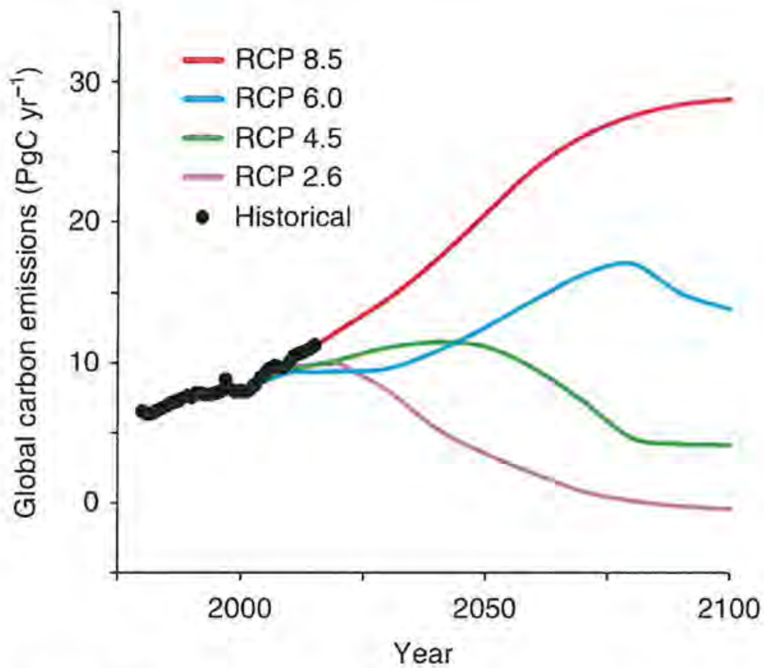

Figure 2. Historical CO2 emissions for 1980-2017 and projected emissions trajectories until 2100 for the four Representative Concentration Pathway (RCP) scenarios. Current global emission trends have very closely followed the "business-as-usual" RCP8.5 scenario trajectory. Figure from Smith and Myers, 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;

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	

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	

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)	**Asset Value, Level of Service, Resource Efficiency** – Significant damage and major outages possible; prolonged events	• Rare, but severe impacts to Hydro Ottawa infrastructure (e.g. 2018 tornado outbreak – damage due to tree and limb falls and flying debris, direct hit of Merivale transmission station, disruption of transportation corridors impacted response efforts).
	EF1+ point probability (i.e. tornado striking a specific asset, e.g. a substation, in the City of Ottawa service area)		

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			

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 Daily T_{max} T_{min} temperature fluctuation of ±4°C 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.

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).

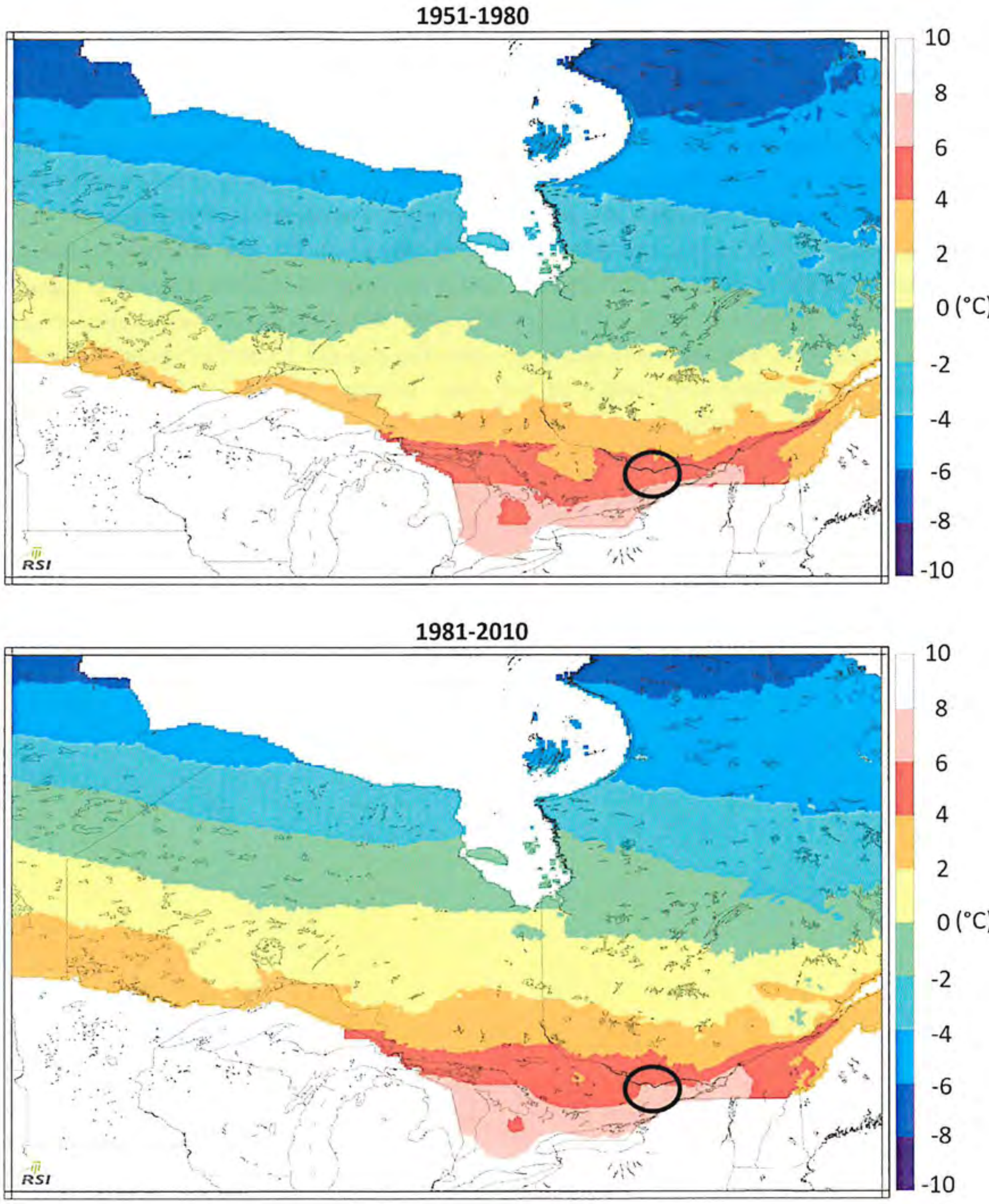

Figure 3. Observed annual mean (2m) air temperature over the 1951-1980 (upper) and 1981-2010 (lower) periods. The change in mean annual temperature can be inferred from comparison of the plots (i.e. the difference in the colouration), with observed increases in temperature throughout Southern Ontario. 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.)

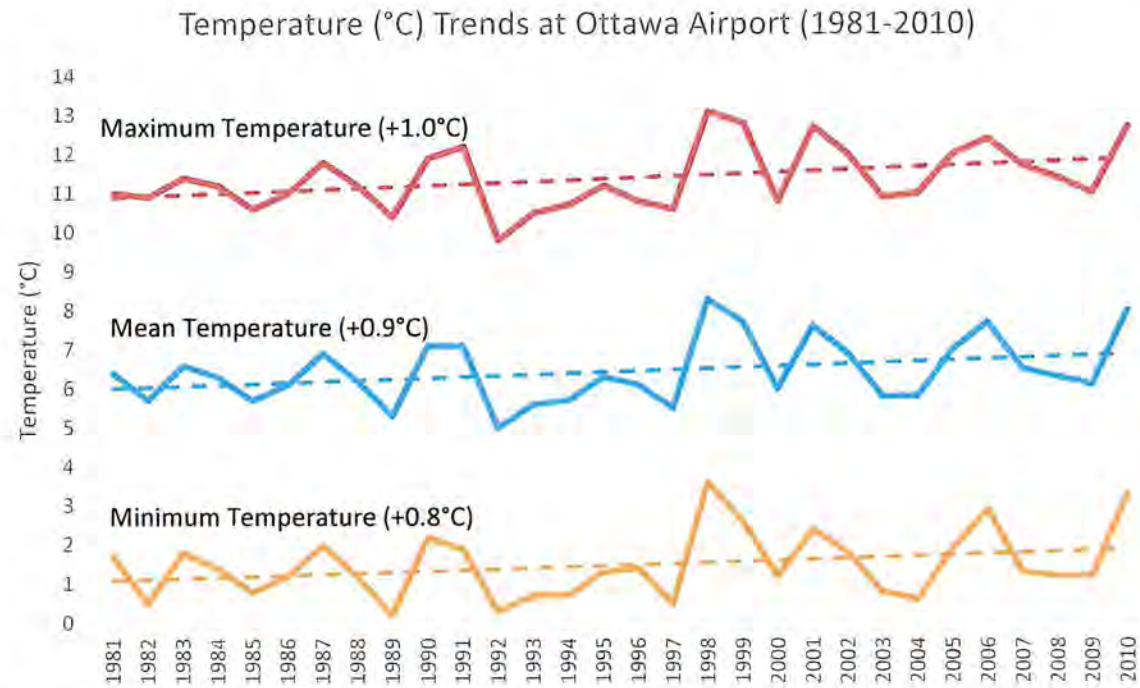

Figure 4. 1981-2010 annual mean, maximum, and minimum temperature data and trends at Ottawa Airport.

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.

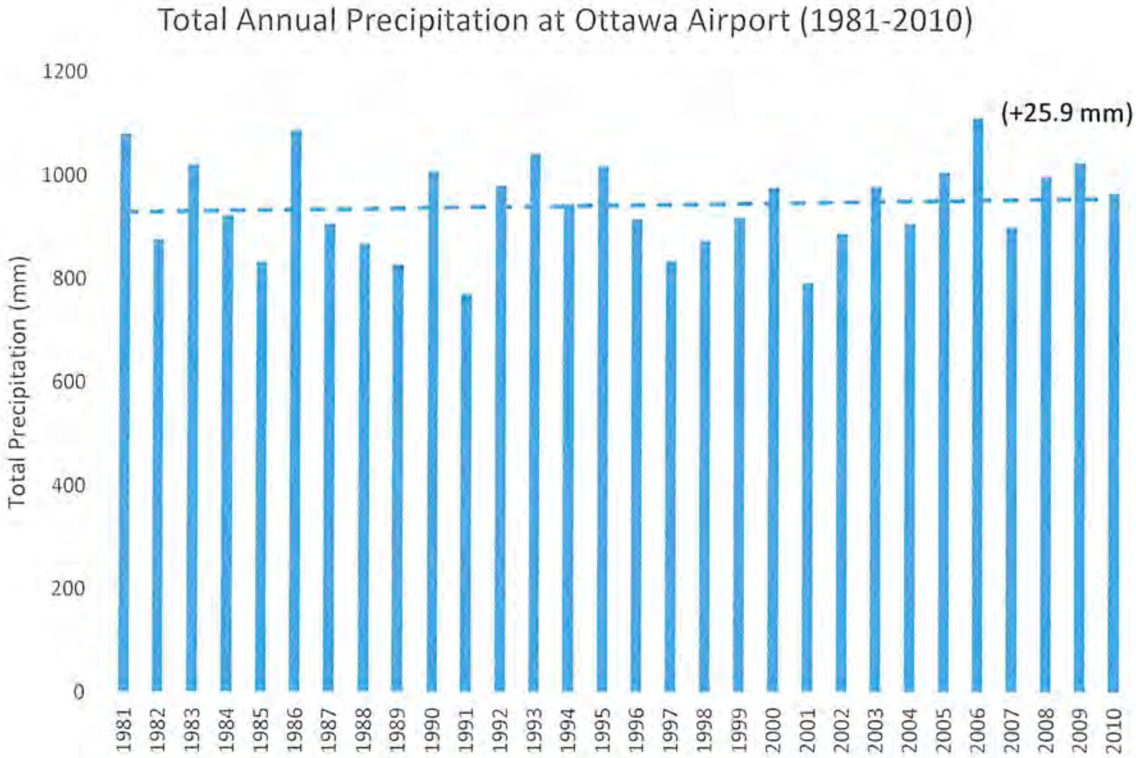

Figure 5. 1981-2010 total annual precipitation data and trend at Ottawa Airport.

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.

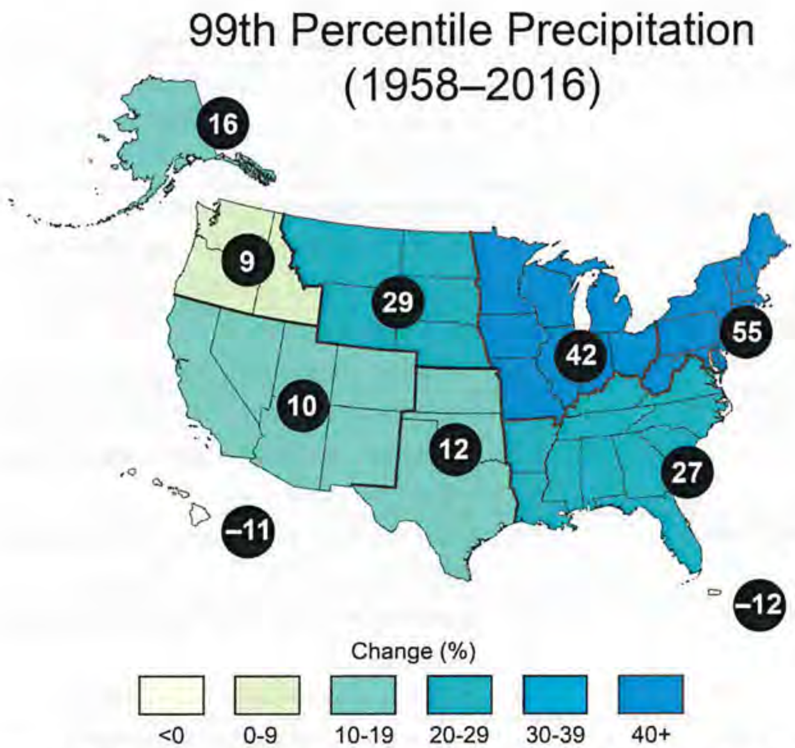

Figure 6. Percent increases in the amount of precipitation falling in daily events that exceed the 99th percentile of all days with precipitation (i.e. the total precipitation falling in the top [heaviest] 1% of daily precipitation events) in the United States, 1958-2012, calculated from daily precipitation 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.

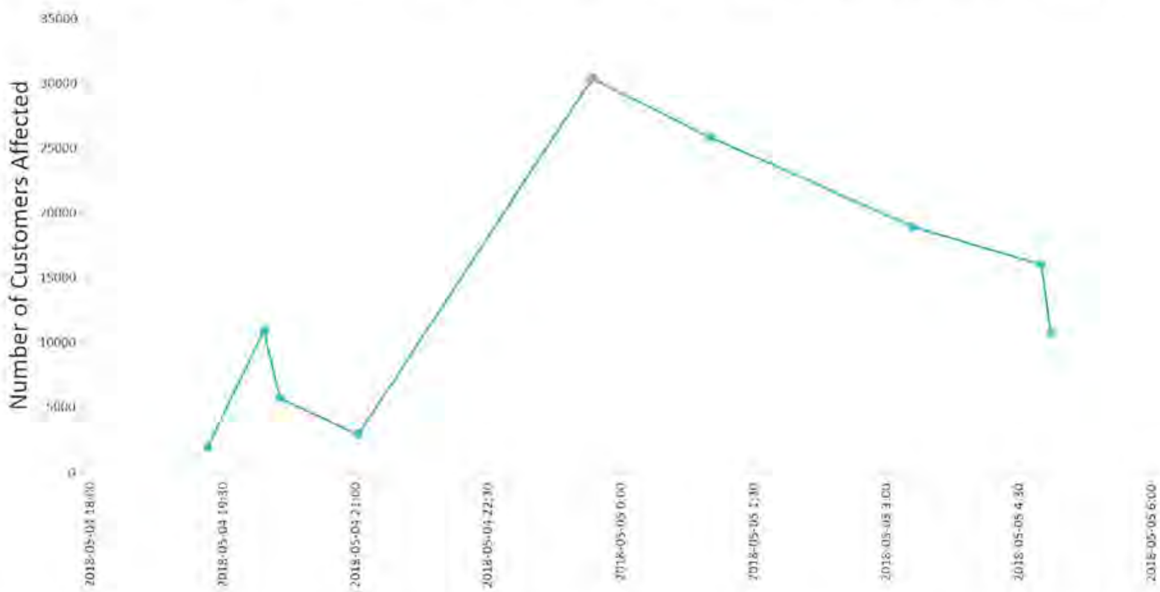

Figure 8. Timeline describing number of customers affected during May 4, 2018 wind storm. Note small peak of ~11,000 between 7:30 and 8:00 PM EDT, followed by much larger peak of >30,000 later in the evening. Total number of customers affected based on outages reported by Hydro Ottawa's Twitter account.

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								

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

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

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.

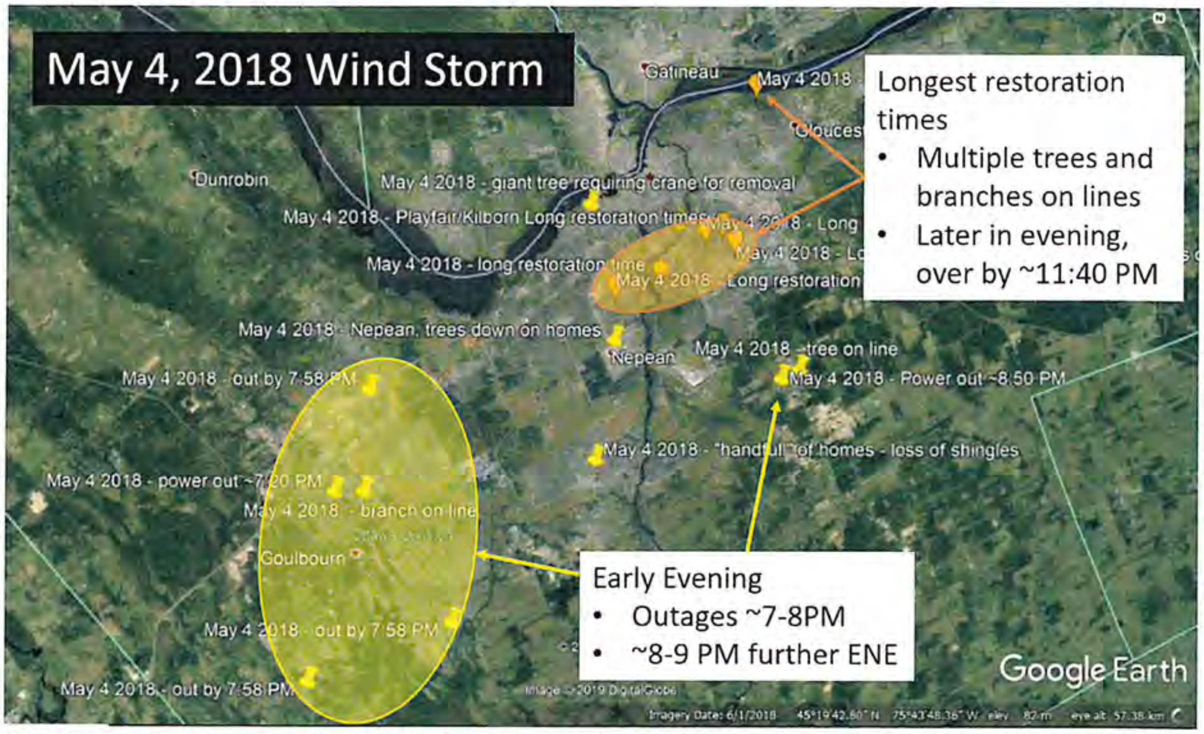

Figure B - 1. Map of damage and outage locations indicating timing and progression of events. Early evening outages SW of the City are circled in yellow, while late evening and long lasting outages are shown in orange.

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.

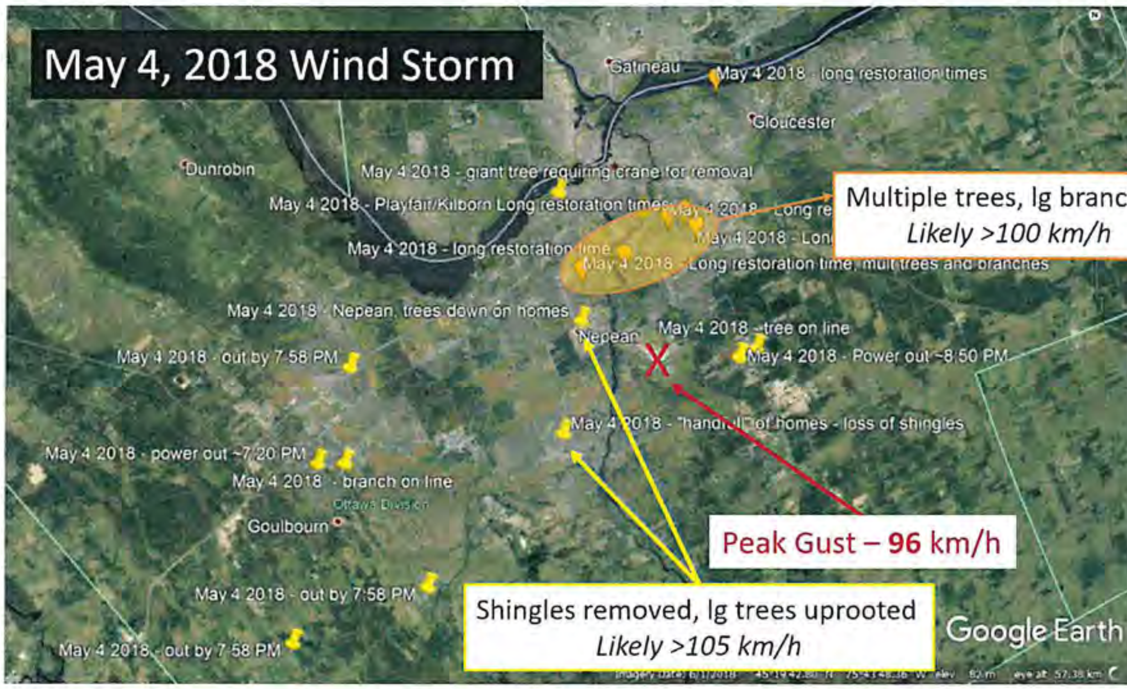

Figure B - 2. Map comparing peak gust value measured at Ottawa International Airport with areas reporting damage suggesting higher wind speed values.

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.

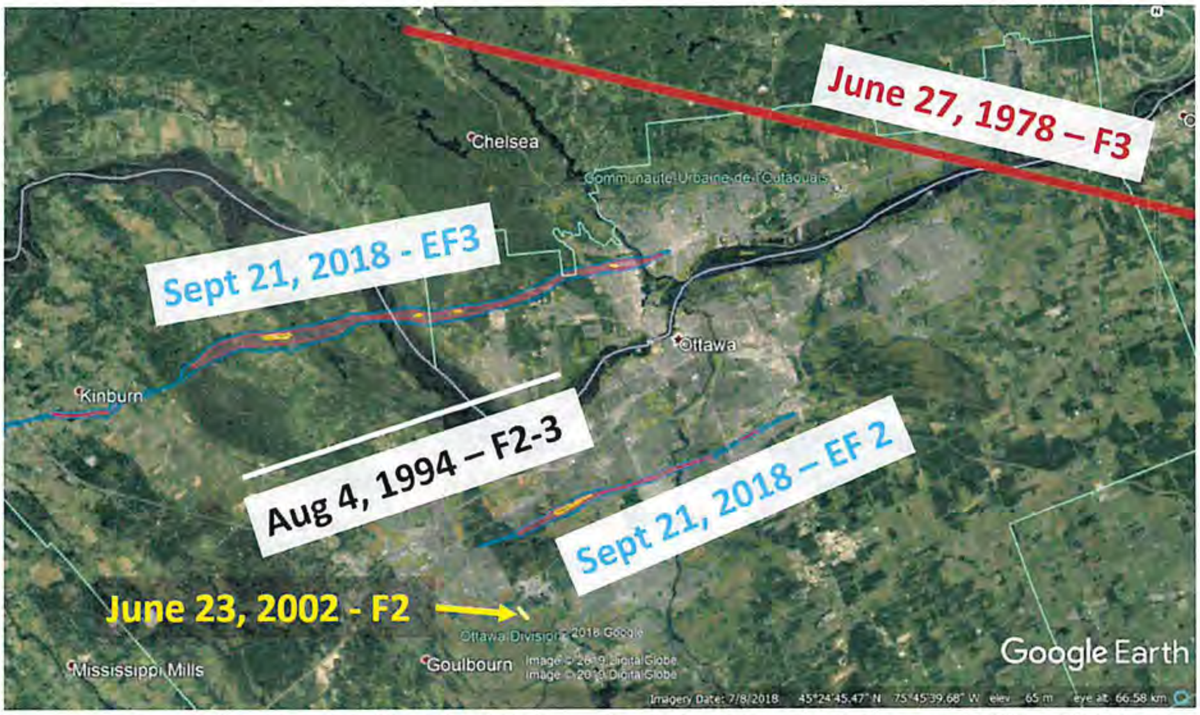

Figure B - 3. Map of all confirmed significant (F2+/EF2+) tornadoes in the Ottawa area for the period 1970 to 2018. Detailed track maps for the Sept 21, 2019 event courtesy of Sills et al. (2018), track data for historical events from Sills et al. (2012).

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:
$T_{max} \geq 25°C; 30°C; 35°C; 40°C$
$T_{mean} \geq 30°C$

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 $T_{max} \geq 25°C$ and $T_{max} \geq 30°C$ 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 $T_{max} \geq 25°C$ and baseline mean of ~14-15 times per year increasing to ~42 times per year in the 2050s for $T_{max} \geq 30°C$ (**Figure C - 1** and **Figure C - 2**, respectively). During the 1981-2010 time period, $T_{max} \geq 35°C$ 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, $T_{max} \geq 40°C$ and $T_{mean} \geq 30°C$ 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.

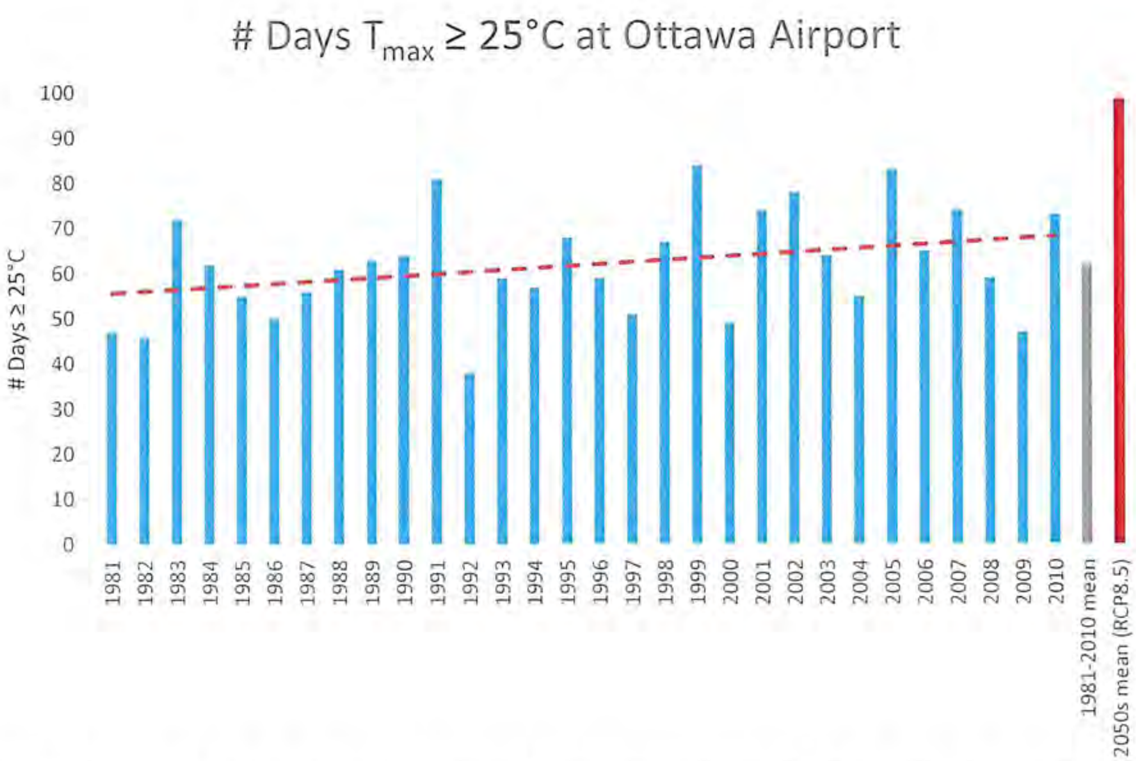

Figure C - 1. Number of days per year with the maximum temperature ≥ 25°C during the 1981-2010 time period at Ottawa Airport. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

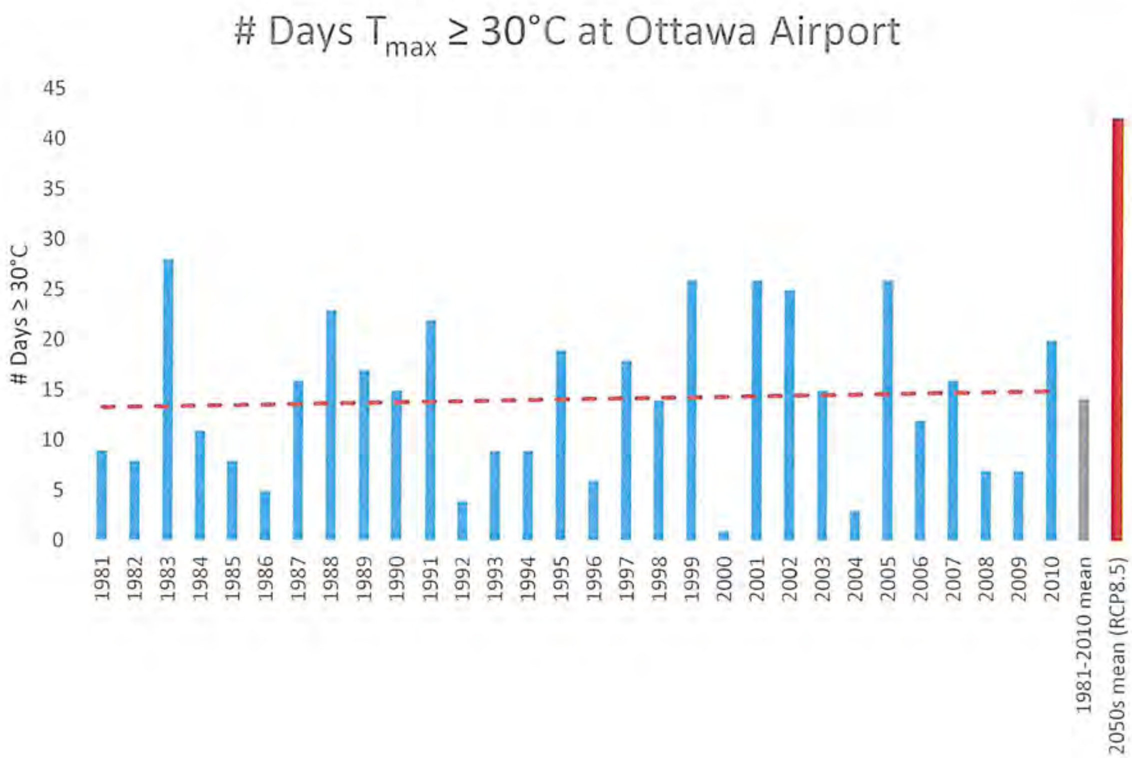

Figure C - 2. Number of days per year with the maximum temperature ≥ 30°C during the 1981-2010 time period at Ottawa Airport. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

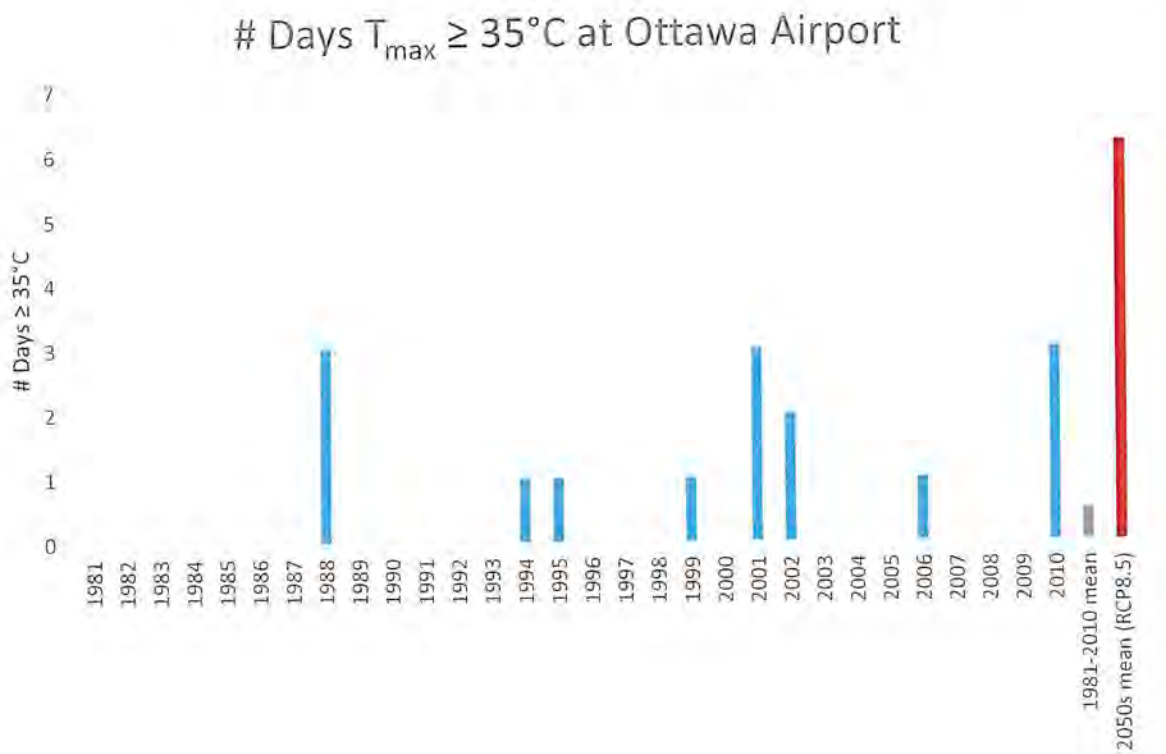

Figure C - 3. Number of days per year with the maximum temperature ≥ 35°C during the 1981-2010 time period at Ottawa Airport. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

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**).

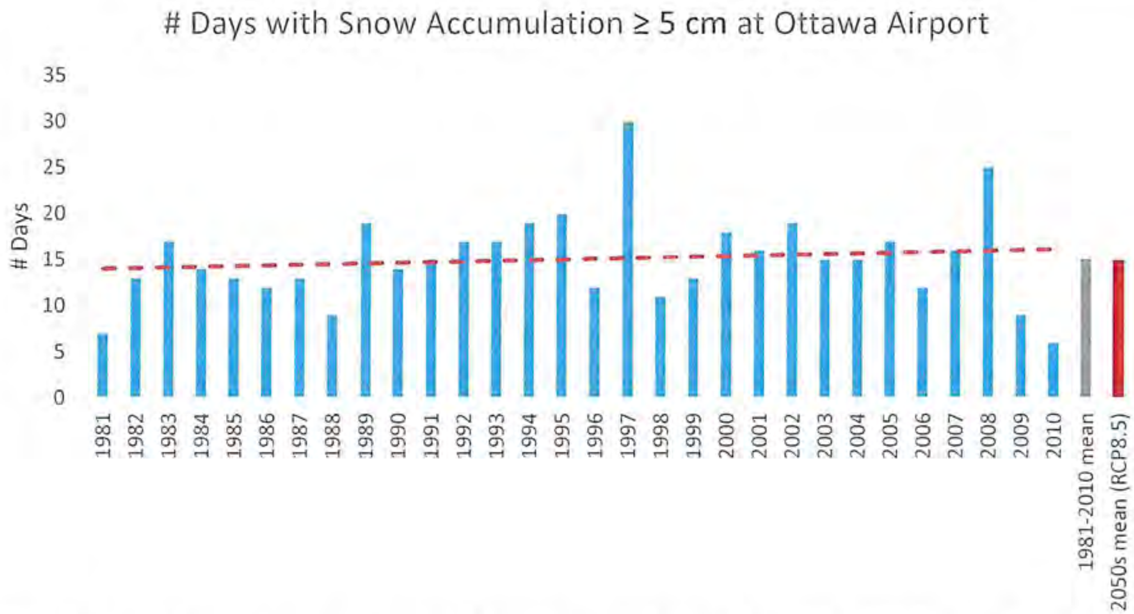

Figure C - 4. Number of events per year with a snowfall accumulation ≥ 5 cm at the Ottawa Airport during the 1981-2010 time period. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

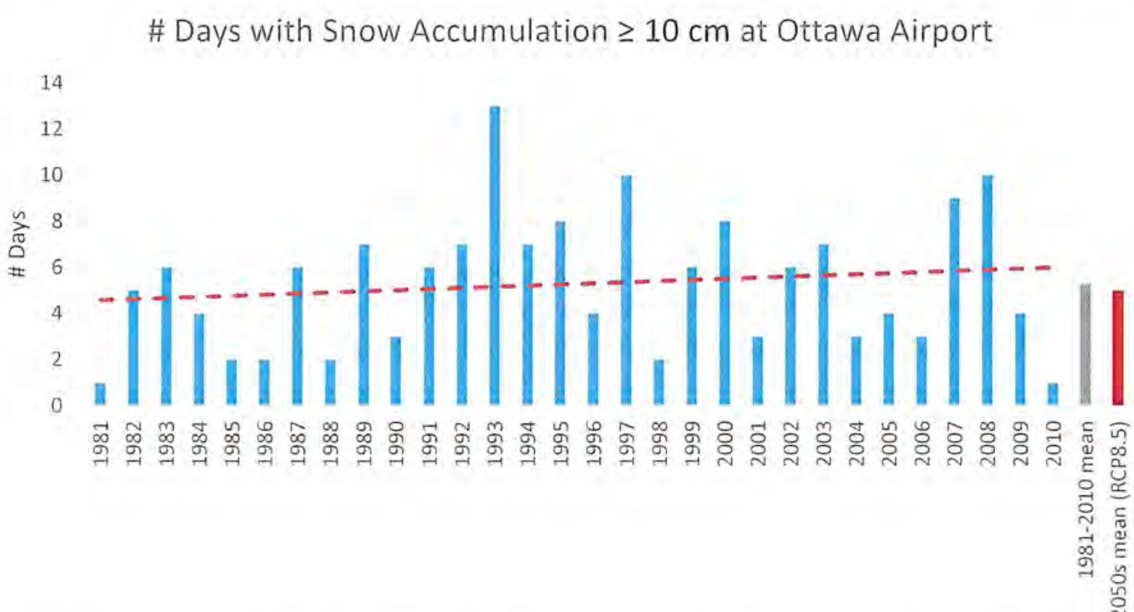

Figure C - 5. Number of events per year with a snowfall accumulation ≥ 10 cm at the Ottawa Airport during the 1981-2010 time period. The annual mean for the 1981-2010 baseline and projected for the 2050s under the RCP8.5 scenario is also presented.

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.

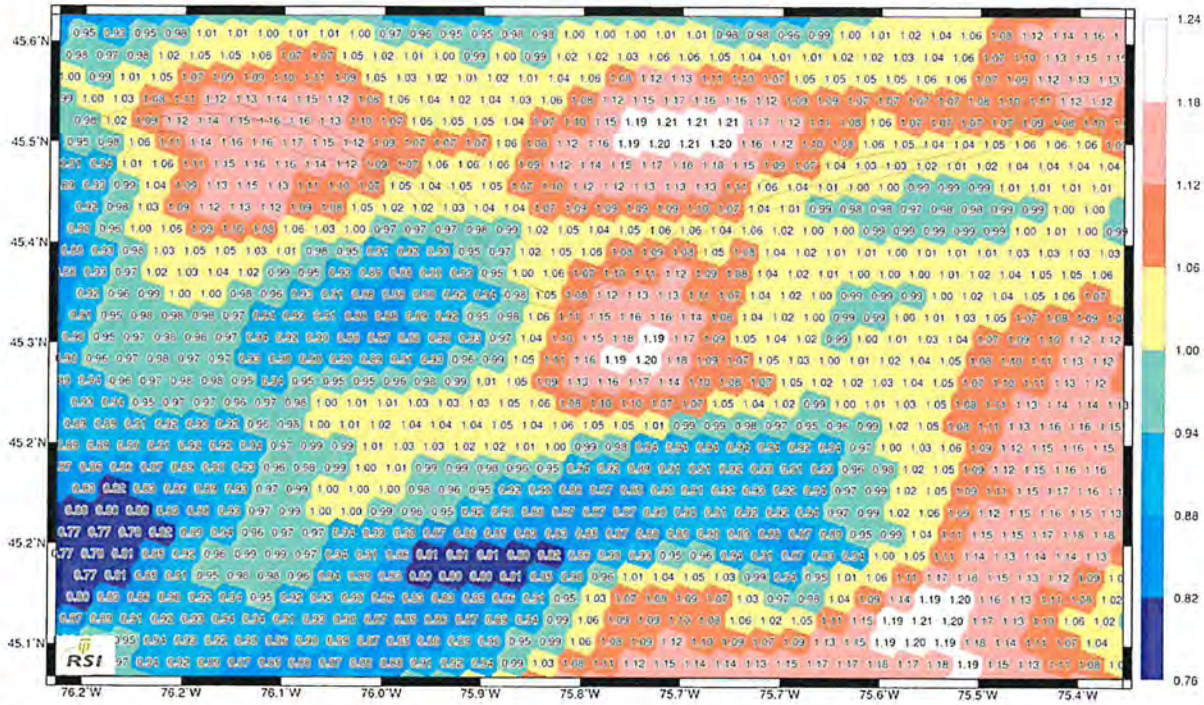

Figure C - 6. Map indicating the lightning flash density in lightning flashes per square kilometre per year for the Greater Ottawa Region and surrounding areas. (Data from the ECCC National Lightning Database; plot produced by Risk Sciences International.)

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).

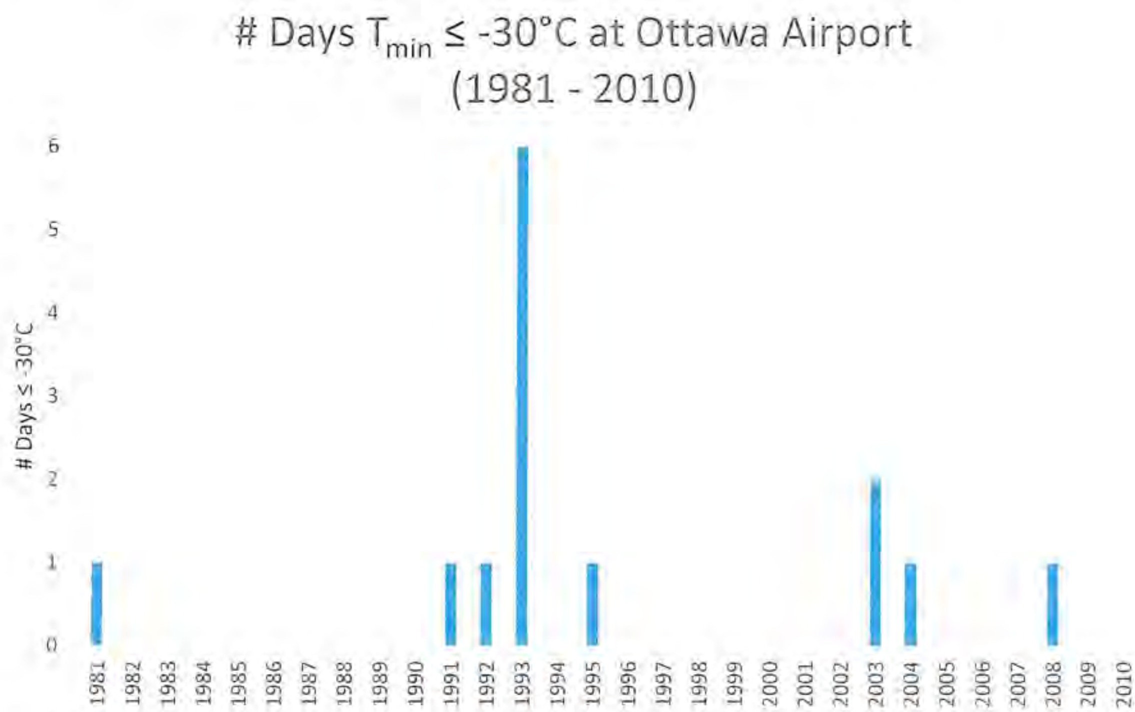

Figure C - 7. Number of days per year with the minimum temperature ≤ -30°C during the 1981-2010 time period at Ottawa Airport.

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.

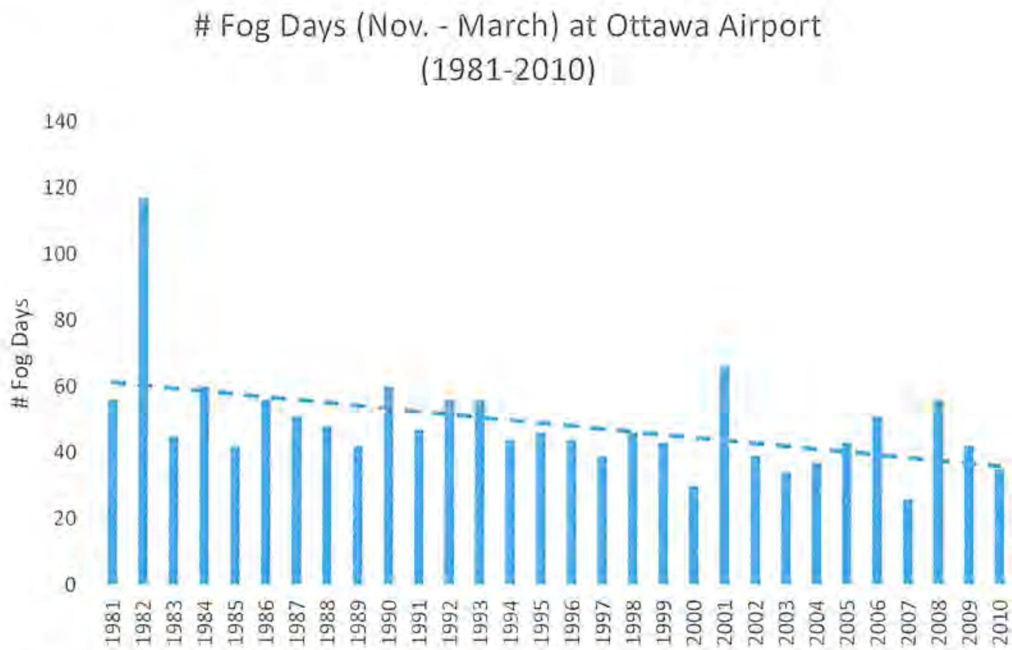

Figure C - 8. Number of days per year with winter (Nov.-March) fog reported at the Ottawa Airport during the 1981-2010 time period.

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.

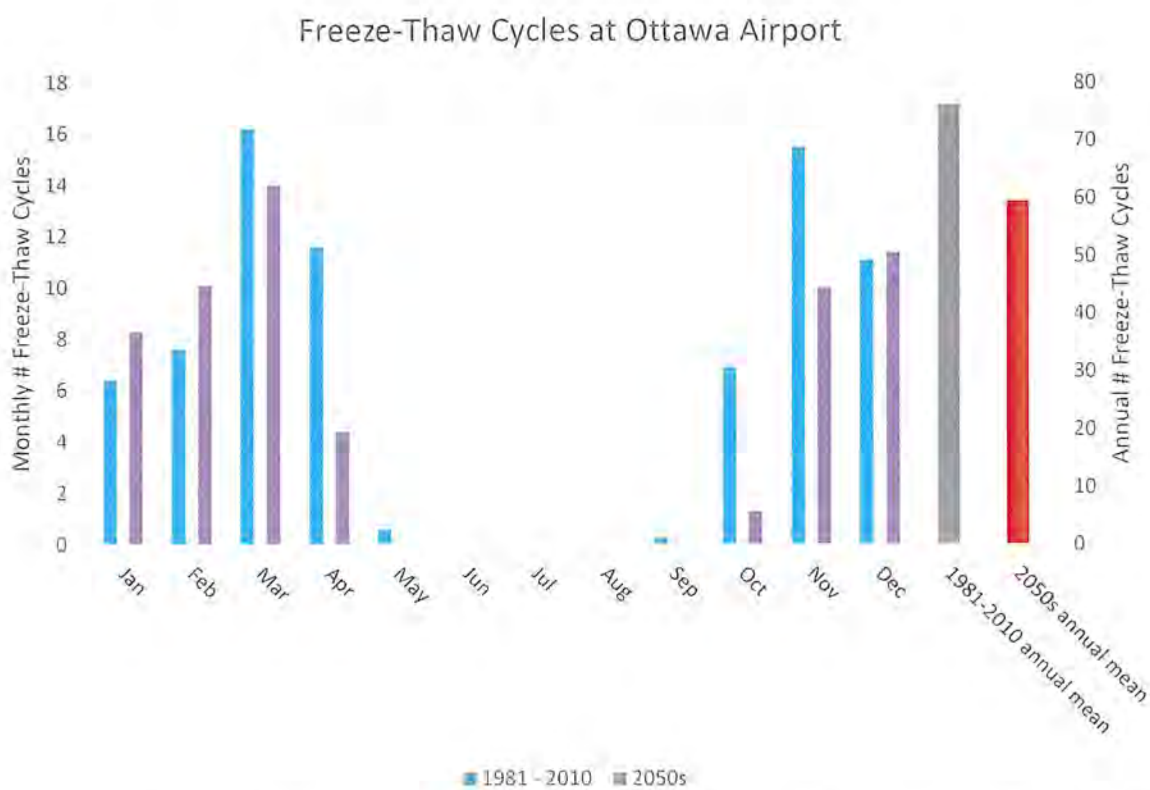

Figure C - 9. Monthly distribution and total annual number of freeze-thaw cycle at the Ottawa Airport during the 1981-2010 time period and projected for the 2050s under the RCP8.5 scenario.

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.

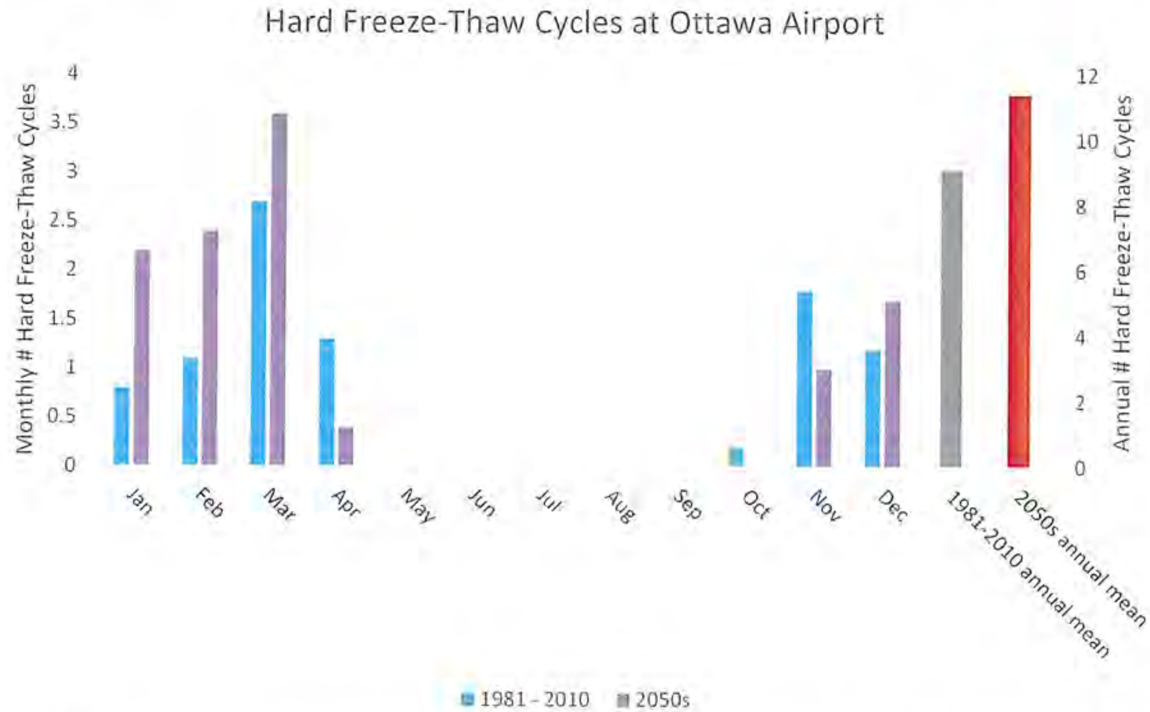

Figure C - 10. Monthly distribution and total annual number of hard freeze-thaw cycle at the Ottawa Airport during the 1981-2010 time period and projected for the 2050s under the RCP8.5 scenario. Hard freeze-thaw cycles are freeze-thaw cycles with a larger temperature fluctuation around 0°C, defined 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

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)

[illegible]

Asset/Infrastructure Element	[illegible]
Current Climate	[illegible]
Power Distribution - Underground	[illegible]
Civil Structures	[illegible]
Cable Chamber & Lid	[illegible]
Duct Windows	[illegible]
Equipment Pad (Above Ground)	[illegible]
Concrete Encased Duct Bank	[illegible]
Underground Cables	[illegible]
Underground Primary Switchgear	[illegible]
Enclosure	[illegible]
Concrete Base (Pad)	[illegible]
Underground Transformers	[illegible]
Enclosure	[illegible]
Concrete Base	[illegible]
Power Distribution - Vaults	[illegible]
Vault Transformers Located in Third Party	[illegible]
Enclosure	[illegible]
Primary Bushing	[illegible]
Secondary Bushing	[illegible]
Casing/Radiators	[illegible]

Asset/Infrastructure Element																
Current Climate	[illegible]	Daily maximum temp. of 35 C and higher	Daily maximum temp. of 40 C and higher	Daily minimum temp. of -25 C and colder	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Asset/Infrastructure Element	
[illegible]	[illegible]

Stantec

Asset/Infrastructure Element	Climate parameters (Current Climate)
	Daily maximum temp. of 35 C and higher; Daily maximum temp. of 40 C and higher; Daily minimum temp. of -25 C and colder; Heat wave; 50 mm of rainfall in 1 hour; Ice accumulation of 25 mm; Ice accumulation of 40mm; Extreme winds; Annual wind speeds; Days with 20 cm or more of snowfall; Freeze-thaw cycles; Freezes with 3-14 fog days
	Y/N; Probability; Final
Power Distribution - Overhead (North-South Generation)	
Distribution Lines	[illegible]
Primary Overhead Conductor	[illegible]
Secondary Overhead Conductors	[illegible]
Ground Conductors	[illegible]
Third Party Equipment	[illegible]
Poles	[illegible]
Pole (Wood)	[illegible]
Pole (Concrete, Composite, Metal)	[illegible]
Cross Arms	[illegible]
Guy Wires and Anchors	[illegible]
Insulators	[illegible]
Surge Arresters	[illegible]
Overhead Transformer	[illegible]
Enclosure	[illegible]
Primary Bushing	[illegible]
Secondary Bushing	[illegible]
Tap Changer	[illegible]
Hanging Lugs	[illegible]
Overhead Load Breaker Switch	[illegible]
Ground Connection	[illegible]
Surge Arresters	[illegible]
Fused Cut Out	[illegible]
Power Distribution - Underground	
Civil Structures	[illegible]
Cable Chamber & Lid	[illegible]
Duct Windows	[illegible]
Equipment Pad (Above Ground)	[illegible]
Concrete Encased Duct Bank	[illegible]
Underground Cables	[illegible]
Underground Primary Switchgear	[illegible]
Enclosure	[illegible]
Concrete Base / Pad	[illegible]
Underground Transformers	[illegible]
Enclosure	[illegible]
Concrete Base	[illegible]
Power Distribution - Vaults	
Vault Transformers (Located in Third Party Buildings)	[illegible]
Enclosure	[illegible]
Primary Bushing	[illegible]
Secondary Bushing	[illegible]
Cooling Radiators	[illegible]

Hydro Ottawa Climate Change Adaptation Plan

FINAL REPORT

November 11, 2019

Prepared for:

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Executive Summary

Hydro Ottawa Limited (Hydro Ottawa) provides electricity to over 330,000 residences and businesses in the City of Ottawa and the Village of Casselman, who depend on a continuous and reliable supply of energy. In recent years, particularly in 2018, Hydro Ottawa distribution infrastructure was subjected to notably 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. (Stantec) to conduct a Climate Change Adaptation Plan (the Plan) for their distribution system and supporting infrastructure to follow up on the risk and vulnerabilities identified in an earlier phase of work. This work is compiled in a standalone report prepared by Stantec, titled Distribution System Climate Risk and Vulnerability Assessment (CRVA).

This Climate Change Adaptation Plan considers the entire geographic extent of Hydro Ottawa's service territory which includes a vast portion of the City of Ottawa and the Village of Casselman and includes both overhead and underground electrical distribution assets. The purpose of this Plan is to identify and make recommendations for actions to reduce the risks identified in the CRVA as well as recommendations for integrating actions into the Hydro Ottawa planning systems and operation practices and procedures.

Both this assessment and the CRVA were completed in general conformance with the Canadian Electricity Association's (CEA) Guide On Adaptation To Climate Change, and the Engineers Canada Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. Furthermore, this methodology aligns with the principles, requirements and guidelines of the ISO 31000:2018 Risk Management Framework and ISO 14090:2019 Adaptation to Climate Change.

Climate changes in the Ottawa region include historical warming trends (approximately 1.7°C per century) which are projected to continue into the future. Seasonally, the most dramatic changes observed are associated with winter minimum temperatures, which constituted a 2.5°C increase between 1939 and 2010. Similarly, Ottawa has seen an increase in precipitation, where total precipitation has increased by 25.9mm over the past 30 years. Future projections indicate increases in total precipitation as well as an increase in the frequency of short duration, high intensity events. Furthermore, the climate modelling projections indicate that wind and other complex events (ex: freezing rain, lightning, etc.) are expected to increase as well.

The Climate Risks and Vulnerability Assessment identified impacts to Hydro Ottawa's infrastructure and operations which are expected to become more prominent in the future due to climate change. For this assessment, infrastructure systems identified in the CRVA have been grouped into four main asset categories: Pole Line Systems (PLS), Underground Line Systems (ULS), Substations (SUB), and Operations (OPS). Adaptation plans were created based on potential mitigation actions developed in a workshop with Hydro Ottawa. The timelines and prioritization of action plans were based on the current risk, future risk and the change in risk over time.

The Adaptation Plan includes recommendations based on possible measures developed in Hydro Ottawa workshops to mitigate the impact of climate related events. These prioritized recommendations are summarized in Table E-1.

Table E-1: Adaptation Plans

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
OPS-1	Refine and establish a policy on wind conditions when a lift bucket should not be used and when work should not be completed to mitigate the risk of injury related to wind.	Distribution Operations Health and Safety	1 year
PLS-1	Develop anti-cascading strategies and standards for hardening of pole line systems to protect against wind and ice accumulation events, including: • Introducing break or stress points into the distribution lines. • Anchoring. • Type of pole. Complete a cost-benefit review of the strategies at critical areas and/or strategic timelines (end of life).	Asset Planning	2 years
PLS-2	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their potential to damage infrastructure or injure personnel during wind and ice events. Noting past program augmentations made in response to past storm events, evaluate feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate.	Forestry Asset Planning	2 years
PLS-3	Complete a technology review and feasibility study of technology that may use reduce ice build-up through pulsing or vibration of distribution lines to prevent ice build-up and galloping of lines.	Standards	2 years
PLS-4	Complete a study/analysis of potential methods to increase detection capabilities for downed lines to increase response time to repair damaged pole line system after damage from wind and/or ice accumulation.	Asset Planning	2 years
SUB-1	Review additional requirements for sanding and gritting prior to site access.	Facilities	2 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
OPS-2	Consider a review of policies surrounding heat stress on outdoor workers and revise to include projected climate changes to mitigate the impacts of heat stress. Policies to consider should including: • A policy on work redistribution (scheduling) to avoid outdoor work during peak heat hours. • Where feasible and risk assessment permits, consider a policy around the adoption and use of modified PPE to improve cooling / ventilation.	Distribution Operations Health and Safety	2 years
OPS-3	Work with Hydro One, and provincial regulators to ensure supply design and standards are aligned with climate risks.	Asset Planning System Operations	2 years
OPS-4	Consider the cost-benefit of the following measures to reduce the risk of employee injuries related to ice accumulation events: • Review, and consider revising policy for requiring installation of winter tires on Hydro-owned vehicles to prevent injuries to personnel rather than through a request/approval process. • Installation and use of additional automated devices to limit need to travel during inclement conditions. • Introducing policies to include heated steps or walkways on Hydro Ottawa properties versus continued salting/sanding.	Fleet & Facilities Asset Planning	2 years
PLS-5	While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Underground distribution lines and infrastructure would mitigate risk from wind, ice accumulation and fog.	Asset Planning	5 years
ULS-1	Complete an engineering review to identify if there are locations vulnerable to overheating (via a detailed assessment of locations that could be vulnerable to temperatures higher than 40°C) and complete a cost-benefit analysis for mitigation options, which may include: • Institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables. • Cool ducts either actively or passively, for example, with thermal fill (a clay slurry).	Asset Planning Standards	5 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
ULS-2	Identify new technologies and processes through research and feasibility or pilot studies to reduce freeze thaw impacts. These may include: • Exploring the use of different materials for manholes instead of concrete that are less susceptible to freeze-thaw (e.g. fiber glass). • Redesign civil structure collars to move with the heading (e.g. telescopic collars).	Asset Planning Standards	5 years
SUB-2	Develop a policy to monitor and inspect substation building and structural components after an ice event to mitigate the risk of structural damage and loss of assets as a result of ice damage to substations.	Facilities Stations	5 years
SUB-3	Complete a cost-benefit analysis of installing protective covers on small exterior equipment, where feasible, to prevent damage/failure as a result of ice accumulation.	Facilities	5 years
SUB-4	In light of current design standards (40 mm of ice accumulations), assess the need for changes to technical specifications and policies for increased load break switch protection which may include: • Installation of alternative devices (i.e. breakers) to switch loads when load break switches are difficult to switch or inoperable. • Installation of switches without exposed contacts (replacement or protection). Update equipment specifications to require that switch operators break ice to allow for operability.	System Operations Asset Planning Standards	5 years
OPS-5	Develop a policy to monitor and inspect building and roofs after an ice event.	Facilities	5 years
OPS-6	Consider updating the work from home policy to eliminate or reduce commuting during extreme weather events and hazardous road conditions, particularly ice accumulation.	Human Resources	5 years
OPS-7	Consider future climate projections at end of life of current system when deciding to replace or rehabilitate building HVAC systems. Integrate requirement into Procurement Policy to size and design based on climate projections (heating and cooling requirements) in conjunction with critical needs (IT server requirements). By integrating future needs into procurement, the risk that cooling is not adequate during 40°C is minimized.	Facilities	5 years
PLS-6	Consider the feasibility of further increasing the frequency of pole washing and cost/benefit based on risk level (current/future) to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	5-10 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
PLS-7	Complete a cost/benefit analysis of expedited replacement of insulators and fused cut-outs with porcelain to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	5-10 years

These and other risk mitigation strategies are discussed in more detail in the main report along with a series of suggested best practices to help improve the resilience of Hydro Ottawa operations moving forward. Suggested best practices are summarized below.

- **Action 1:** Continue to invest in Smart Grid technology to increase resilience of the distribution system.
- **Action 2:** Continue to conduct post-disaster event analyses to identify lessons learned.
- **Action 3:** Continual improvement of emergency response planning, including communication protocols before, during and after extreme weather event.
- **Action 4:** Require that operating budgets account for climate risks and resiliency needs.
- **Action 5:** Continue to collaborate and plan with third-party service (e.g. City of Ottawa) providers to mitigate emerging risks and increase resilience of emergency planning procedures.
- **Action 6:** Consider wildfires as a potential risk that may emerge in the future and review the need for Wildfire Management Plans on an annual basis.
- **Action 7:** Collaborate with other utilities, regulators, and governments to develop guidance and protocols for climate resilience electrical infrastructure.
- **Action 8:** Build broad awareness and education among staff, such as incorporating extreme climate events and risks into health and safety communication and training materials.

Abbreviations

CRVA	Climate Risk and Vulnerability Assessment
GDP	Gross Domestic Product
GHG	Greenhouse Gas
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
OPS	Operations
PIEVC	Public Infrastructure Engineering Vulnerability Committee
PLS	Pole Line System
RCP	Representative Concentration Pathways
SUB	Substations
ULS	Underground Line Systems

1.0 INTRODUCTION

1.1 ABOUT HYDRO OTTAWA LIMITED

Hydro Ottawa Limited (Hydro Ottawa) provides electricity to over 330,000 residences and businesses in the City of Ottawa and the Village of Casselman, who depend on a continuous and reliable supply of energy. Its core business is electricity distribution and utility services with a service area of 1,116 km^2 which includes both the City of Ottawa and the Village of Casselman.

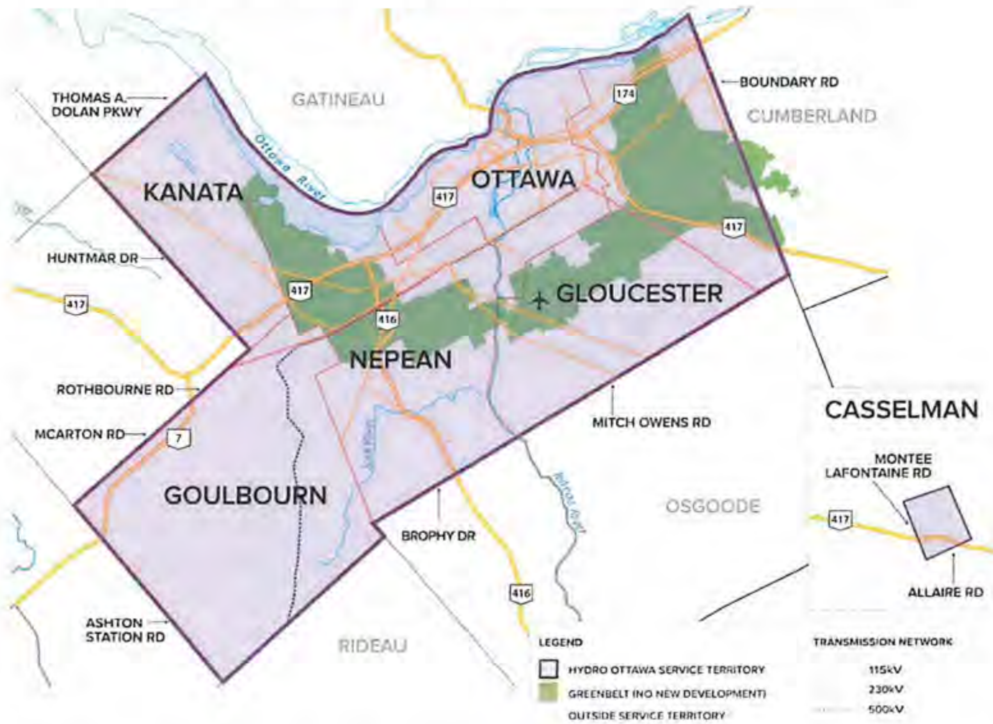

Figure 1: Map of Hydro Ottawa Service Territory[1]

[1] Hydro Ottawa. 2018. <https://hydroottawa.com/about/governance/overview>

1.2 FUTURE CLIMATE CHALLENGE

Hydro Ottawa is committed to creating long-term value for its shareholder, benefitting their customers and the communities it serves. However, climate change poses a serious threat to Hydro Ottawa's ability to deliver on that commitment. This was recently evidenced by the 2018 ice and windstorms of the spring, and the tornadoes that struck the service territory on September 21st, 2018. While these weather events had unavoidable impacts on the outage durations, Hydro Ottawa was able to moderate that impact due to past improvements to the physical infrastructure as well as to monitoring and remote response capabilities.

Hydro Ottawa has recognized the that 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 greater range of potentially costly and disruptive impacts to the electrical distribution system, services, and operations. The inevitability of these climatic changes has prompted Hydro Ottawa to plan, monitor and adapt their systems and infrastructure to increase their resilience and limit the impact and damage that these extreme weather events can have on their services.

Hydro Ottawa has retained Stantec Consulting Ltd. (Stantec) to conduct a Climate Change Adaptation Plan (the Plan) for their distribution system and supporting infrastructure to follow up on the risk and vulnerabilities identified in an earlier phase of work. This work culminated in a standalone report prepared by Stantec, titled Distribution System Climate Risk and Vulnerability Assessment (CRVA). The risks identified in the CRVA are further detailed in Section 5 and available under separate cover. As a follow up to the CRVA, this Climate Change Adaptation Plan was developed.

1.3 PURPOSE OF THIS PLAN

This Climate Change Adaptation Plan (the Plan) considers the entire geographic extent of Hydro Ottawa's service territory which covers a vast portion of the City of Ottawa and the Village of Casselman, and includes both overhead and underground electrical distribution assets. The purpose of this Plan is to identify and make recommendations for actions to reduce the risks identified in the CRVA as well as recommendations for integrating actions into the Hydro Ottawa planning systems and operations.

The Plan, similar to the CRVA, was developed through a series of interviews and workshops with Hydro Ottawa staff.

2.0 CLIMATE CHANGE ADAPTATION

2.1 THE RISKS

In 2007, the Intergovernmental Panel on Climate Change (IPCC) concluded that "[the] warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global mean sea level."[2] The impacts of climate change are already being experienced, and the inertia in the atmosphere dictates that the planet is 'locked into' some level of temperature rise due to historic greenhouse gas (GHG) emissions. In fact, some changes are "effectively irreversible", e.g. major melting of the ice sheets[3], and can have abrupt and severe impacts to our global climate.

2.2 THE COSTS

While the costs of extreme weather events depend on multiple factors, climate change is already increasing the intensity of storms, floods, droughts and other severe weather events in Canada. Since the 1980's, catastrophic losses from weather-related events have been growing (Figure 2: Catastrophic Losses in Canada (1983-2018)

and are expected to grow from about \$5 billion in 2020 to between \$21 billion and \$43 billion under a 2°C scenario.[4] The Canadian insurance industry defines a catastrophic event as one that exceeds a threshold of \$25 million in insured losses.

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[2] IPCC (2007) Climate Change 2007: Synthesis Report. Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, Paschauri, R.K. and Reisinger, A. (eds)], (Geneva, Switzerland: IPCC), p. 2.
[3] http://www.ipcc.ch/ipccreports/tar/vol4/011.htm
[4] Canada, National Round Table on the Environment and the Economy (2011) Paying the Price: The Economic Impacts of Climate Change for Canada (Ottawa: National Round Table on the Environment and the Economy), 162 p.

Figure 2: Catastrophic Losses in Canada (1983-2018)[5]

These costs have come close to, or exceeded, $1 billion in most years since 2009. They surpassed $1.5 billion in 2011 and 2017, $2.0 billion in 2018, $3 billion in 2013 and $5.0 billion in 2016. In the past decade, the sum of all severe weather-related catastrophic events has exceeded $20 billion. In 2018 alone, Hydro Ottawa's electrical distribution infrastructure was impacted by costly climate events 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. The impact of these events range in magnitude, but included service disruption to customers, damage to private property and distribution infrastructure and systems such as structural damage, reduced service life for asset components and for assets themselves, and increased stress to systems and operations. Increases in the frequency and intensity of these extreme events are likely to result in higher repair and maintenance costs, loss of asset value, and interruption of services or production if no risk mitigation and adaptation actions are taken.

With the IPCC concluding that the electricity sector is one of the sectors most at risk of disruption from climate change, and the occurrence of climate events already causing costly impacts, there is growing pressure from stakeholder for organizations to take responsibility to minimize the vulnerability of assets to a changing climate. Liabilities can often be attributed to the inadequate design or mismanagement of infrastructure that arise as a result of climate change and the impact can create public and environmental hazards that should have been mitigated or avoided entirely.

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[5] https://globalnews.ca/news/5060791/commentary-climate-change-construction/

2.3 RESPONDING TO THE IMPACTS OF CLIMATE CHANGE

Addressing climate change requires efforts to prepare for changes that are irreversible and already underway, known as climate adaptation. Climate change adaptation involves making adjustments not only to infrastructure and operations but by integrating considerations for climate change into the decision-making process. Adaptation means enabling a sector or process to have a greater range of tolerance to extreme weather events (Figure 3). Most importantly, climate adaptation is now an essential aspect of managing infrastructure.

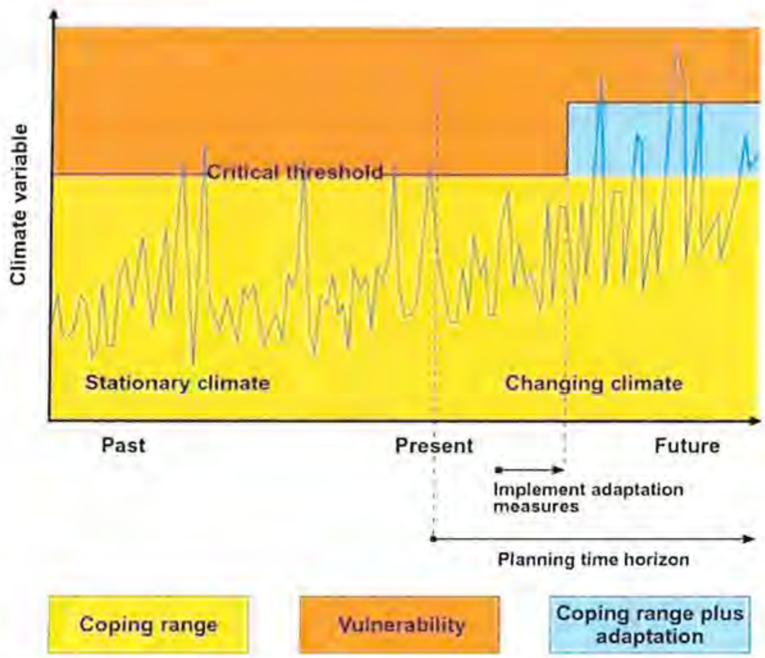

Figure 3: Adaptation Aims to Reduce Vulnerability by Increasing Coping Ranges[6]

Adaptation actions that are taken prior to experiencing specific climate change trends are called "anticipatory or proactive" and those taken after a trend or event has occurred are considered "reactive". Planned proactive adaptation actions typically incur lower long-term costs as the actions preserve assets, address issues of premature aging and increase overall resilience[7]. Successful adaptation does not necessarily mean that climate related impacts will no longer occur; rather, the impacts will still likely occur, but will be less severe in both harm and economic costs than if no adaptation measures been implemented.

[6] http://www.erm.com/en/insights/feature-articles/a-changing-climate-for-the-extractives-sector/

[7] Natural Resources Canada. (2009). What is adaptation? Retrieved from https://www.nrcan.gc.ca/environment/impacts-adaptation/adaptation-101/10025.

Although it is no longer possible to avoid the impacts of climate change, it is possible to reduce the cost and impacts of climate change to various extents. There is a business case for adaptation; this was clearly outlined in an economic report commissioned by the UK government called *The Stern Review*, which concluded, "the benefits of strong and early action far outweigh the economic costs of not acting." Using results from economic models, *The Stern Review* estimated that if society does not act, the overall costs and risks of climate change will be equivalent to losing at least 5% of global Gross Domestic Product (GDP) annually – potentially as much as 20% of GDP. In contrast, the estimated costs of implementing actions to reduce GHG emissions and avoid some of the worst impacts of climate change could be limited to around 1% of global GDP. Most recently, the National Round Table on the Environment and the Economy concluded that the for every dollar spent on climate change adaptation now, \$9 to \$38 of damages can be avoided in the future.[8]

[8] http://nrt-trn.ca/wp-content/uploads/2011/09/paying-the-price.pdf

3.0 PREDICTING FUTURE CLIMATE CHANGE AND RISK

To understand anticipated future climate conditions in Hydro Ottawa's service territory, current and historical data from regional Environment Canada weather stations was analyzed in relation to projected global climate trends. Future climate conditions were projected based on Intergovernmental Panel on Climate Change (IPCC) global Representative Concentration Pathways (RCPs), while current and historical weather data was retrieved from Environment Canada records from local weather stations located at the Macdonald-Cartier International Airport and Russell, ON. From this data, localized climate projections were developed for the representative 30-year climate period centered on the 2050s (2041 – 2070) under the "business-as-usual" carbon emissions scenario, RCP8.5. These projections were then used estimate potential extreme weather events and general long-term patterns and trends by that could be expected to be experienced in the service territory during this future climate period.

The future climate conditions identified in the CRVA are based on a 'business as usual' greenhouse gas emissions scenario, which is referred by the IPCC as RCP 8.5 (Figure 4). Based on this scenario, it is assumed that global carbon emissions will continue to rise until 2100. Although some progress has been made in reducing global GHG emissions, current estimates of GHG emissions are still close to following the RCP 8.5 path and thus the CRVA and this Plan are based on risks identified from future climate projections estimated by the RCP 8.5 scenario.

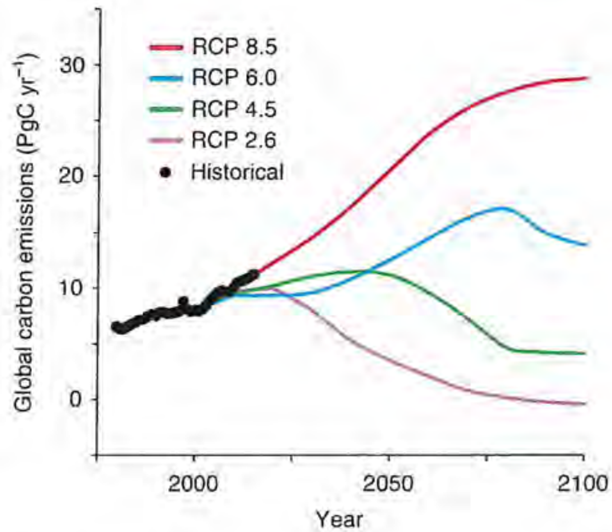

Figure 4: RCP Emissions Scenarios[9]

Climate modeling uses various GHG emissions scenarios, known as Representative Concentration Pathways (RCPs), to project future climate variables under different concentrations and rates of release of GHGs to the atmosphere, as well as different global energy balances. Various future trajectories of GHG emissions are possible depending on the global mitigation efforts in the coming years. RCPs are established by IPCC the international body for assessing the science related to climate change. The IPCC has set four GHG emissions scenarios through RCPs. RCP 8.5 is the internationally recognized the most pessimistic - "business as usual" GHG emissions scenario. Other GHG emissions scenarios represent more substantial and sustained reductions in GHG emissions: RCP 6, 4.5 and 2.6 (For example, the RCP 2.6 emissions scenario may be achievable with extensive adoption of biofuels/renewable energy and large-scale changes in global consumption habits, along with carbon capture and storage. RCP2.6 is representative of a scenario that aims to keep global warming likely below 2°C above pre-industrial temperatures. RCP 4.5 is considered the 'medium stabilization' scenario where global mitigation efforts result in intermediate levels of GHG emissions (IPCC, 2014).

A summary of potential climate changes centered around the 2050s identified in the CRVA for the Hydro Ottawa service area, is presented in Table 1.

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[9] Source: https://www.nature.com/articles/s41558-018-0253-3

Table 1: Summary of Potential Climatic Changes by 2050

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 Duration – High Intensity)	• Increased intensity of events • Reduced return periods (e.g. 20-yr return period event becoming a 10-yr return period event in the future)
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/h; 120 km/h)
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)

4.0 APPROACH TO RISK AND ADAPTATION PLANNING

4.1 IDENTIFYING RISK AND ADAPTATION MEASURES

The CRVA was used to evaluate potential impacts and risks to the Hydro Ottawa electrical distribution system and supporting infrastructure as a result of changing climate and extreme weather events. This assessment process followed the Canadian Electricity Association's guide on adaptation to climate change, and Engineers Canada's Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. The process involved the systematic review of historical climate information and the projection of the nature, severity and probability of future climate changes and events. The assessment of climatic changes was used to establish the exposure of infrastructure systems to these climate events. The impact of a particular damaging or disruptive climate event was then quantified and used to calculate the risk for a particular climate-infrastructure interaction. This process was repeated for all applicable infrastructure elements to produce an electrical distribution infrastructure climate risk profile.

The CRVA followed the following methodology (details of the process are provided in the CRVA report):

1. Identification of climate events (e.g. temperature, precipitation, winds) and their threshold values above which infrastructure performance would be affected and projecting the probability of occurrence of the climate hazards in the future (i.e. 2050s).
2. Assignment of a probability score for each climate event based on the climate data. This involved converting the projected probability of occurrence of future climate parameters into the five-point rating scale used in Hydro Ottawa's Asset Management System Risk Procedures.
3. Assignment of a severity rating for the impact of climate events on each element of the distribution system considered in the assessment. Impacts on the infrastructure were assessed for various performance criteria. This part of the assessment was completed through a staff workshop.
4. Calculation of the risk for each infrastructure element was performed using the formula: Risk = Severity x Probability (Table 2).
5. Using Hydro Ottawa's Asset Management System Risk Table (Table 3), medium, high and very high risks to infrastructure and operations were identified.

The adaptive capacity – the ability of a system to respond which takes into consideration factors like, age, design setting, etc.– of the infrastructure elements were taken into account during the risk assessment stage.

Table 2: Sample Risk Scoring Visualization

		Severity				
		Insignificant	**Minor**	**Moderate**	**Extreme**	**Significant**
Likelihood	**Rare**	1	4	8	16	25
	Unlikely	2	8	16	32	50
	Possibly	3	12	24	48	75
	Likely	4	16	32	64	100
	Almost Certain	5	20	40	80	125

Table 3: Hydro Ottawa Risk Rating System

Risk Score	Risk Rating
Low	≤10
Medium	11-30
High	31-60
Very High	≥60

The development of the Adaptation Plan consisted of the following steps:

1. Validation of medium to very high risks to infrastructure and operations as well as the impacts in a workshop with Hydro Ottawa staff (See Appendix B for the list of the attendees).
2. Selection of risk mitigation or adaptation measures to reduce the impacts of medium to very high future climate risks; developed through the workshop with Hydro Ottawa.
3. Prioritization of actions based on the risk levels, change in risk (current to future) and Hydro Ottawa's Asset Management System Risk Procedures.
4. Assignment of responsibilities and the development of indicators to track and monitor progress in the Enterprise Risk Management System (ERMS).

5.0 IDENTIFIED RISK AND ADAPTATION MEASURES

5.1 INFRASTRUCTURE ELEMENTS AT RISK

The medium, high and very high future climate related risks developed in the CRVA are provided in Table 4 for a given climate parameter. For each climate parameter, the asset performance affected, impacts and consequences are identified as well as the current and future risk rating. The difference between the current risk and the future risk is generally attributed to the impact of a changing climate as well as the age of the infrastructure. Red risk ratings identify high and very high risks.

Table 4: Medium and Very High 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	45 45	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.
	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	• Potentially reduced capacity due to increased daily electricity demand from end user (e.g., A/C units).	• Additional strain on, and limits to the underground electrical infrastructure capacity.
Annual wind speeds of 120 km/h 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.	• 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.
					• 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.
	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.	• 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.
					• 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.

Climate Parameter	System/Component Affected	Risk Rating Current Climate	Risk Rating Future Climate	Asset Performance Affected	Impacts	Result / Consequence
Easterly winds of 80 km/h 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	• 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.
	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.	• 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.
					• 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.
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 shared resources 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 and Hydro One shared resources • 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.	• Health and safety concerns for staff, contractors and/or public.
					• Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof.	• 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.
					• Ice accumulation on building mounted equipment (roof, exterior walls).	• 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.	• Health and safety concerns for staff, contractors and/or public. • Delay in restoration.
					• Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof.	• 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.
					• Ice accumulation on building mounted equipment (roof, exterior walls).	• Reduced efficiency and/or functionality, and failure of equipment affected.

Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
Ice accumulation of 40mm (30-year occurrence) (continued)	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.
	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.	• 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.
					• Ice accretion on lines in excess of 12.5 mm (0.5 inches) accompanied by a 90km/h wind could result in structural failure. • Uneven ice accretion could cause swinging or 'galloping' in the lines. • Damage to poles and attached equipment.	• 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.
					• Damages to lines from fallen trees or broken tree limbs.	• 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.
					• 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.
	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.	• 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.
					• Ice accretion on lines in excess of 12.5 mm (0.5 inches) accompanied by a 90km/h wind could result in structural failure. • Uneven ice accretion could cause swinging or 'galloping' in the lines. • Damage to poles and attached equipment.	• 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.

Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
Ice accumulation of 40mm (30-year occurrence) (continued)					• Damages to lines from fallen trees or broken tree limbs.	• 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.
					• 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.
	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.
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.
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 which are a result of contaminant build-up on the insulators and the fog reducing the dielectric strength of the air which increases the probability of a flashover.	• 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 which are a result of contaminant build-up on the insulators and the fog reducing the dielectric strength of the air which increases the probability of a flashover.	• 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 which are a result of contaminant build-up on the insulators and the fog reducing the dielectric strength of the air which increases the probability of a flashover probability of a flashover.	• 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.

5.2 ADAPTATION MEASURES

5.2.1 Adaptation Workshop

A climate adaptation planning workshop was conducted on June 27, 2019 with Hydro Ottawa staff and Stantec's risk and adaptation planning team. The purpose of the workshop was to validate the risks identified in the CRVA and to identify adaptation measures.

The workshop split participants into two groups to review the medium, high and very high climate risks and develop a range of adaptation measures for each.

A list of participants who attended the risk assessment workshop is presented in **Appendix B**.

5.2.2 Prioritizing Actions

The adaptation measures from the workshop were assessed and prioritized based on the level of risk as well as the change in risk in the current climate and future climate. Actions were prioritized taking into consideration both current and future risk ratings prioritizing those in the very high and high category and an assessment of the change in risk as identified by the risk factor. The risk factor represents the change in risk in the future climate scenario and is calculated by dividing the future risk by the current risk rating. Timelines to implement were developed based on the same review with longer implementation times for lower risk rating that increase in the future scenario. The timelines for adaptation measures represent the schedule for completing any analysis (e.g. cost-benefit analysis, policy review and revisions, etc.) and incorporation into a business operation such as policy, or plan.

The sections below present the significant risks and potential adaptation measures for each of the major infrastructure categories evaluated. The four categories used are pole line systems, underground line systems, substations and operations.

5.3 POLE LINE SYSTEM

5.3.1 Risk and Potential Adaptation Actions

High winds (>120 km/h - 30-year occurrence) causing direct damage to the poles, pole mounted equipment, and distribution lines as well as damage from falling tree or tree limbs pose the highest climate risk to Hydro Ottawa's infrastructure in current and future climates.

Ice accumulation (>40 mm - 30-year occurrence) currently poses a medium and high risk to infrastructure elements with the risk escalating to very high for the East-West distribution lines. The risk rating increased in the future for all assets impacted by ice accumulation.

Risks to infrastructure elements from fog are projected to increase in the future but remained in the medium range.

Easterly winds (>80 km/h) currently pose a medium risk to North-South distribution lines; this is not expected to measurably change in the future.

The actions identified during the Hydro Ottawa workshop are identified in Table 5.

Table 5: Impacts to Pole Line System - Current and Future

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Power Distribution: East-West lines and poles	Damage to poles and lines from high wind events.	81	81	1.0	Use of higher strength structures (e.g. concrete, composite, metal poles) as anchoring in anti-cascading strategy. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Power Distribution: East-West lines and poles	Risk of damages from falling trees, broken tree limbs or flying debris.	81	81	1.0	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Power Distribution: North-South lines and poles	Damage to poles and lines from high wind events.	108	108	1.0	Use of higher strength structures (e.g. concrete, composite, metal poles) as anchoring in anti-cascading strategy. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Power Distribution: North-South lines and poles	Risk of damages from falling trees, broken tree limbs or flying debris.	108	108	1.0	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Easterly winds of 80 km/h or higher (cool season [Oct.-March])	Power Distribution: North-South Lines and Poles	Damage from falling trees, broken tree limbs or flying debris.	32	32	1.0	Develop anti-cascading strategies (e.g. introduce break or stress points in lines). Increase detection capabilities for downed lines. Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Easterly winds of 80 km/h or higher (cool season [Oct.-March]) (continued)	Power Distribution: East-West Lines and Poles	Damage from falling trees, broken tree limbs or flying debris.	24	24	1.0	Develop anti-cascading strategies (e.g. introduce break or stress points in lines). Increase detection capabilities for downed lines. Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Ice accumulation of 40mm (30-year occurrence)	Power Distribution: East-West lines and poles	Damage from increased weight on overhead 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. Damages to lines from fallen trees or broken tree limbs. Damage to poles and other surface equipment from vehicles losing control on icy roads.	51	68	1.3	Develop anti-cascading strategies (e.g. introduce break or stress points in lines). Increase detection capabilities for downed lines. Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Research technology and feasibility of pulsing or vibrating lines to reduce ice build-up.
Ice accumulation of 40mm (30-year occurrence)	Power Distribution: North-South lines and poles	Damage from increased weight on overhead 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. Damages to lines from fallen trees or broken tree limbs. Damage to poles and other surface equipment from vehicles losing control on icy roads.	36	48	1.3	Develop anti-cascading strategies (e.g. introduce break or stress points in lines). Increase detection capabilities for downed lines. Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Research technology and feasibility of pulsing or vibrating lines to reduce ice build-up.

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Ice accumulation of 40mm (30-year occurrence) (continued)	Power Distribution: North-South lines and poles	Damages to lines from fallen trees or broken tree limbs.	36	48	1.3	Consider updating the vegetation management plan to account for the impacts and risks of increased invasive species and their impacts on infrastructure and personnel. For example, modify the vegetation management plan to include the following actions: • Trimming trees more often/aggressively or include heritage tree. • Include trees in the fall zone if vulnerable through a condition assessment. • Work with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Season with ≥ 50 fog days (Nov.-March)	Power Distribution: All directions	Pole fires as a result of contaminants accumulating onto insulators and presence of fog.	18	24	1.3	Expedite the replacement of porcelain insulators with polymer insulators beyond replacement during maintenance. Consider the feasibility of further increasing the frequency of pole washing and cost/benefit based on risk level (current/future). While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Season with ≥ 50 fog days (Nov.-March)	Power Distribution: North-South - Fused Cut Out	Insulator breakdown on fused cut outs.	12	16	1.3	Replace porcelain fused cutouts with polymer fused cutouts on an expedited basis. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.

5.8.2 Pole Line System Recommended Actions

To address the future climate risks in the pole line system, the following recommendations are built on the actions identified by Hydro Ottawa in the Workshop.

Table 6: Recommendations for Pole Line System (PLS)

Priority Level	Initiative	Responsibility	Business Operation to Integrate Outcome	Climate Event Mitigated	Timeline to Complete and Integrate into Business Operations (if applicable)	Monitoring Strategy
PLS-1	Develop anti-cascading strategies and standards for hardening of pole line systems to protect against wind and ice accumulation events, including: • Introducing break or stress points into the distribution lines. • Anchoring. • type of pole. Complete a cost-benefit review of the strategies at critical areas and/or strategic timelines (end of life).	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Wind, ice accumulation	2 years	Monitor power outages from cascading events year over year and track by climate event.
PLS-2	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their potential to damage infrastructure or injure personnel during wind and ice events. Noting past program augmentations made in response to past storm events, evaluate feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate.	Forestry Asset Planning	Vegetation Management Plan	Wind, ice accumulation	2 years	Review outage report as a result of tree damage on an annual basis and adjust Vegetation Management Plan as required.
PLS-3	Complete a technology review and feasibility study of technology that may use reduce ice build-up through pulsing or vibration of distribution lines to prevent ice build-up and galloping of lines.	Standards	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Ice accumulation	2 years	Line and pole damage and ice accumulation.
PLS-4	Complete a study/analysis of potential methods to increase detection capabilities for downed lines to increase response time to repair damaged pole line system after damage from wind and/or ice accumulation.	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Wind, ice accumulation	2 years	Monitor power restoration response time to event.
PLS-5	While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Underground distribution lines and infrastructure would mitigate risk from wind, ice accumulation and fog.	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Wind, ice accumulation, fog	5 years	Outage reports for weather events and cost of damage estimates.
PLS-6	Consider the feasibility of further increasing the frequency of pole washing and cost/benefit based on risk level (current/future) to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Fog	5-10 years	Monitor pole fires and fog days on a year over year basis
PLS-7	Complete a cost/benefit analysis of expedited replacement of insulators and fused cut-outs with porcelain to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Fog	5-10 years	Monitor pole fires and fog days on a year over year basis.

5.4 UNDERGROUND LINES SYSTEM

5.4.1 Risk and Potential Adaptation Actions

The CRVA identified only one interaction that presented a medium or higher risk: impacts of freeze-thaw events on civil structures. This risk is currently medium and projected to remain medium in the future.

The actions identified during the Hydro Ottawa workshop are identified in Table 7.

Table 7: Impacts to Underground Lines System - Current and Future

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Daily maximum temp. of 40°C	Power Distribution: Underground – Underground Cables	Loss of asset life due High ambient temperatures in combination with the heating of cables resulting from increasing electrical loading.	10	25	2.5	Review to identify, if there are locations vulnerable to overheating (via a detailed assessment of locations that could be vulnerable to temperatures higher than 40°C) and: • Institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables. • Cool ducts either actively or passively, for example, with thermal fil (a clay slurry).
Freeze-thaw cycles – Daily Tmax/Tmin temp. fluctuation of ±4°C around 0°C	Power Distribution: Underground - Civil Structures	Water penetration into or around civil structures which freezes causing stress on material.	16	24	1.5	Explore the use of different materials for manholes (fiber glass instead of concrete) that are less susceptible to freeze-thaw. Redesign civil structure collars to move with the heading (e.g. telescopic collars).

5.4.2 Underground Line Systems Recommended Actions

To address the future climate risks with underground line systems, the following recommendations are built on the actions identified by Hydro Ottawa in the Workshop.

Table 8: Recommendations for Underground Line Systems (ULS)

Priority Level	Initiative	Responsibility	Business Operation to Integrate Outcome	Climate Event Mitigated	Timeline to Complete and Integrate into Business Operations (if applicable)	Monitoring Strategy
ULS-1	Complete an engineering review to identify if there are locations vulnerable to overheating (via a detailed assessment of locations that could be vulnerable to temperatures higher than 40°C) and complete a cost-benefit analysis for mitigation options, which may include: • Institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables. • Cool ducts either actively or passively, for example, with thermal fill (a clay slurry).	Asset Planning Standards	Asset Management Plan UG Cable R0	Maximum Temperatures	5 years	Temperature runs within prescribed levels. Premature cable failure events and occurrences of 40°C days.
ULS-2	Identify new technologies and processes through research and feasibility or pilot studies to reduce freeze thaw impacts. These may include: • Exploring the use of different materials for manholes instead of concrete that are less susceptible to freeze-thaw (e.g. fiber glass). • Redesign civil structure collars to move with the heading (e.g. telescopic collars).	Asset Planning Standards	Asset Management Plan - Civil Structures	Freeze-thaw events	5 years	Track freeze-thaw damage and annual freeze-thaw days.

5.5 SUBSTATIONS

5.5.1 Risk and Potential Adaptation Actions

All climate risks identified for substations and substation components are related to ice accumulation of 40mm (30-year occurrence), which has been found to impact building access, roof loading, exterior mounted equipment, and load break switches. All these risks were found to increase in the future. The risks related to substation buildings increased from medium to a high in the future. The actions identified during the Hydro Ottawa workshop are identified in Table 9.

Table 9: Substations - Current and Future

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Ice accumulation of 40mm (30-year occurrence)	Substations - Buildings and Structural Components	Access to the building is hindered due to heavy ice accumulation.	24	32	1.3	Increase spreading of gravel and grit before site access.
Ice accumulation of 40mm (30-year occurrence)	Substations - Buildings and Structural Components	Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof.	24	32	1.3	Develop a policy to monitor and inspect substation building and structural components after an ice event.
Ice accumulation of 40mm (30-year occurrence)	Substations - Buildings and Structural Components	Ice accumulation on building mounted equipment (exterior walls).	24	32	1.3	Install covers on vulnerable equipment attached to buildings (where feasible).
Ice accumulation of 40mm (30-year occurrence)	Substations: Station Load Break Switch	Ice accretion on load break switches could result in difficulty transferring loads.	18	24	1.3	Install switches without exposed contacts. Update equipment specifications to require that switch operators break ice to allow for operability. Consider alternative devices (i.e. breakers) to switch loads when load break switches are difficult to switch or inoperable.

5.5.2 Substations: Recommended Actions

To address the future climate risks to substations, the following recommendations are built on the actions identified by Hydro Ottawa in the Workshop.

Table 10: Recommendations for Substations (SUB)

Priority Level	Initiative	Responsibility	Business Operation to Integrate Outcome	Climate Event Mitigated	Timeline to Complete and Integrate into Business Operations (if applicable)	Monitoring Strategy
SUB-1	Review additional requirements for sanding and gritting prior to site access.	Facilities	Maintenance Procedures	Ice accumulation	2 years	Delays due to inaccessibility.
SUB-2	Develop a policy to monitor and inspect substation building and structural components after an ice event to mitigate the risk of structural damage and loss of assets as a result of ice damage to substations.	Facilities Stations	Maintenance Procedures	Ice accumulation	5 years	Number of leaks or damages. Track maintenance costs.
SUB-3	Complete a cost-benefit analysis of installing protective covers on small exterior equipment, where feasible, to prevent damage/failure as a result of ice accumulation.	Facilities	Asset Management Plans	Ice accumulation	5 years	Number of failures of attached equipment due to ice.
SUB-4	In light of current design standards (40 mm of ice accumulations), assess the need for changes to technical specifications and policies for increased load break switch protection which may include: • Installation of alternative devices (i.e. breakers) to switch loads when load break switches are difficult to switch or inoperable. • Installation of switches without exposed contacts (replacement or protection). • Update equipment specifications to require that switch operators break ice to allow for operability.	System Operations Asset Planning Standards	Asset Management Plan - Station Switchgear and Breakers	Ice accumulation	5 years	Number of operational failures due to ice.

5.6 OPERATIONS

5.6.1 Risk and Potential Adaptation Actions

Climate risks related to operations are associated with personnel, administrative buildings, and third-party interactions with Hydro One. These assets are impacted by daily maximum temperatures of 35°C and 40°C and higher, winds of 80 km/h and 120 km/h and higher, and ice accumulation of 40mm. The highest rated climate risks to Hydro Ottawa operations are heat stress on outdoor operators and maintenance personnel, and a loss of supply from Hydro One due to ice accumulation; these risks will increase in the future.

Risks associated with ice accumulation include impacts on administrative building roof loads and access; these risks have a medium risk rating in the current climate but will increase to high in the future. Ice accumulation was also identified as a high risk (current and future climates) to outdoor operators and maintenance staff.

Lastly, high maximum temperatures requiring higher cooling demands on administrative buildings produces a medium risk level in the current climate; this risk will remain medium in the future.

The actions identified during the Hydro Ottawa workshop are identified in Table 11.

Table 11: Impacts to Operations - Current and Future

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Daily maximum temp. of 40°C and higher	Operators	Potential heat stress impacts on personnel working outdoors. Exacerbated by humidex.	26	65	2.5	Work redistribution (scheduling) to avoid outdoor work during peak heat hours. Risk assessment to be completed to determine if potential for use of modified PPE that has improved cooling / ventilation and consideration for modifying worksite requirements where fire retardant may not be necessary.
Daily maximum temp. of 40°C and higher	Administrative and Operational Buildings	Increased cooling demands for the buildings, including critical systems (e.g., communication and IT systems).	8	20	2.5	Consider future climate projections at end of life of current system when deciding to replace or retrofit building HVAC systems.
Daily maximum temp. of 35°C and higher	Administrative and Operational Buildings	Increased cooling demands for the buildings, including critical systems (e.g., communication and IT systems).	12	20	1.7	Consider future climate projections at end of life of current system when deciding to replace or retrofit building HVAC systems.
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Operators	Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards.	36	36	1.0	This would result in a stop work authority; however, there is a need to refine and establish a wind condition policy establishing when a lift bucket should not be used and when work should not be completed.
Easterly winds of 80 km/h or higher (cool season [Oct.-March])	Operators/ Powerline Maintenance Staff	Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards.	24	24	1.0	This would result in a stop work authority; however, there is a need to refine and establish a wind condition policy establishing when a lift bucket should not be used and when work should not be completed.
Ice accumulation of 40mm (30-year occurrence)	Third Party Services and Interactions: Hydro One	Loss of supply to Hydro Ottawa. Damages to Hydro One and Hydro Ottawa shared resources. Loss of transmission. Loss of redundancy. Damage to equipment.	54	72	1.3	Work with Hydro One, and provincial regulators to ensure supply design and standards are aligned with climate risks.
Ice accumulation of 40mm (30-year occurrence)	Administrative and Operational Buildings	Access to the building is hindered due to heavy ice accumulation.	24	32	1.3	Update the work from home plan to eliminate commuting during extreme weather events and hazardous road conditions.

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Ice accumulation of 40mm (30-year occurrence)	Administrative and Operational Buildings	Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof may impact structural and assets.	24	32	1.3	Monitor, inspect and repair roof after climate event to prevent protect assets, equipment within the building.
Ice accumulation of 40mm (30-year occurrence)	Operators/Powerline Maintenance Staff	Injuries to operators and personnel.	39	52	1.3	Review, and consider revising policy for requiring installation of winter tires on Hydro-owned vehicles to prevent injuries to personnel rather than through a request/approval process. Installation and use of remotely operable switching devices to reduce travel requirements during inclement conditions. Introduce policies to include heated steps or walkways on Hydro Ottawa properties versus continued salting/sanding.

5.7 OPERATIONS: RECOMMENDED ACTIONS

To address the future climate risks to operations, the following recommendations are built on the actions identified by Hydro Ottawa in the Workshop.

Table 12: Recommendations for Operations (OPS)

Priority Level	Initiative	Responsibility	Business Operation to Integrate Outcome	Climate Event Mitigated	Timeline to Complete and Integrate into Business Operations (if applicable)	Monitoring Strategy
OPS-1	Refine and establish a policy on wind conditions when a lift bucket should not be used and when work should not be completed to mitigate the risk of injury related to wind.	Distribution Operations Health and Safety	Health and Safety Policy/Practice	Wind	1 year	Monitoring of the number of wind-related events and health and safety incidents associated with wind and lift buckets.
OPS-2	Consider a review of policies surrounding heat stress on outdoor workers and revise to include projected climate changes to mitigate the impacts of heat stress. Policies to consider should including: • A policy on work redistribution (scheduling) to avoid outdoor work during peak heat hours. • Where feasible and risk assessment permits, consider a policy around the adoption and use of modified PPE to improve cooling / ventilation.	Distribution Operations Health and Safety	Health and Safety Policy/Practice	Heat events	2 years	Monitor the number of heat-related incidents and daily max temperatures in excess of 35 °C and 40°C.
OPS-3	Work with Hydro One, and provincial regulators to ensure supply design and standards are aligned with climate risks.	Asset Planning System Operations	Various	Ice accumulation, wind	2 years	Track the frequency and scale of outages resulting from Hydro One service disruption.
OPS-4	Consider the cost-benefit of the following measures to reduce the risk of employee injuries related to ice accumulation events: • Review, and consider revising policy for requiring installation of winter tires on Hydro-owned vehicles to prevent injuries to personnel rather than through a request/approval process. • Installation and use of additional automated devices to limit need to travel during inclement conditions. • Introducing policies to include heated steps or walkways on Hydro Ottawa properties versus continued salting/sanding.	Fleet & Facilities Asset Planning	Health and Safety Policy/Practice	Ice accumulation	2 years	Monitor the number of ice-related incidents (near miss, incidents).
OPS-5	Develop a policy to monitor and inspect building and roofs after an ice event.	Facilities	Maintenance Procedures	Ice accumulation	5 years	Tracking of damage by weather event (if known). Track maintenance costs.
OPS-6	Consider updating the work from home policy to eliminate or reduce commuting during extreme weather events and hazardous road conditions, particularly ice accumulation.	Human Resources	Human Resources Policy	Ice accumulation	5 years	Safety bulletin for tracking number of slips, falls, and other ice-related incidents.
OPS-7	Consider future climate projections at end of life of current system when deciding to replace or rehabilitate building HVAC systems. Integrate requirement into Procurement Policy to size and design based on climate projections (heating and cooling requirements) in conjunction with critical needs (IT server requirements). By integrating future needs into procurement, the risk that cooling is not adequate during 40°C is minimized.	Facilities	Procurement Policy	Heat event	5 years	Monitor the efficiency and service requirements of the building's HVAC system and environmental controls.

5.8 BEST PRACTICES FOR A CHANGING CLIMATE

In addition to the recommendations for adaptation measures identified and prioritized in Section 5.3 to 5.6 that were developed in the Hydro Ottawa workshop, the Table 13 presents a number of best practices recommended to guide the organization in their on-going efforts to build resilience.

Table 13: Best Practices for Operations

Action	Action Description
Action 1: Continue to invest in Smart Grid technology to increase resilience of the distribution system.	Hydro Ottawa has invested and continues to invest in capital funding projects to build Smart Grid technology. As Smart Grid technology continues to evolve and mature, Hydro Ottawa should continue to seek opportunities to increase resilience of the system through enhanced Smart Grid technology and system transfer capacity.
Action 2: Continue to conduct post-disaster event analyses to identify lessons learned.	Continue to comprehensively review the outcomes of disaster and emergency events and their effect on Hydro Ottawa owned properties staff and service delivery Continue to track and report data on damages experienced and identify recommended mitigation strategies and response protocols for future similar events Consider whether events will warrant strategic decisions for Hydro Ottawa properties (e g hardening, replacement, relocation etc). Distribute findings to all relevant staff and leadership via standardized reports
Action 3: Continual improvement of emergency response planning, including communication protocols before, during and after extreme weather events.	Continual improvement of Crisis Management Plan with lessons learned and post-disaster analyses and consider opportunities to: • Clarify protocols and staff education within Hydro Ottawa for staff to better understand their roles during an emergency. • Implementing an equipment sharing program or equipment rental agreements with local companies / contractors to avoid equipment limitations during an emergency • Contingency planning for fuel supply.
Action 4: Require that operating budgets account for climate risks mitigation and resiliency needs.	To successfully integrate climate change into an organization, it must be accounted for by management and operational decision-makers through budget planning, service planning, project management, enterprise risk management, asset management, energy management and procurement decisions.
Action 5: Continue to collaborate and plan with third-party service (e.g. City of Ottawa) providers to mitigate emerging risks and increase resilience of emergency planning procedures.	Other third-party risks to Hydro Ottawa's operations are related to their partnerships with the City of Ottawa (fuel supply, stormwater drainage and winter maintenance), partners for emergency response, and telecommunications. Engage and collaborate with third-parties to mitigate emerging risks, share lessons learned and build resilient emergency planning procedures.
Action 6: Consider wildfires as a potential risk that may emerge in the future and review the need for Wildfire Management Plans on an annual basis.	Wildfires are considered as a special case as they are generally related to a combination of weather events (i.e. temperature, rainfall). Wildfires currently pose a low risk to Hydro Ottawa; however, wildfire threat may escalate in the future. It is recommended that Hydro Ottawa monitor changes in fire threat days year over year and complete an assessment of the need to development a Wildfire Management Plan as part of the annual planning system.
Action 7: Collaborate with other utilities, regulators, and governments to develop guidance and protocols for climate resilience electrical infrastructure.	Work with partners to develop guidance and protocols for climate resilient electrical infrastructure. Review pilot projects conducted by peers to assess lessons learned. Adopt findings as necessary.
Action 8: Build broad awareness and education among staff, such as incorporating extreme climate events and risks into health and safety communication and training materials.	Share existing information and best practices with employees contractors and the public to promote electrical system safety in extreme temperatures and weather

5.9 IMPLEMENTATION

The Chief Electricity Distribution Officer will be primarily responsible for the implementation of Plan with individual actions falling to the responsibility of the relevant departments as deemed appropriate. Hydro Ottawa will need to dedicate staff time and annual funding for the Plan to be successful in its implementation. It will also be important for Hydro Ottawa to continually monitor, report and review progress on these activities so that they can be adjusted as necessary to improve the outcomes.

5.10 IMPLEMENTATION SCHEDULE

The Plan is intended to be a living document. Updates may be made to accommodate changes in policies, staff or financial resources, and unexpected extreme weather events. This flexibility will ensure that Hydro Ottawa is not constrained to certain parameters should new opportunities for implementation arise. The preliminary implementation schedule was developed to identify and allocate resources required to implement priority actions.

A summary of prioritize recommendations for Adaptation Planning is provided in Table 14.

Table 14: Prioritized Actions

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
OPS-1	Refine and establish a policy on wind conditions when a lift bucket should not be used and when work should not be completed to mitigate the risk of injury related to wind.	Distribution Operations Health and Safety	1 year
PLS-1	Develop anti-cascading strategies and standards for hardening of pole line systems to protect against wind and ice accumulation events, including: • Introducing break or stress points into the distribution lines. • Anchoring. • Type of pole. Complete a cost-benefit review of the strategies at critical areas and/or strategic timelines (end of life).	Asset Planning	2 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
PLS-2	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their potential to damage infrastructure or injure personnel during wind and ice events. Noting past program augmentations made in response to past storm events, evaluate feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate.	Forestry Asset Planning	2 years
PLS-3	Complete a technology review and feasibility study of technology that may use reduce ice build-up through pulsing or vibration of distribution lines to prevent ice build-up and galloping of lines.	Standards	2 years
PLS-4	Complete a study/analysis of potential methods to increase detection capabilities for downed lines to increase response time to repair damaged pole line system after damage from wind and/or ice accumulation.	Asset Planning	2 years
SUB-1	Review additional requirements for sanding and gritting prior to site access.	Facilities	2 years
OPS-2	Consider a review of policies surrounding heat stress on outdoor workers and revise to include projected climate changes to mitigate the impacts of heat stress. Policies to consider should including: • A policy on work redistribution (scheduling) to avoid outdoor work during peak heat hours. • Where feasible and risk assessment permits, consider a policy around the adoption and use of modified PPE to improve cooling / ventilation.	Distribution Operations Health and Safety	2 years
OPS-3	Work with Hydro One, and provincial regulators to ensure supply design and standards are aligned with climate risks.	Asset Planning System Operations	2 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
OPS-4	Consider the cost-benefit of the following measures to reduce the risk of employee injuries related to ice accumulation events: • Review, and consider revising policy for requiring installation of winter tires on Hydro-owned vehicles to prevent injuries to personnel rather than through a request/approval process. • Installation and use of additional automated devices to limit need to travel during inclement conditions • Introducing policies to include heated steps or walkways on Hydro Ottawa properties versus continued salting/sanding	Fleet & Facilities Asset Planning	2 years
PLS-5	While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Underground distribution lines and infrastructure would mitigate risk from wind, ice accumulation and fog.	Asset Planning	5 years
ULS-1	Complete an engineering review to identify if there are locations vulnerable to overheating (via a detailed assessment of locations that could be vulnerable to temperatures higher than 40°C) and complete a cost-benefit analysis for mitigation options, which may include: • Institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables. • Cool ducts either actively or passively, for example, with thermal fill (a clay slurry).	Asset Planning Standards	5 years
ULS-2	Identify new technologies and processes through research and feasibility or pilot studies to reduce freeze thaw impacts. These may include: • Exploring the use of different materials for manholes instead of concrete that are less susceptible to freeze-thaw (e.g. fiber glass). • Redesign civil structure collars to move with the heading (e.g. telescopic collars).	Asset Planning Standards	5 years
SUB-2	Develop a policy to monitor and inspect substation building and structural components after an ice event to mitigate the risk of structural damage and loss of assets as a result of ice damage to substations.	Facilities Stations	5 years
SUB-3	Complete a cost-benefit analysis of installing protective covers on small exterior equipment, where feasible, to prevent damage/failure as a result of ice accumulation.	Facilities	5 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
SUB-4	In light of current design standards (40 mm of ice accumulations), assess the need for changes to technical specifications and policies for increased load break switch protection which may include: • Installation of alternative devices (i.e. breakers) to switch loads when load break switches are difficult to switch or inoperable. • Installation of switches without exposed contacts (replacement or protection). • Update equipment specifications to require that switch operators break ice to allow for operability.	System Operations Asset Planning Standards	5 years
OPS-5	Develop a policy to monitor and inspect building and roofs after an ice event.	Facilities	5 years
OPS-6	Consider updating the work from home policy to eliminate or reduce commuting during extreme weather events and hazardous road conditions, particularly ice accumulation.	Human Resources	5 years
OPS-7	Consider future climate projections at end of life of current system when deciding to replace or rehabilitate building HVAC systems. Integrate requirement into Procurement Policy to size and design based on climate projections (heating and cooling requirements) in conjunction with critical needs (IT server requirements). By integrating future needs into procurement, the risk that cooling is not adequate during 40oC is minimized.	Facilities	5 years
PLS-6	Consider the feasibility of further increasing the frequency of pole washing and cost/benefit based on risk level (current/future) to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	5-10 years
PLS-7	Complete a cost/benefit analysis of expedited replacement of insulators and fused cut-outs with porcelain to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	5-10 years

5.11 RESOURCE & BUDGET PLANNING

Many priority actions will be constrained by financial resources, available human resources and conflicting demands. By continuing to use a risk-based approach to action planning and considering climate resilience infrastructure and staffing needs in the budget planning process, Hydro Ottawa will be well-positioned to implement resilience strategies.

5.12 REPORTING & COMMUNICATION

Monitoring is an important part of the adaptation planning process. It provides an opportunity for Hydro Ottawa to examine performance of the adaptation actions and assess whether the estimated risks and vulnerabilities have changed. These learning outcomes can then be integrated into future strategies and actions. It is recommended that monitoring and reporting be undertaken on an annual basis. Designated lead managers should be responsible for providing updates on the status of action implementation, timelines, costs, indicators, and other details as required. The purpose of this reporting is to:

- Raise awareness and increase understanding of anticipated climate trends and their consequences for Hydro Ottawa and to provide context on specific risks, barriers and opportunities.
- Inform and consult with stakeholders on climate science, risk assessment methodologies used, findings, and recommendations to empower decision-making and collaboration around the actions recommended in this Plan.
- Take stock of both Hydro Ottawa and their partners efforts to share success stories and foster learning in the energy distribution sector.

At a minimum, the reporting should include:

- A description of the work that has been completed.
- Identification of any issues or challenges faced in advancing each action.
- List of new actions to address issues, barriers and challenges.
- An indication of progress toward achieving each initiative, using the following scale:
  - Not Started – The initiative has not been implemented.
  - On Track – The initiative has been implemented. For various initiatives, progress will be measured through metrics like maintenance costs, number of failures due to ice, damages due to trees, mitigation return on investment, etc. Other actions will either be noted as completed or not.
  - Outstanding – An issue, barrier and/or challenge is prohibiting the action from being implemented.
  - Delayed – The action has been delayed or placed on hold.
  - Completed – The action has been completed.

For initiatives that are at risk or delayed, the report should identify the barriers and challenges so that new initiatives can be implemented to address these aspects.

Formal updates to this Plan are recommended to occur on a five-year cycle and should focus on reviewing current climate science and its anticipated impacts to operations, staff, and infrastructure. This will also provide opportunity to take stock of progress made, share lessons learned, and to revisit the planning process to take advantage of any new technologies, or knowledge that could benefit operations.

APPENDICES

Appendix A WORKSHOP SUMMARY TABLES

ASSET ELEMENT: BUILDING & STRUCTURAL ELEMENTS

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	24	32	Administrative and Operational Buildings	Ice accumulation of 40mm (30-year occurrence)	• Access to the building is hindered due to heavy ice accumulation	• Health and safety concerns for staff, contractors and/or public	1. C/P – Salting entranceway, parking area, and walkways 2. P – Work at home policy	1. Low 2. Low	1. Low (issue remains off-property, i.e. challenge of getting to work still exists) 2. Medium: • Field staff: low • Office staff: high	1. Low 2. Medium	1. Availability of salt 1. Environmental concern 2. Doesn't work for everyone 2. Ability to respond to emergencies 2. Ability to track productivity	1. Facilitator 2. Human Resources	1. Maintenance contractor 2. IBEW (staff union)	1. Low 2. Medium	• Number of slips and falls • Develop a way to monitoring productivity remotely
High	24	32	Administrative and Operational Buildings	Ice accumulation of 40mm (30-year occurrence)	• Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof	• 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	• Monitor / inspections • Repair roof if damaged *Since Hydro Ottawa does not know how increased ice storms might affect their buildings, they suggest monitoring and acting reactively until the consequences are known. *In the past, Hydro Ottawa has sent someone up to rook to clear snow/ ice, however, this is an H&S issue	• Low	• Medium	• Low	• Access • Resources	• Facilities • Operations	• Facilities/Ops	• Low	• Number of leaks/damages • Maintenance cost

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: BUILDING & STRUCTURAL ELEMENTS

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	24	32	Administrative and Operational Buildings	Ice accumulation of 40mm (30-year occurrence)	• Ice accumulation on building mounted equipment (roof, exterior walls)	• Reduced efficiency and/or functionality, and failure of equipment affected	• Monitor and inspect • Install cover on smaller equipment. • *Since Hydro Ottawa does not know how increased ice storms might affect their buildings, they suggest monitoring and acting reactively until the consequences are known.	1. Low 2. Low	1. Medium 2. Medium	1. Low 2. Low	• Identifying problem area/devices • Access • Resources	• Stations • Grid technology	• Stations • Grid technology • System operation • Facilities	1. Low 2. Low	• Number of failures due to ice. • Monitor mitigation expenditures
Moderate	12	20	Administrative and Operational Buildings	Daily maximum temp. of 40°C and higher	• 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	• Building automation system could likely handle the change, however if overloaded, might sound an alert. *It was noted that the IT group has critical infrastructure within the building that is specially climate controlled.								

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: OPERATORS / POWERLINE MAINTENANCE STAFF

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Short, Medium, Long)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*
Very High	26	65	Operators / Powerline Maintenance Staff	Daily maximum temp. of 40°C and higher	• 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	1. C – follow recommendations from H&S for work conditions related to heat stress 2. C – safety meetings / summer letdown with staff 3. P – possible work redistribution (scheduling) to avoid outdoor work during peak heat hours 4. P – modified PPE to improve cooling / ventilation 5 C – modify work site to not require full fire-retardant clothing – expand to other PPE requirements	3. Low – Cap 4. Medium – O&M 5. Low – Cap	3. Medium 4. Low 5. Low	3. Low 4. Low 5. Low	3. Other work to redistribute to 4. H&S approval technology exists safety requirement 5. Ability to modify	3. Operations/ scheduling 4. Health & Safety 5. Operations	3. Union 4. Vendors	3. Medium 4. Low 5. Low
High	39	52	Operators / Powerline Maintenance Staff	Ice accumulation of 40mm (30-year occurrence)	• 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	1. C – Boot ice spikes as needed 2. C – Safety driving training 3. P – Winter tires 4. C – Salt usage increased 5. P – automated devices 6. P – heated steps/ walkways policy (new)	3. Medium 5. High 6. Low	3. Medium 5. Low 6. Low	3. Low 5. High 6. Low	3. Cost, storage 5. Scada bond width, visual open 6. None	3. Fleet 5. Asset planning 6. Facilities	3. Tire shops 5. Vendors 6. Vendors	3. Low 5. Medium 6. Low
High	36	36	Operators / Powerline Maintenance Staff	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards	• Health and safety concern for personnel working outdoors, especially at heights	• C – Winds of this magnitude would result in a stop work authority • P – Need a more concrete policy on wind conditions where you would not use the lift bucket							

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Short, Medium, Long)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*
High	24	24	Operators / Powerline Maintenance Staff	Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	• Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards	• Health and safety concern for personnel working outdoors, especially at heights	• C – Winds of this magnitude may result in a stop work authority • P – Need a more concrete policy on wind conditions where you would not use the lift bucket							

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

ASSET ELEMENT: POWER DISTRIBUTION: SUBSTATIONS

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	24	32	Buildings and Structural Components	Ice accumulation of 40mm (30-year occurrence)	• Access to the building is hindered due to heavy ice accumulation	• Health and safety concerns for staff, contractors and/or public • Delay in restoration	• Plow and spread gravel / grit before site access. *This takes place regularly under contract, but additional 'as needed' calls to the snow removal contractor are needed from time to time. *Hydro Ottawa avoids using salt where possible for environmental reasons.	• Low	• Medium	• Low	• Availability of contractors to spread grit	• Field operators/ managers (facilities)	• Contractor • Hydro One	• Low	• Safety bulletin for tracking • H&S, number of slips & falls / incidents
High	24	32	Buildings and Structural Components	Ice accumulation of 40mm (30-year occurrence)	• Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof	• 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	• Monitor / inspections • Repair roof if damaged *Since Hydro Ottawa does not know how increased ice storms might affect their buildings, they suggest monitoring and acting reactively until the consequences are known. *In the past, Hydro Ottawa has sent someone up to roof to clear snow/ ice, however, this is an H&S issue.	• Low	• Medium	• Low	• Access • Resources	• Facilities • Operations	• Facilities/Ops	• Low	• Number of leaks/damages • Maintenance cost

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ASSET ELEMENT: POWER DISTRIBUTION: SUBSTATIONS

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	24	32	Buildings and Structural Components	Ice accumulation of 40mm (30-year occurrence)	• Ice accumulation on building mounted equipment (roof, exterior walls)	• Reduced efficiency and/or functionality, and failure of equipment affected	1. Monitor and inspect 2. Install cover on smaller equipment. *Since Hydro Ottawa does not know how increased ice storms might affect their buildings, they suggest monitoring and acting reactively until the consequences are known.	1. Low 2. Low	1. Medium 2. Medium	1. Low 2. Low	• Identifying problem area/devices • Access • Resources	• Stations • Grid technology	• Stations • Grid technology • System operation • Facilities	1. Low 2. Low	• Number of failures due to ice • Monitor mitigation expenditures
Moderate	18	24	Station Load Break Switch	Ice accumulation of 40mm (30-year occurrence)	• 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	1. Operators to break ice to allow for operability 2. Use alternative devices to switch loads 3. Install switches without exposed contacts	1. Low 2. Low 3. High	1. Medium 2. Medium 3. High	1. Low 2. Low 3. High	1. Limitations of safe practices 1. Availability of qualified operators 3. Cost of devices 3. Space limitation 3. Risk assessment	1. Operations 3. Engineering and operations	1. Health & Safety 3. Health & Safety 3. Standards 3. Operations 3. Vendors	1. Low 2. Medium 3. Medium -high	• Number of operation failures to ice

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ASSET ELEMENT: POWER DISTRIBUTION: NORTH-SOUTH

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	108	108	Lines & Poles	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• Damage to poles and lines from high wind events.	• 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	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. P – Break/stress point to limit cascading failure 4. C – increase pole class (new installs) 5. C – Design for 90km/hr winds 6. C – Partnering agreements with contractors/ utilities for resourcing when needed 7. P – increased detection capabilities for downed lines 8. C – Public safety lines on grounds 9. C – review of N-S arterial lines and guying	1. High – Cap 2. Medium – O&M 3. Medium – Cap 7. Medium – Cap	1. High 2. Medium 3. Low 7. Low	1. High 2. Medium 3. Medium 7. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 3. Study 7. Study	1. Asset planning 2. Standards 3. Standards 7. Asset planning	1. Utility coordination 2. City of Ottawa consultant 3. Consultant 7. CEA/CEATZ	1. Hight 2. Medium 3. Medium 7. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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ASSET ELEMENT: POWER DISTRIBUTION: NORTH-SOUTH

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	108	108	Lines & Poles	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• 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	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – Trim trees more often/aggressively or heritage trees 7. C – tree planting advice brochure/ standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro infrastructure/ equipment 8. P – include trees in fall zone/condition assessment	1. High 2. Medium 3. Medium 6. High 8. Medium	1. High 2. Low 3. Low 6. Medium 8. Medium	1. High 2. Medium 3. High 6. Medium 8. Medium	1. Cost casements, equipment, location, resources, customer acceptance 2. Study 3. Study 6. Budget, customer, city acceptance 8. Customer and city acceptance	1. Asset planning 2. Standards 3. Asset planning 6. Forestry 8. Standards	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 6. High 8. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts

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High	36	48	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damage from increased weight on overhead lines • Ice falling off of 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	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. C – increase pole class (new installs) 4. Install hardened equipment (strength of insulators) expedite vs. normal replacement *current action is just to implement based on design practices 5. Pulse/vibrate lines	1. High 2. Medium 3. Medium 4. High - Cap 5. High - O&M	1. High 2. Low 3. Low 4. Medium 5. High	1. High 2. Medium 3. Medium 4. Medium 5. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 4. Study to ensure no unwanted consequences ex. Now poles fail vs insulators 5. Study needed, resources, cost, public safety	1. Asset planning 2. Standards 4. Asset planning 5. System office	1. Utility coordination 2. City of Ottawa consultant 4. Vendors 5. Other utilities CEATZ	1. High 2. Medium 4. Medium 5. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?
High	36	48	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Ice accretion on lines of 12.5 mm (0.5 inches) and more accompanied by a 90km/h wind could result in swinging or 'galloping' in the lines • Damage to poles and attached equipment	• 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	***Covered in previous***								

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High	36	48	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damages to lines from fallen trees or broken tree limbs.	• 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	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – Trim trees more often/aggressively or heritage trees 7. C – tree planting advice brochure/ standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro infrastructure/ equipment	1. High 2. Medium 3. Medium 7. High	1. High 2. Low 3. Low 7. Medium	1. High 2. Medium 3. High 7. Medium	1. Cost casements, equipment, location, resources, customer acceptance 2. Study 3. Study 7. Budget, customer, city acceptance	1. Asset planning 2. Standards 3. Asset planning 7. Forestry	1. Utility coordination 2. Consultant CEA/CEATZ	1. High 2. Medium 3. High 7. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts
High	36	48	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• 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	1. C – Install pole laterals for risers 2. C – Install bollards for pad-mounted equipment in vehicle areas 3. P – Install pole laterals on all poles 4. P – Change pole standard to a higher strength material 5. P – Underground pad-mounted equipment (submersible)	3. Medium 4. High (+) 3. High (+)							

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High	32	32	Lines & Poles	Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	• Guy wires in north-south lines are installed to support against prevailing westerly winds; poles and lines are therefore damaged from to high easterly winds	• 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	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. P – Break/stress point to limit cascading failure 4. C – increase pole class (new installs) 5. C – Design for 90km/hr winds 6. C – Partnering agreements with contractors/ utilities for resourcing 7. P – increased detection for downed lines 8. C – Public safety lines on grounds C – reviewed N-S arterial lines and guying	1. High - Cap 2. Medium - O&M 3. Medium - Cap 7. Medium - Cap	1. High 2. Medium 3. Low 7. Low	1. High 2. Medium 3. Medium 7. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements , study 3. Study 7. Study	1. Asset planning 2. Standards 3. Standards 7. Asset planning	1. Utility coordination 2. City of Ottawa consultant 3. Consultant 7. CEA/CEATZ	1. High 2. Medium 3. Medium 7. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?

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High	32	32	Lines & Poles	Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	• 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	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – more often/aggressively or heritage trees 7. C – tree planting advice brochure/standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro 8. P – include trees in fall zone/condition assessment	1. High 2. Medium 3. Medium 6. High 8. Medium	1. High 2. Low 3. Low 6. Medium 8. Medium	1. High 2. Medium 3. High 6. Medium 8. Medium	1. Cost casements, equipment, location, resources, customer acceptance 2. Study 3. Study 6. Budget, customer, city acceptance 8. Customer and city acceptance	1. Asset planning 2. Standards 3. Asset planning 6. Forestry 8. Standards	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 6. High 8. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts
Moderate	18	24	Poles	Season with ≥ 50 fog days (Nov.-March)	• 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	1. C – replace porcelain insulators with polymer when doing work on pole 2. C- insulator water washing (twice/year in high travelled roads) 3. P – proactive/ expedited replacement of porcelain insulators with polymer 4. P – increase pole washing program	3. High - Cap 4. Medium - O&M	3. High 4. Medium	3. Medium 4. Low	3. Budget 4. Ongoing O&M expenses	3. Asset planning 4. Asset planning	4. Contractor	3. Low 4. Low	• Number of pole fires • SAIDI/SAIFI

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Moderate	12	16	Fused Cut Out	Season with ≥ 50 fog days (Nov.-March)	• 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	1. C – replace porcelain with polymer fused cutouts when doing work on pole 2. P – proactive/ expedited replacement of porcelain with polymer	1. High 2. Medium	1. High 2. High	1. Medium 2. Medium	1. Budget 2. Budget	1. Asset Planning 2. Asset Planning		1. Low 2. Low	• Number of pole fires • SAIDI/SAIFI

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ASSET ELEMENT: POWER DISTRIBUTION: EAST-WEST

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	108	108	Lines & Poles	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• Damage to poles and lines from high wind events.	• 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	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. P – Break/stress point to limit cascading failure 4. C – increase pole class (new installs) 5. C – Design for 90km/hr winds 6. C – Partnering agreements with contractors/ utilities for resourcing when needed 7. P – increased detection capabilities for downed lines 8. C – Public safety lines on grounds 9. C – review of N-S arterial lines and guying	1. High – Cap 2. Medium – O&M 3. Medium – Cap 7. Medium – Cap	1. High 2. Medium 3. Low 7. Low	1. High 2. Medium 3. Medium 7. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 3. Study 7. Study	1. Asset planning 2. Standards 3. Standards 7. Asset planning	1. Utility coordination 2. City of Ottawa consultant 3. Consultant 7. CEA/CEATZ	1. Hight 2. Medium 3. Medium 7. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?

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ASSET ELEMENT: POWER DISTRIBUTION: EAST-WEST

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	108	108	Lines & Poles	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• 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	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – Trim trees more often/aggressively or heritage trees 7. C – tree planting advice brochure/ standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro infrastructure/ equipment 8. P – include trees in fall zone/condition assessment	1. High 2. Medium 3. Medium 6. High 8. Medium	1. High 2. Low 3. Low 6. Medium 8. Medium	1. High 2. Medium 3. High 6. Medium 8. Medium	1. Cost easements, equipment, location, resources, customer acceptance 2. Study 3. Study 6. Budget, customer, city acceptance 8. Customer and city acceptance	1. Asset planning 2. Standards 3. Asset planning 6. Forestry 8. Standards	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 6. High 8. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts.

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: POWER DISTRIBUTION: EAST-WEST

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	36	68	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damage from increased weight on overhead lines • Ice falling off of 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	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. C – increase pole class (new installs) 4. Install hardened equipment (strength of insulators) expedite vs. normal replacement *current action is just to implement based on design practices 5. Pulse/vibrate lines	1. High 2. Medium 3. Medium 4. High – Cap 5. High - O&M	1. High 2. Low 3. Low 4. Medium 5. High	1. High 2. Medium 3. Medium 4. Medium 5. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 4. Study to ensure no unwanted consequences ex. Now poles fail vs insulators 5. Study needed, resources, cost, public safety	1. Asset planning 2. Standards 4. Asset planning 5. System office	1. Utility coordination 2. City of Ottawa consultant 4. Vendors 5. Other utilities CEATZ	1. High 2. Medium 4. Medium 5. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?
Very High	36	68	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Ice accretion on lines of 12.5 mm (0.5 inches) and more accompanied by a 90km/h wind could result in swinging or 'galloping' in the lines. • Damage to poles and attached equipment	• 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	***Covered in previous***								

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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	36	68	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damages to lines from fallen trees or broken tree limbs.	• 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	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – Trim trees more often/aggressively or heritage trees 7. C – tree planting advice brochure/ standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro infrastructure/ equipment	1. High 2. Medium 3. Medium 7. High	1. High 2. Low 3. Low 7. Medium	1. High 2. Medium 3. High 7. Medium	1. Cost casements, equipment, location, resources, customer acceptance 2. Study 3. Study 7. Budget, customer, city acceptance	1. Asset planning 2. Standards 3. Asset planning 7. Forestry	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 7. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	36	68	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• 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	1. C – Install pole laterals for risers 2. C – Install bollards for pad-mounted equipment in vehicle areas 3. P – Install pole laterals on all poles 4. P – Change pole standard to higher strength material 5. P – Underground pad-mounted equipment (submersible)	3. Medium 4. High (+) 5. High (+)							
Moderate	18	24	Poles	Season with ≥ 50 fog days (Nov.-March)	• 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	1. C – replace porcelain insulators with polymer when doing work on pole 2. C- insulator water washing (twice/year in high travelled roads) 3. P – proactive/ expedited replacement of porcelain insulators with polymer 4. P – increase pole washing program	3. High – Cap 4. Medium - O&M	3. High 4. Medium	3. Medium 4. Low	3. Budget 4. Ongoing O&M expenses	3. Asset planning 4. Asset planning	4. Contractor	3. Low 4. Low	• Number of pole fires • SAIDI/SAIFI

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Moderate	32	32	Lines & Poles	Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	• Risk of pole damage from strong winds	• 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	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. P – Break/stress point to limit cascading failure 4. C – increase pole class (new installs) 5. C – Design for 90km/hr winds 6. C – Partnering agreements with contractors/ utilities for resourcing 7. P – increased detection for downed lines 8. C – Public safety lines on grounds 9. C – reviewed N-S arterial lines and guying	1. High - Cap 2. Medium - O&M 3. Medium - Cap 7. Medium - Cap	1. High 2. Medium 3. Low 7. Low	1. High 2. Medium 3. Medium 7. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 3. Study 7. Study	1. Asset planning 2. Standards 3. Standards 7. Asset planning	1. Utility coordination 2. City of Ottawa consultant 3. Consultant 7. CEA/CEATZ	1. High 2. Medium 3. Medium 7. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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ASSET ELEMENT: POWER DISTRIBUTION: EAST-WEST

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Moderate	32	32	Lines & Poles	Easterly winds of 60 km/hr or higher (cool season [Oct.-March])	• Risk of damages from falling trees or broken tree limbs.	• 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	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – more often/aggressively or heritage trees 7. C – tree planting advice brochure/standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro 8. P – include trees in fall zone/condition assessment	1. High 2. Medium 3. Medium 6. High 8. Medium	1. High 2. Low 3. Low 6. Medium 8. Medium	1. High 2. Medium 3. High 6. Medium 8. Medium	1. Cost easements, equipment, location, resources, customer acceptance 2. Study 3. Study 6. Budget, customer, city acceptance 8. Customer and city acceptance	1. Asset planning 2. Standards 3. Asset planning 6. Forestry 8. Standards	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 6. High 8. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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ASSET ELEMENT: POWER DISTRIBUTION: EAST-WEST

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Moderate	18	24	Poles	Season with ≥ 50 fog days (Nov.-March)	• 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	1. C – replace porcelain insulators with polymer when doing work on pole 2. C- insulator water washing (twice/year in high travelled roads) 3. P – proactive/ expedited replacement of porcelain insulators with polymer 9. P – increase pole washing program	3. High - Cap 4. Medium - O&M	3. High 4. Medium	3. Medium 4. Low	3. Budget 4. Ongoing O&M expenses	3. Asset planning 4. Asset planning	4. Contractor	3. Low 4. Low	• Number of pole fires • SAIDI/SAIFI
Moderate	12	16	Fuse & Cut Out	Season with ≥ 50 fog days (Nov.-March)	• 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	1. C – replace porcelain with polymer fused cutouts when doing work on pole 2. P – proactive/ expedited replacement of porcelain with polymer	1. High 2. Medium	1. High 2. High	1. Medium 2. Medium	1. Budget 2. Budget	1. Asset Planning 2. Asset Planning		1. Low 2. Low	• Number of pole fires • SAIDI/SAIFI

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: POWER DISTRIBUTION: UNDERGROUND

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	
Moderate	10	25	Underground Cables	Daily maximum temp. of 40°C and higher	• Potentially reduced capacity due to increased daily electricity demand from end user (e.g., A/C units)	• Additional strain on, and limits to the underground electrical infrastructure capacity.	Identifying vulnerable locations (via a detailed assessment of locations that could be vulnerable to temperatures higher than -40°C) and; 1. institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables 2. replacing cable material to one that will not overheat as readily 3. Cool ducts either actively or passively with thermal fill (a clay slurry) 4. Deploy community level energy storage to reduce peaks	1. Low 2. High 3. High 4. High	1. High 2. High 3. Medium 4. Medium	1. Low 2. Medium 3. High 4. High	1. Insufficient alternative (low system cap) 3. Cost 3. Room for cooling equipment 3. Increased O&M 4. Coordinating with community 4. Customer implications	1. Assets 2. Assets 3. Assets 4. Assets	1. Operation finances 2. Operation finances 3. Operation finances 4. Operation finances & community	1. Low 2. Low 3. Medium 4. High	Monitor cables for premature failure Trending within SCATA, data monitoring Temps run within the prescribed levels

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: POWER DISTRIBUTION: UNDERGROUND

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	
Moderate	16	24	Civil Structures	Freeze-thaw cycles – Daily Tmax Tmin temp. fluctuation of ±4°C around 0°C	• 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	1. Explore different materials for manholes instead of concrete that are less susceptible to freeze-thaw (e.g. fibre glass) 2. Explore continuous pipe rather than sectional pieces to eliminate joints were shifting can occur 3. Exploration of redesign collars to move with the heading (e.g. telescopic heading) 4. Explore moving utility to under sidewalk from under roadway where the temperature is more consistent	1. Low 2. Low 3. Low 4. Low	1. Low 2. Low 3. Low 4. Low	1. Low 2. Low 3. Low 4. Low	Resourcing	Assets Standards	Asset/standards	1. Low 2. Low 3. Low 4. Low	Viable solutions came out of exploratory work

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
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Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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EXTERNAL THIRD PARTIES

Element	External Third Party(ies) Affected	Impacts	Result / Consequence	Actions Available *Current + Potential*	Resource Requirements (Cost, Staff Time, Etc.)	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action
Power supply, shared infrastructure, attached equipment	Hydro-One	• Loss of supply to Hydro Ottawa (this happens to some extent approximately once per month) • Damages to poles shared between Hydro One and Hydro Ottawa • Loss of transmission • Loss of redundancy • Damage to equipment due to Hydro One-related issues	• 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	1. C – System distribution / contingency planning (need to install distribution ties to remedy, doing so continues building the resilience of the system as well) 2. P – Coordination of construction standards between Hydro Ottawa and Hydro One	1. Resources/financial 2. Resources/financial	1. Medium	1. Medium	1. Medium	1. Cost 1. Availability of physically redundant system (since all power is channeled to Ottawa through one corridor)	1. Asset planning / system operations 2. Asset planning / system operations	1. Hydro One 1. IESO 2. Hydro One
Telecommunications	Phone Service & Fibre lines	• Potential for Hydro Ottawa equipment damage if support by damaged communication poles • Loss of communication services	• Health and Safety • Communication to field personnel and field equipment • Loss of communication to customers • SCATA system	• C – Any vendor that runs a critical service to Hydro Ottawa, an agreement is in place. • C – Highly redundant communications services plan. For example, the operations center has landline phones, cell phones, and satellite phones			• High • High				

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Element	External Third Party(ies) Affected	Impacts	Result / Consequence	Actions Available *Current + Potential*	Resource Requirements (Cost, Staff Time, Etc.)	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action

Emergency Response (Capability & Capacity)	Partners & Internal	• Inability to get resources for response both external and holiday staff
		• Logistically complex
		• Staff potentially not fit for duty
			• Stress on staff
			• Delayed services restoration
				• C – For large-scale events, difficult to acquire additional resources as most geographically close resources are also affected. For small-scale events, Hydro Ottawa calls external aid when internal resources are exhausted. Logistics for external aid includes:
				  • 12-hour on/off scheduling
				  • Food services provided to aid workers
				  • Hydro Ottawa headquarters building open to aid workers and provides critical services
				  • Lodging provided
				HO noted the difficulties of how to determine when to call for aid. Sometimes there is political pressure to call for aid prematurely.
				• C – Have increased stand-by capacity
				• P – Formalize emergency response plan and clarify protocols and staff education within Hydro Ottawa for staff to better understand their roles during an emergency.
				• P – Equipment sharing program or equipment rental agreements with local companies / contractors if limited by equipment during an emergency							

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EXTERNAL THIRD PARTIES

Element	External Third Party(ies) Affected	Impacts	Result / Consequence	Actions Available *Current + Potential*	Resource Requirements (Cost, Staff Time, Etc.)	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action
Stormwater drainage, winter maintenance	City Ottawa	• Surface flooding • Snow removal • Debris removal • Plows hitting U/G equipment and poles • Flooded areas and overland flow flooding vaults and transformers due to plugged storm drains *For example, blocked rear-yard storm drains are a regular culprit for overland flooding and impacting pad-mounted transformers. • Manholes full of water • Snowplows hitting/damaging response vehicle • City of Ottawa plan hitting roadside transformers • Snow piling and storage on or around pad-mounting transformers • Salting damages to Hydro Ottawa equipment	• Potential impacts on equipment if City does not maintain stormwater system • Damages and delays due to winter maintenance activities • Delays in service or in response capacity	1. Identify location where there are particular issues related to stormwater / flooding and winter road maintenance issues to Hydro Ottawa equipment and work with the City of Ottawa to mitigate 2. Install snow marker flags to highlight the location of equipment during winter months Note: Hydro Ottawa calls the City of Ottawa to provided extra snow removal if needed when HO requires access to snowed-in areas		• Low • Low	• High • Medium	• Medium • Low	• City of Ottawa budgets • Public push back	• Asset planning • Standards • Operations • Communications	• Public works department • Community communication

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Low	< $100,000	< $10,000	< 1 year	< 25%
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Element	External Third Party(ies) Affected	Impacts	Result / Consequence	Actions Available *Current + Potential*	Resource Requirements (Cost, Staff Time, Etc.)	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action
Fuel Supply	City Ottawa	• Hydro Ottawa vehicles not able to travel • Lack of fuel supply for backup generators • Partner and contractors' inability to support while stranded at work/home	• Delays in service • People stranded at work/site/home • Lack of emergency backup power	1. P – Store fuel 2. P – Modify work to manage fuel 3. P – EV fleet 4. C – Contract with fuel suppliers for generators 5. P – City of Ottawa / Hydro Ottawa emergency fuel strategy. Understand City's risk	1. Cost, staff, space, training 2. N/A 3. Cost, tech, Power 5. Staff time	1. Medium 2. N/A 3. High 5. Low	1. Medium 2. N/A 3. High 5. High	1. Medium 2. N/A 3. Low 5. Medium	1. Historical practice 2. Policies, union 3. Chargers, purchasing, existing fleet 5. Relationships	1. Facilities/fleet 2. OPS 3. Fleet 5. Fleet	1. City, field partners 2. City, union 3. Vendors 5. City
	Hydro Ottawa Subsidiaries	*No real impacts from subsidiaries*									

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Low	< $100,000	< $10,000	< 1 year	< 25%
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High	> $2,000,000	> $200,000	> 3 years	> 75%

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Appendix B ADAPTION PLANNING WORKSHOP ATTENDEES

Participant	Role
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
Matthew McGrath	Hydro Ottawa, Project Manager, Supervisor, Distribution Layouts
Greg Bell	Hydro Ottawa, Manager, Distribution Operations (Underground)
Margret Flores	Hydro Ottawa, Supervisor, Asset Planning
Ben Hazlett	Hydro Ottawa, Manager, Distribution Policies and Standards
Ed Donkersteeg	Hydro Ottawa, Supervisor, Standards
Doug Boldock	Hydro Ottawa, System Operations
Chris Murphy	Hydro Ottawa, Supervisor, Distribution Design
Kyle Smith	Hydro Ottawa, Supervisor, Standards

ISO 55000 Gap Analysis

Private and confidential

Prepared for: Hydro Ottawa

Project No: 131850
Document Version: 1
Date: 27th March 2019

Version History

Date	Version	Author(s)	Notes
26/03/2019	Issue 1	A J McHarrie	

Final Approval

Date	Version	Approval	Notes
28/03/2019	Issue 1	David Roberts	

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Executive summary

EA Technology was invited to provide Hydro Ottawa with a gap analysis assessment for their Asset Management System (AMS) in-line with the requirements of ISO 55001. Hydro Ottawa have already carried out a previous gap analysis assessment, which identified a number of gaps which have already been addressed. Hydro Ottawa requested that EA Technology should carry out an ISO55000 gap analysis assessment of their AMS to provide an independent and objective view of their level of conformance to the ISO 55000 standard and the maturity of their AMS. This gap analysis was carried out at Hydro Ottawa's Merivale Road offices on the 25th to the 28th February 2019.

This document details the findings of the audit and provides a list of conclusions and recommendations that will assist Hydro Ottawa with their ambition of obtaining ISO55000 accreditation.

The radar chart below (Figure 1) illustrates the maturity scoring for the gap analysis assessment, carried out on the Hydro Ottawa's AMS. It can be seen that for a such a new system it has demonstrated what could be judged as conformance (green line) for twenty one of the twenty-seven assessed sections of ISO 55001.

For clarity the red line indicates the results of the previous gap analysis audit, the green line indicates what would be considered as conformance, and the blue line indicates the results of the gap analysis detailed within this document.

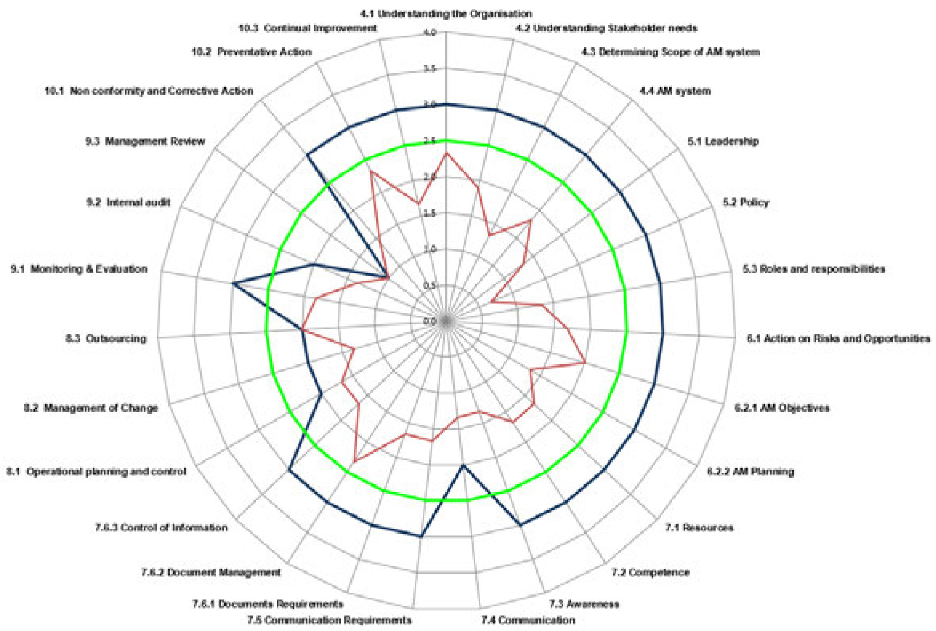


Figure 1 – Hydro Ottawa AMS Maturity Scoring

The gap analysis assessment carried out on the AMS was very encouraging as Hydro Ottawa were able to demonstrate that a large majority of the requisite processes were in place. The gaps identified in this document are typically due to the maturity of the AMS, and therefore the lack of a full management review and Internal Audit cycle.

As the most difficult and time-consuming activities are usually the creation and implementation of processes, it can be seen that Hydro Ottawa have already done a large majority of the work required to implement an effective AMS through creating new or adopting existing Hydro Ottawa processes.

Contents

1. Background

EA Technology was invited to provide Hydro Ottawa Limited (Hydro Ottawa or HOL) with a gap analysis assessment of their Asset Management System (AMS) against the requirements of ISO55001. The work carried out under this gap analysis assessment was exclusively for Hydro Ottawa, who are a regulated electricity distribution company, operating in the City of Ottawa and the Village of Casselman. Hydro Ottawa's electricity distribution system serves over 324,000 residential and commercial customers across a service area of 1,100 square kilometres.

The gap analysis described in this document is the second gap analysis carried out on Hydro Ottawa's AMS, and was requested to identify conformance against the ISO55001 requirements in view of recent work carried out on the AMS. The results from the previous gap analysis (Figure 1 Executive Summary) are illustrated in this document to show progress; however, it should be noted that EA Technology's audit team carrying out the gap analysis assessment were unaware of these results until after the gap analysis assessment was finalized.

2. Scope of the Document.

EA Technology carried out an ISO55000 gap analysis assessment at Hydro Ottawa's Merivale Road offices on the 25th to the 28th February 2019. The scope of the project was to assess the size of any gaps that exist between Hydro Ottawa's AMS and the requirements detailed in ISO55001. This document provides a list of conclusions and recommendations that will assist Hydro Ottawa with their ambition of obtaining ISO55000 accreditation.

3. Gap Analysis

3.1 Schedule

EA Technology carried out an ISO55000 gap analysis assessment on Hydro Ottawa's AMS from the 25th to the 28th February 2019. The gap analysis assessment was carried out to provide Hydro Ottawa with an independent objective view of the conformance of Hydro Ottawa's AMS against the requirements of ISO55001.

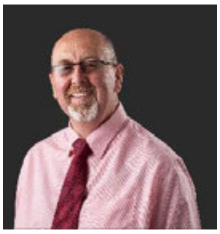
Figure 1illustrates a high-level view of the gap analysis schedule carried out between the 25th and the 28th of February. A more detailed schedule is provided in Appendix I, which details individual audit sessions and attendees.

	AM	PM
Day 1 – Monday, 25th February 2019	Introduction / Context	Leadership
Day 2 – Tuesday, 26th February 2019	Site Visit	Planning
Day 3 – Wednesday, 27th February 2019	Performance / Support	Support
Day 4 – Thursday, 28th February 2019	Operation / Planning	Improvement / Presentation

Figure 1 – Gap analysis schedule

3.2 Audit Team

Lead Auditor: Andrew McHarrie



Andrew is a Principal Consultant who currently holds the position of Head of Asset Management and Power System Studies. He has over 40 years' experience in the electrical utility sector, since he started work as an apprentice electrician in the late seventies. Andrew is a chartered engineer and a Fellow of the IET, and an active member of the Institute of Asset Management. Andrew is a member of a number of Asset Management working groups and has recently contributed to the review of the new ISO55002 standard.

Support Auditor: Tim Erwin

Tim Erwin holds the position of National Sales Manager for EA Technology USA. He has over 20 years as a protection and control engineer for medium and high voltage applications with 9 year at ABB. He graduated with a BS in electrical engineering from The New Jersey Institute of Technology. He is a member of IEEE.

3.3 Findings

During the gap analysis the audit team assessed the conformance of all seven sections of the ISO55001 standard (Sections 4 to 10), which implements 27 clauses. The gap analysis assessment was carried out with the assistance of EA Technology's bespoke gap analysis tool that is based on the IAM's SAM tool. During the assessment the audit team were looking for appropriate answers to specific questions plus where appropriate some form of evidence to prove validity and maturity. The following sections detail the findings of the gap analysis, which illustrates the score, the summary of any discussions and evidence provided for each clause.

Section 4. Context of the Organisation

Clause 4.1: Understanding the organisation and its context

The aim of clause 4.1 is to provide context and structure in which an organisation can manage its assets efficiently and effectively. To do this the context of the organisation implementing the AMS must be identified, as an AMS must support, and be driven by the organisation's objectives.

In understanding the context of the organisation, implementing the AMS will ensure that:

- the alignment of all internal and external stakeholders and their issues will be considered
- the AM policy, objectives and plans are developed so as to obtain maximum benefit from its assets in support of the organisation's objectives, and/or business plan

Maturity Score: 3

Discussion
HOL's overall strategy for the organisation is refreshed every 5 years, which is in line with their regulatory submission. The current 5-year strategy provides an overview of Hydro Ottawa's business strategy and financial projections for 2016 to 2020. The strategy document informs HOL's relevant stakeholders about issues that shape HOL's business environment and how HOL intends to respond to such issues. HOL hold an annual board retreat, which verifies the alignment with HOL's strategic plan and carries out a SWOT analysis based on HOL's business environment (regulations, customer input, environmental challenges) and determines any issues and their potential impacts. HOL hold monthly/bi weekly executive management meetings Enterprise risk management team tracks "business risks" and meet on a monthly basis and report to the board on a quarterly basis. HOL tracks issues concerning the development of distributed generation, energy storage and sectionalisation through their Smart Energy Executive Steering Committee. HOL have an internal website that communicates issues to all HOL staff (HydroBuzz) HOL produced the Strategic Direction Document 2016 – 2020 as evidence, This document is currently being reviewed in line with HOL's rate submission, which is due for late 2019 for the 2021 - 2026 period.

Conclusions	
C4.1	Hydro Ottawa have demonstrated that they fully understand the context of their organization by considering issues that can affect its business environment.

Clause 4.2: Understanding the needs and expectations of Stakeholders

The organisation should identify and review the stakeholders that are relevant to the asset management System. The needs and expectations of these stakeholders should be identified and how they impact on Asset Management decision making and reporting.

Following engagement with relevant stakeholders, mandatory requirements and expectations should be documented and communicated. Levels of service should then be reviewed at regular intervals so that stakeholder needs are concurrent with those listed.

Maturity Score: 3

Discussion

HOL demonstrated a broad set of interactions with stakeholders and stakeholder engagement process.

HOL have a Customer Service Experience Committee that assess new customer needs as well as assessing the performance of the customer experience. Inputs into the committee meeting will be customer complaints, customer enquiries (customer call centres)

Call centre staff are trained to respond to customer needs e.g. Key accounts, Vulnerable customers.

HOL demonstrated that they proactively ask customers their needs

HOL provided evidence of HOL's:

- Customer Service Experience Committee Meetings;
- Customer Satisfaction 2018 process;
- Customer engagement overview;
- Low - Volume Focus Group Report illustrates stakeholder requirements (Innovative)
    - The 'Innovate - Low Volume Focus Group Report Draft' document illustrated the Identified priorities of HOL customers (price, Reliability, Efficiency and cost reductions etc
- The Customer Satisfaction Results 2018 CEA National CSAT presentation (x3) was presented to demonstrate stakeholder engagement. The presentation demonstrated engagement and benchmarked against the province of Ontario and nationally.
    - 1st presentation was the annual CEA (Canadian Electricity Association) customer satisfaction survey
    - 2nd was Residential and small business customers
    - 3rd was Large Customers

HOL have a Customer Experience committee that assesses how HOL engage with its customers plus they also report any significant stakeholder requirements. This committee is made up of cross business personnel.

The 'Customer Engagement Program Overview' document was submitted to illustrate how HOL demonstrate stakeholder engagement to the regulator, which is part of the rate submission.

Conclusions	
C4.2	HOL demonstrated that they engage with stakeholders that are relevant to its Asset Management System and their needs and requirements are considered.

Clause 4.3: Determining the scope of the asset management system

Based upon the outcomes of reviews of its context and stakeholder requirements and expectations, the organisation should define (or review) the boundaries of its AMS, establishing its scope in the process.

Maturity Score: 3

Discussion	
HOL's Asset Management System is documented in HOL's 'IAS0002 Asset Management System Manual' document. HOL have a sentence in the Asset Management System Manual that excludes facilities, fleet and information technology, this should be reinforced in the SAMP so that the table displays the major asset groups and a statement below, which states what is explicitly outside the AMS scope. The AMS manual makes a reference to 'other management systems'. It is suggested that HOL's current management systems should be detailed (ISO9001, ISO14001). The network area is mapped out in the SAMP document. The stakeholders and the roles and responsibilities are also detailed in the SAMP.	
Conclusions	
C4.3	HOL document the scope of the AMS through its AMS and SAMP documents.
Recommendation	
R4.3a	It is recommended that HOL should document in the SAMP document which Assets are explicitly excluded from the AMS.
R4.3b	It is recommended that HOL should make reference to HOL's current management systems (ISO9001, ISO14001) in the AMS Manual.

Clause 4.4: Asset management system

The AMS is the framework in which all asset documents are written, reviewed and used.

The SAMP shows alignment of how corporate objectives are met through AM objectives and AM plans.

The AMS and the SAMP should be reviewed on an annual basis to:

- determine if the corporate objectives or business needs are meet through the SAMP
- Determine if the AMS provides an effective and efficient framework to support the organisation in meeting its business needs and corporate objectives

Maturity Score: 3

Discussion	
HOL have a documented AMS manual document, which specifies each of the requirements of ISO55001. The AMS Manual is the responsibility of the Asset Manager who reviews and updates it. HOL have an Asset Management System Key Elements flowchart (ISO55000) with the addition of the documents that constitute the AMS. The AMS manual aligns to the requirements of ISO55001 and it references other documents that constitute the AMS. HOL have continual improvement document 'Asset Management System continual improvement' document that specifies the process for continually improving the AMS. The document specifies the setting of KPIs, HOL have created an Asset Management Council (AMC), which sits to provide information and offer insight and feedback into the creation and development of the AMS. The AMC sits once a month (progress meetings) and every quarter, when it reviews the KPIs. HOL have a SAMP document that has a diagram that aligns the Corporate Strategic Direction, the Corporate Strategic Objectives, Asset Management Objectives, Asset Management Measures. The Asset Management Plans align to the Asset Management Objectives through the template layout. The AMPs detail the AS-IS and the To-Be situations and the SAMP details the strategy to accomplish these.	
Conclusions	
C4.4	HOL have demonstrated that they document the AMS through the AMS Manual document and the SAMP.

Section 5. Leadership

Overview

Every organisation needs leadership to provide direction and drive the AMS. It is also important that the roles and responsibilities in implementing and managing the AMS are established implemented and reviewed.

ISO 55002 (2018) states that '*top management should ensure that it demonstrates leadership and commitment by taking an active role in engaging, promoting, directing and supporting, communicating and monitoring the performance, effectiveness and continual improvement of the assets, asset management and the asset management system*…'

Clause 5.1: Leadership and commitment

Top management is responsible for creating the vision and values that guide policies within the organisation. They should also have responsibility for developing the AM policy and AM objectives and ensuring that these align with the organisational objectives. Managers (or designated leaders) at all levels of the organisation should be involved in the planning, implementation and operation of the AMS.

The commitment of top management to the AMS is important to its success, as top management should not only provide direction in the form of organisational objectives, but ensure sufficient resource is assigned to successfully implement the AMS.

Top management should ensure that the AMS is compatible with the organisational objectives and promotes continual improvement, cross functional collaboration and risk management. Top management also defines the responsibilities, accountabilities and AM objectives and AM strategies, which create the environment for the AMS.

Maturity Score: 3

Discussion

HOL demonstrate leadership through:
 	
• The Chief Electricity Distribution Officer and the President are signatories on the Asset Management Policy;
• The direction for implementing HOL's Asset Management System is top down;
    ○ An example of this was illustrated by the presentation of a Corporate Performance Goals and Priorities - 'Complete Asset Management ISO55000 standards project' which is reported to the HOL Board Holding Board;
• All members on the AMC committee are sponsored by Top Management. Risks are escalated through the sponsors who would raise it with the Board;
    ○ The AMC participation graphic illustrates how the AMC is made up of different parts of the organisation;
• The Chief Electricity Distribution Officer sponsors and signs off the AMC terms of reference;
• Top management supports the stakeholder engagement process through engagement of a third party to obtain stakeholder requirements;
• The existence of the Asset Management Objectives & Performance Measures document, which illustrates a number of activities that demonstrate top management approval and resources;
• An example of top management communications was provided that illustrated the importance of Asset Management to HOL;
    ○ HOL have employee emails that link to news stories on the Intranet;

- The Risk Management approach used in the AMS is aligned to the ERM process at corporate level, the AMS document aligns the risk management approaches and references the Risk Register and its scoring criteria;
- The 2018 Performance scorecard was submitted as evidence that the Chief Distribution Officer has ownership of implementing the AMS within the ISO55000 project that he has to deliver to the Board.
    - This presentation was given to the HOHI (Hydro Ottawa Holdings Inc) and HOL (Hydro Ottawa Limited) Board of Directors
- The 2019 CFO Divisional Scorecard was provided as evidence that the CFO is responsible for the Rate application to the regulator, the rate application is processed through the regulatory director supported by the Distribution business (Asset Management)

Conclusions	
C5.1	HOL have demonstrated that top management at all levels of the organisation are involved in the planning, implementation and operation of the AMS

Clause 5.2: Asset Management Policy

The AM policy should set out the commitment of the AMS and provide a framework for the setting of AM objectives that are appropriate to the purpose of the organisation.

The AM policy is a commitment from the top management that the organisation will adopt Asset Management throughout its business.

The AM policy should be communicated to all stakeholders (internal and external) including any outsourced contractors working on Hydro Ottawa's assets or AMS.

The AM policy should be created in a consistent way with other company policies and should be reviewed periodically and updated where required.

Maturity Score: 3

Discussion
The HOL Asset Management Policy is signed by the Chief Electricity Distribution Officer and the President. The Asset Management Policy is communicated to all staff through HOL's HydroBuzz, staff emails and physical copies are posted in HO's Head Office Currently HOL do not communicate the Asset Management Policy to their contractors.

Conclusions	
C5.2	Currently HOL do not communicate the Asset Management Policy to their contractors.

Recommendation	
R5.2	It is recommended that the Asset Management Policy is included in the contractor on-boarding process and maybe the Contractor intranet.

Clause 5.3: Organisational roles, responsibilities and authorities

The organisation should define the responsibilities and authorities of each AM key function (internal and outsourced). Typically, this will take the form of job descriptions or similar and be reflected by way of an organisational chart.

Top management shall assign responsibly and authority for the following:

- establishing and controlling the SAMP
- ensuring the AMS supports delivery of the SAMP
- ensuring the SAMP conforms to the requirements of ISO 55000
- ensuring the suitability, adequacy and effectiveness of the AMS
- ensuring and updating the AM plans
- reporting on the performance of the AMS to top management and stakeholders alike

Maturity Score: 3

Discussion	
HOL have a part in the SAMP document that specifies the high level AMS roles and responsibilities Other responsibilities are mapped to roles throughout the SAMP and AMS documents. For example, the 'Review of the SAMP' illustrates that the SAMP is updated as required by the Asset Manager and Approved by the Asset Owner	
Conclusions	
C5.3	HOL document roles and responsibilities within the AMS Manual and SAMP documents.
Recommendation	
R5.3	It is recommended that HOL ensure that the responsibilities documented in the SAMP and AMS Manual documents are reflected in personal job descriptions.

Section 6. Planning

Section 6.1: Actions to address risks and opportunities for the asset management system

In planning the AMS, the organisation shall consider external and internal issues that are relevant to its purpose and that affect its ability to achieve its intended outcomes. Associated risks and opportunities should be considered and addressed so as to:

- provide assurance that the AMS can achieve its intended objectives
- mitigate risk by implementing suitable controls
- achieve continual improvement

Maturity Score: 3

Discussion

Projects are prioritized on the value to the organization – the risk is monetized and replacement would reduce that risk therefore representing value.

Once a project has been identified it is risk scored in HOL's C55 application - Worst performing circuits, load lost, customers affected etc.

The value score prioritizes projects on their value to the organization.

HOL's 'IAP0022 Schedule 1 Risk Register R0' was supplied as evidence of HOL's risk register, which illustrates how HOL record and assess risks, plus how they assess the effects of any control actions required to mitigate against these risks.

Figure 2 illustrates that HOL consider the risks associated with the planning of their Asset Management Plans.

*Figure 2 – Asset Management * Expenditure Process*

Conclusions

C6.1	HOL have demonstrated that they consider external and internal issues that affect its ability to achieve its intended outcomes.

6.2: Asset management objectives and planning to achieve them

Clause 6.2.1: Asset management objectives

A fundamental of the AM system is to ensure alignment between the organizational objectives and the technical and financial decisions, plans and activities.

Defined AM objectives form the link between the organisation's AM policy, strategy, corporate objectives and individual plans. The organisation should develop its AM plans in-line with its time horizons which in turn meet the organisation's needs and take account of periods of responsibility and life of assets.

AM objectives are created through the AM policy therefore enabling organisation's corporate objectives to be met using the AMS.

Maturity Score: 3

Discussion
HOL have a set of generic Asset Management Objectives in the SAMP document, which are aligned to HOL's Organizational Objectives These generic Asset Management Objectives are further defined in each of the individual Asset Management Plan documents. The alignment of the Asset Management objectives and the Organisational objectives in the SAMP document and the further defining of the asset management objectives in the individual Asset Management Plans illustrates a clear line of sight between the business plans and the planning function.

Conclusions	
C6.2.1	HOL have demonstrated that Asset Management Objectives are created and linked to HOL's Organizational Objectives.

Clause 6.2.2: Planning to achieve Asset management objectives

In order for an organisation to achieve its objectives, plans need to create, document and maintain asset management plans that consider, and are compatible with other business functions. Asset Management Plans need to consider risks and opportunities across the asset's life cycles, and provide details of objectives, the organisation shall determine how and when the plans will be carried out/completed.

Maturity Score: 3

Discussion

HO have a number of AMPs that illustrate how a number of asset groups will be managed over their lifecycles.
 	
There are currently 11 AMPs with another 2 under development. The AMPs have been defined through legacy management and regulatory reporting of assets.
 	
The 'IAP0005 Asset Management Plan Pole, Fixtures and Primary Overhead Conductor R0' was provided as evidence and demonstrated that each Asset Management Plan provided:
 	
• Asset Management Objectives – The following bullets in **Bold** text are the Asset Management Objectives that are aligned to the Organizational Objectives in the SAMP document, and their sub bullets are the further defining of these objectives.
    ○ **Levels of Service**
        ▪ Impact on system reliability through electrical interruptions which may be localized, affecting customers connected to that specific pole or overhead conductor, or a wider outage, affecting a large number of customers supplied by the connecting conductors
        ▪ Achieve quicker reliability restoration as failed poles, fixtures or overhead conductors are easier to locate compared to underground equipment
    ○ **Health, Safety & Environmental Stewardship**
        ▪ Impact employee and public safety due to fallen poles and downed overhead conductors
        ▪ Achieve clearances for public safety from roads, walk ways, rail lines, buildings, etc.
        ▪ Impact environmental stewardship by failing to support oil filled equipment
    ○ **Asset Value**
        ▪ Achieve reduced costs due to economic effectiveness of overhead vs. underground distribution
        ▪ Impact asset lifecycle cost as an emergency replacement is more costly than planned replacement
    ○ **Resource Efficiency**
        ▪ Impact resource optimization as a single emergency replacement is less efficient than planned replacement which usually has multiple poles in a row
• Asset Performance
• Asset Lifecycle Management
• Future Demand
• Resource Plan
• Continuous Improvement
• Implementation

Conclusions	
C6.2.2	HOL have clearly demonstrated that they create, document and maintain asset management plans that consider, risks and opportunities across the asset's life cycles, and provide details of objectives.

Section 7. Support

Clause 7.1: Resources

The organisation shall determine and provide adequate resource for the establishment, implementation, maintenance and continual improvement of its AMS. In doing so the organisation shall ensure compliance with its AM objectives and for implementing activities specified in its AM plans.

Resource should be considered as part of the organisation's planning stage and communicated with the relevant stakeholders to ensure effective collaboration and to determine the required resources to deliver the AM objectives and AM plans.

Maturity Score: 3

Discussion
HOL have a strategic workforce plan that determines the resources on an hour per $ basis. The Asset Management Plans are rolled up to the corporate Rate application which is used to inform the '2021-2025 Resource Hours v1 Feb 7 2019' which illustrated how HOL evaluate resources at a program level. More specific assessments are carried out, and the 'power Line Technicians WFP Summary October 2018' document was shown as evidence HOL review the planned against actual headcount which is reported to the board on an annual basis. A slide that demonstrated actual resource hiring against planned was shown as evidence. The '2021-20125 Resource Hours v1 Feb 7 2019' illustrated the resource hours for the constrained version of the roll up of all of the Asset Management Plans"

Conclusions	
C7.1	HOL have demonstrated that they link resource requirements to their plans and their regulatory submission

Clause 7.2: Competence

To ensure all AM activities are effectively carried out, the organisation shall identify the correct level of competency required for each individual AM role. Therefore, each individual competence must be evaluated and documented.

The organisation should carry out a periodic review of its competence requirements to ensure continued credibility and effectiveness. Training or mentoring may be employed for situations where competencies are known to be deficient.

For outsourced resource, the organisation's training department or similar should maintain a list of approved contractors and their relevant competency levels.

Maturity Score: 3

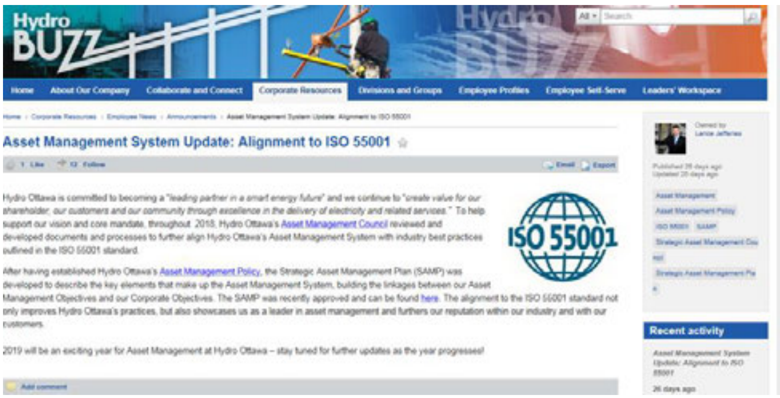
Discussion
HOL have a 'Workday' system that notifies staff and their managers when training (refresher training) needs to be carried out. Each manager has a report on each of their direct reports that detail their competence needs and training requirements; Each member of staff has their own transcript that details their training requirements; Everyone is notified about their upcoming training requirements and anyone that does not enrol within the required timescale is logged and requested to enrol; HOL provided a Job description to illustrate that competence needs are documented, and a training record was provided as evidence to demonstrate how HOL ensure competence is achieved and maintained; The 'Power Line Technicians WFP Summary - October 2018' document was provided as evidence that the resource is considered over a 3- year period, and the 'PLT Training Profile' spreadsheet demonstrated the training required to achieve competence.

Conclusions	
C7.2	HOL have demonstrated that they consider, evaluate and track staff competence

Clause 7.3: Awareness

To ensure AM Activities are correctly carried out, individuals working under the control of the organisation must have appropriate awareness of the AMS, and their impact on its effectiveness. Individuals should be made aware of the AM policy, how their work activities may impact the AMS (including risk and mitigation) and any non-conformances. This should be extended to appropriate external stakeholders such as contractors working on the organisation's assets and should be recognized in an individual's defined roles and responsibilities.

Maturity Score: 3

Discussion
All HOL asset management documentation is made available to HOL employees Posters that illustrate and communicate ISO55000 and AM activities" Hydro Ottawa make their staff aware of their AMS through "Hydro Buzz" (Figure 3)  *Figure 3 – HydroBuzz* The audit team attended a substation inspection during the gap analysis, and staff questioned were fully aware of their obligations under the AMS plus they were also fully conversant with the data they collect and the importance of this data in informing Asset Management decisions.

Conclusions	
C7.3	During the audit Hydro Ottawa demonstrated a good level of awareness.

Recommendation	
R7.3	It is recommended that Hydro Ottawa continue to make their staff as aware as possible regarding the AMS, as the awareness process conducted during the audit was minimal compared to a certification audit.

Clause 7.4: Communication

AM activities should be communicated at different levels to different stakeholders so as to inform the relevant participants exactly who could impact the AM plans and the achievement of the AM objectives. Good communication of the AMS will promote engagement with stakeholders, whilst enhancing transparency and accountability of the AMS.

Maturity Score: 2

Discussion

HOL have a communication plan that illustrates:

- Internal and external communication processes;
- How Hydro Ottawa communicate with certain customers;
- Roles and responsibilities in-line with communication requirements;
- How Hydro Ottawa continually improves its communications

Hydro Ottawa use ‘All User’ emails to communicate Asset Management information and awareness of the AMS with their staff. The following email was provided as evidence (Figure 4).

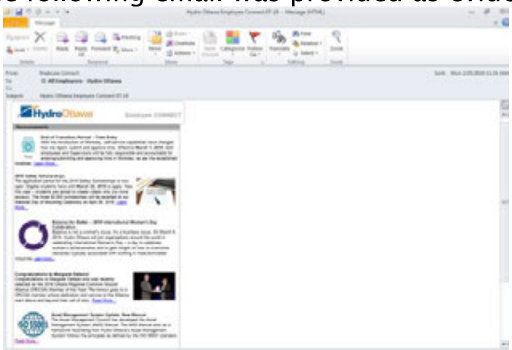


Figure 4 – Staff Communication

HOL’s Asset Management Council (AMC) determines:

- What stakeholders are relevant to the AMS;
- The requirements and expectations of these stakeholders with respect to asset management;
- The stakeholder requirements for recording financial and non-financial information relevant to asset management.

HOL communicate with their stakeholders through a broad set of interactions.

Call centre staff are trained to communicate effectively with customers, and to identify their needs e.g. Key accounts, Vulnerable customers.

HOL have a Customer Experience committee that assesses how HOL engage with its customers plus they also report any significant stakeholder requirements. This committee is made up of cross business personnel.

The 'Customer Engagement Program Overview' document was submitted to illustrate how HOL communicate with their customers. This document is part of HOL’s rate submission.

HOL need to expand the major known communication tasks

Conclusions

C7.4	HOL have demonstrated that they effectively communicate with their relevant stakeholders; however, it was felt that the major known communication tasks need expanding within HOL’s Asset Management documentation.

Recommendation

R7.4	It is recommended that HOL document major known communication tasks in the AMS or SAMP document.

Clause 7.5: Information requirements

To ensure the efficient operation of the AMS and the achievement of the organisation's objectives, pertinent information should be determined and collected. Information should be sourced using a systematic approach and stored in assigned repositories. Security, copying and archiving should be considered.

Maturity Score: 3

Discussion
HOL have determined what information requirements are needed to determine the health condition of its assets. This was formulated from the employment of a contractor HOL have a KPI dashboard that illustrates the KPIs for different parts of the AMS. Some are mandated regulatory requirements however most are tracking the AMS. A number of criteria were TBC such as the 'Asset Value - Value Optimization'. Evidence was produced in the 'IA0025 - Asset Management System Continual Improvement Plan R0' document that illustrated how HOL determine what information is required to populate this KPI. 'The average normalized capital value of projects to the budget of the projects presently planned by Hydro Ottawa. This index is meant to demonstrate the expected value for money obtained from the project portfolio for system renewal and system service projects.' The AMC was used to decide on the KPIs and the information requirements that support them. one of the Asset Management Council minutes were shown as evidence as well as a couple of presentations that were delivered to the AMC to prompt discussion on KPIs. HOL have a risk register which identifies deficiencies in information which would result in a risk. The SAMP details the requirements of Data quality Electrical Distribution CAD & GIS Construction Drawing Standard illustrates the information requirements plus the 'Placing construction proposals in GIS' was produced to illustrate how HOL quality assures data input. HOL are looking at creating a KPI and audit process for the data in its information systems. It is recommended that HOL create this (level of confidence in its data)"

Conclusions	
C7.5a	HOL have demonstrated that they have identified the required information to ensure that they can make effective Asset Management decisions.
C7.5b	HOL use a systematic approach to acquiring and storing information in designated repositories.

Recommendation	
R7.5	It is recommended that HOL create a KPI(s) that provides a level of confidence in their asset information.

7.6: Documented Information

Clause 7.6.1: General

To ensure the efficient operation of the AMS and the achievement of the organisation's objectives the organisation shall make sure that sufficient documented information is available to satisfy the requirements of ISO55001 and all applicable legal and regulatory requirements. Sufficient documented Information shall also be provided to ensure the effectiveness of the Asset Management System.

Maturity Score: 3

Discussion
HOL have an AMS document that specifies the documented information required for its AMS In addition to this the AMS Manual references a number of supporting documents that are deemed relevant, such as: ● Hydro Ottawa – Strategic Direction ● Hydro Ottawa – IAS-0001 – Asset Management Policy ● Hydro Ottawa – Asset Management Plans ● Hydro Ottawa – IAP0022 – Asset Management System Risk Procedure ● Hydro Ottawa – IAP0021 – AMS Communication Plan ● Hydro Ottawa – IAP0025 – Continual Improvement Plan ● Hydro Ottawa – ESS0008 – Equipment Approval Process ● Hydro Ottawa – POL-En-006.01 – Approval Authority for Procurements and Distributions ● Hydro Ottawa – POL-Fi-003.01 – Procurement Policy ● Hydro Ottawa – PRO-Fi-013.00 – Contract Procurement Process ● Hydro Ottawa – POL-Fi-009.00 – Internal Controls over Financial Reporting ● Hydro Ottawa – POL-Fi-013.00 – Capitalization Policy ● Hydro Ottawa – DFS0007 – Control and Retention of Tech Based Docs and SWM ● Hydro Ottawa – POL-IM-001.00 – Information Management Policy ● Hydro Ottawa – PRO-MS-002.09 – Document and Data Management ● Hydro Ottawa – Records Classification and Retention V9.1 ● Ontario Energy Board – Distribution System Code ● British Standards Institution – ISO55001 – Asset Management – Management System ● British Standards Institution – ISO14001 – Environmental Management System ● British Standards Institution – 18001 – Occupational Health and Safety Assessment Series ● Institute of Asset Management – an Anatomy

Conclusions	
C7.6.1	HOL have demonstrated that they have sufficient documentation to satisfy the requirements of ISO55001

Clause 7.6.2: Creating and Updating

To ensure the effectiveness of documented information the organisation shall ensure that when the documents are created or reviewed, that they are constantly described, identified, formatted and documented in the correct media type. All documents that have been created or reviewed shall also be approved by a suitable authority for their suitability and adequacy.

Maturity Score: 3

Discussion	
HOL have a document that specifies how HOL write documents 'Technical "Text Based" Document' was shown as evidence of how HOL control the formatting of documents. Hydro Ottawa Brand Guide Jan 2016 illustrates how Presentations can be created. All brand templates are kept in HydroBuzz Technical Standards are also kept in the Technical Standards Portal."	
Conclusions	
C7.6.2	HOL demonstrated that they effectively create and manage their documented information.

Clause 7.6.3: Control of documented information

For the effective implementation of the AMS the organisation should ensure that the documented information deemed as relevant to its assets and Asset Management System is adequately controlled and available to use as appropriate to organisation. All documented information should be adequately protected, and be controlled to ensure the correct distribution, access, retrieval and use. The documented information should also be correctly stored and preserved including the control of any changes.

Maturity Score: 3

Discussion	
The 'Control and Retention of Technical Based Documents and Standard Work Methods' details the control of HOLS documents, A flowchart illustrates the control process. All documentation has been readily available throughout the audit. HOL have a database that details the revision dates on all HOL documents, HOL also use this database to generate document numbers. HOL have a document identification number format that within the 'Technical Based Document & Standard Work Method Number Format' document 3 letters identify the document type and the remaining 4 numbers are just sequential.	
Conclusions	
C7.6.3	HOL have demonstrated that they effectively control their documented information.

Section 8. Operation

Clause 8.1: Operational planning and control

The organisation should establish operational planning and control processes in order to support the effective delivery of the activities contained within the asset management plan. The processes should identify who is responsible for the planning and how the defined activities will be executed, including how risks arising during the planning and execution will be managed and controlled.

Maturity Score: 2

Discussion	
Sustainment is HOL's capital program projects HOL have a C55 (Copperleaf) (project tracker system) that records changes to projects. A project was identified on the 'Capital Program Tracking' spreadsheet as being deleted and the changes were linked in C55 (the example was new, so all changes were not in the C55 system) HOL map out project progress for different crews in a Gant chart style, the WhiteBoard' spreadsheet estimates the project dependent upon the labour hours and % completes. A project was identified on the white board and checked in the Capital Program Tracking spreadsheet and it checked out. The whiteboard spreadsheet is reviewed at bi monthly (twice a month) meetings which have a good cross functional attendance. This is a recurring invite on outlook for each of the HOL areas. A budgetary forecast review is carried out on a monthly basis. There is no direct link from all of these processes and the risk register.	
Conclusions	
C8.1	HOL have demonstrated that they have operational planning and control processes that support the effective delivery of the activities contained within the asset management plans; however, these processes are not linked to HOL’s risk register.
Recommendation	
R8.1	It is recommended that HOL should link their operational planning and control processes to HOL’s risk register.

Clause 8.2: Management of change

Planned changes within the organisation could have an impact on achieving the corporate objectives and associated delivery of the AM plans, therefore such changes should be assessed to identify any risks and impact these changes may have. Risks identified, controls should be implemented to mitigate possible adverse effects on the AM plans, AM objectives and corporate objectives.

It is the responsibility of the person making change to assess if this change has any impact on the AM objectives and ultimately the organisation's corporate goals.

All change should be documented and clearly express what change has occurred, the impact of this change and the mitigating controls that are required.

It is important to note that any change to the AM plans should be adequately assessed for its impact on the existing AM objectives.

Maturity Score: 2

Discussion

Changes to any technical standards need to be in-line with the 'Signing authority for technical based documents'

Project changes need to be as per the Change Request template which is documented in C55

A Change in the direction of a project will be in-line with the Planning Directive.

It is unclear how management of change is carried out for changes to the AMS and how Management of Change requests are monitored and recorded.

As a management of change process identifies and determines any potential risks associated with a change, any significant risks should therefore be reflected in HOL's Risk Register. There is currently no documented link to the risk register from the management of change processes.

The flowchart below (Figure 5) illustrates a management of change process that identifies risks of any change request

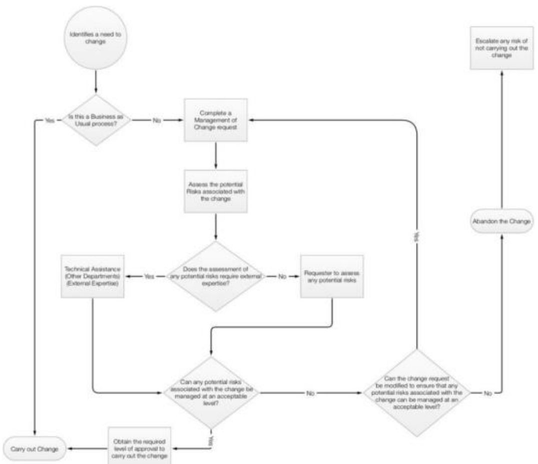


Figure 5 – Generic Management of Change flowchart

Conclusions

C8.2a	Management of change is controlled within HOL for technical standards/documents and projects; however, it is unclear how management of change is carried out for changes to the AMS and how Management of Change requests are monitored and assessed.

C8.2b	There is currently no link between the management of change processes and HOL's Risk Register.
Recommendation	
R8.2a	It is recommended that HOL should document how it will consider and manage changes to its AMS.
R8.2b	It is recommended that HOL should consider how Management of Change requests are monitored and recorded.
R8.2c	It is recommended that HOL should link any significant risks identified from a management of change process to HOL's risk register
R8.2d	It is recommended that HOL create a process that identifies the requisite parts of a management of change request (see diagram above).

Clause 8.3: Outsourcing

Outsourcing is a common method for an organisation that prefers to perform certain AM activities using an external service provider. When these activities influence the achievement of the AM objectives, these should be part of the AMS and should be documented.

For outsourced activities, the organisation should implement controls so as to provide assurance that actual performance is as planned. The performance of outsourced activities should be subject to regular management reviews.

When outsourcing any life cycle activities and AM activities, the organisation should consider the associated risk and impact on its assets and AMS.

Maturity Score: 2

Discussion	
HOL's RFSO (Request for standing offer) sets out a set of parameters that the outsourced company needs to adhere to. Each contractor is approved on their ISN Grade (IS Network) Each contractor goes through an onboarding process. Outsourced contractors do not currently receive HOL's Asset Management Policy or Asset Management Awareness training. This should be added to the contractor on-boarding process."	
Conclusions	
C8.3	HOL do consider the technical requirements and competence of their outsourced contractors; however, currently outsourced contractors do not receive a copy of HOL's Asset Management Policy or awareness training.
Recommendation	
R8.3a	It is recommended that HOL ensure that all outsourced contractors are aware of HOL's Asset Management Policy.
R8.3b	It is recommended that HOL provide all outsourced contractors with Asset Management Awareness training, possibly through the on-boarding process.

Section 9. Performance and Evaluation

Clause 9.1: Monitoring, measurement, analysis and evaluation

The organisation should develop processes to provide for the systematic measurement, monitoring, analysis and evaluation of the organisation's assets, AMS and AM activity on a regular basis.

Maturity Score: 3

Discussion
HOL have a corporate scorecard that measures the organizational objectives. Each division then has KPIs that they need to achieve. The Scorecard for Q4 2018 was shown as evidence which illustrated many different metrics under the following areas: ● Financial Strength ● Customer Value ● Organizational Effectiveness ● Productivity ● Corporate Citizenship Each time HOL have a reported unplanned outage the operator will categorize the failure mode, such as Tree contact, Lightning etc. (Regulatory Cause Codes). The operational staff will then amend the identified cause if it is different to the one reported. Failures are monitored to determine whether HOL should carry out a full failure investigation. CEA Association (Service continuity committee) benchmarks the failures of all Canadian Utilities. The taxonomy of the System Interruption Database (HOL database) allows HOL to assess common failures and failure types.

Conclusions	
C9.1	HOL have demonstrated that they developed processes to provide for the systematic measurement, monitoring, analysis and evaluation of the organisation's assets, AMS and AM activity.

Clause 9.2: Internal audit

The organisation shall conduct internal audits at regular intervals to ensure the suitability and efficiency of its AMS.

The organisation should establish an audit process to direct the planning and conduct of audits, and to determine the audits needed to meet its objectives. The process should be based on the organisation's activities, its risk assessments, the results of past audits, and other relevant factors.

Maturity Score: 2

Discussion	
HOL have an independent Audit group that has an annual audit plan that is risk based. Parts of the Asset Management System that are consistent with HOL's quality management system have undergone some internal auditing. HOL have not currently carried out an internal audit upon its Asset Management System, due to its maturity.	
Conclusions	
C9.2	HOL have all of the requisite processes and audit expertise to carry out internal auditing of the AMS.
Recommendation	
R9.2	It is recommended that HOL's internal audit team carry out an internal audit upon HOL's AMS.

Clause 9.3: Management review

Top management should review the organisation's assets, AMS and AM activity, as well as the operation of its policy, objectives and plans, at planned intervals, to ensure their suitability, adequacy and effectiveness.

Maturity Score: 1

Discussion	
The AMC is due to start holding quarterly meetings that review the AMS and its performance. HOL are to use the AMC quarterly meetings to carry out the Management Review of the AMS; however, it is felt that the quarterly meetings are not the correct forum to carry out an in-depth management review of the AMS. The tracking of KPIs in the AMC quarterly meetings is good practice and will contribute to the Management Review process.	
Conclusions	
C9.3a	Due to the maturity of HOL's AMS, HOL have not yet carried out a full management review.
C9.3b	The tracking of KPIs in the AMC quarterly meetings is good practice and will contribute to the Management Review process
Recommendation	
R9.3a	It is recommended that HOL carry out a management review of the AMS separately to the AMC quarterly meetings.
R9.3b	It is recommended that HOL determine and document the minimum content of the management review process

Section 10. Improvement

Clause 10.1: Nonconformity and corrective action

The organisation should establish plans and processes to control nonconformities and their associated consequences, so as to minimize any adverse effects on the organisation and on stakeholder needs and expectations. This can be accomplished by documenting and reviewing past non-conformities, evaluating how the consequences were dealt with and by determining methodologies to prevent future nonconformity.

Nonconformities can occur in two ways:
- Nonconformity of the AMS
- Nonconformity of assets

Maturity Score: 3

Discussion
HOL receive non-conformance information through the OMS (Outage Management System), Call centres, Dispatch, Inspection, staff observation. I Net Dispatcher holds the incident/failures these are then sent electronically to the field staff or via a 'General Construction Order & CVP Certificate The details of any asset changes are recorded and the GIS is changed. The 'General Construction Order & CVP Certificate' green is indicative of daily work whereas a Pink certificate indicates further work required. An audit is carried out on HOL every March to determine HOL's compliance with their Technical Standards. The auditor checks a number of projects against the current applicable technical standards. If HOL need to deviate from a standard they need to complete a Deviation Form that identifies the deviation. These forms are held in the project folders and in a central folder. The central folder is then interrogated by the Policy and standards section to determine whether the standards need changing. The AMS is monitored through the AMC

Conclusions	
C10.1a	HOL have demonstrated that they have established plans and processes to control nonconformities and their associated consequences.

Clause 10.2: Preventive Action

Preventive actions, which may include predictive actions, are those taken to address the root causes of potential failures or incidents, as a proactive measure, before such incidents occur. The organisation should establish, implement and maintain processes for initiating preventive or predictive actions. Asset inspections will be carried out by the relevant operations and maintenance departments.

Maturity Score: 3

Discussion	
HOL determine preventative actions through Standards committees, or the Reliability council. The Standards committee are asset types and spread across a wide range of staff - an example was given about the change from Cedar to Red Pine poles. The reliability council looks at trends in outages.	
Conclusions	
C10.2	HOL demonstrated that they consider predictive actions to address the root causes of potential failures or incidents, as a proactive measure, before such incidents occur.

Clause 10.3: Continual Improvement

Opportunities for improvement should be identified, assessed and implemented across the organisation as appropriate, through a combination of monitoring and corrective actions for the assets, asset management, or asset management system. Continual improvement should be regarded as an ongoing iterative activity, with the ultimate aim of delivering the organisational objectives.

Maturity Score: 3

Discussion	
HOL participate in several working groups, councils and agencies. HOL participate in conferences. HOL are members of CEATI HOL identify areas for continuous improvement in each of the Asset Management Plans.	
Conclusions	
C10.3	HOL have demonstrated that they consider and actively pursue continuous improvement of their AMS and Asset Management activities.

4. Discussion

Figure 6 illustrates the maturity scoring for the gap analysis assessment carried out on Hydro Ottawa's Asset Management System. It can be seen that for a such a new system it has demonstrated conformance for twenty-one of the twenty-seven assessed sections of ISO55001. The scoring of each of the ISO55001 clauses, is in-line with the scoring methodology in Appendix II.

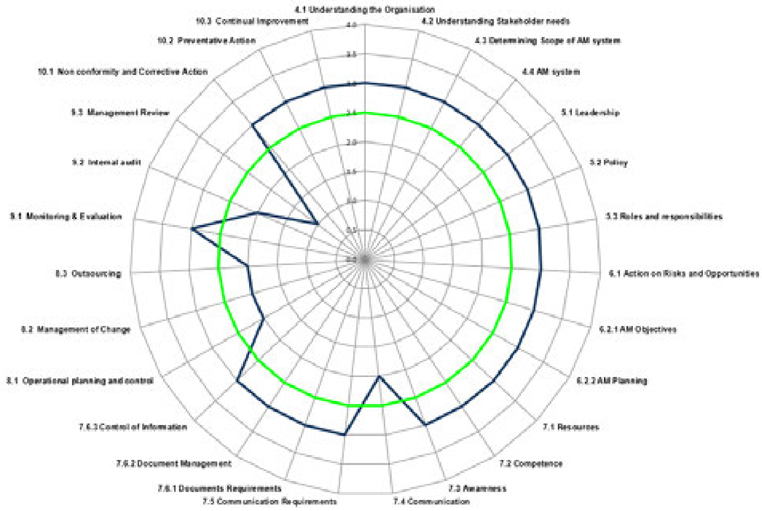


Figure 6- Maturity Assessment

Figure 7 illustrates the average gap across each of the seven ISO55001sections, which highlights the areas that have the largest gaps. It should be noted that the green line indicates what would be seen as conformance of the requirements of ISO55001.

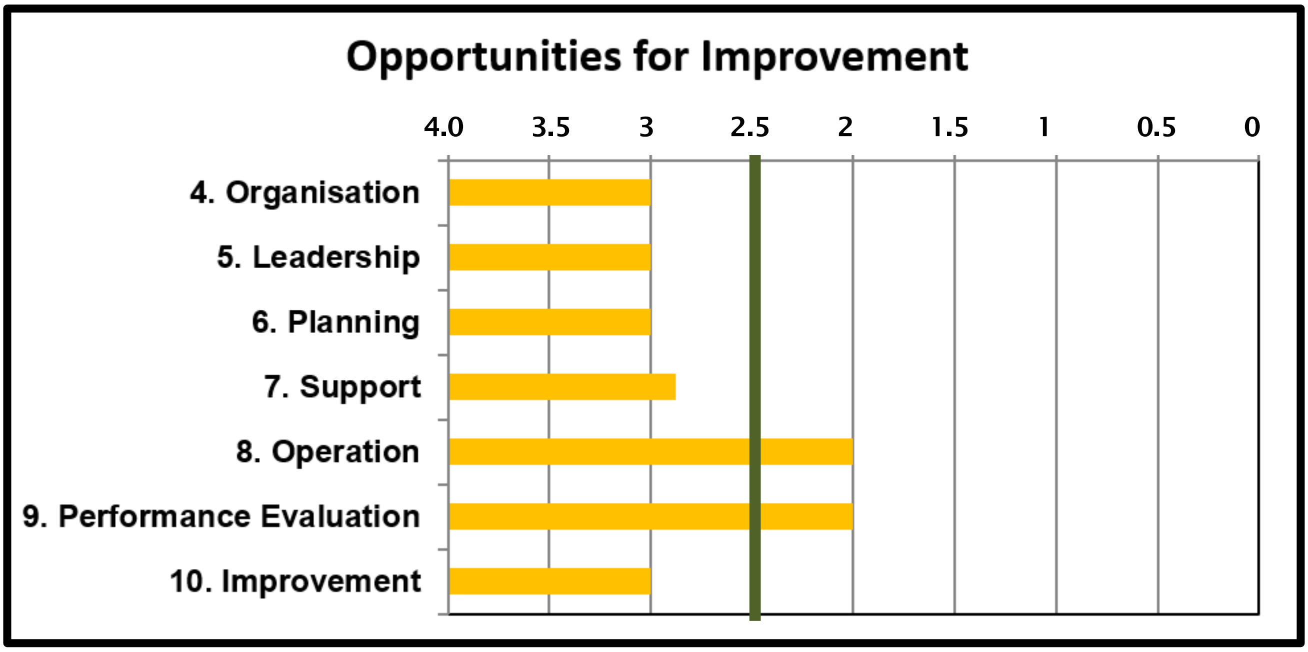


Figure 7 – Improvement Opportunities

It can be seen that section 8 (Operation) and section 9 (Performance Evaluation) have the largest gaps. The cause of the gap in section 8 is that all of the three clauses that make up section 8 have scored a maturity score of 2. Within Section 9, clause 9.2 (Internal Audit) scored a 2 and clause 9.3 (Management Review) scored a 1.

The low scoring of these clauses is commonly caused by the audited organisation not having the requisite processes in place; however, for Hydro Ottawa it is due to the immaturity of its Asset Management System.

As the most difficult and time-consuming activities are usually the creation and implementation of processes, it can be seen that Hydro Ottawa simply need to execute an Internal Audit on its Asset Management System and define and carry out its annual Management Review to close these identified gaps.

There are seventeen recommendations in this document, which EA Technology recommends that Hydro Ottawa carry out in order to comply with the requirements of ISO55001.

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5. Conclusions

Note the Conclusions are numbered in line with the relevant parts of ISO 55001.

C4.1	Hydro Ottawa have demonstrated that they fully understand the context of their organization by considering issues that can affect its business environment.
C4.2	HOL demonstrated that they engage with stakeholders that are relevant to its Asset Management System and their needs and requirements are considered.
C4.3	HOL document the scope of the AMS through its AMS and SAMP documents.
C4.4	HOL have demonstrated that they document the AMS through the AMS Manual document and the SAMP.
C5.1	HOL have demonstrated that top management at all levels of the organisation are involved in the planning, implementation and operation of the AMS.
C5.2	Currently HOL do not communicate the Asset Management Policy to their contractors.
C5.3	HOL document roles and responsibilities within the AMS Manual and SAMP documents.
C6.1	HOL have demonstrated that they consider external and internal issues that affect its ability to achieve its intended outcomes.
C6.2.1	HOL have demonstrated that Asset Management Objectives are created and linked to HOL's Organizational Objectives.
C6.2.2	HOL have clearly demonstrated that they create, document and maintain asset management plans that consider, risks and opportunities across the asset's life cycles, and provide details of objectives.
C7.1	HOL have demonstrated that they link resource requirements to their plans and their regulatory submission.
C7.2	HOL have demonstrated that they consider, evaluate and track staff competence.
C7.3	During the audit Hydro Ottawa demonstrated a good level of awareness.
C7.4	HOL have demonstrated that they effectively communicate with their relevant stakeholders; however, it was felt that the major known communication tasks need expanding within HOL's Asset Management documentation.
C7.5a	HOL have demonstrated that they have identified the required information to ensure that they can make effective Asset Management decisions.
C7.5b	HOL use a systematic approach to acquiring and storing information in designated repositories.

C7.6.1	HOL have demonstrated that they have sufficient documentation to satisfy the requirements of ISO55001.
C7.6.2	HOL demonstrated that they effectively create and manage their documented information.
C7.6.3	HOL have demonstrated that they effectively control their documented information.
C8.1	HOL have demonstrated that they have operational planning and control processes that support the effective delivery of the activities contained within the asset management plans; however, these processes are not linked to HOL's risk register.
C8.2a	Management of change is controlled within HOL for technical standards/documents and projects; however, it is unclear how management of change is carried out for changes to the AMS and how Management of Change requests are monitored and assessed.
C8.2b	There is currently no link between the management of change processes and HOL's Risk Register.
C8.3	HOL do consider the technical requirements and competence of their outsourced contractors; however, currently outsourced contractors do not receive a copy of HOL's Asset Management Policy or awareness training.
C9.1	HOL have demonstrated that they developed processes to provide for the systematic measurement, monitoring, analysis and evaluation of the organisation's assets, AMS and AM activity.
C9.2	HOL have all of the requisite processes and audit expertise to carry out internal auditing of the AMS.
C9.3a	Due to the maturity of HOL's AMS, HOL have not yet carried out a full management review.
C9.3b	The tracking of KPIs in the AMC quarterly meetings is good practice and will contribute to the Management Review process.
C10.1a	HOL have demonstrated that they have established plans and processes to control nonconformities and their associated consequences.
C10.2	HOL demonstrated that they consider predictive actions to address the root causes of potential failures or incidents, as a proactive measure, before such incidents occur.
C10.3	HOL have demonstrated that they consider and actively pursue continuous improvement of their AMS and Asset Management activities.

6. Recommendations

Note the Recommendations are numbered in line with the relevant parts of ISO 55001.

R4.3a	It is recommended that HOL should document in the SAMP document which Assets are explicitly excluded from the AMS.
R4.3b	It is recommended that HOL should make reference to HOL's current management systems (ISO9001, ISO14001) in the AMS Manual.
R5.2	It is recommended that the Asset Management Policy is included in the contractor on-boarding process and maybe the Contractor intranet.
R5.3	It is recommended that HOL ensure that the responsibilities documented in the SAMP and AMS Manual documents are reflected in personal job descriptions.
R7.3	It is recommended that Hydro Ottawa continue to make their staff as aware as possible regarding the AMS, as the awareness process conducted during the audit was minimal compared to a certification audit.
R7.4	It is recommended that HOL document major known communication tasks in the AMS or SAMP document.
R7.5	It is recommended that HOL create a KPI(s) that provides a level of confidence in their asset information.
R8.1	It is recommended that HOL should link their operational planning and control processes to HOL's risk register.
R8.2a	It is recommended that HOL should document how it will consider and manage changes to its AMS.
R8.2b	It is recommended that HOL should consider how Management of Change requests are monitored and recorded.
R8.2c	It is recommended that HOL should link any significant risks identified from a management of change process to HOL's risk register
R8.2d	It is recommended that HOL create a process that identifies the requisite parts of a management of change request (see diagram above).
R8.3a	It is recommended that HOL ensure that all outsourced contractors are aware of HOL's Asset Management Policy.
R8.3b	It is recommended that HOL provide all outsourced contractors with Asset Management Awareness training, possibly through the on-boarding process.
R9.2	It is recommended that HOL's internal audit team carry out an internal audit upon HOL's AMS.
R9.3a	It is recommended that HOL carry out a management review of the AMS separately to the AMC quarterly meetings.
R9.3b	It is recommended that HOL determine and document the minimum content of the management review process.

Appendix I Audit Schedule

ISO55000 Gap Analysis Schedule
Monday 25th February 2019 to Thursday 28th February 2019

	AM	PM
Day 1	Introduction / Context	Leadership
Day 2	Site Visit	Planning
Day 3	Planning / Support	Support
Day 4	Operation / Performance Evaluation	Improvement / Presentation

Audit Steering Committee
Jenna Matt Margaret Ben Steve

Name	Position
Lance Jefferies	Chief Electricity Distribution Officer
Guillaume Paradis	Director, Distribution Engineering & Asset Management
Joseph Muglia	Director, Distribution Operations
Jenna Gillis	Manager, Asset Planning
Ben Hazlett	Manager, Distribution Policies and Standards
Matthew McGrath	Supervisor, Maintenance and Reliability
Margaret Flores	Supervisor, Asset Planning
Doug Baldock	Manager, System Operations
Greg Van Dusen	Director, Regulatory Affairs
Kirk Thomson	Management Accountant
Brent Fletcher	Manager, Program Management and Business Performance
Tony Stinziano	Manager, Distribution Design
Kristy Biddle	Manager, Talent Performance and Development
Ed Donkersteeg	Supervisor, Standards
Shannon Fowler	Engineering Intern - Smart Grid
David Ayer	Manager, Supply Chain
Greg Bell	Manager, Distribution Operations
Brian Kuhn	Manager, Distribution Operations

Day 1: Monday 25th February 2019

Time	Title	Activity	Areas covered	Suggested Attendees by EA Technology	Suggested Attendees from HOL
09:00 to 09:30	Introduction	Presentation	Introduction Review of project Overview of Audit Aims and outputs	Project Team Senior Management	Lance Guillaume Joseph Audit Steering Committee
09:30 to 10:30	Context of the Organisation	Meeting	Understanding the organization and its context Understanding the needs and expectations of stakeholders	Senior Management Persons that deal with stakeholder engagement and use this information to determine the organisation's objectives	Lance Guillaume Joseph Audit Steering Committee
10:30 to 10:45	Comfort Break				
10:45 to 12:30	Context of the Organisation	Meeting	Scope of the asset management system Strategic Asset Management Plan	Asset Manager(s)	Guillaume Joseph Jenna
12:30 to 13:30	Lunch				
13:30 to 15:30	Leadership	Meeting	Leadership and commitment Policy Organisational Roles, Responsibilities and Authorities	Senior Management Asset Manager(s)	Lance Guillaume Joseph Jenna
15:30 to 15:45	Comfort Break				
15:45 to 16:30	Collate Results/Contingency				

Day 2: Tuesday 26th February 2019

Time	Title	Activity	Areas covered	Suggested Attendees by EA Technology	Suggested Attendees from HOL
08:45 to 09:00	Review	Meeting	Review of day 1	Key project team members	Audit Steering Committee
09:00 to 12:00	Site Visit	Assessment of a field operation	Data Collection Awareness		Organized by Steve Hawthorne
12:00 to 13:00	Lunch				
13:30 to 15:30	Planning	Meeting	Asset Management Objectives Risks and opportunities Planning to achieve Asset Management Objectives	Planning Engineers Asset Manager(s)	Jenna Margaret Matt Planners + Maint Eng
15:30 to 15:45	Comfort Break				
15:45 to 16:30	Collate Results/Contingency				

Day 3: Wednesday 27th February 2019

Time	Title	Activity	Areas covered	Suggested Attendees by EA Technology	Suggested Attendees from HOL
08:45 to 09:00	Review	Meeting	Review of days 1 & 2	Key project team members	Audit Steering Committee
09:00 to 10:30	Performance Evaluation	Meeting	Monitoring, measurement, analysis and evaluation Internal audit Management review	Asset Manager(s) Operations Auditor	Jenna Doug Greg Van Dusen Kirk
10:30 to 10:45	Comfort Break				
10:45 to 12:30	Support	Meeting	Resources Competence Awareness	Human Resources Asset Manager(s)	Brent HR - Kristy Biddle Tony Jenna
12:30 to 13:30	Lunch				
13:30 to 15:30	Support	Meeting	Communication Information Requirements Documented Information	Asset Manager(s) Standards and Policy Engineers IT	Jenna Ben Ed Shannon
15:30 to 15:45	Comfort Break				
15:45 to 16:30	Collate Results				

Day 4: Thursday 28th February 2019

Time	Title	Activity	Areas covered	Suggested Attendees by EA Technology	Suggested Attendees from HOL
08:45 to 09:00	Review	Meeting	Review of days 1 & 2	Key project team members	Audit Steering Committee
09:00 to 10:30	Operation	Meeting	Operational planning and control Management of Change Outsourcing	Asset Manager(s) Operations Managers Human Resources	Doug Brent HR - Kristy Biddle David Ayer Jenna
10:30 to 10:45	Comfort Break				
10:45 to 12:30	Planning	Meeting	Asset Management Objectives Risks and opportunities Planning to achieve Asset Management Objectives	Planning Engineers Asset Manager(s)	Jenna Margaret Matt Planners + Maint Eng
12:30 to 13:30	Lunch				
13:30 to 15:3	Improvement	Meeting	Nonconformity and corrective action Preventive action Continual improvement	Asset Manager(s) Operations	Jenna Greg Bell Brian
15:30 to 15:45	Comfort Break				
15:45 to 16:30	Results	Presentation	Initial Findings	Project Team Senior Management	Lance Guillaume Joseph Audit Steering Committee

Appendix II ISO 55001 Maturity Assessment

EA Technology will apply the IAM's scoring criteria to all of the ISO 55001 sections assessed during a gap analysis and Stage 1 and Stage 2 certification audits. The scoring criteria represents five "levels" of asset management maturity (Level 0 to Level 4). The maturity levels as defined by the IAM are summarized as follows:

- Maturity Level 0 (Learning)
    - The elements required are not in place. The organisation is in the process of developing an understanding of ISO 55000.
- Maturity Level 1 (Applying)
    - The organisation has a basic understanding of the requirements It is in the process of deciding how the elements will be applied and has started to apply them.
- Maturity Level 2 (Embedding)
    - The organisation has a good understanding of ISO 55000. It has decided how the elements of ISO 55000 will be applied and work is progressing on implementation.
- Maturity Level 3 (Optimising and Integrating)
    - All elements of ISO 55000 are in place and are being applied and are integrated. Only minor inconsistencies may exist.
- Maturity Level 4 (Beyond ISO 55000)
    - Using processes and approaches that go beyond the requirements of ISO 55000. Pushing the boundaries of asset management development to implement new concepts and ideas.

Global Footprint

We provide products, services and support for customers in 90 countries, through our offices in Australia, China, Europe, Singapore, UAE and USA, together with more than 40 distribution partners.

Our Expertise

We provide world-leading asset management solutions for power plant and networks.

Our customers include electricity generation, transmission and distribution companies, together with major power plant operators in the private and public sectors.

- Our products, services, management systems and knowledge enable customers to:
- Prevent outages
- Assess the condition of assets
- Understand why assets fail
- Optimize network operations
- Make smarter investment decisions
- Build smarter grids
- Achieve the latest standards
- Develop their power skills

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PEOPLE. DRIVE. RESULTS.

Hydro Ottawa Local Achievable Potential Study

Final Report
Hydro Ottawa Limited

October 30, 2019

REV.	DESCRIPTION	DATE	PRPD	CHKD	APPRD
02	Final Report	30-Oct-2019	AS	TA	TA
01	Draft Report	21-Oct-2019	AS	TA	TA
00	Draft Report	01-Oct-2019	AS	TA	TA
			SNC-Lavalin		

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Oct 30, 2019

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List of acronyms

APS	Achievable Potential Study
BES	Battery Energy Storage
CDM	Conservation and Demand Management
DB	Dun & Bradstreet Database
DER	Distributed Energy Resources
EUF	End-Use Forecasting
EUI	Energy Use Intensity
HOL	Hydro Ottawa Ltd
HR	High Rise
IESO	Independent Electricity System Operator
kWh	Kilo Watt hour
LAP	Local Achievable Potential
LR	Low Rise
MAL	IESO's Measure and Assumption lists
MPAC	Municipal Property Assessment Corporation
MURB	Multi-Unit Residential Building
NRCAN	Natural Resources Canada
OEB	Ontario Energy Board
SCIEU	Survey of Commercial and Institutional Energy Use
SHEU	Survey of Household Energy Use
sq. ft.	Square feet

1. Executive Summary

This is the final report for the study entitled "Hydro Ottawa Local Achievable Potential (LAP) Study," which commenced on Dec. 7, 2018. This study, undertaken at the request of Hydro Ottawa Ltd, Ontario, is conducted by SNC-Lavalin Inc. Toronto, Canada, as the Consultant.

The objective of this study is to evaluate non-wires options potential to offset load growth in the Kanata North area to defer or eliminate the need for new infrastructure. The non-wire options considered in this study include Conservation and Demand Side Management (CDM) Programs, distributed generation, and energy storage.

The study included the following tasks

› Determining the local load characterization for Kanata North area served by Kanata and Marchwood MTS
› Identifying the technically feasible measures for addressing the local area needs
› Evaluating market analysis of feasible measures and developing adoption and cost curves
› Developing an Excel tool to Assess the impact of incentives on the achievable potential and determining the combinations of CDM and DERs measures that provide maximum savings for a given avoided cost and incentive levels

a) Local Load Characterization

The Kanata North area serves prominently residential and commercial sectors. Table 1-1 and Table 1-2 show the total estimated electrical consumptions for Kanata and Marchwood, respectively.

Table 1-1 Estimated consumptions (kWh) for Kanata MTS

Kanata	624F1	624F2	624F3	624F5	624F6	Total
Residential	21,957,355	6,777,998	3,546,205	705,710	12,049,252	45,036,520
Commercial	35,437,231	52,884,403	7,694,143	75,889,460	28,808,356	200,713,593
Industrial	0	3,339,425	0	0	0	3,339,425
Total	57,394,587	63,001,826	11,240,347	76,595,170	40,857,608	249,089,538

Table 1-2 Estimated consumptions for Marchwood MTS

Marchwood	MWDF1	MWDF2	MWDF3	MWDF4	Total
Residential	16,556,027	13,659,061	19,679,985	13,625,418	63,520,491
Commercial	31,584,597	20,260,960	10,979,980	27,307,879	90,133,415
Industrial	0	0	0	0	0
Total	48,140,624	33,920,021	30,659,965	40,933,296	153,653,906

Figure 1-1 and Figure 1-2 show the end-use segmentation for the residential and commercial sectors of Kanata North area.

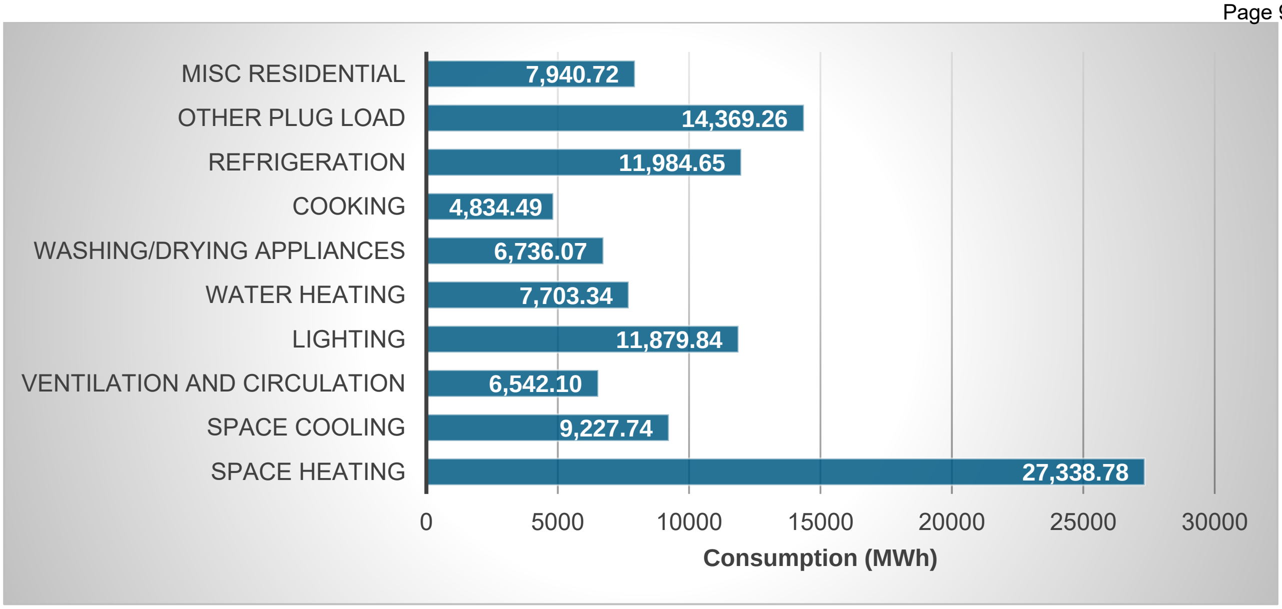

Figure 1-1 End-use Segmentation for Residential Sector, Kanata North Area

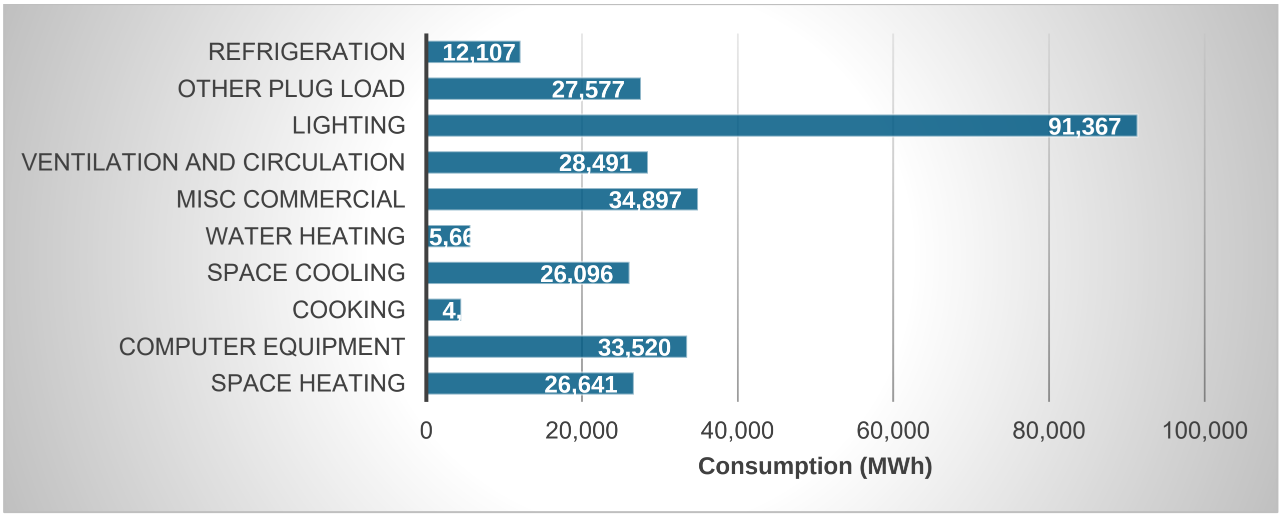

Figure 1-2 End-use Segmentation for Commercial Sector, Kanata North Area

The aggregated commercial and residential forecast of the Kanata North area is illustrated in Figure 1-3. A total increase in electricity consumption of 4% from 402,743 MWh in 2018 to 418,971 MWh is forecasted by 2040. The commercial section is expected to provide the largest increase in electricity use, rising from 290,847 MWh in 2018 to 319,038 MWh (9.7 % increase). The residential sector electricity consumption is expected to show a decrease from 108,557 MWh in 2018 to 99,309 MWh in 2040 (8.51 % decrease).

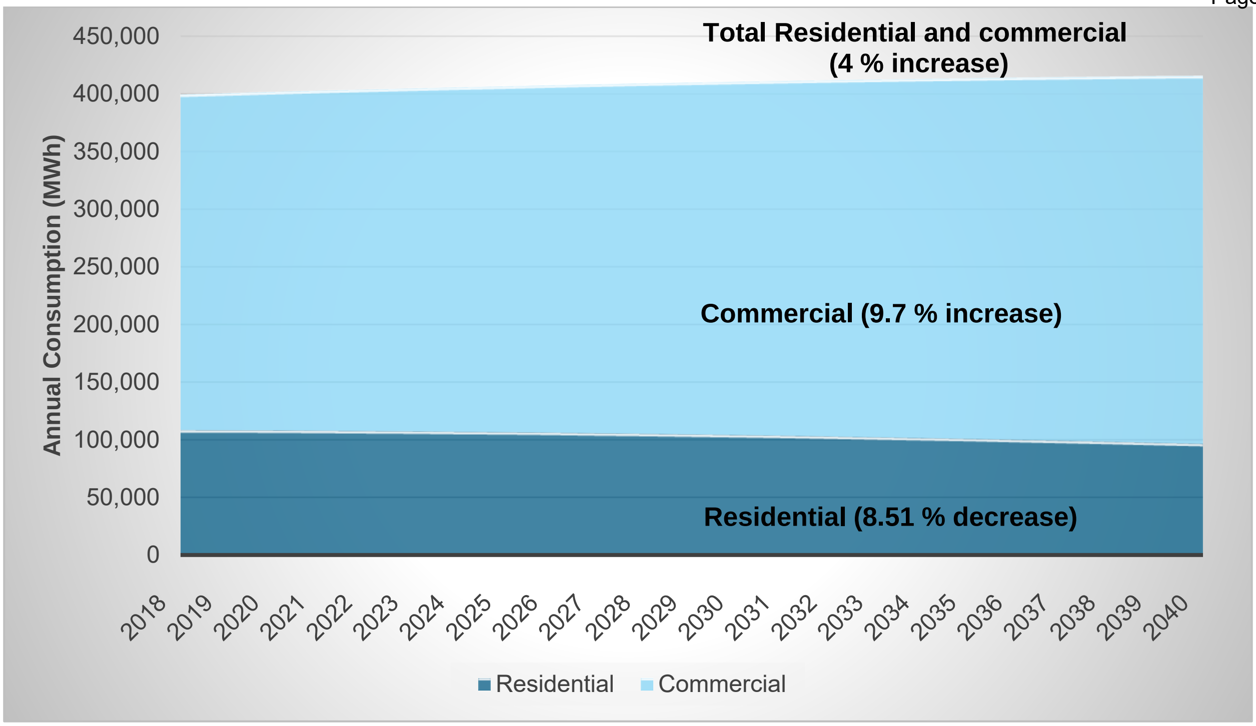

Figure 1-3 Kanata-Marchwood forecast (2018-2040) by sector

b) Technical Potential of Non-Wire Alternatives for Peak Reduction

The conservation and demand management (CDM) measures were developed with input from IESO and other CDM measures from North American jurisdictions, that could be rolled into the market quickly, are added to the CDM list of measures. The annual energy consumption saving, as well as the peak demand savings, were estimated for each measure then shortlisted based on their effectiveness addressing the summer peak demand at the Kanata North area.

The maximum potential for peak demand reduction for each measure was evaluated based on the local area load segmentation, the number of equipment per subsector, the consumption of the total equipment as a percentage of the end-use consumption, and the fraction of equipment that is energy efficient.

Finally, the aggregated technical potential for peak reduction for all the CDM measures was evaluated. The total residential summer peak reduction in 2023 was estimated to be 4.713 MW, while the total commercial summer peak reduction in 2023 was estimated to be 13.691 MW. Figure 1-4 shows the technical potential Summer peak reduction for each subsector; the largest technical potential was estimated for the single-family subsector, which accounts for 62.725 % of the total peak reduction in 2023. Figure 1-5 shows the technical potential Summer peak reduction for each subsector; the largest technical potential was estimated for the office subsector, which accounts for 61.19 % of the total peak reduction in 2023.

In addition to the CDM measures, the impact of the Distributed Energy Resources (DER) on Kanata-Marchwood summer peak was considered, the analysis is categorized into load shifting using battery energy storage system and renewable-based distributed generation. The technical potential for peak reduction of the battery energy storage is calculated on the utility-scale and on the large customers-scale. Moreover, the technical potential of photovoltaic roof-top distributed generation mounted on the residential and commercial buildings is calculated. The results, presented in Figure 1-6, show that the maximum technical potential of the battery storage is 5.87 MW, and the technical potential of the photovoltaic PV Distributed generators DG is 7.03 MW, in addition to the technical potential of the CDM measures (i.e., 18.4 MW).

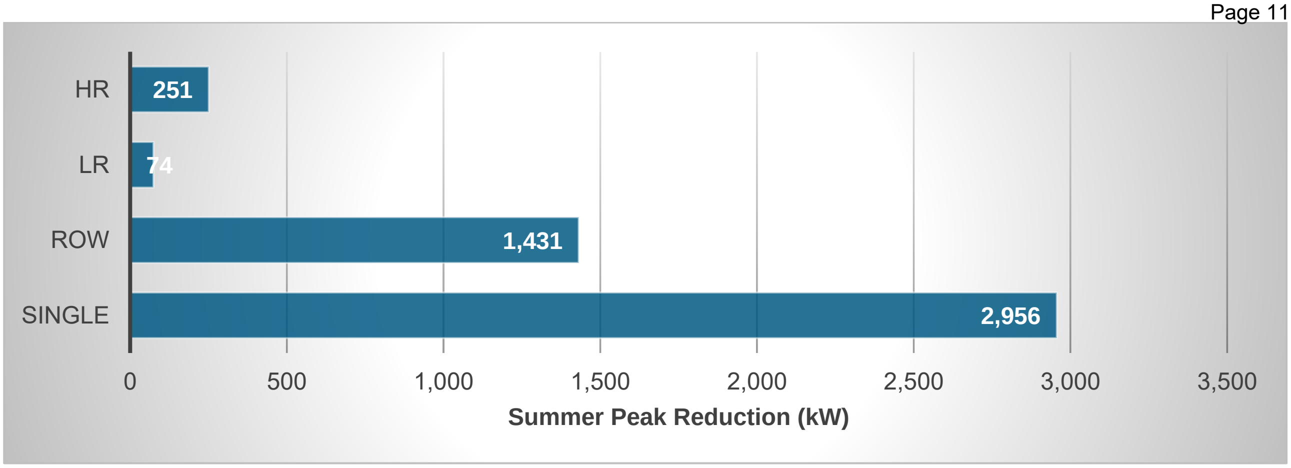

Figure 1-4 Technical Potential Peak Reduction by Residential Subsector in 2023

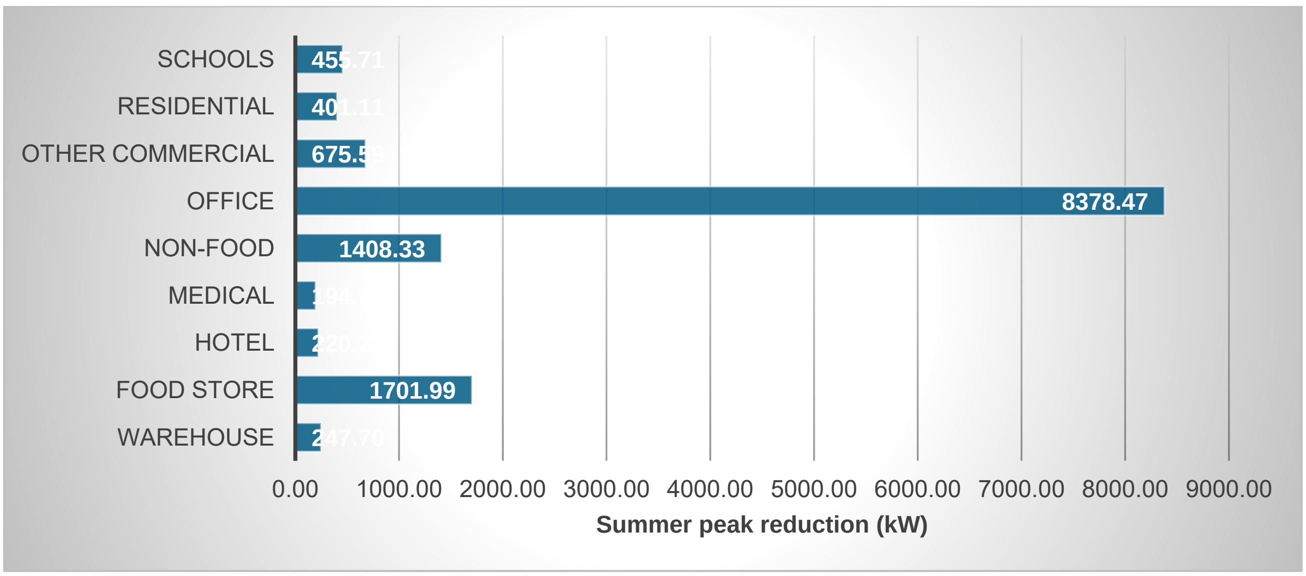

Figure 1-5 Technical Potential Peak Reduction by Commercial Subsectors in 2023

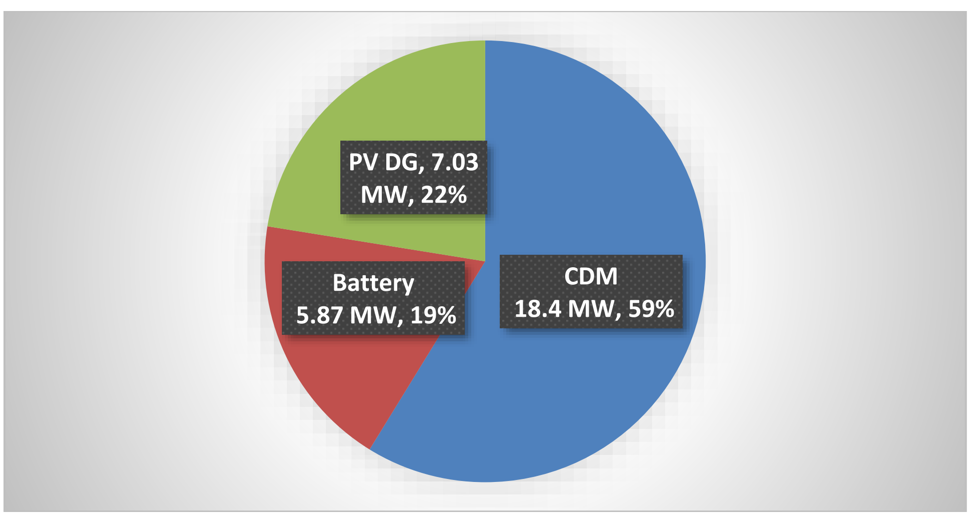

Figure 1-6 Percentage contribution of each of the technical potential on peak reduction

c) Market Analysis

Historical participation in CDM was analyzed and used to develop the adoption curve for each measure. Using the developed adoption curves the aggregated achievable potential for peak reduction for all the CDM measures was estimated. The total achievable potential for residential sector in 2023 was estimated to be 481.31 kW. The total achievable potential for commercial sector in 2023 was estimated to be 5972.96 kW. The total achievable potential for the peak reduction of the CDM measures is estimated at 6454.915 kW. Figures 1-7 and 1-8 show the estimated values for the achievable potential vs. technical potential of the CDM measures for the residential and commercial sectors respectively.

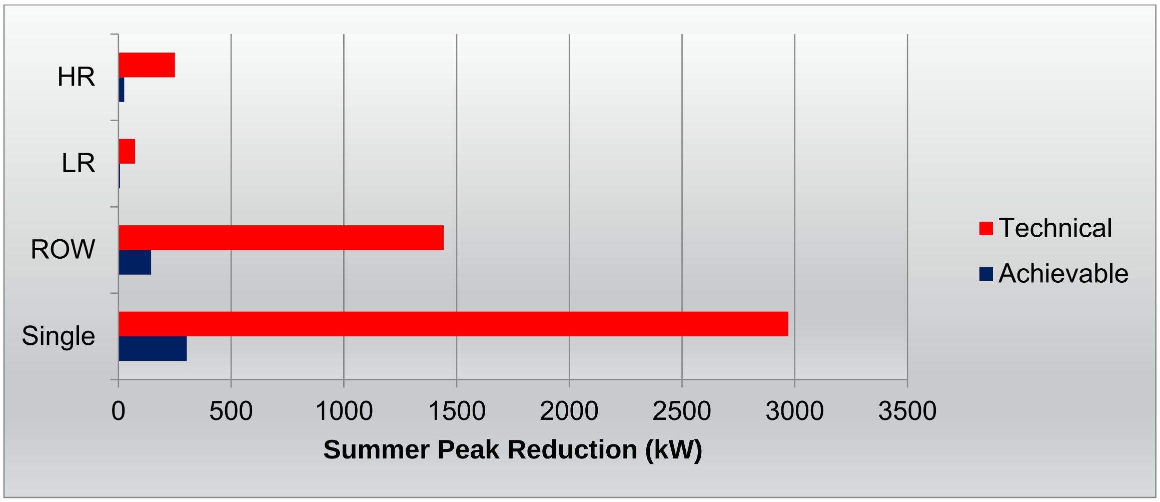

Figure 1-7 Technical Vs. Achievable Potential, Residential Subsector

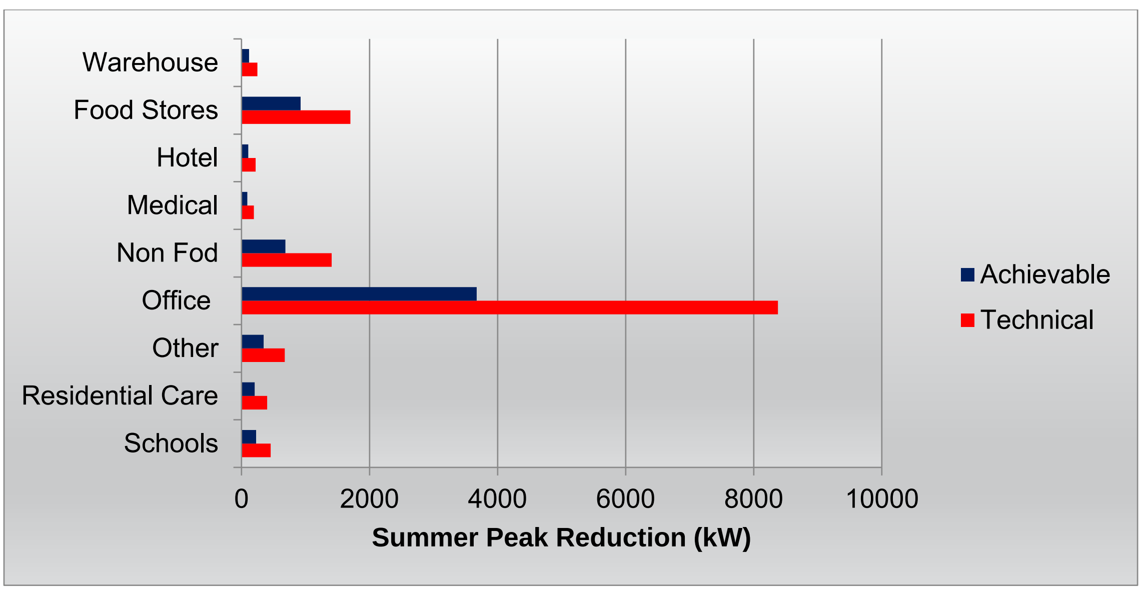

Figure 1-8 Technical Vs. Achievable Potential, Commercial Subsector

d) Assessment of the Impact of Incentive on Achievable Potential

Economic analysis was conducted to determine the required level of incentive for the DER project investment (Battery Energy Storage (BES) and PV DGs) to be profitable. The economic analysis shows that the required incentives for the customer-scale battery project are in a range of $ 5,570-6,930 per kW peak reduction. This incentive level is significantly high relative to the corresponding savings and is not economically viable. As a result, the customer-scale BES was excluded from the achievable potential analysis, as discussed with HOL and IESO. For a profitable PV DG project investment, the incentives per installed kW were estimated to be 1140.76 and 2,200 $/kW for the residential and commercial PV roof-top, respectively. The achievable potential for peak reduction for the PV DGs (DER measures) was estimated to be 0.36 MW based on the information provided by HOL.

An Excel tool was developed to evaluate the impact of incentives on the achievable potential and to determine the combination of CDM and DERs measures that provide maximum peak reduction for a given avoided costs and incentive levels. Input to the tool includes the incentive level per each measure, peak demand reduction per unit, and the achievable potential of each measure.

The tool was used to evaluate the impact of incentives variations on the achievable potential. The price elasticity values were used to establish the adjustment factor to be applied to the base case modelled savings estimates, where the price elasticity is a basic measure of demand or supply sensitivity to changes in price. An elasticity value of 1.0 would indicate a product that is perfectly elastic, while a value of 0 would indicate that the product is inelastic (changes in prices have no effect on demand or supply)

The incentive cost curve is constructed based on the peak demand reduction cost of all the CDM and DER measures. The curve, presented in Figure 1-9, shows each measure as a step in the curve, with the horizontal length of each step indicating the achievable potential of the measure, and its height above the horizontal axis indicates the incentive costs per kW ($/kW) of reduction.

The achievable potential and the corresponding budget are estimated for various incentive levels including current incentive levels, 5 % increase, 10 % increase, 20 % increase, and 40 % increase, as given in Figure 1-9, where the horizontal axis represents the total estimated achievable potential in kW up to the year 2023, while, the vertical axis represents the total budget provided in the form of incentives for participants up to year 2023. The curve, presented in Figure 1-9, shows each measure as a step in the curve, with the horizontal length of each step indicating the achievable potential of the measure, and its height above the horizontal axis indicates the corresponding incentive costs ($).

The avoided costs (avoided energy costs and avoided capacity costs) are estimated for different scenarios to determine the savings the utility would have if it deferred building the plant.

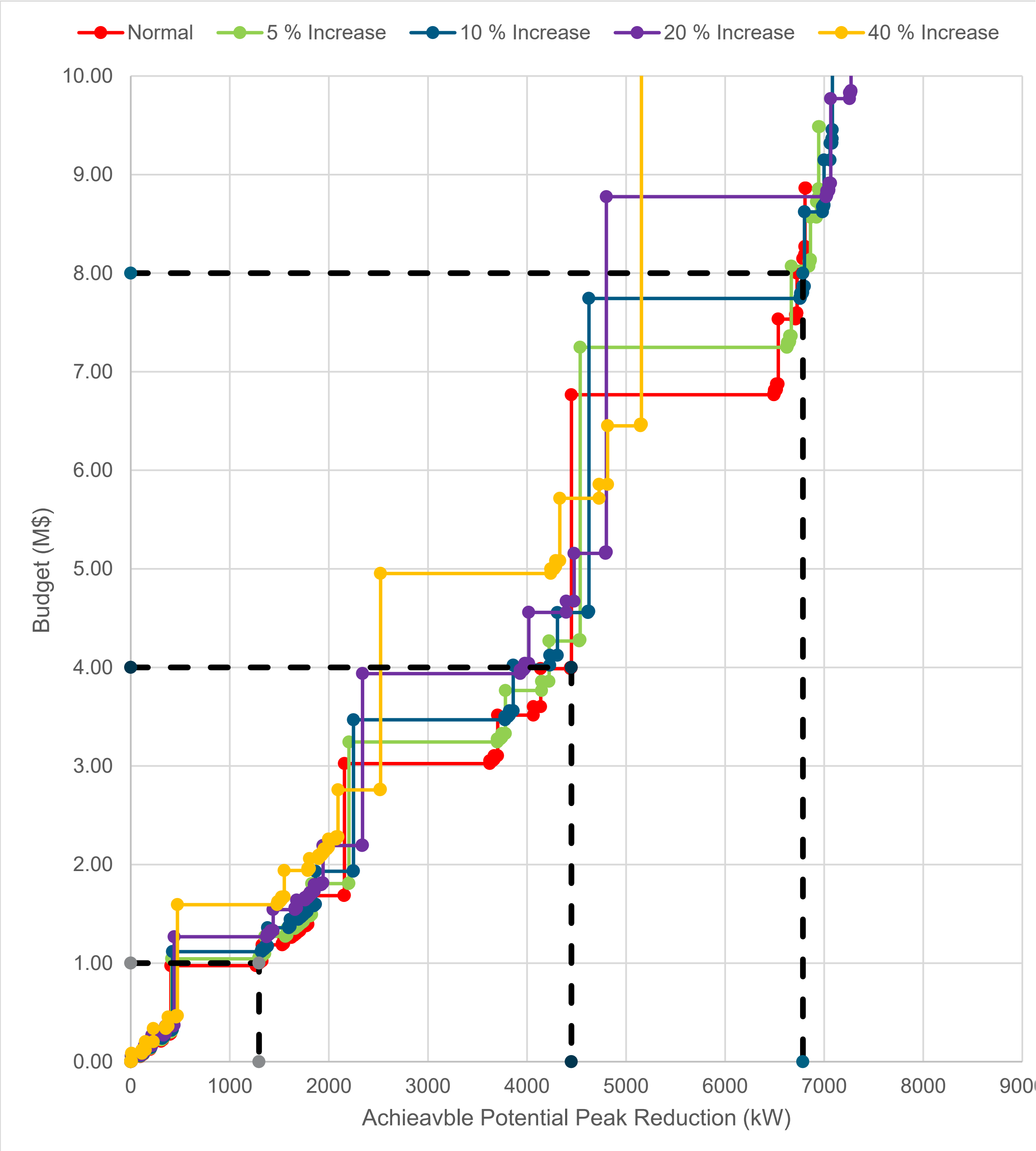

Figure 1-9 Achievable potential up to the year 2023 versus budget for various incentive levels

1.1. Conclusions and Recommendations

The analysis reveals the following:

- For the residential sector, the achievable potential at the current incentive levels provided by IESO is estimated at 481.95 kW. Increasing the incentive levels by 40 % is estimated to increase the peak reduction between 529.86 – 539.88 kW.
- For the commercial sector, the achievable potential at the current incentive levels is estimated at 5972.96 kW. Increasing the incentive levels by 40 % is estimated to increase the peak reduction between 6990.75 – 7071.98 kW.
- For DERs, the achievable potential at the incentive levels recommended in this study is estimated at 360.3 kW. Increasing the incentive levels by 40 % is estimated to increase the peak reduction between 396.33– 403.82 kW.
- For commercial-scale battery storage, the required incentive levels are estimated between $ 4432-5791 per kW of peak reduction.
- For utility-scale energy storage, the budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- For residential and commercial PV rooftop, the incentives per installed kW are 1140.76 $/kW and 2200 $/kW. This incentive level would provide the minimum attractive rate of return of 7%.
- The maximum achievable peak demand reduction is estimated at 6,814.95 kW (6.81 MW) for an incremental budget of C$ 8,862,912 (excluding program administrative cost). It is worth noting that higher achievable potential is reachable with the consideration of utility-scale energy storage. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- The desired peak demand reduction, which represents the gap between the existing summer peak and 2023 forecasted peak is 18.5 MW and 26.5 MW for median and extreme weather conditions forecast, which cannot be achievable from the CDM program.
- The certainty of some load growth, such as (Broccolini Business Park) and (550 Innovation (Ciena)) should be checked annually due to their high required demand, and their exclusion would reduce the gap significantly.
- In addition to serving load growth in the Kanata area, the newly planned transformer station will improve system reliability and availability by providing backup service for other stations in the area such as Terry Fox TMS station.
- The higher achievable potential is reachable with the consideration of utility-scale energy storage. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- The avoided costs for budget scenario 3 (C$ 8,000,000) is estimated at C$ 5,075,557.41, in addition to C$ 1,144,000 (transmission capacity cost) for each deferral year and C$ 160,000 (distribution capacity cost) for each deferral year.

1.2. Lessons Learned

The lessons learned from this study are summarized as follows:

- Data collection took a substantial amount of time and effort. In the future, it is recommended to allocate more time in the schedule for the same as part of Milestone 1. A dedicated point of contact for data collection in the Hydro Ottawa aided greatly in the data collection effort.
- The addition of a few more stations would be beneficial (as data collection time and effort would not increase substantially). As such, more detailed study could be performed in a cost-effective manner.
- It would be preferable to cast a wider net and spend more time on understanding the different CDM measures that could pave a path to understand new technologies. Additional time in the schedule of future studies should be allocated for this activity.
- A future APS study, may entail analysis of sensitivity scenarios that would evaluate the impact of EV and electrification, multiple penetration levels of EV & electrifications could be considered in the analysis (business as usual, moderate, and aggressive (green) scenario)
- Development of a load research focus group within the HOL would help collect and analyze data related to end use behaviour within each sector and sub-sector served by HOL. This is particularly important as the energy use pattern may change significantly over the next decade. The group can collect data via surveys, interviews, market research, and direct load measurements for selected representative samples.

2. Introduction

The achievable potential study is required through a direction from Ontario's Minister of Energy. The IESO is required to coordinate, support, and fund the delivery of conservation and demand management (CDM) programs by HOL to determine the possible potential solutions to lower the summer peak demand in the Kanata-Marchwood area.

The achievable potential of peak load reduction would allow for more efficient use of existing facilities and infrastructure and differ or eliminate the need for a new transformer station. Based on the HOL plan, the new station (new Kanata North) is planned to be in service in 2028. Therefore, the presented study focuses on the short-term technical potential scenarios that may differ or eliminate the need for the new station.

The required local achievable potential study (L-APS) focuses on the non-wires options for load growth reduction at the Kanata North area. The Kanata North area includes a combination of the residential and commercial load with a large business park area supplied from Kanata MTS and Marchwood MTS. The methodology of the L-APS develops unique energy use profiles to reflect the composition of the Kanata North area load. The objective of this study is conducted through the following milestones:

a) Milestone 1: the aim of this stage is to determine the local load characterization for Kanata and Marchwood
b) Milestone 2: the main target of this milestone is to identify the technically feasible measures for addressing local area needs
c) Milestone 3: this milestone provides a market analysis of feasible measure through the development of adoption and cost curves
d) Milestone 4: this milestone is covering the development of updateable Excel model to assess CDM and DER options for addressing local needs

This remainder of this report is organized as follows: Section 3 describes the determination of the local load characterization for the Kanata North area served by Kanata and Marchwood MTS. Based on the load characterization, the technically feasible measures are developed in Section 4. The market analysis and achievable potential of the identified technically feasible measures are determined in Section 5. Finally, a comprehensive evaluation is conducted in Section 6 to assess the impact of incentives on the achievable potential and to determine the combinations of CDM and DERs measures providing maximum savings for a given avoided costs and incentive levels.

3. Local Load Characterization

The local load characterization for the Kanata North area served by Kanata and Marchwood MTS is presented in this section.

The sector and subsector energy load profiles for the Kanata North area, which serves prominently residential and commercial/ sectors, were evaluated. For each sector, the energy share distributions were estimated, and then each sector was segmented by subsectors (i.e., building type). Also, the end-use profiles for each sector were calculated. The end-use profiles from the IESO's recent achievable potential studies, as well as NRCAN residential and commercial end-use surveys, were used to develop the end-use profiles.

The total actual annual consumptions for Kanata and Marchwood MTS was compared to the total consumptions determined from the bottom-up analysis to calculate the calibration factor. After performing the calibration, the annual consumption for each feeder was obtained by calibrating the feeder's consumption obtained from the analysis.

3.1. Methodology

The segmentation of Kanata North area customers by sector, by subsector, and by end-use were carried out following the method presented in [1], [2]. Then, the calibration of the obtained profile to changes in sales and customer forecasts is performed.

The energy share distributions for the residential and commercial/institutional sectors are determined, and then each sector is segmented by subsectors (i.e., building type). This classification is aligned with the IESO's End-Use Forecasting (EUF) model for planning purposes.

End-use profiles are developed for each sector, End-use profiles from the IESO's recent achievable potential studies [2] as well as NRCAN residential and commercial end-use surveys are used to develop the end-use profiles for this study.

The total reported (actual) annual consumptions for Kanata and Marchwood MTS are compared with the total consumptions determined from the bottom-up analysis to determine the gap and to calculate the calibration factor. After performing the calibration, the annual consumption for each feeder is obtained by calibrating the feeder's consumption obtained from the analysis.

HOL declared that no fuel switching or change in load profile is anticipated or forecasted. The findings of the Hemson study [3], the official community plan for Kanata North [4], and NRCAN surveys were used to develop the load forecast over the study period.

For Distributed Energy Resources, HOL and IESO provided the complete list of existing DERs, the total contract capacity of the DERs at Kanata-Marchwood area, and the forecasted effective capacities of the DERs and the CDM.

3.2. Load Segmentation for Base Year and Reference Case Forecast

3.2.1. Kanata MTS Load Segmentation for Base Year (2018) by Sector/ Subsector

The methodology presented in section 3.1 is applied to Kanata premises that consist of five feeders named 624F1, 624F2, 624F3, 624F5, 624F6. This section shows the analysis performed for the five feeders shown in Figure 3-1. These feeders' service areas are covering residential and commercial loads, as well as one large industrial load located at feeder 624F2.

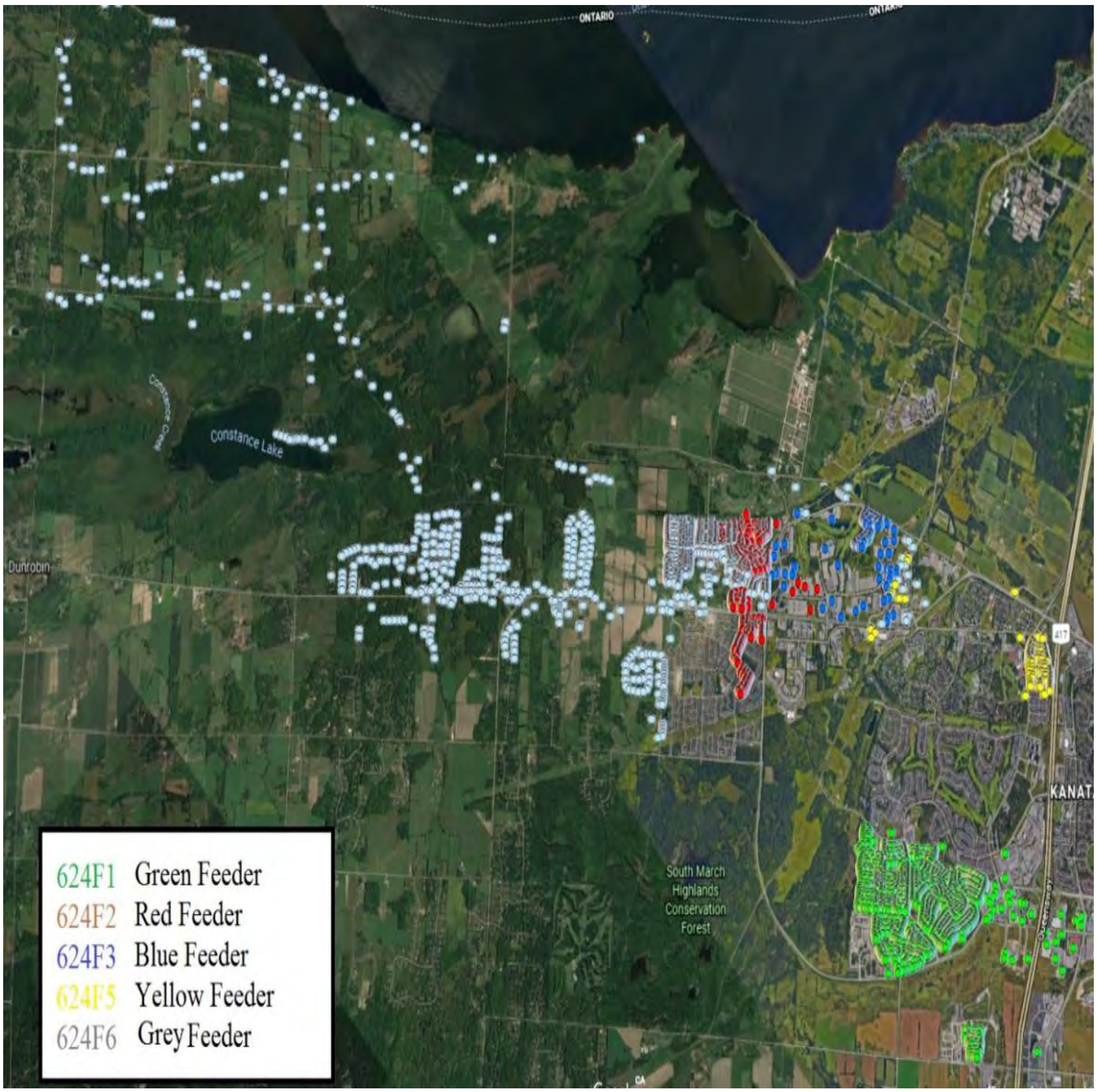

Figure 3-1 Kanata MTS service area

3.2.1.1. Kanata MTS Residential Load Segmentation

The residential sector buildings are subdivided to four subsectors based on the definition presented in Table A-1 in Appendix A, the number of residential buildings in each subsector is counted using Google Earth [5] files provided by HOL and adjusted using the total residential building number provided by HOL; Table 3-1 summarizes the number of buildings in each subsector for each of the five feeders.

Table 3-1 Residential Subsectors Premises, Kanata MTS

Residential building type	Single-family	ROW	Low rise	High rise	Total
Number of units / Subsector for feeder 624F1	1596	924	192	0	2712
Number of units / Subsector for feeder 624F2	458	387	0	0	845
Number of units / Subsector for feeder 624F3	111	169	94	194	568
Number of units / Subsector for feeder 624F5	22	81	0	0	103
Number of units / Subsector for feeder 624F6	652	945	0	0	1597
Number of units / Subsector for Kanata MTS	2839	2506	286	194	5825

The NRCAN residential building (SHEU) database [6] is used to determine the energy intensity per premise; Table 3-2 summarises the energy intensities for all residential subsectors in Ontario. The methodology discussed in section 3.1 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each subsector are obtained. Then, the average estimated kWh per residential customer is calculated using the total residential consumption and the total number of residential buildings; the average estimated kWh per customer for Kanata MTS is 7,732 kWh which is close to the actual kWh per residential customer reported in the OEB yearbook [7] (i.e., 7,537 kWh). Thus, no calibration is needed. A summary of the total residential consumption for the Kanata MTS service area is presented in Table 3-3.

Table 3-2 Residential Subsectors Energy Intensity [6]

Residential building type	Single-family	ROW	Low rise	High rise
Annual Total Energy intensity (eMWh/household)	38.75	26.55	8.18	9.58
Annual Electricity intensity (MWH/household)	9.65	6.09	4.81	5.12

Table 3-3 Total Residential Subsectors Energy Consumptions for Kanata MTS

Residential building type	Single Family	ROW	Low Rise	High Rise	Total
Annual Electricity consumptions (MWh)	27,404	15,264	1,376	993	45,037
Total Annual Energy consumptions (eMWh)	109,999	66,546	2,338	1,858	180,741

3.2.1.2. Kanata MTS Commercial Load Segmentation

The commercial sector buildings are subdivided to subsectors based on the definition presented in Table A-2 in Appendix A. Dun & Bradstreet database [8], MPAC database [9], and Google Earth files are used to determine the number, area, and activity of all commercial buildings located at each of the five feeders of Kanata MTS. The energy intensities for all commercial subsectors are obtained using the NRCAN commercial building SCIEU database [10]. The methodology discussed in section 3.1 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each commercial subsector are obtained; a summary of the total commercial consumption for Kanata MTS service area is presented in Table 3-4.

Table 3-4 Commercial Subsectors Energy Consumption, Kanata MTS

Commercial Subsector	Annual Electricity Consumption (MWh)
Office buildings (non-medical)	90,018
Medical office buildings	3,135
Elementary and/or secondary schools	1,416
Assisted daily/residential care facilities	1,197
Warehouses Wholesale	5,106
Hotels, motels or lodges	3,003
Hospitals	0
Food and beverage stores	13,653
Non-food retail stores	11,414
Other activity or function	5,282

3.2.2. Marchwood MTS Load Segmentation for Base Year (2018) by Sector/ Subsector

The methodology discussed in section 3.1 is applied to Marchwood premises that consist of four feeders named MWDF1, MWDF2, MWDF3, and MWDF4. This section presents the analysis performed for the four feeders shown in Figure 3-2. These feeders' service areas are covering different residential and commercial loads.

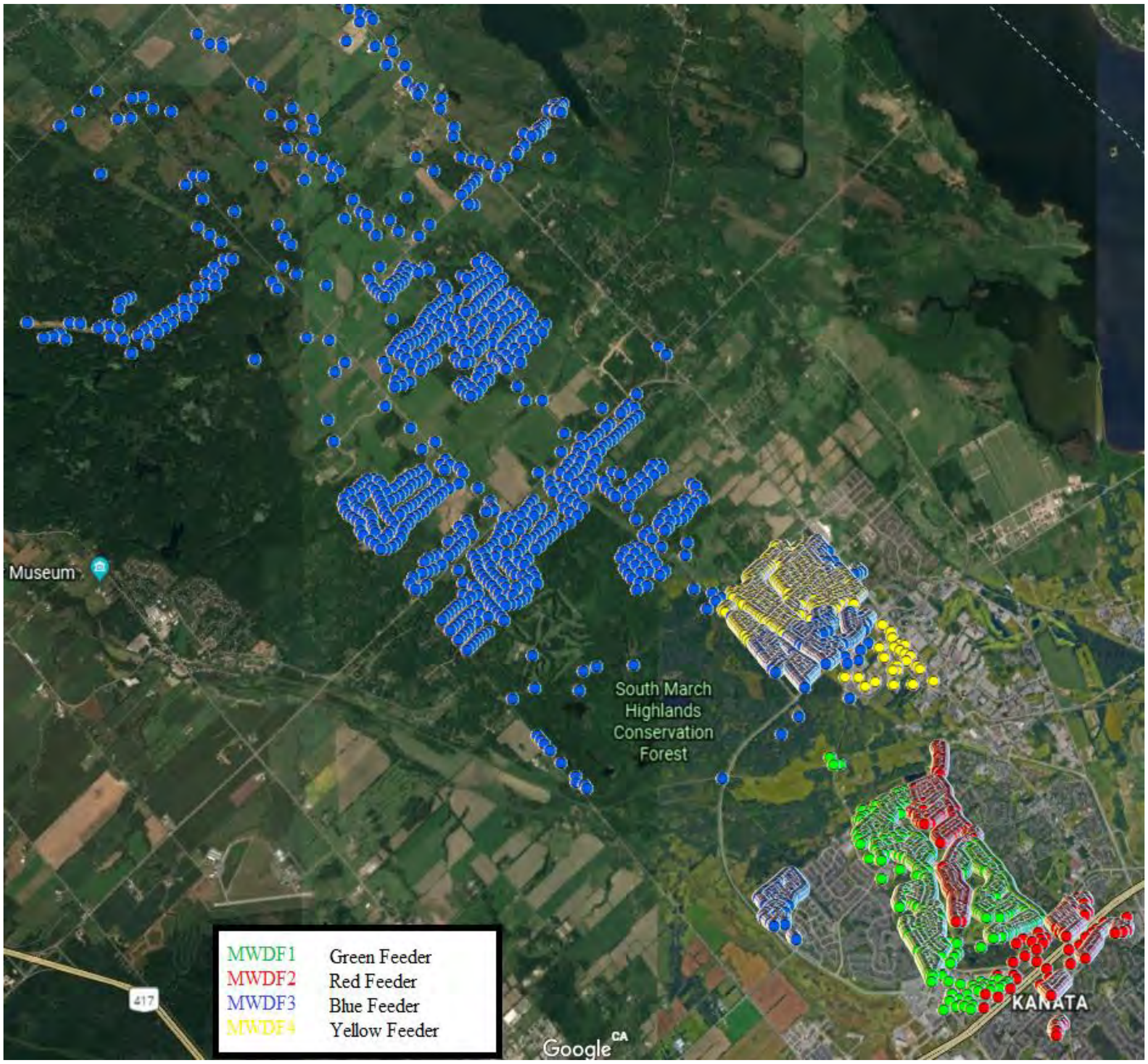

Figure 3-2 Marchwood MTS service area

3.2.2.1. Marchwood MTS Residential Load Segmentation

The residential sector buildings are subdivided into four subsectors, and the number of residential buildings in each subsector is counted using Google Earth files provided by HOL; Table 3-5 summarizes the number of buildings in each subsector for each of the four feeders.

Table 3-5 Residential Subsectors Premises, Marchwood MTS

Residential Building Type	Single-Family	ROW	Low Rise	High Rise	Total
Number of premises / subsector for feeder MWDF1	1076	649	62	0	1787
Number of premises / subsector for feeder MWDF 2	584	696	0	739	2019
Number of premises / subsector for feeder MWDF3	1435	889	86	0	2410
Number of premises / subsector for feeder MWDF4	1192	348	0	0	1540
Number of premises / subsector for Marchwood MTS	4287	2582	148	739	7756

The NRCAN residential building (SCEU) database is used to determine the energy intensity per premise, as summarized in Table 3-2. The total annual energy, annual electricity consumption, and the annual Natural gas consumption for each subsector are obtained. Then, the average estimated kWh per residential customer is calculated using the total residential consumption and the total number of residential buildings; the average estimated kWh per customer for Kanata MTS is 7,802 kWh which is very close to the actual kWh per residential customer reported in the OEB yearbook (i.e., 7,537 kWh). Thus, no adjustment for the used EUIs needed. A summary of the total residential consumption for the Marchwood MTS service area is presented in Table 3-6.

Table 3-6 Total Residential Subsectors Energy Consumptions for Marchwood MTS

Residential Building Type	Single-Family	ROW	Low Rise	High Rise	Total
Annual electricity consumptions (MWh)	41,381	15,726	712	3,783	41,381
Total annual energy consumptions (eMWh)	166,103	68,564	1,210	7,076	166,103

3.2.2.2. Marchwood MTS Commercial Load Segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, and activity of all commercial buildings located at each of the four feeders of Marchwood MTS. The energy intensities for all commercial subsectors are obtained using the NRCAN commercial building SCIEU database. The methodology described in section 3.1 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each commercial subsector are obtained; a summary of the total commercial consumption for the Marchwood MTS service area is presented in Table 3-7.

Table 3-7 Commercial Subsectors Energy Consumption, Marchwood MTS

Commercial Subsector	Annual Electricity Consumption (MWh)
Office buildings (non-medical)	31,555
Medical office buildings	2,475
Elementary and/or secondary schools	3,477
Assisted daily/residential care facilities	3,818
Warehouses Wholesale	1,498
Hotels, motels or lodges	3,205
Hospitals	0
Food and beverage stores	12,607
Non-food retail stores	13,690
Other activity or function	3,766

3.2.3. Calibrated Load Segmentation for Base Year

The calibration methodology described in section 3.1.3 is applied to determine the calibration factor for each sector. The actual annual consumption for Kanata and Marchwood MTS is obtained using the data provided by HOL; this consumption is reduced by a factor of 17 % to represent the share of street lighting and a factor of 3 % to account for the system losses (obtained from 2017 OEB Yearbook [5]) as shown in Tables 3-8 and 3-9.

Table 3-8 Actual and estimated consumptions for Kanata MTS

Kanata		Consumptions (kWh)
Actual consumptions	with street lighting	321,700,199
	without street lighting	267,011,165
	without street lighting & losses	259,000,830
Estimated consumptions	Residential	45,036,520
	Commercial	189,328,355
	Industrial	3,150,000
	Total	237,514,875
Gap		-21,485,955

Table 3-9 Actual and estimated consumptions for Marchwood MTS

Marchwood		Consumptions (kWh)
Actual consumptions	with street lighting	178,540,075
	without street lighting	148,188,262
	without street lighting & losses	143,742,614
Estimated consumptions	Residential	63,520,491
	Commercial	85,020,705
	Industrial	0
	Total	148,541,196
Gap		4,798,582

The reported metered KWh for residential customers is compared to the bottom-up estimation, and the results are closely matched. Thus, the estimated annual consumption for the residential sector is kept without calibration. Then, the calibration factor is calculated for the commercial and industrial sectors, as the ratio between the total actual annual consumption for commercial and industrial sectors divided by the total bottom-up estimated annual consumption for commercial and industrial sectors (Table 3-10).

Table 3-10 Calibration Factor Calculation

	Kanata	Marchwood	Sum	Sum of commercial and Industrial
Total actual (kWh)	259,000,830	143,742,614	402,743,445	294,186,433
Total estimated (kWh)	237,514,875	148,541,196	386,056,071	277,499,060
Calibration Factor	= (294,186,433 / 277,499,060) =1.06			

3.2.3.1. Calibrated Load Segmentation by Sector/Sub-sector

The obtained calibration factor is used to modify the estimated consumption for each feeder; i.e., the calibration factor is multiplied times the bottom-up estimation of each feeder to determine a bottom-up estimation that is matching the actual annual consumptions. Tables 3-11 and 3-12 show the total estimated electrical consumptions (after calibration) for Kanata and Marchwood, respectively.

Table 3-11 Estimated consumptions (kWh) for Kanata MTS after calibration

Kanata	624F1	624F2	624F3	624F5	624F6	Total
Residential	21,957,355	6,777,998	3,546,205	705,710	12,049,252	45,036,520
Commercial	35,437,231	52,884,403	7,694,143	75,889,460	28,808,356	200,713,593
Industrial	0	3,339,425	0	0	0	3,339,425
Total	57,394,587	63,001,826	11,240,347	76,595,170	40,857,608	249,089,538

Table 3-12 Estimated consumptions (kWh) for Marchwood MTS after calibration

Marchwood	MWDF1	MWDF2	MWDF3	MWDF4	Total
Residential	16,556,027	13,659,061	19,679,985	13,625,418	63,520,491
Commercial	31,584,597	20,260,960	10,979,980	27,307,879	90,133,415
Industrial	0	0	0	0	0
Total	48,140,624	33,920,021	30,659,965	40,933,296	153,653,906

3.2.4. End-Use Load Segmentation for Base Year

3.2.4.1. Kanata End-Use Segmentation

Based on the end-uses profiles provided by IESO for the residential and commercial sectors, the end-use load segmentation was developed. The end-use classification was performed using the calibrated annual consumption of the loads.

The end-use segmentations for Kanata MTS are developed for the residential sector and subsectors. Kanata residential and commercial end-use segmentation for the residential sector is presented in Figure 3-3 and Figure 3-4, respectively.

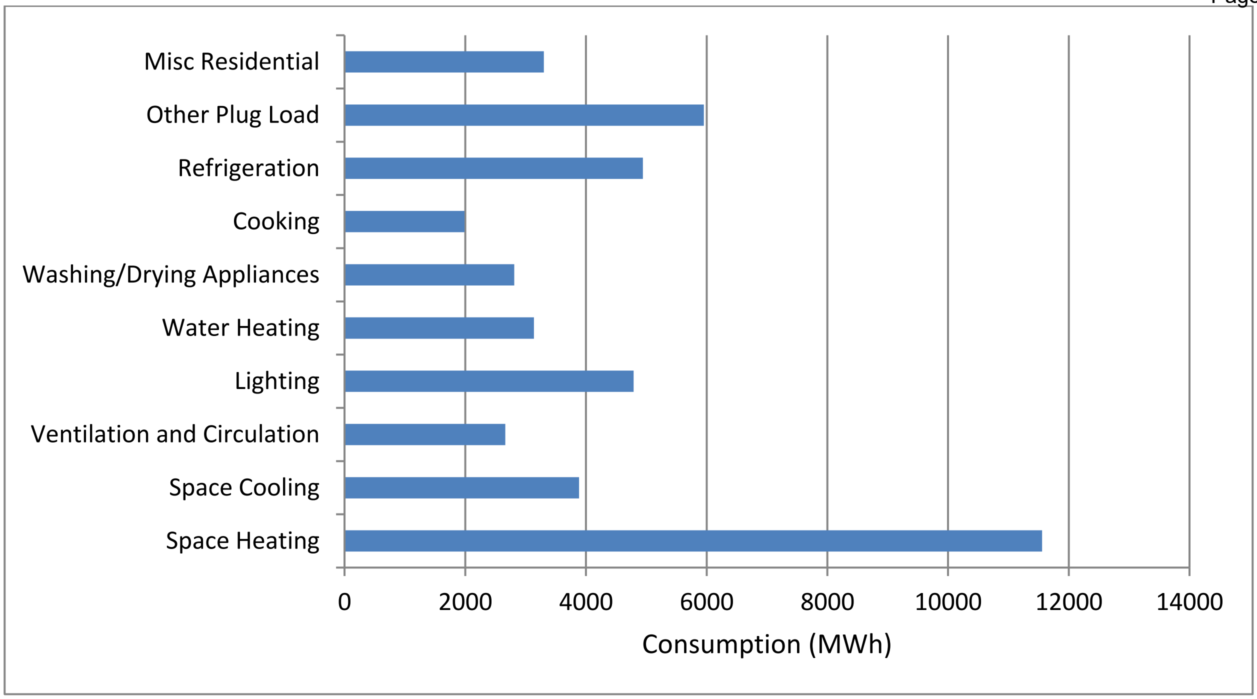

Figure 3-3 End-use Segmentation for Residential Sector, Kanata MTS

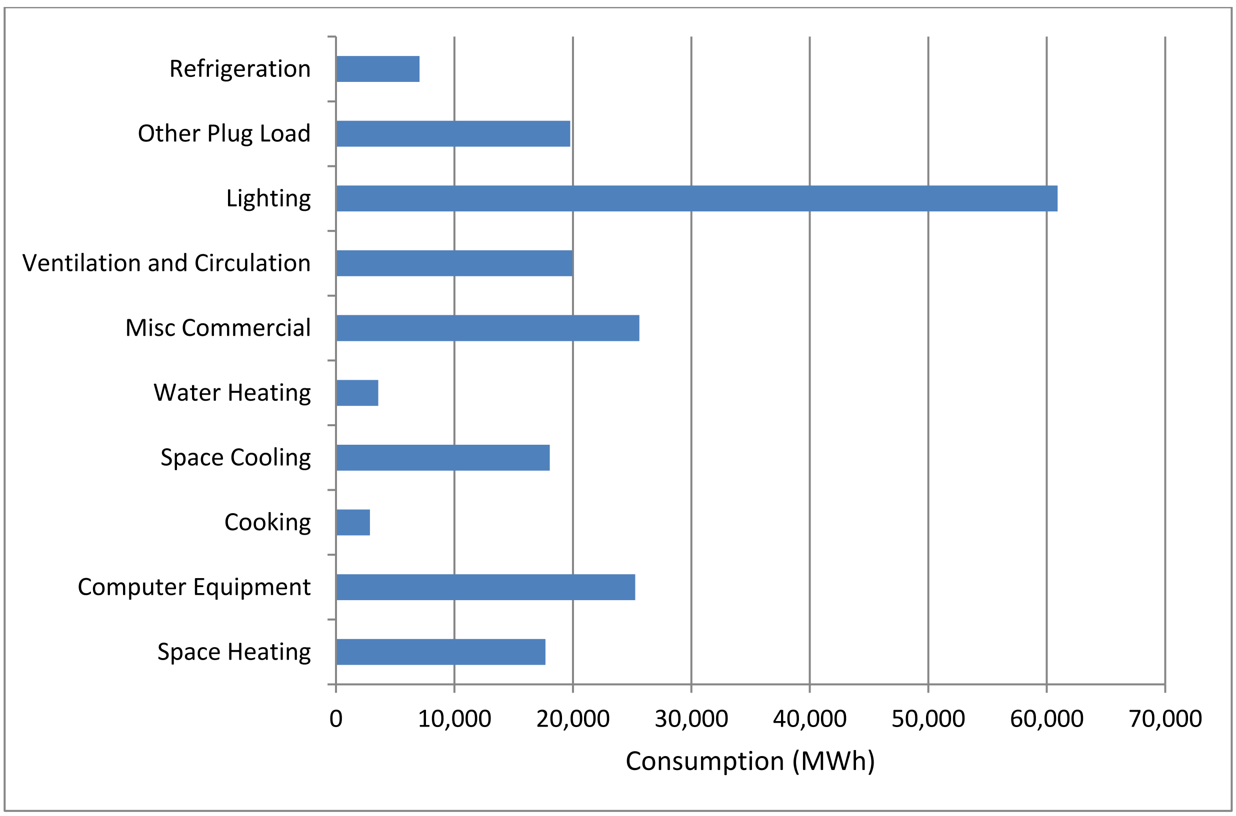

Figure 3-4 End-use Segmentation for Commercial Sector, Kanata MTS

3.2.4.2. Marchwood MTS End-Use Load Segmentation

The end-use segmentations for Marchwood MTS are developed for the residential and commercial sector and subsectors. The residential and commercial end-use segmentation is presented in Figure 3-5 and Figure 3-6.

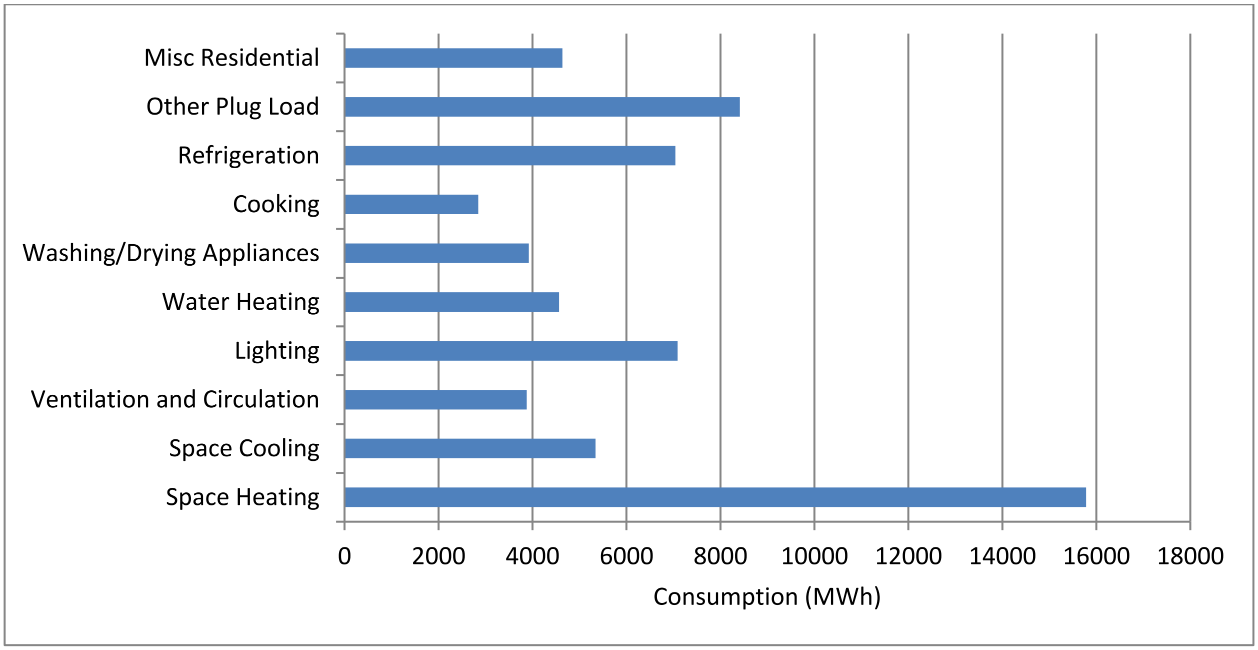

Figure 3-5 End-use Segmentation for Residential Sector, Marchwood MTS

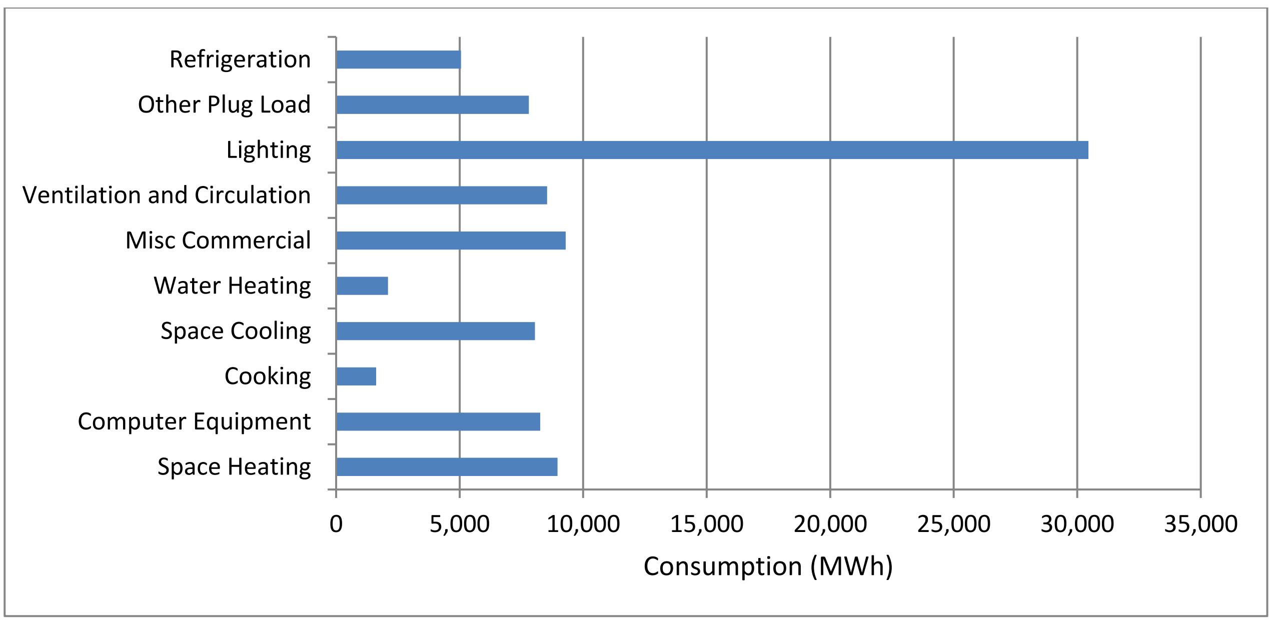

Figure 3-6 End-use Segmentation for Commercial Sector, Marchwood MTS

3.2.5. Reference Case Forecast: 2019- 2040

3.2.5.1. Residential Forecast

The NRCAN historical data for the number of residential buildings and energy intensity was used to develop a residential load forecast. The official community plan for Kanata North shows that the potential distribution for residential units over the planning period (i.e., 2018 to 20131) is as shown in Table 3-13. The official residential building plan for Kanata North was used to calibrate the residential building forecast.

Table 3-13 Potential Unit Distribution for Kanata North [4]

Unit Type	Potential Unit Distribution
Single Detached	960 Units
Apartments	527 Units
Street Townhouses and other ground-oriented multiple dwelling	1477 Units

Based on the base year residential demand, the calibrated forecasts of residential buildings number, and the forecasted energy intensities, the residential forecast for Kanata and Marchwood MTS are obtained. Moreover, the residential subsectors consumptions for the base year are compared to the short-term forecasted consumptions (i.e., 2023) and the long-term forecasted consumptions (i.e., 2040). The comparison results are presented in Figures 3-7 and 3-8 for Kanata and Marchwood MTS, respectively. Furthermore, the end-use residential forecasts for Kanata and Marchwood MTS are developed, as shown in Figures 3-9 and 3-10, respectively.

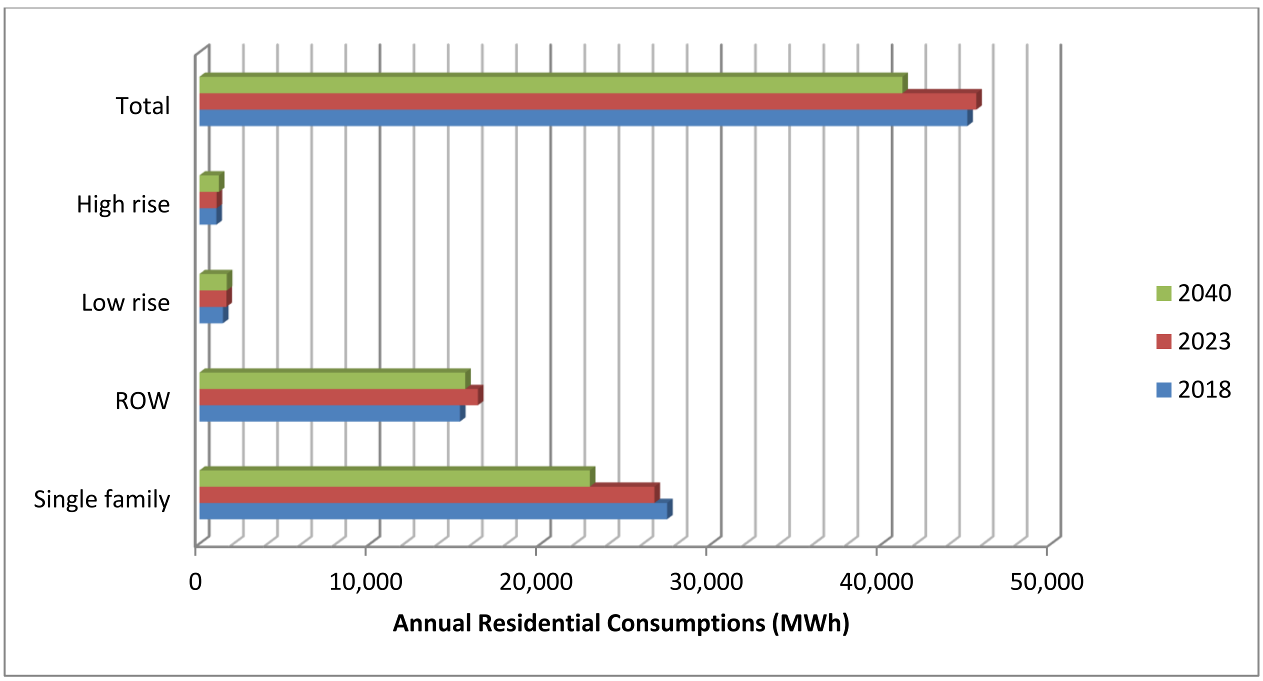

Figure 3-7 Residential sector load forecast, Kanata MTS

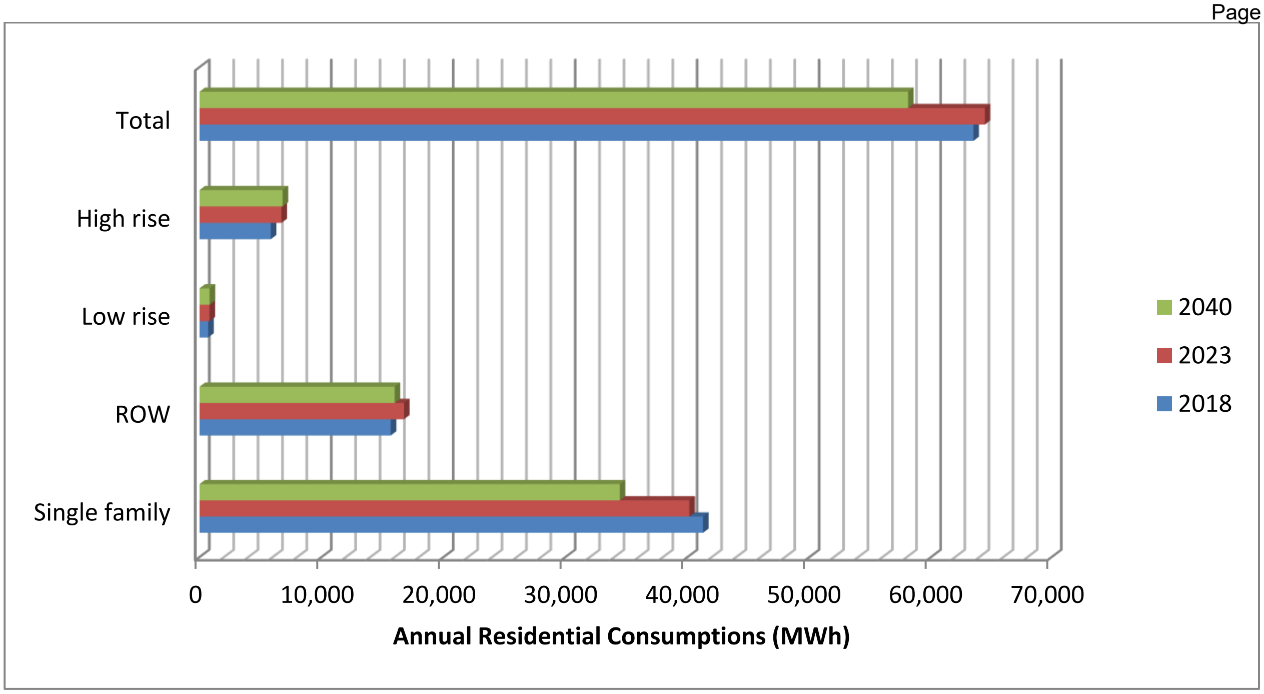

Figure 3-8 Residential sector load forecast, Marchwood MTS

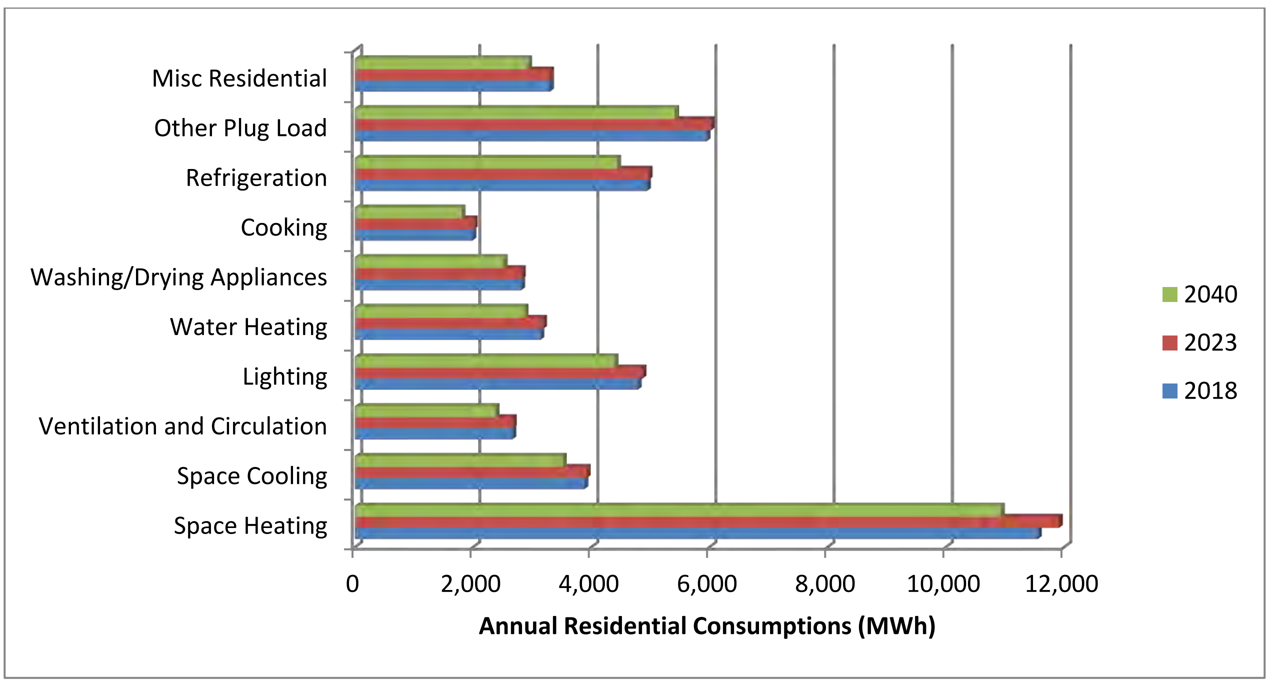

Figure 3-9 Residential load forecast by end-use, Kanata MTS

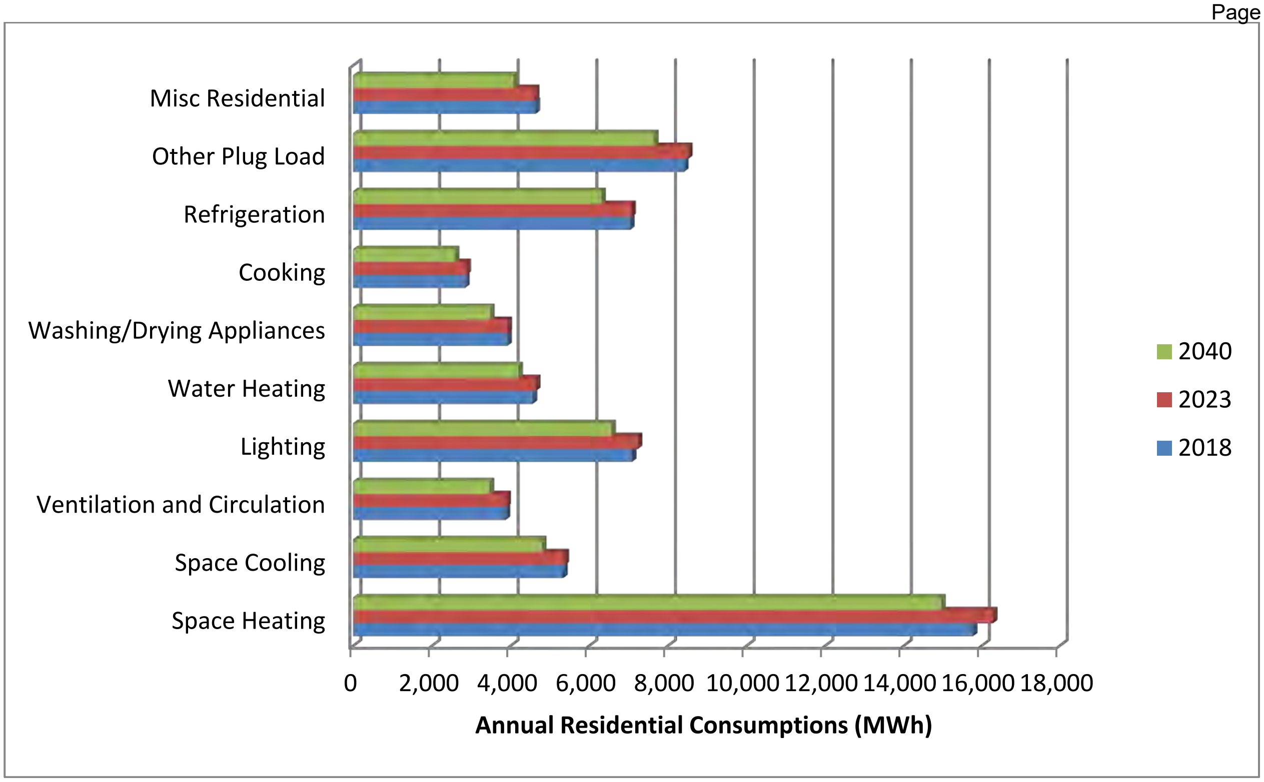

Figure 3-10 Residential load forecast by end-use, Marchwood MTS

3.2.5.2. Commercial Forecast

The forecast of the square footage of the commercial subsectors at Kanata and Marchwood MTS was developed using the base-year commercial sector estimation as well as the Hemson study provided by IESO. The forecast for the energy intensity for each commercial subsector was constructed based on NRCAN historical energy intensities for commercial subsectors.

The commercial forecast for Kanata and Marchwood MTS was carried out based on the base year commercial load consumption, the area forecast of commercial subsectors, and the forecasted energy intensities for commercial subsectors. Moreover, the commercial subsectors consumptions for the base year are compared to the short-term forecasted consumptions (i.e., 2023) and the long-term forecasted consumptions (i.e., 2040). The comparison results are presented in Figures 3-11 and 3-12 for Kanata and Marchwood MTS, respectively. Furthermore, the end-use residential forecasts for Kanata and Marchwood MTS were developed and shown in Figures 3-13 and 3-14, respectively.

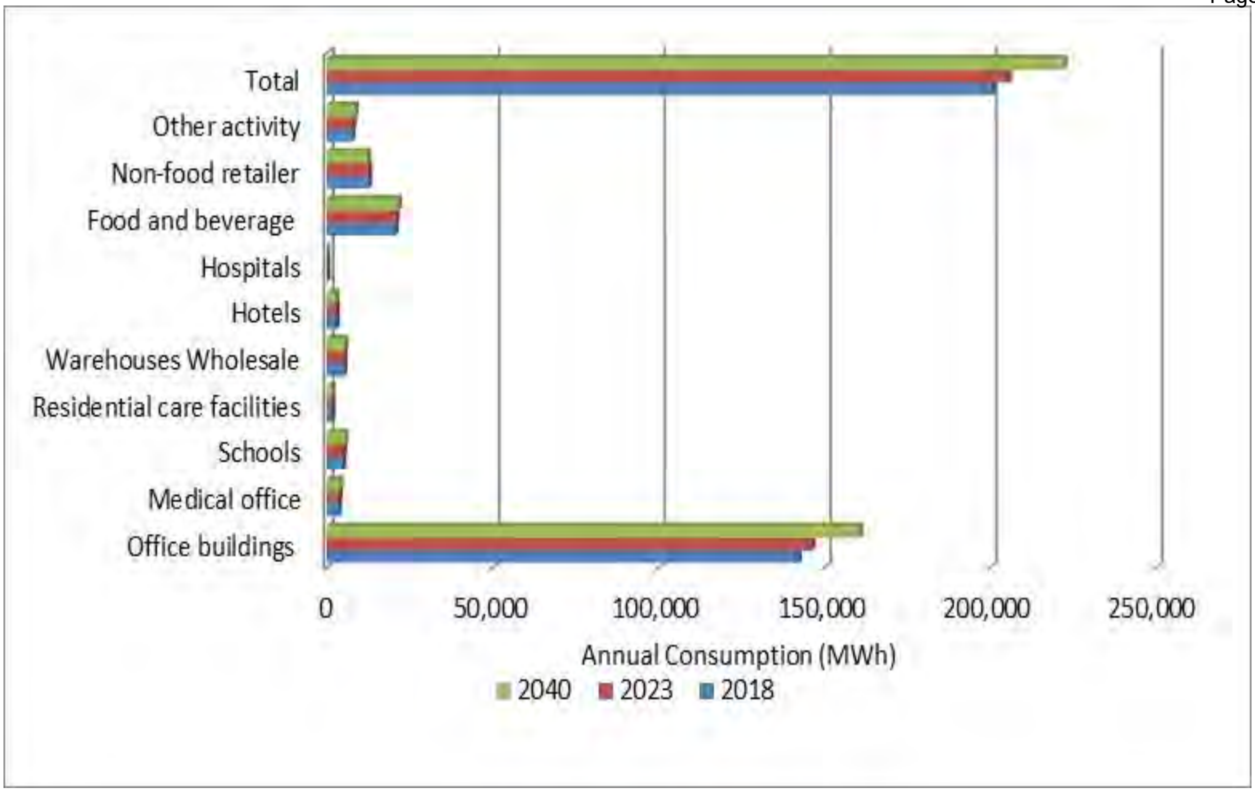

Figure 3-11 Commercial sector load forecast, Kanata MTS

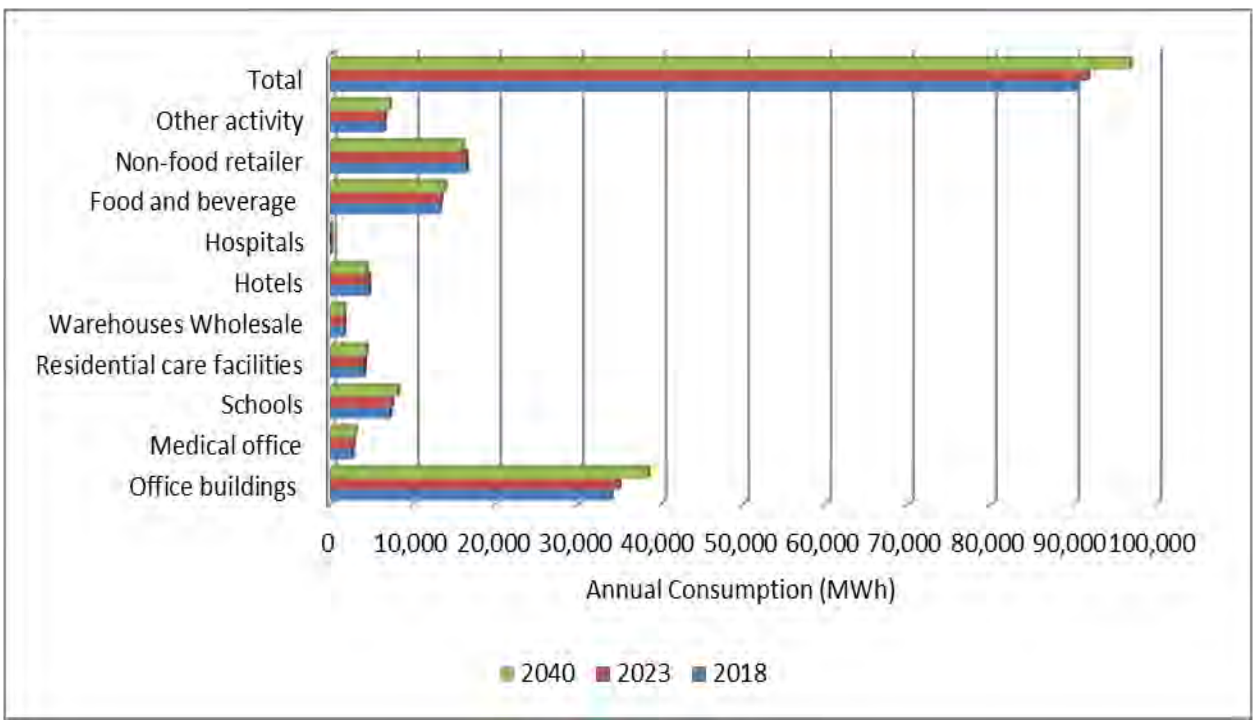

Figure 3-12 Commercial sector load forecast, Marchwood MTS

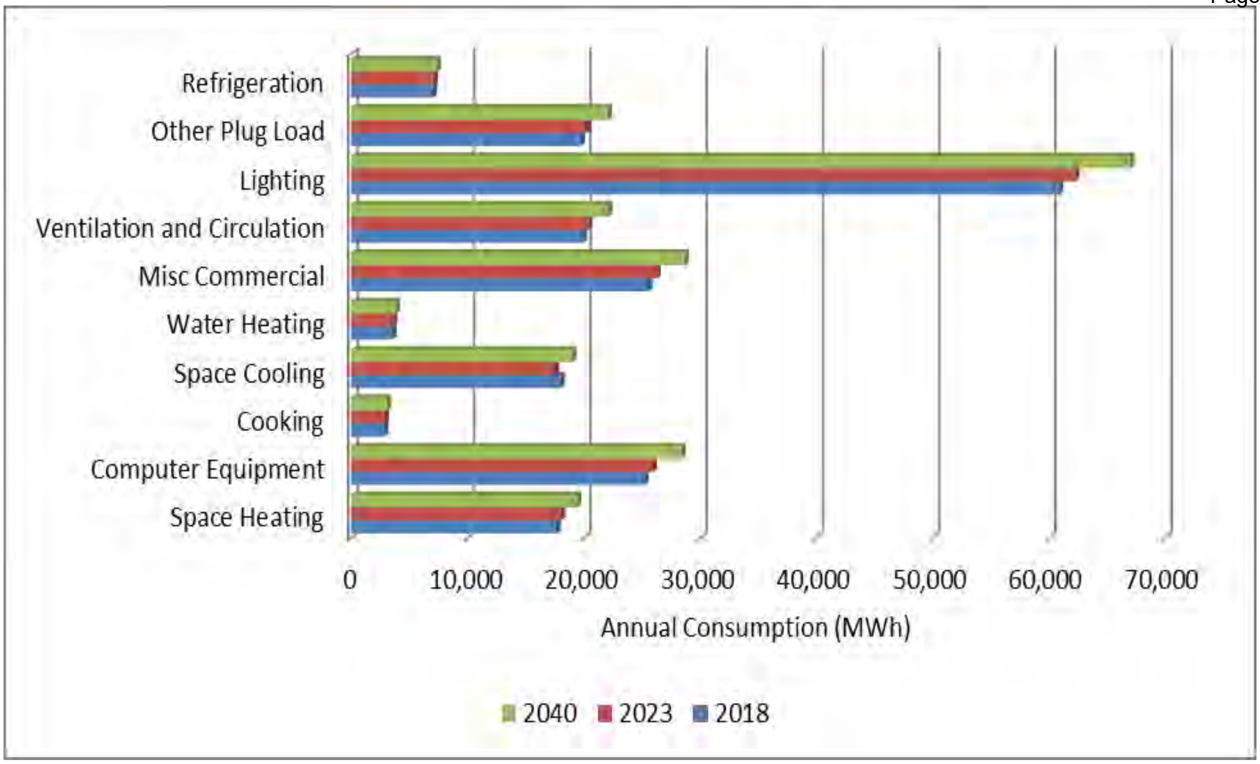

Figure 3-13 Commercial sector load forecast by end-use, Kanata MTS

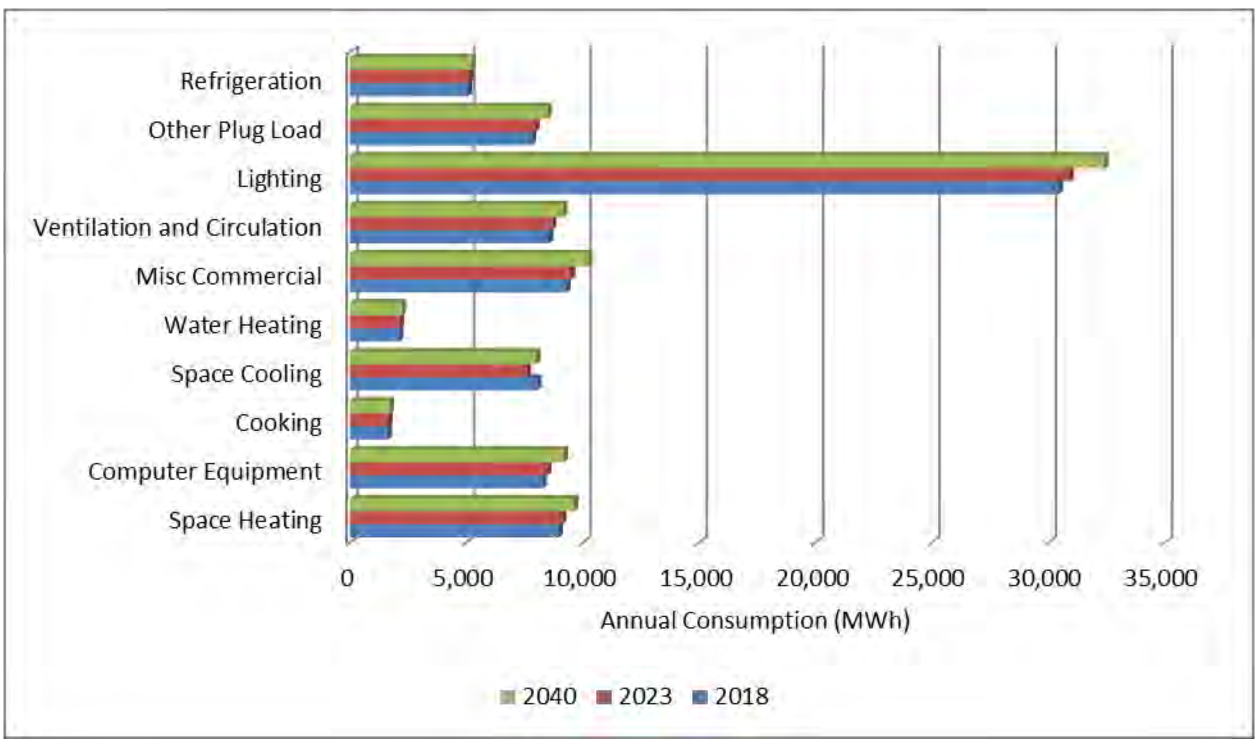

Figure 3-14 Commercial load forecast by end-use, Marchwood MTS

3.2.5.3. Aggregated Forecast

The aggregated commercial and residential forecast of the Kanata-Marchwood area is calculated and illustrated in Figure 3-15. When compared to the base year of 2018, the total aggregated load forecast for 2040 estimates an overall increase in electricity consumption of 4% from 402,743 MWh in 2018 to 418,971 MWh in 2040. The commercial section is expected to provide the most significant increase in electricity use, rising from 290,847 MWh in 2018 to 319,038 MWh (9.7 % increase). The residential sector electricity consumption is expected to show a decrease from 108,557 MWh in 2018 to 99,309 MWh in 2040 (8.51 % decrease). The industrial forecast is assumed to be constant over the forecasting period as one industrial building only exists at Kanata-Marchwood area.

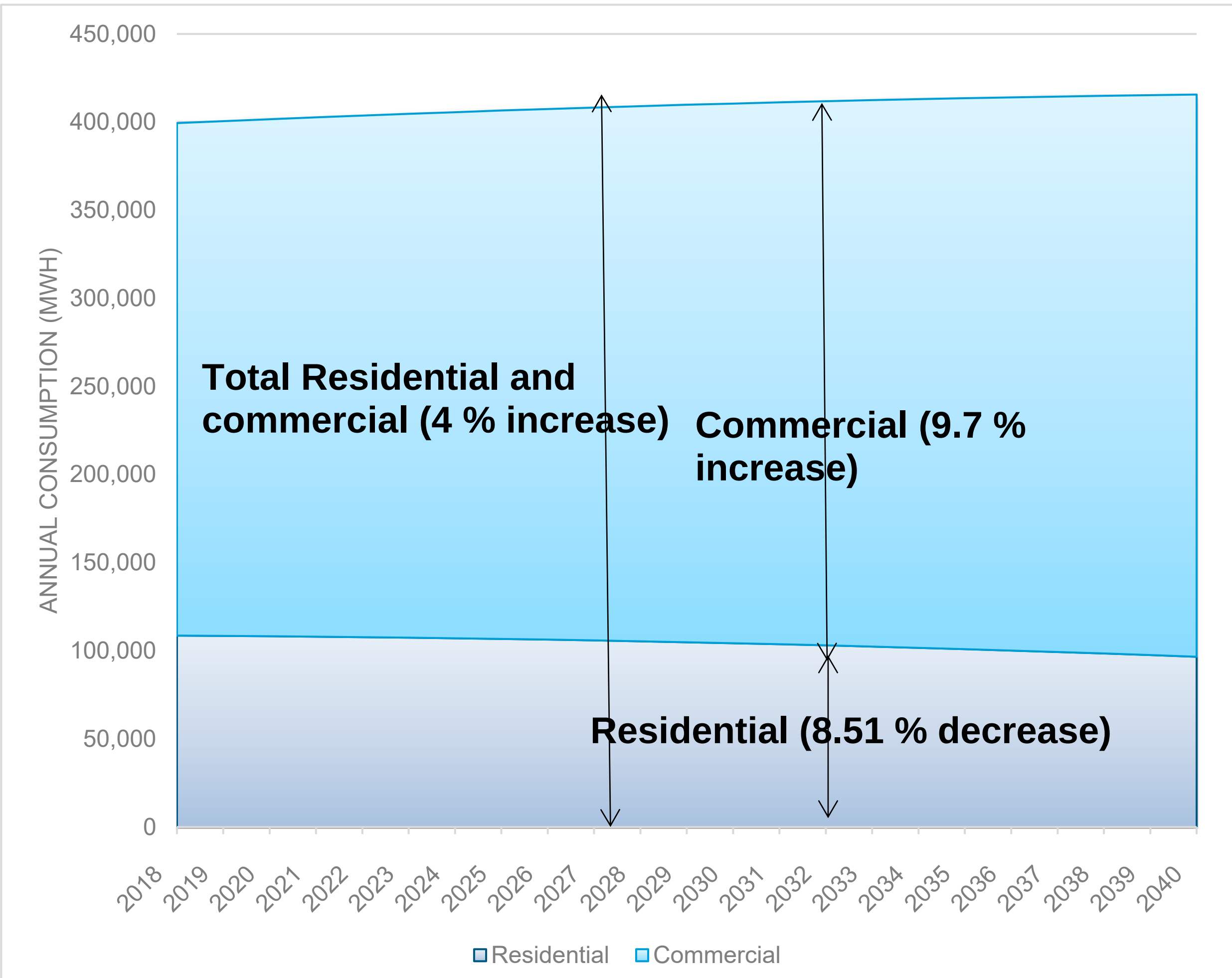

Figure 3-15 Kanata-Marchwood forecast (2018-2040) by sector

3.2.6. Participation in CDM and DER Programs

The historical participation of the loads in the CDM programs and the existing DERs, as well as the potential for expansion, were provided by HOL. The complete list of existing DERs at the Kanata-Marchwood area is presented in Table 3-14. Moreover, the total contract capacity of the DERs at Kanata-Marchwood area is presented in Table 3-15. The forecasted effective capacities of the DERs and the CDM are presented in Tables 3-16 and 3-17, respectively.

Table 3-14 Existing Energy Resources Facilities at Kanata-Marchwood

Station	Feeder	Capacity (KW)	Fuel Type
Kanata MTS	624F1	400	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	2.5	Solar PV
Kanata MTS	624F1	500	Solar PV
Kanata MTS	624F1	8	Solar PV
Kanata MTS	624F5	250	Solar PV
Kanata MTS	624F1	40	Solar PV
Kanata MTS	624F2	5120	Battery
Marchwood MTS	MWDF1	10	Solar PV
Marchwood MTS	MWDF2	250	Solar PV
Marchwood MTS	MWDF3	65	Solar PV
Marchwood MTS	MWDF1	250	Solar PV
Marchwood MTS	MWDF1	150	Solar PV
Marchwood MTS	MWDF3	297	Solar PV
Marchwood MTS	MWDF2	150	Solar PV
Marchwood MTS	MWDF3	10	Solar PV
Marchwood MTS	MWDF3	100	Solar
Marchwood MTS	MWDF4	990	Battery

Table 3-15 DERs Contract Capacity at Kanata-Marchwood

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Capacity connected to Kanata MTS (MW)	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94

Table 3-16 DERs Effective Capacity at Kanata-Marchwood

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Capacity connected to Kanata MTS (MW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3

Table 3-17 CDM Effective Capacity at Kanata-Marchwood

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CDM Effective Capacity Reduction Marchwood MTS (MW)	1.8	2.3	2.6	2.3	2.4	2.6	2.9	3.4	3.8	4.3
CDM Effective Capacity Reduction Kanata MTS	2.3	2.7	3.1	3.2	3.2	3.4	3.9	4.2	4.8	5.4

3.3. Findings and Observations

› The largest decrease in electricity consumption in the residential sector is expected to occur in the single-family subsector (16.25% decrease from 2018 to 2040).

› The electricity consumption of the ROW subsector is expected to increase up to the year 2026 (7 % increase from 2018 to 2026), and then the ROW consumption will fall for the remaining forecasted years (4.67% decrease from 2018 to 2040).

› The electricity consumption of low-rise and high-rise subsectors is expected to increase over the forecasted period (16.67% increase for low-rise and high-rise)

› At the end-use level, all residential end-use items are expected to decrease in electricity use.

› Increased electricity usage is expected for all commercial subsectors, except for non-food retailers and hotels that are expected to decrease in electricity use (3.28 decrease for non-food retailers and 6.36 decrease for hotels).

› At the end-use level, all commercial end-use items are expected to increase in electricity use. Lighting shows the most significant increase, while cooking, space cooling, water heating, and refrigeration show the lowest growth.

4. Identification of Technically Feasible Measures

The objective of this task is to identify the technically feasible measures for addressing local area needs. Data from different sources were collected on the conservation and demand management (CDM) measures, where the 2018 and 2019 IESO's Measure and Assumption lists (MAL) represented the basis for the measure research. In addition, the list of measures of the 2016's APS provided by the IESO for Ottawa was also included [1]. Moreover, other CDM measures from North American Jurisdictions (outside existing MAL), that could be rolled into the market quickly were added to the CDM list of measures used. For each measure, the annual energy consumption saving, as well as the peak demand savings were calculated and screened to determine the shortlisted measures that can impact the summer peak demand at the Kanata North area.

The maximum potential for peak demand reduction for each measure was calculated based on the local area load segmentation discussed in Section 3, the number of equipment per subsector, the consumption of the total equipment as a percentage of the end-use consumption, and the fraction of equipment that is energy efficient. Finally, the technical potential for peak reduction for all the CDM measures was obtained by aggregating the decrease associated with each measure.

In addition to the CDM measures, the impact of the DER on Kanata-Marchwood summer peak was assessed; the analysis is categorized into load shifting using battery energy storage system and renewable-based distributed generation. The technical potential for peak reduction of the battery energy storage is calculated on the utility-scale and on the large customers-scale. Moreover, the technical potential of photovoltaic roof-top distributed generation mounted on the residential and commercial buildings is calculated. Based on the calculated technical potentials for the CDM and DER measures, the total technical potential for the peak reduction of the Kanata North area is calculated.

4.1. Peak Load Analysis for Kanata North Area

4.1.1. Historical Peak Load Analysis

Based on the data received from HOL, the historical peak loading was analyzed, Figure 4-1 shows the coincidental combined peak load for the years 2012 to 2016 for Kanata MTS and Marchwood MTS. Kanata MTS contains 2 X 41.7 MVA transformers, and Marchwood MTS has 2 X 33 MVA transformers. Thus, the combined N-1 ratings for the two stations is 74.7 MVA. The limited-time ratings (LTR) for Kanata MTS is 54.5 MVA, and for Marchwood, MTS is 34 MVA; thus, the combined LTR for the two stations is 88.5 MVA. It worth noting that all the maximum peak loading occurred at the Summer Season for all these years. The highest historical coincidental loading occurred in 2016 with a summer peak of 105.2 MW, while the winter coincidental peak load for this year was 77 MW. This historical data analysis shows that the Summer peak is always more significant than the Winter peak for all available historical data. In addition, the Summer peak exceeded the combined LTR for the two stations over the past years.

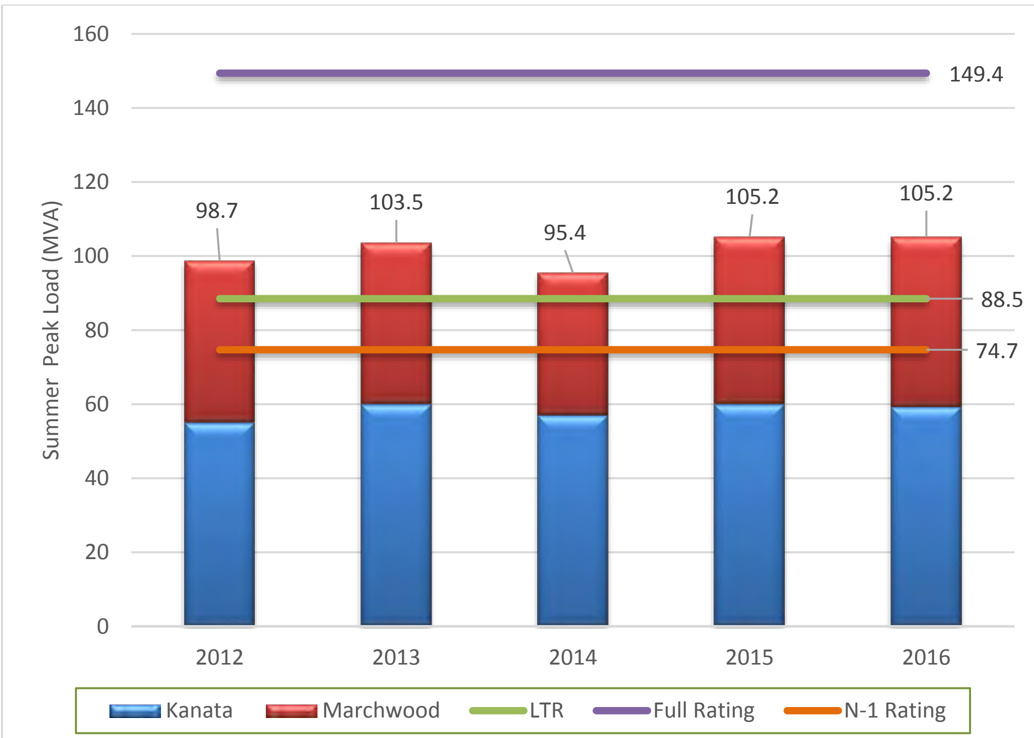

Figure 4-1 Historical Peak Loading for Kanata-Marchwood

4.1.2. Base Year Peak Load

The chronological loading curves for the peak day for the Winter and Summer seasons are determined based on the feeder hourly loading profiles for years 2017 and 2018. Figure 4-2 shows the chronological loading curve for the summer peak. The highest peak loading during the summer was reached on July 5th, while for the Winter Season the highest peak was reached on January 5th. The winter peak is 14.7% less compared to Summer, and the total number of days for the Winter season where the peak loading exceeded the planning ratings is ten days, while this number increased to 52 days in the Summer Season. Based on this analysis, the Winter Peak will not be analyzed given the available data and the large difference between winter and summer peak. Therefore, non-wire solutions should be addressing the Summer peak to lower this peak below the planning ratings of the two stations.

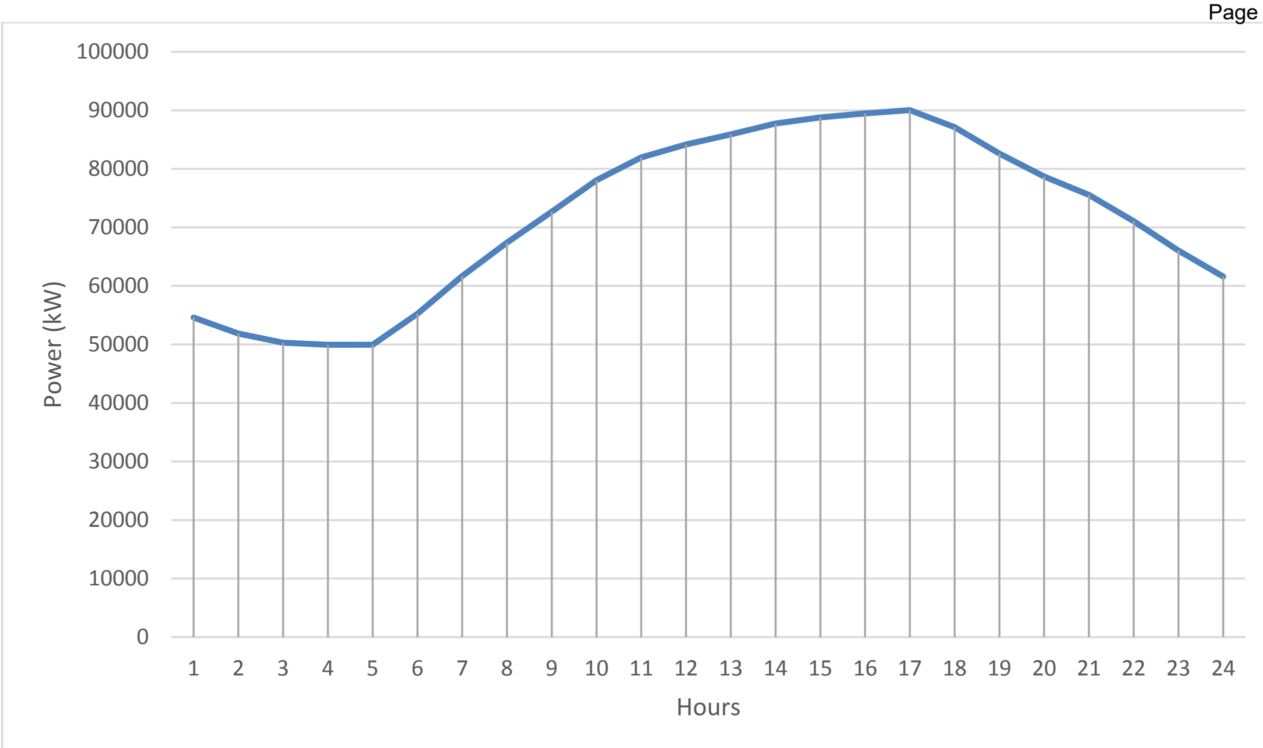

Figure 4-2 Peak Coincident Loading Day for the Base Year for Kanata-Marchwood, Summer Season Year 2018

4.1.3. Peak Load Forecast

The coincident peak forecast for the Summer season is developed using the IESO peak load at the base-year (2018) and by considering the median weather conditions, as shown in Figure 4-3, and by using extreme weather conditions as shown in Figure 4-4. The Summer peak is expected to exceed the combined LTR rating of the two stations (i.e., 88.5 MVA). It should be mentioned that the certainty of some load growth, such as (Broccolini Business Park) and (550 Innovation (Ciena)), should be checked annually due to the high required demand.

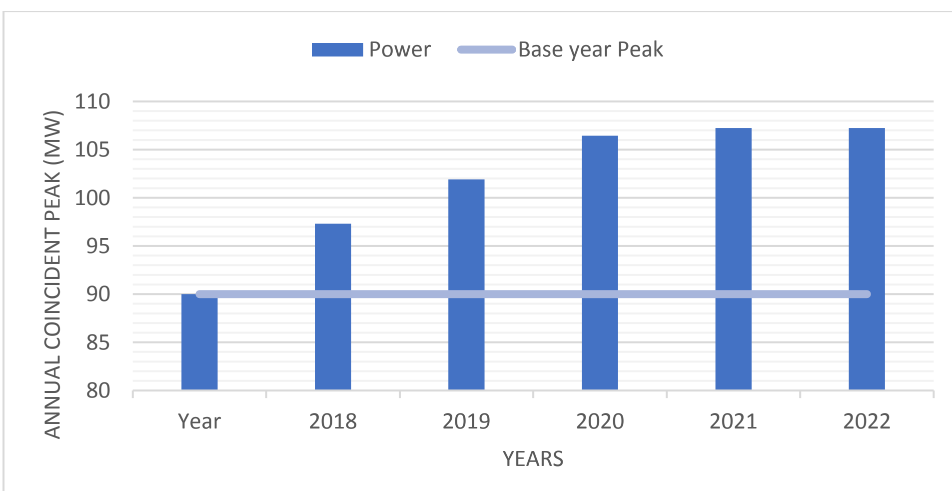

Figure 4-3 Forecasted Coincident Peak Loading for Kanata-Marchwood, Median Weather

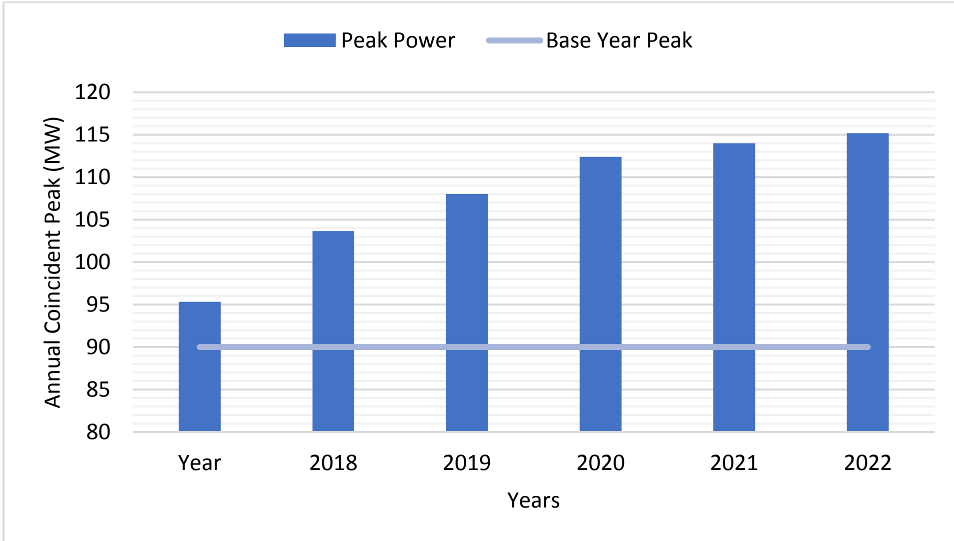

Figure 4-4 Forecasted Coincident Peak Loading for Kanata-Marchwood, Extreme Weather

4.2. Technical Potential of CDM Measures

The technical potential scenario estimates the saving potential when all technically feasible non-wire solutions are implemented at their full technical potential. This saving potential is the maximum potential that is not considering the economics of the measures nor customer adoption. This section presents the methodology followed for shortlisting the available CDM measures in Ontario and for calculating the technical potential of these measures.

4.2.1. Methodology

The primary project rationale is to determine the possible potential solutions to lower the summer peak demand in the Kanata-Marchwood area. The achievable potential of Summer peak load reduction would allow for more efficient use of existing facilities and infrastructure and differ or eliminate the need for a new station. Based on the HOL plan, the new station (New Kanata North) is planned to be in service in 2028. Therefore, the presented study focuses on the short-term technical potential scenarios that may differ or eliminate the need for the new station.

The relevant data on the available conservation measures were collected from IESO's MAL, the 2016's APS, and from other North American Jurisdictions [11] - [15]. Then, the measures were screened to determine the effective ones that can address the summer peak demand at Kanata North area; three screening stages are followed to exclude the measures that are not suitable for addressing the local area needs; i.e., measures of subsectors/end uses not available in Kanata area, measures that are no longer offered in 2018 and 2019 IESO list of measures, and measures that have no impact on summer peak demand.

For each measure, compared to the base case equipment, the consumption, annual energy saving, and peak demand reduction are determined. For each measure in each competition group, the following data were collected: the fraction of equipment that is energy efficient and the number of equipment per subsector, and the consumption of the total equipment as a percentage of end-use consumption. Then, the maximum potential for peak demand reduction for each measure is calculated.

4.2.2. Mapping of CDM Measures

The measure competition groups were developed for each subsector/end-use separately. Each competition group consolidates similar measures that could be an alternative to each other. For example, the competition groups for the space cooling end-use are a thermal envelope, space cooling control, room/window air conditions, and central AC. The measures in each competition group are alternatives to each other, while a measure from the room AC group cannot compete with measures of the central AC group. The aggregated measure savings potential for each competitive group is determined; double-count of potential savings is avoided by limiting the total adoption to 100% within each measure competition group.

The complete list of competition groups mapped to subsectors, and end-use are presented in Table 4-1 and 4-2 for residential and commercial sectors, respectively. The subsectors mentioned in Table 4-2 are office, medical office, hotels, residential care, non-food retailers, food retailers, schools, warehouse wholesale, and other commercials.

Table 4-1 Residential Sector Competition Groups

End-use	Competition Groups
Indoor Lighting	Screw-in lamps, light control
Outdoor Lighting	Screw-in lamps, light control
Common Area Lighting	Screw-in lamps, light control
Cooking	Wall Oven
Refrigeration	Refrigerators, Freezers
Space Cooling	Control, Thermal Envelope, Room AC, Central AC, Other Cooling
Water Heating	Pipe Insulation, Showerhead, Water heater, Aerator
Plug Loads	Televisions, Water cooler
Washer Dryer	Washing Machines, Dryers, Dishwashers
Ventilation	Dehumidifiers

Table 4-2 Commercial Sector Competition Groups

End-use	Competition Groups
Subsector Lighting	Screw-in lamps, light control
Subsector space cooling	Packaged AC units, Chillers, Room AC
Subsector refrigeration	Residential size refrigerators, Walk-in refrigerators, Cabinet, pipes insulation, strip curtain, Gasket.
Subsector plug loads	Ice machine, Vending machine
Subsector computers	Computers
Subsector Domestic Hot Water	Water heater
Subsector cooking	Dishwasher, cooking
Subsector Miscellaneous commercial	Visc commercial
Subsector ventilation and circulation	Ventilation and circulation

4.2.3. Results and Discussions

The methodology described in section 4.2.1 is applied to the Kanata-Marchwood load profile, for the year 2023 forecasted load, forecasted number of residential units and forecasted commercial areas were used to determine the technical potential, due to CDM measures, for this year. The factors required for calculating the technical potential; (i.e., the measure share, the energy efficient factor, and the total number of equipment per household or square footage) are obtained from the residential survey provided by IESO and the commercial CDM data provided by HOL. The missing information is completed using NRCAN residential and commercial surveys [10], [16], and EIA's Commercial Buildings Energy Consumption Survey (CBECS) [17].

4.2.3.1. Residential Sector

The technical potential peak reduction is calculated for each competition group of the residential subsector/ end-use, and the total technical potential peak reduction is calculated for each subsector and end-use. The overall residential summer peak reduction in 2023 was estimated to be 4.713 MW. Figure 4-5 shows the technical potential Summer peak reduction for each subsector; the most significant technical potential was determined for the single-family subsector, which accounts for 62.725 % of the total peak reduction in 2023. Figures 4-6 to 4-9 show the reductions per residential end-use for each subsector.

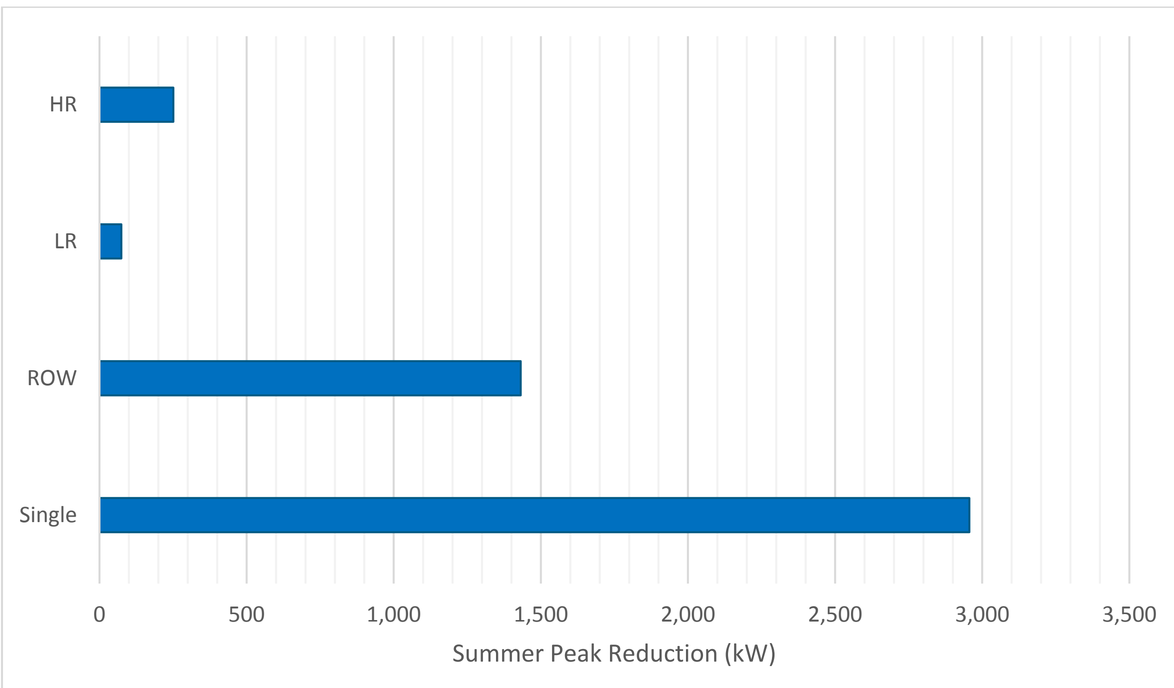

Figure 4-5 Technical Potential Peak Reduction by Residential Subsector in 2023

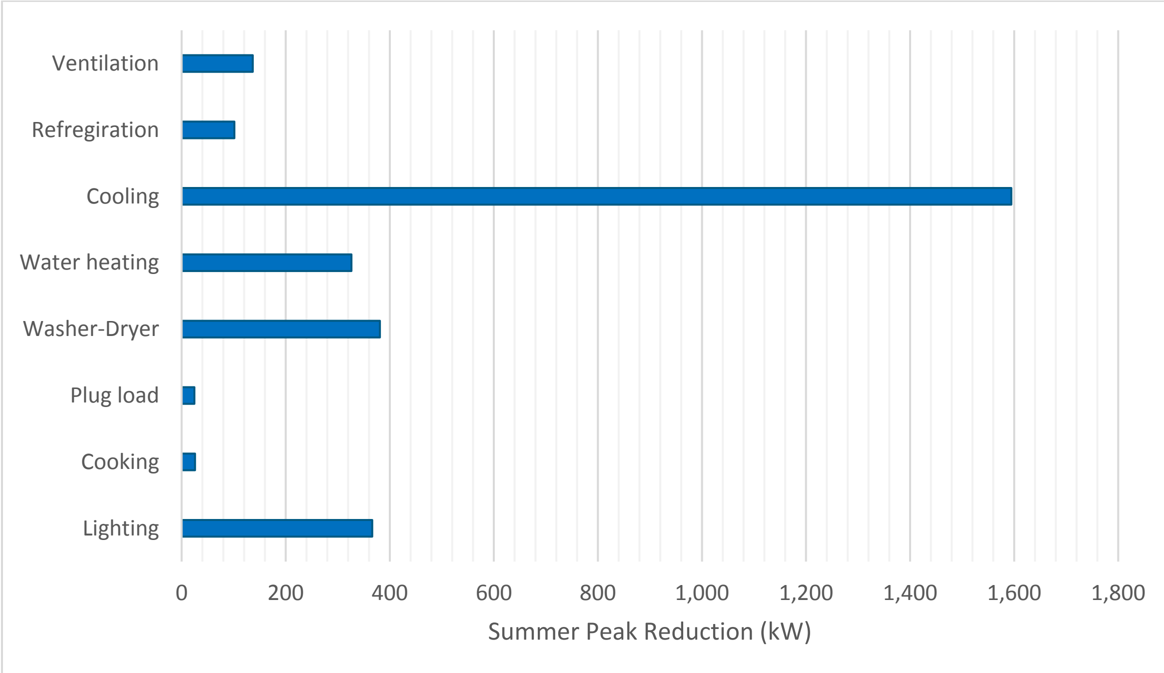

Figure 4-6 Technical Potential Peak Reduction by End-use in 2023, Single-family

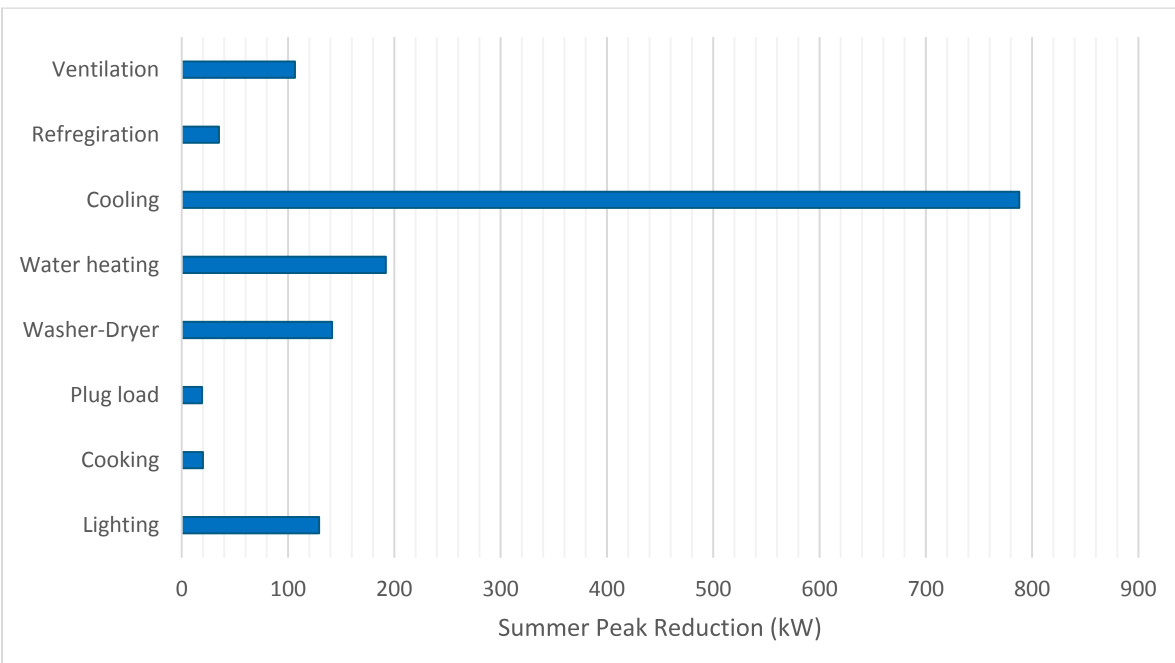

Figure 4-7 Technical Potential Peak Reduction by End-use in 2023, ROW

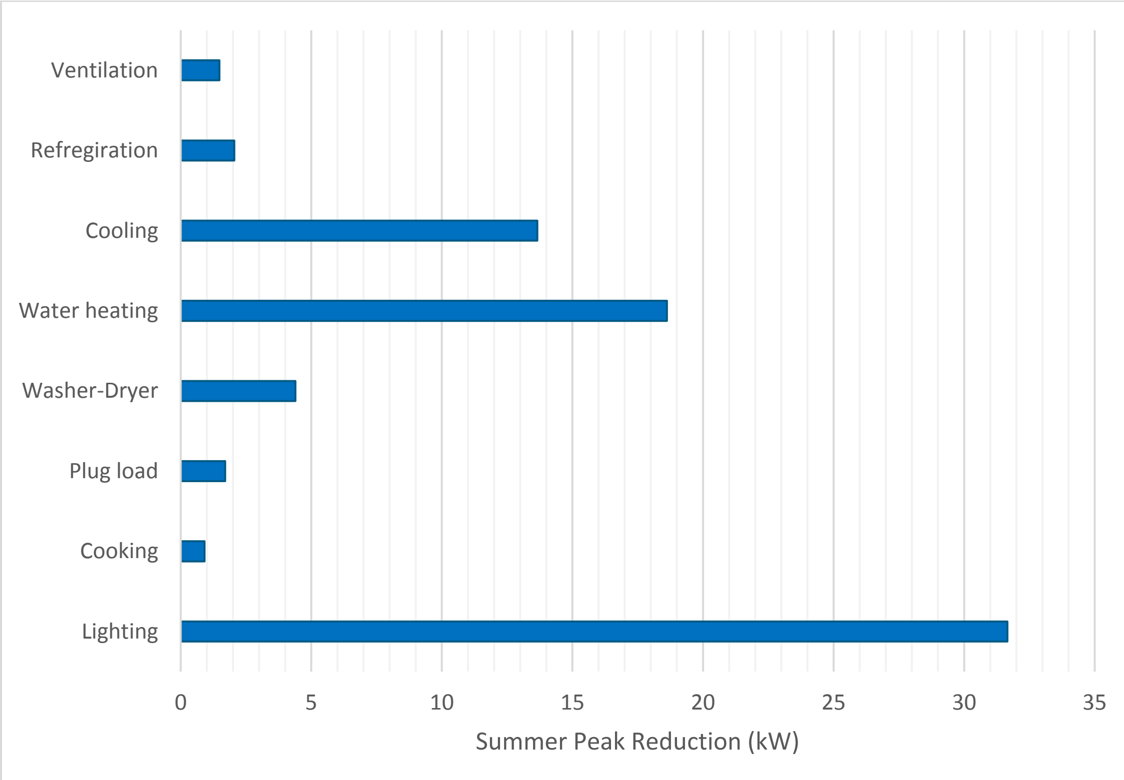

Figure 4-8 Technical Potential Peak Reduction by End-use in 2023, Low Rise

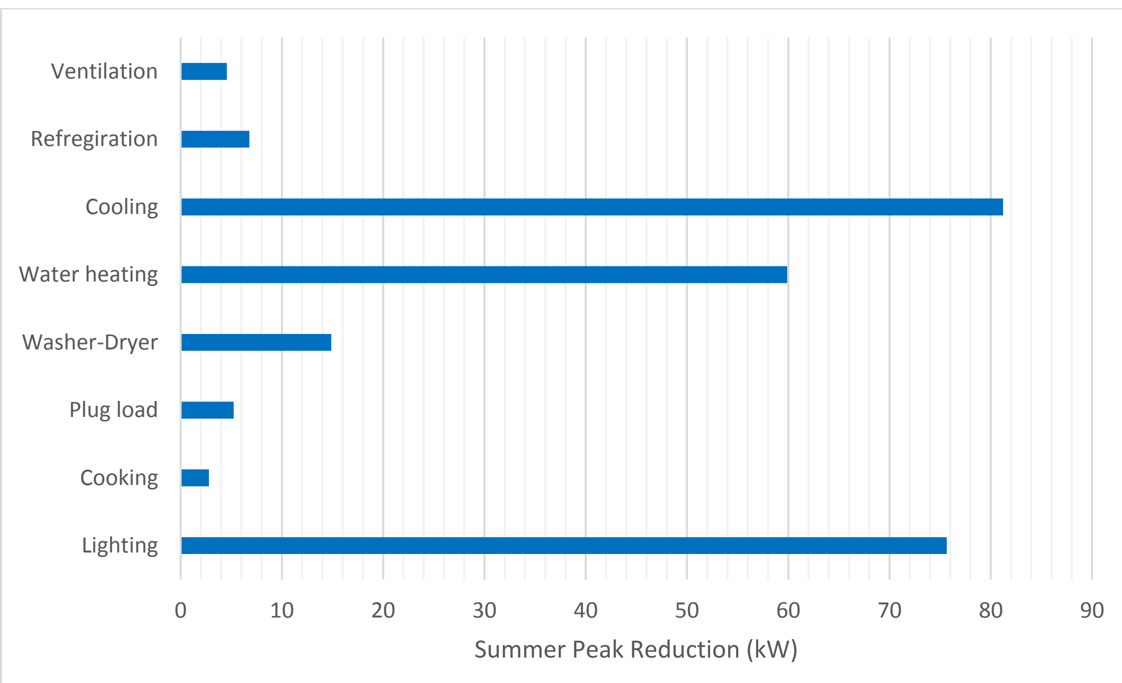

Figure 4-9 Technical Potential Peak Reduction by End-use in 2023, High Rise

4.2.3.2. Commercial Sector

The technical potential peak reduction is calculated for each competition group of the commercial subsector/ end-use, and the total technical potential peak reduction is calculated for each subsector and end-use. The overall commercial summer peak reduction in 2023 was estimated to be 13.691 MW. Figure 4-10 shows the technical potential Summer peak reduction for each subsector; the most significant technical potential was determined for the office subsector, which accounts for 61.19 % of the total peak reduction in 2023 followed by the food stores subsector that accounts for 12.43%. Figure 4-11 shows the overall reductions per commercial end-use. The lighting end-use accounts for the most significant peak reductions of 58.17% of the overall reductions.

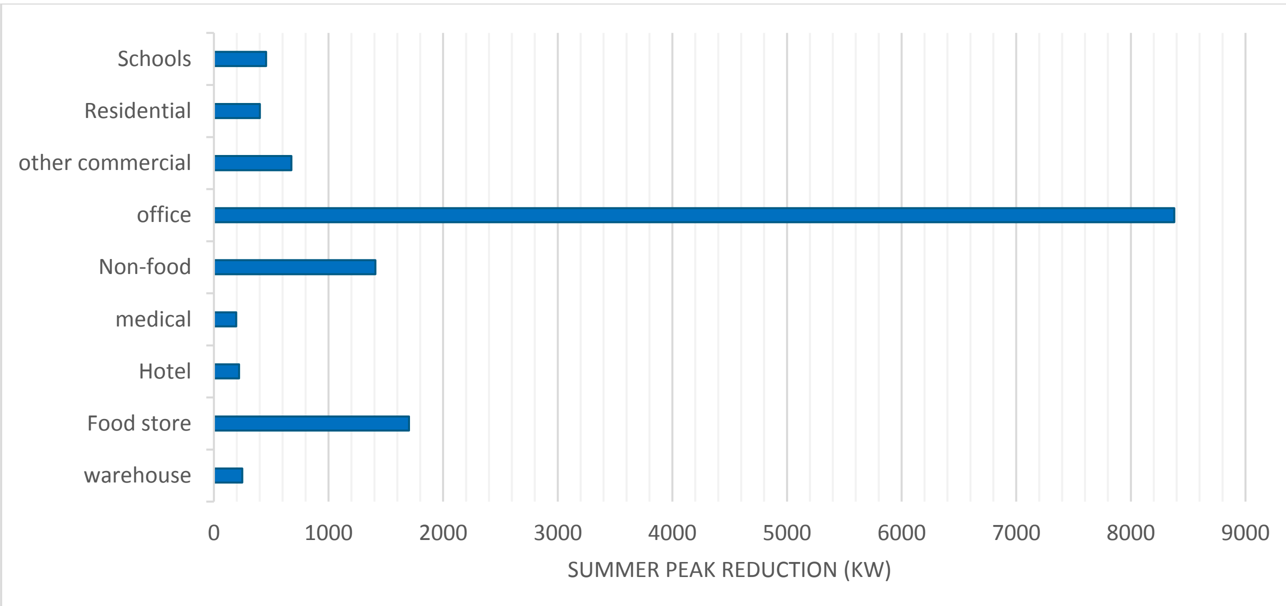

Figure 4-10 Technical Potential Peak Reduction by Commercial Subsectors in 2023

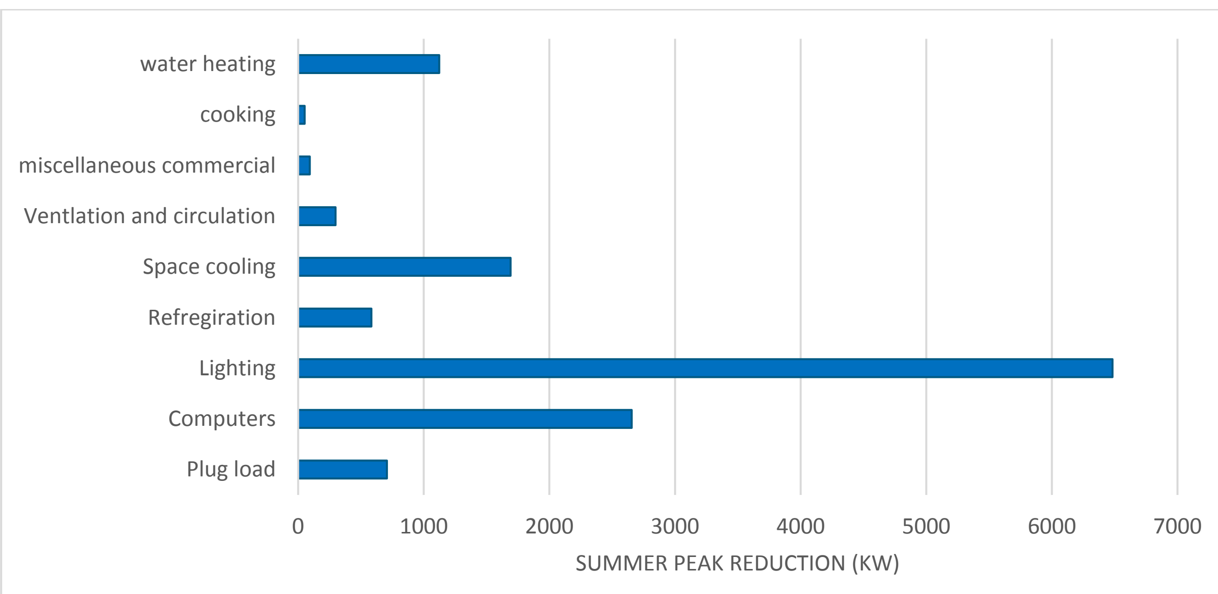

Figure 4-11 Technical Potential Peak Reduction by End-use, Commercial Sector

4.2.4. CDM Peak Reduction Portfolio

The total technical potential reduction in 2023 was calculated to be 18,396 MW, and the residential sector accounts for 26%, while the commercial sector accounts for 74 %, as shown in Figure 4-12. As only one industrial building is located at Kanata-Marchwood and there is no plan for expansion, the industrial sector CDM measures were not included in the shortlisted measures. In addition, the street lighting does not contribute to the Summer Peak reduction as the peak hour coincides with the daytime.

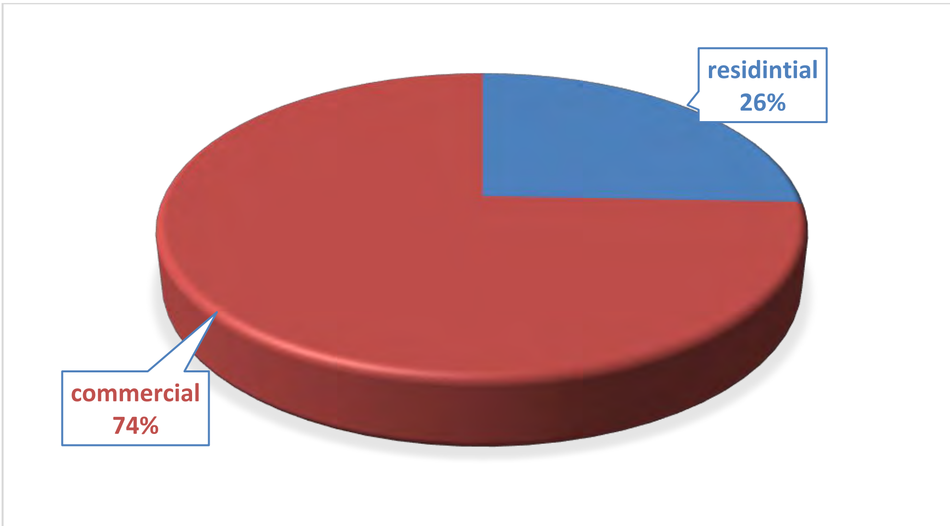

Figure 4-12 Total Technical Potential of CDM measures

4.3. Technical Potential of Load Shifting Measures

This objective of this task is to analyse the impact of load shifting measures that includes Time of Use (TOU) and Battery Energy Storage (BES) on Kanata-Marchwood summer peak.

HOL already adopted the TOU pricing for the Regulated Price Plan (RPP) customers. Most of the residential customers and the small commercial customers (i.e., 50kW to 1000 kW) are RPP customers. The larger commercial customers (i.e. Wholesale Market Participants (WMP)) purchase electricity through the IESO directly. Therefore, the TOU pricing is implicitly included in the wholesale energy prices. Thus, for the TOU, it was concluded that the TOU pricing measure is already applied in the Kanata North area, and no additional load shifting could be achieved using it.

The possibility of load shifting using the battery energy storage system was performed for two scenarios, i.e., utility-scale and large customers-scale. The load shifting analysis determined the technical potential of using a battery owned by HOL and installed at the substation. Moreover, the technical potential for installing batteries owned by large customers greater than 1000 KW was also determined.

4.3.1. Utility-Scale Battery Energy Storage

The total system peak is analyzed, as shown in Figure 4-13, and the potential for peak reduction using substation scale battery storage is determined. Two scenarios are studied, i.e., batteries that are capable of discharging for 4 or 6 hours. The adequate battery size for the 4 hours scenario is 7,60 kWh, and this battery can reduce the system peak by 2.92 MW (shaving the peak from 90.05 MW to 87.11 MW). For the 6 hours scenario, the battery size is 24,125 kWh, and this battery can reduce the system peak by 5.87 MW.

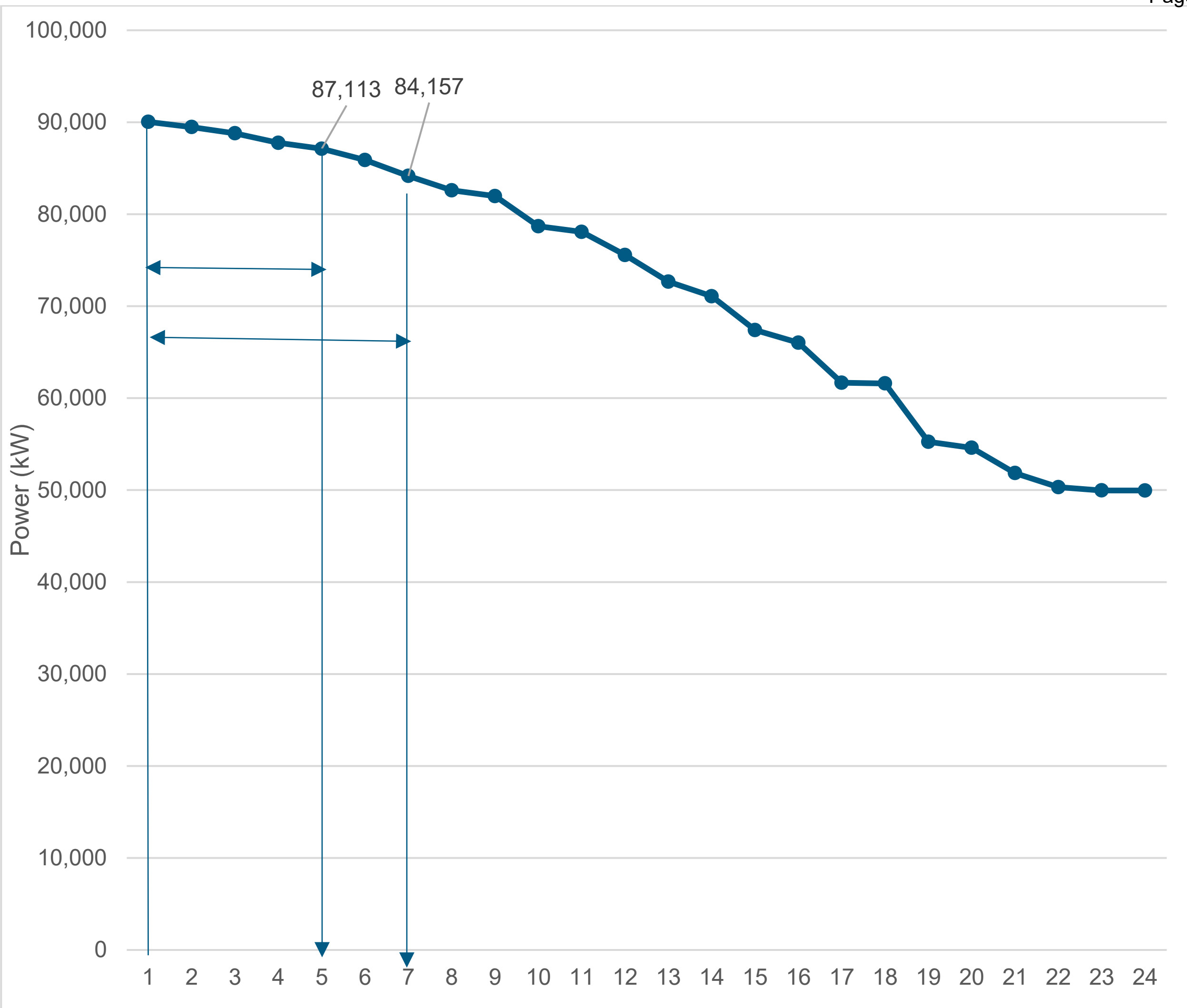

Figure 4-13 Load Duration Curve of the Summer Peak Day

4.3.2. Customer-Scale Battery Energy Storage

The potential for peak reduction using customer scale battery storage is determined. Two scenarios are studied, i.e. batteries that are capable of discharging for 4 or 6 hours. The adequate battery size for the 4 hours and 6 hours scenarios are determined for the large customers greater than 1000kW. The corresponding technical potentials of peak reduction for these batteries are obtained. Table 4-3 shows the customer meter reference number and the adequate battery sizes for both scenarios as well as the technical potential of these batteries. The total technical potential peak reduction for the 4-hour battery is 746 kW, while for the 6-hour battery, the reduction is 1,186 kW.

Table 4-3 Technical Potential of Large Customer Batteries

Meter Data Reference Number	Customer Maximum Load (kW)	Four Hours Scenario		Six Hours Scenario	
		Battery Capacity (kWh)	Technical Potential for Peak Reduction (kW)	Battery Capacity (kWh)	Technical Potential for Peak Reduction (kW)
1064575000	2,077	52.92	21.6	78.48	25.92
1323516000	1,013	129.6	72.9	181.08	82.08
2261516000	1,655	35.46	13.86	194.22	44.28
2313175000	2,173	166.88	69.44	327.6	100.24
2589675000	1,597	142.56	52.2	467.64	106.38
3948590255	2,278	62.04	19.92	141.36	34.32
5430710301	1,230	33.72	17.52	77.88	25.32
5649575000	1,479	75.24	29.76	263.52	65.04
6445807039	1,050	102.24	32.94	171	45.18
7489675000	1,055	68.13	27.45	121.5	36.99
8079416000	1,967	57.60	21.96	242.82	54.18
9046027318	2,098	15.48	6.3	55.08	12.96
9098675000	3,396	400.76	173.88	689.13	245.97
9771025037	1,097	31.32	17.16	34.8	17.76
9858616000	1,105	198.96	60.48	368.28	93.96
9866575000	3,594	40.08	25.32	97.68	36.54
9951516000	1,053	26.46	10.26	42.3	12.96
9982475000	8,273	227.67	91.41	545.73	145.95

4.4. Technical Potential of DG Measures

The impact of roof-top small-scale PV DGs located at residential and commercial buildings on the system peak was assessed. Helioscope software was used to determine the optimal distribution of the PV panels. The software utilized the actual solar irradiances at the Kanata North area to develop the daily profile of the PV DG output power and the DG capacity. The minimum daily power profile for the Summer season was used to determine the technical potential for the Summer peak reduction using the PV DGs.

4.4.1. Technical Potential of Commercial DGs

One large commercial building located at Terry Fox Dr. is selected (shown in Figure 4-14) to determine the technical potential per square footage. The optimal PV module distribution is developed, as shown in Figure 4-15, and the minimum Summer day output powers are obtained as presented in Fig 4-16. The results show that this PV DG can reduce the summer peak by 12.2 kW.

Figure 4-14 Location of the Selected Commercial Building

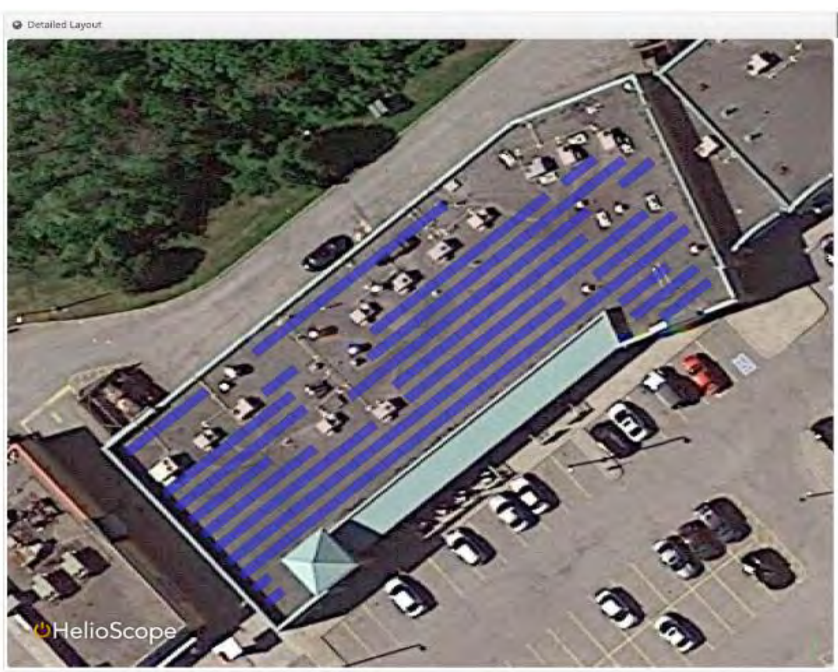

Figure 4-15 Layout of the PV arrays, Commercial Building

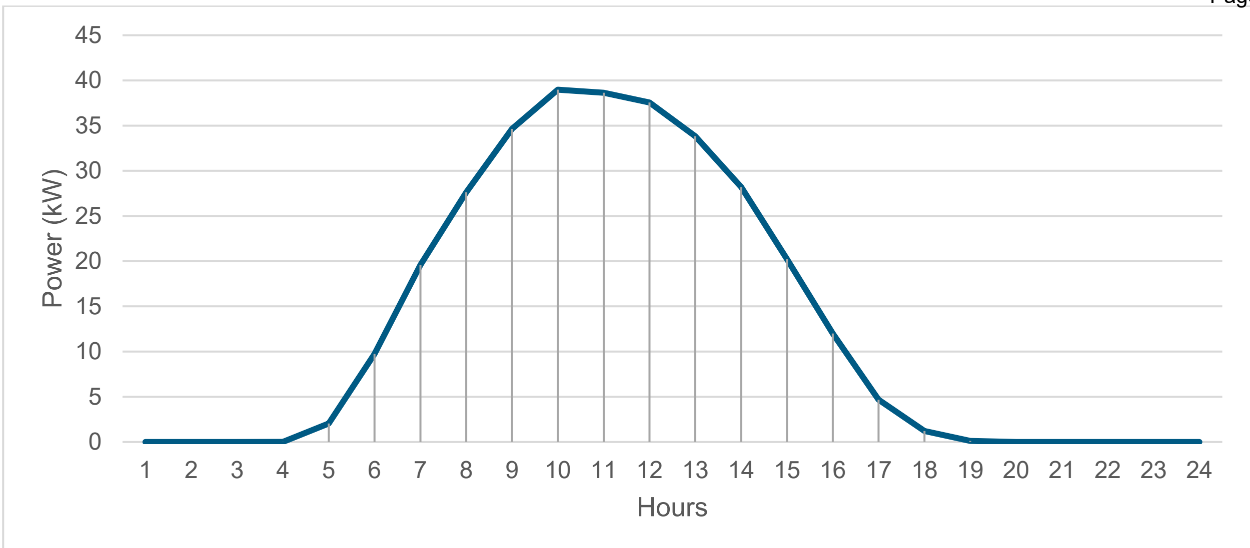

Figure 4-16 Minimum Hourly Output Power for a Summer Day, Commercial Building

The square area of the roof of the selected building is 13,788 square feet. The total square area of the roofs at Kanata North is obtained using MPAC data and adjusted using the square footage forecast developed in milestone #1. The total square footage forecasted in the year 2023 is found to be 7,945,730 square feet. Therefore, the total technical potential for peak reduction using roof-top PV DGs, mounted on commercial buildings, is 7.03 MW.

4.4.2. Technical Potential of Residential DGs

The same procedure is applied for the residential buildings; two houses were selected; one single-family house and one ROW house. Helioscope was used to determine the optimal PV module distribution. Figures 4-17 shows the optimal PV module distribution for the selected single-family house.

Figure 4-17 Layout of the PV arrays, Single-Family House

The minimum Summer day output powers are obtained as presented in Figure 4-18 and 4-19 for the single family and the ROW house, respectively. The results show that the PV DG mounted on the single-family house reduced the Summer peak by 2.732 kW, and that of the ROW house reduced the Summer peak by 1.793 kW.

To calculate the total technical potential for peak reduction for all residential buildings, the residential building forecast developed in Section 3 was used. The total forecasted single-family houses in 2023 are 7,468 houses, and the forecasted RO housed in 2023 are 5,826 houses. Therefore, the total technical potential for peak reduction using roof-top PV DGs is 20.4 MW for the single-family and 10.446 MW for the ROW. Therefore, the total technical potential of peak reduction for the residential sector is 30.84 MW and the total technical potential of the DER is 37.87 MW.

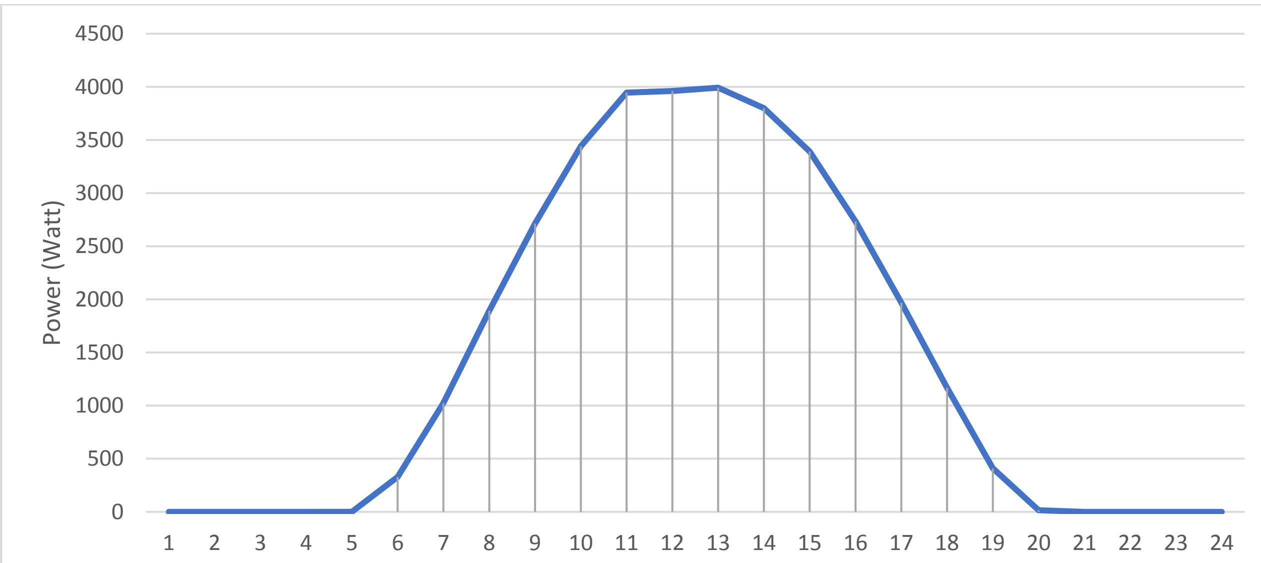

Figure 4-18 Minimum Hourly Output Power for a Summer Day, Single-Family House

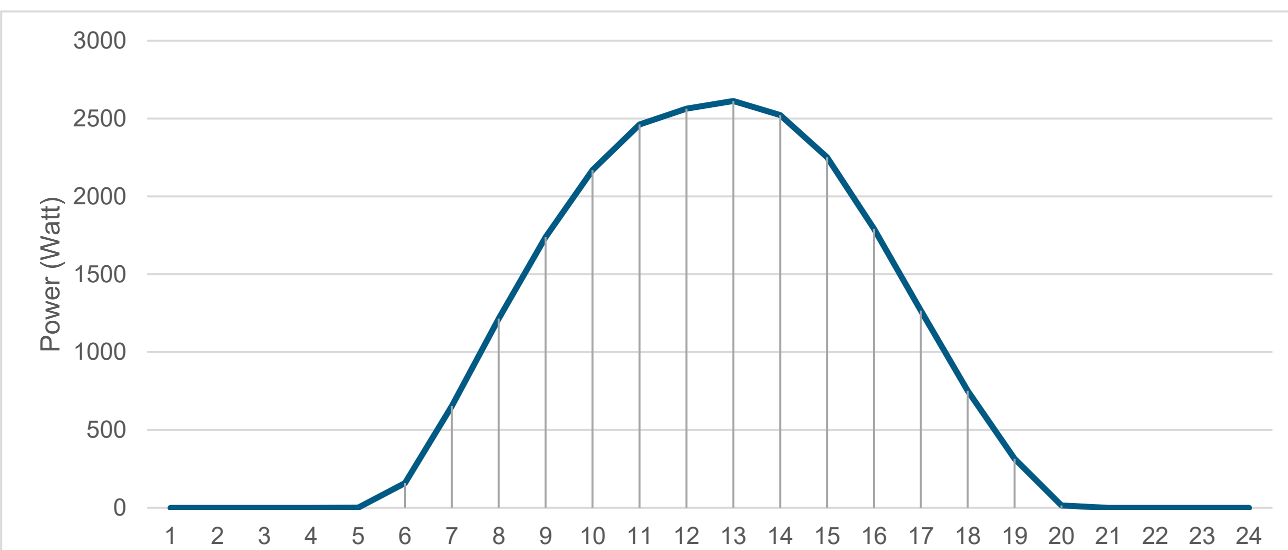

Figure 4-19 Minimum Hourly Output Power for a Summer Day, ROW House

5. Market Analysis of the Feasible Measures

Market analysis of all feasible CDM and DER are discussed in this section.

Adoption curves were developed to estimate the achievable potential of the CDM measures, which are curves estimating the participation of eligible customers in a program, based on their willingness to accept new technology or an idea, at a particular year as a percentage of the total population as shown in Figure 5-1 [18]. The adoption curve for each of the CDM measures was developed based on the historical participation in CDM programs and the values of the bass diffusion equation.

In addition, the impact of the Distributed Energy Resources (DER) on Kanata-Marchwood summer peak reduction is evaluated; the impact analysis is categorized into load shifting using a battery energy storage (BES) system and renewable-based distributed generation.

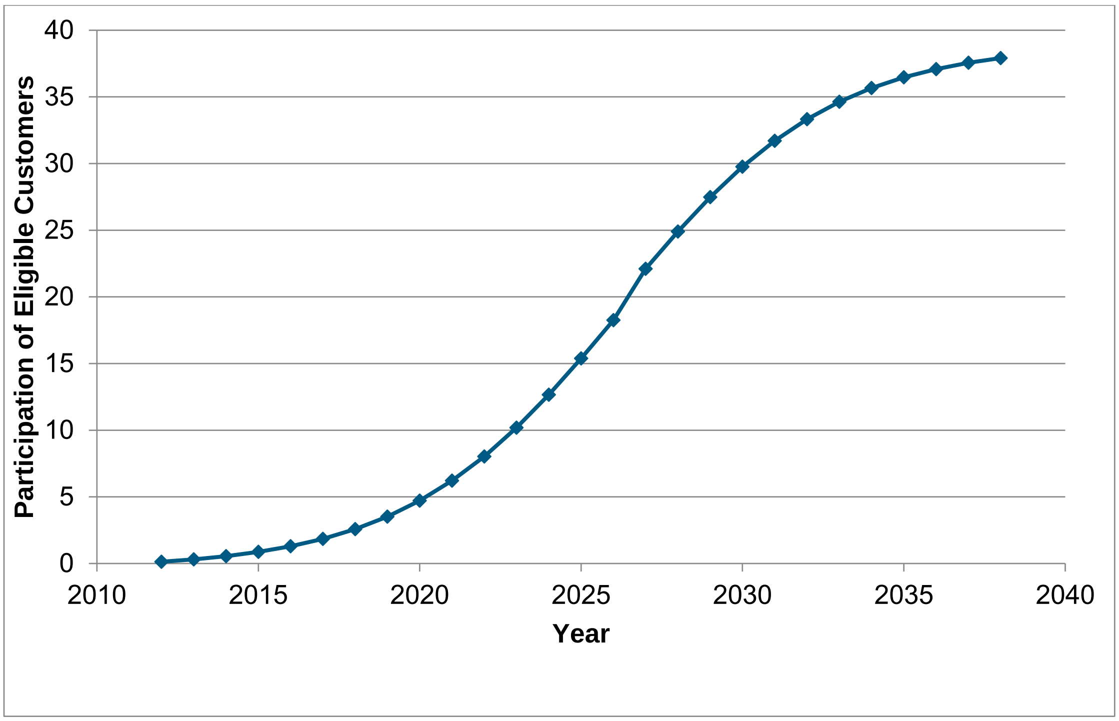

Figure 5-1 Adoption Curve

5.1. Achievable Potential of CDM Measures

The achievable potential is estimated using the technical potential determined in Section 3 after considering the customer adoption.

Based on the HOL plan, the new station (new Kanata North) is planned to be in service in 2028. Therefore, the presented study focuses on short-term achievable potential scenarios. This section shows the methodology followed for calculating the achievable potential of the CDM measures.

5.1.1. Methodology

Assessing achievable potential requires: calculating the technical potential of the CDM measures (identified in Section 3) and estimating the rate at which cost-effective measures could be adopted over time. The following key items were considered and addressed in developing the methodology:

- Historical performance of programs in HOL
- Development of adoption curves
- Mapping of measures to the adoption curves

The steps implemented in developing the adoption curves are:

- Measures categorization by sectors and subsectors first, and then further classification by end-use was done.
- For each end-use, the competition groups were developed. The obtained measures were mapped to the competition groups/ end-use/ subsector/ sector.
- The values of p, q, and m parameters in the bass diffusion equation were developed using statistical analysis of Ontario historic program participation data as provided by HOL [19]. These values were used to establish the adoption curves.
- Measures were then mapped to the adoption curves.
- The achievable potential for peak demand reduction for each measure was calculated as follows:

$$Achievable\ potential\ of\ measure = \frac{Technical\ potential\ of\ measure\ \times \text{number of}\ adopters}{eligible\ population}$$

5.1.2. Results and Discussions

The methodology described in section 5.1.1 is applied to the Kanata-Marchwood technically feasible measures developed in section #4.

5.1.2.1. Residential Sector

The achievable potential peak reduction is calculated for each competition group of the residential subsector/ end-use, and the total achievable potential peak reduction is calculated for each subsector and end-use. Figure 5-2 shows the technical and achievable potential summer peak reduction for each subsector; the most significant achievable potential was estimated for the single-family subsector, which accounts for 63.13% of the total peak reduction in 2023. Figures 5-3 to 5-6 show the reductions per residential end-use for each subsector. The overall achievable residential summer peak reduction in 2023 was estimated to be 481.31 kW, which accounts for 10.22% compared with the technical potential of the residential measures that had a value of 4.7 MW.

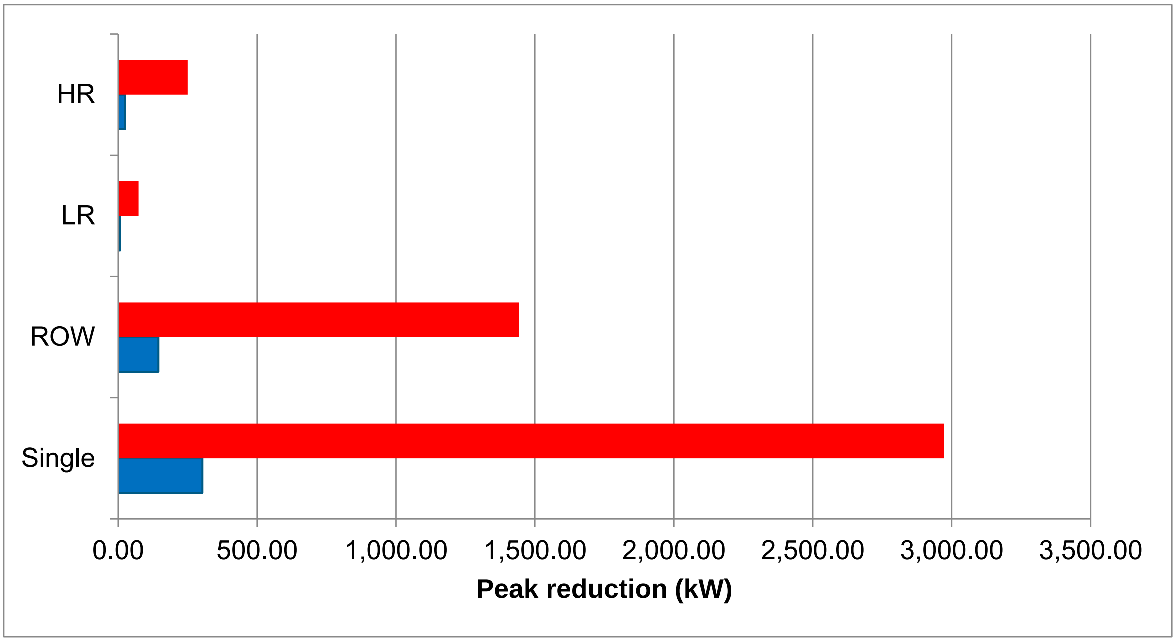

Figure 5-2 Technical and Achievable Potential Peak Reduction by Residential Subsector in 2023

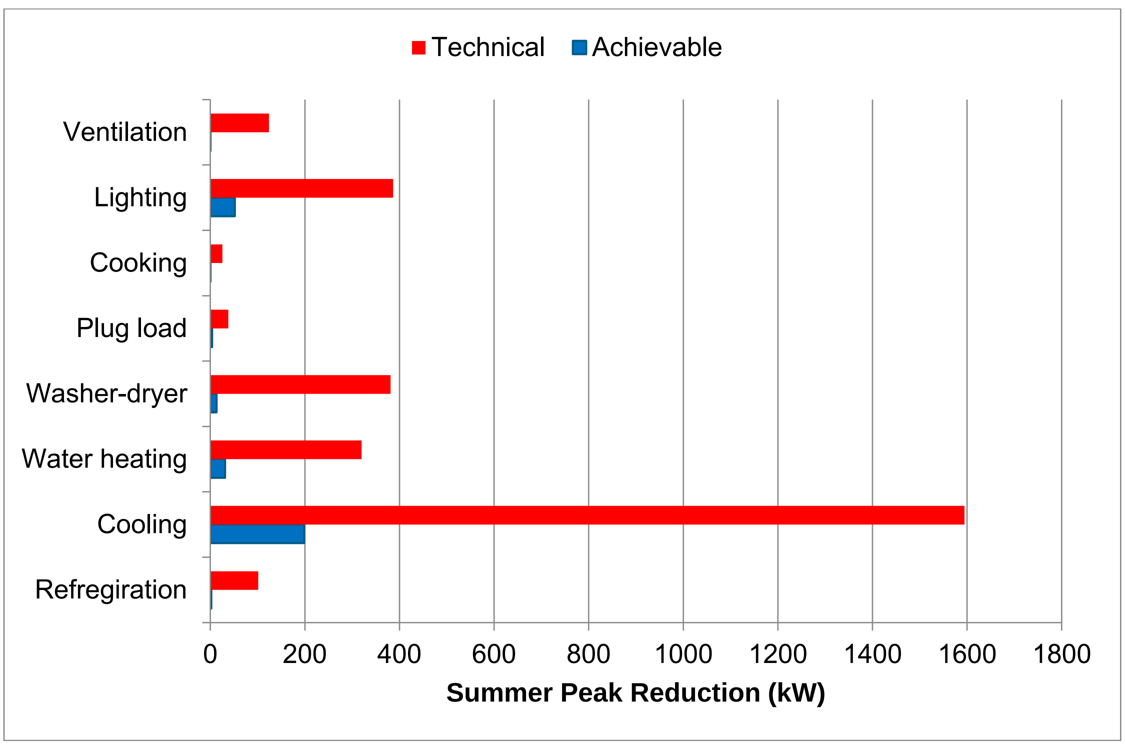

Figure 5-3 Technical and Achievable Potential Peak Reduction by End-use in 2023, Single-family

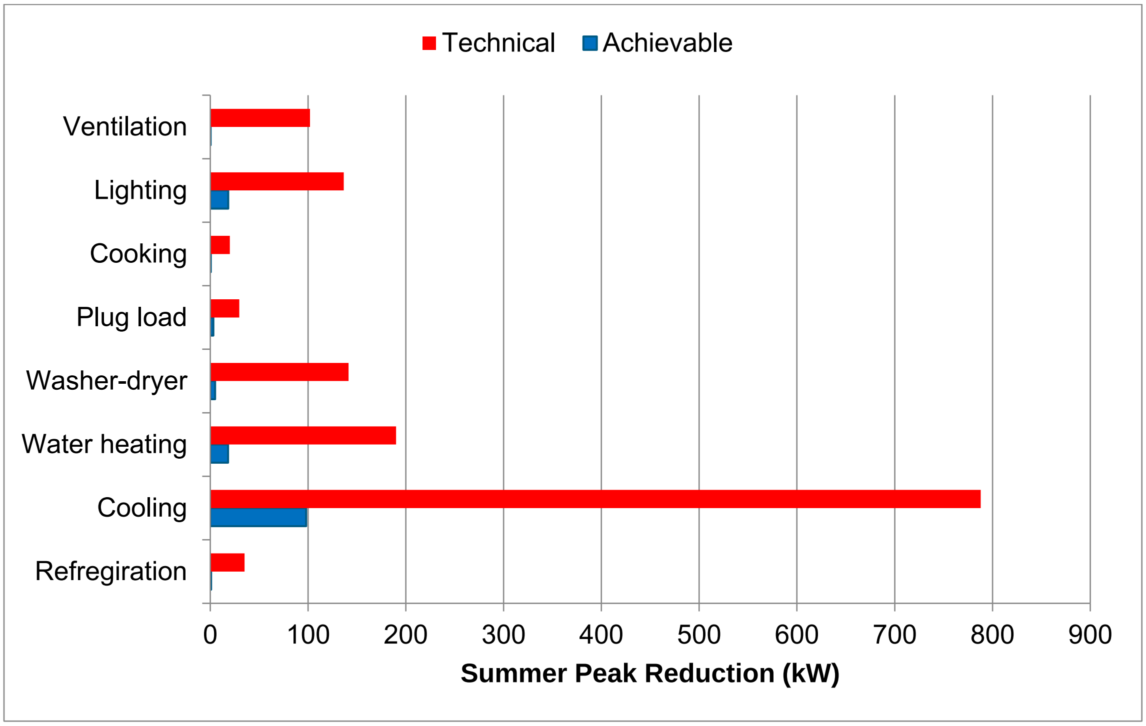

Figure 5-4 Technical and Achievable Potential Peak Reduction by End-use in 2023, Row

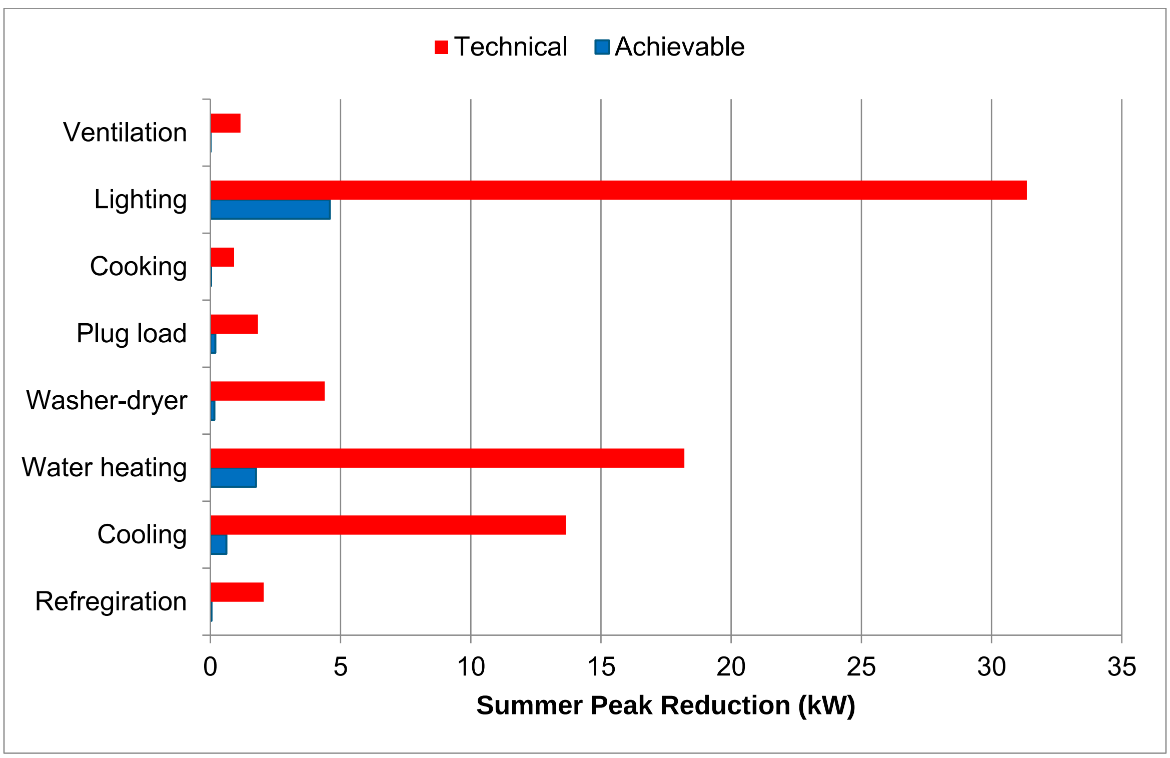

Figure 5-5 Achievable Potential Peak Reduction by End-use in 2023, Low Rise

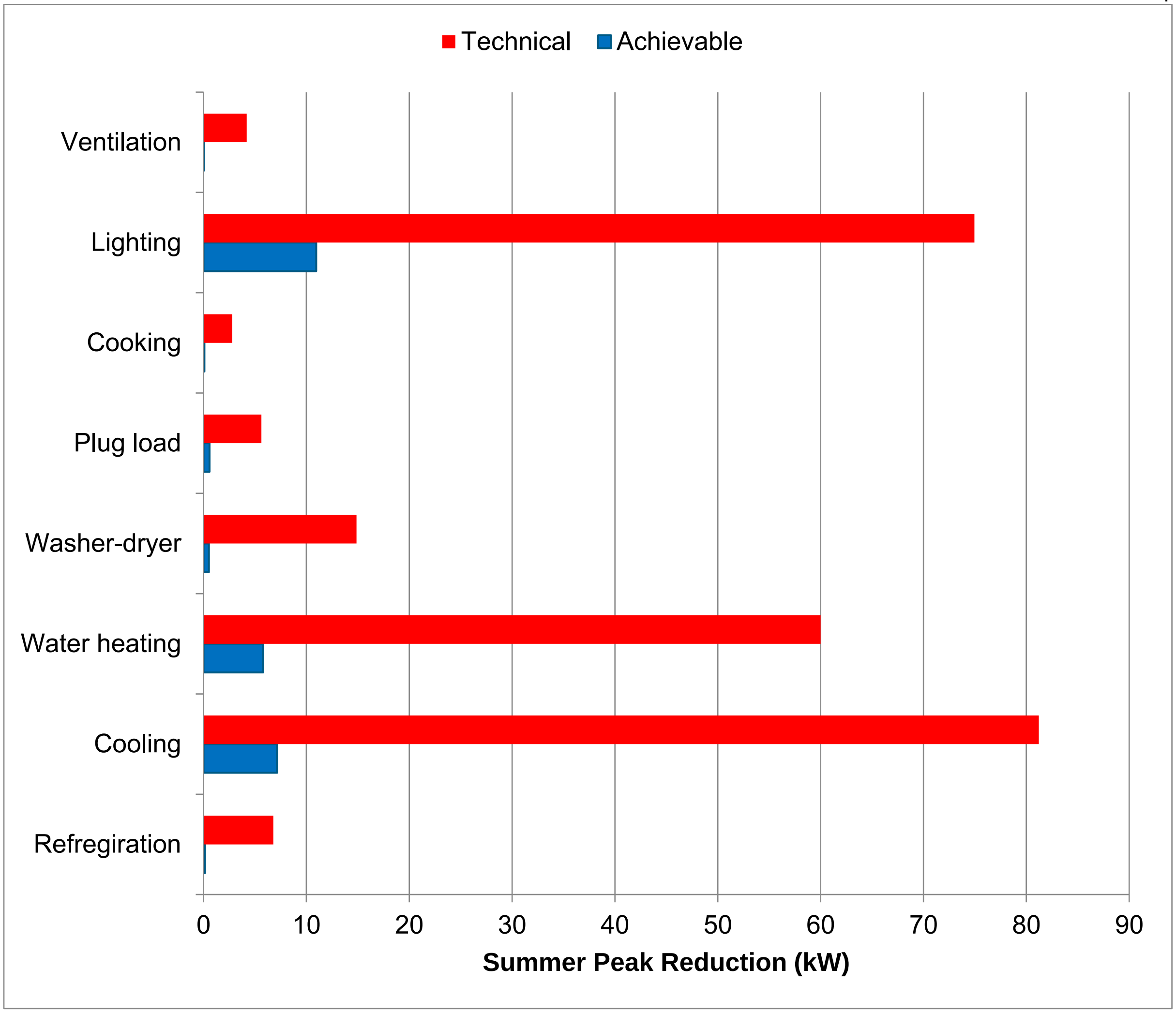

Figure 5-6 Achievable Potential Peak Reduction by End-use in 2023, High Rise

5.1.2.2. Commercial Sector

The achievable potential peak reduction is calculated for each competition group of the commercial subsector/ end-use, and the total achievable potential peak reduction is calculated for each subsector and end-use. Figure 5-7 shows the technical and achievable potential summer peak reduction for each subsector; the most significant achievable potential was estimated for the office subsector, which accounts for 57.58 % of the total peak reduction in 2023 followed by the food stores subsector that accounts for 14.48%. Figure 5-8 shows the overall reductions per commercial end-use; the lighting end-use represents the largest peak reductions of 60.51% of the overall reductions. The overall achievable commercial summer peak reduction in 2023 was estimated to be 5972.96 kW.

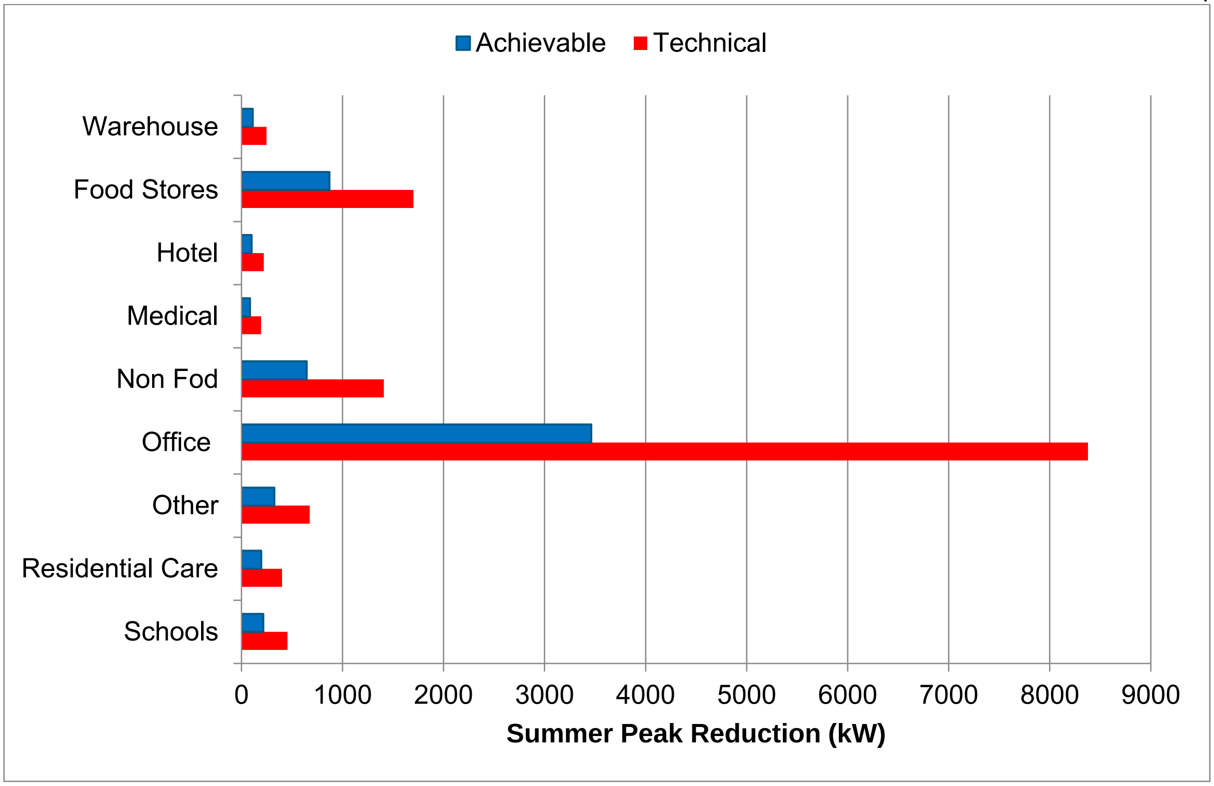

Figure 5-7 Technical and Achievable Potential Peak Reduction by Commercial Subsectors in 2023

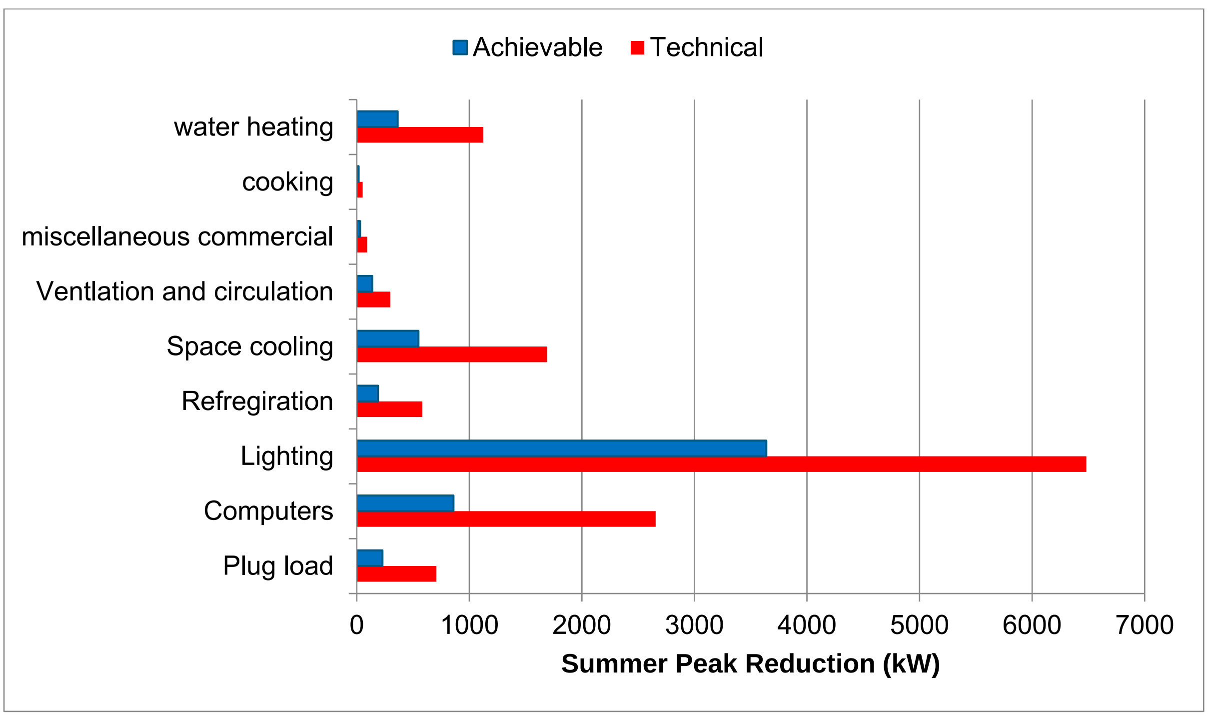

Figure 5-8 Technical and Achievable Potential Peak Reduction by End-use, Commercial Sector

5.2. Cost Analysis of Load Shifting Measures

The possibility of load shifting using the Battery Energy Storage (BES) system was performed for two scenarios, i.e., utility-scale and large customers-scale. In Section 4, the technical potential for using a battery owned by HOL and installed at the substation was determined. Moreover, the technical potential for installing batteries owned by large customers greater than 1000 kW was also determined. For each scenario, two cases were studied, i.e., batteries that are capable of discharging for 4 or 6 hours. In this section, the cost analysis for the BES is analyzed, as will be illustrated in the next subsections.

5.2.1. Utility-Scale Battery Energy Storage

The total system peak for the year 2023 was analyzed in Section 4, and the potential for peak reduction using substation-scale battery storage was determined for the 4-hour and 6-hour batteries. For utility-scale BES, no incentives will be provided since the BES is owned by HOL, and hence, only the economic analysis will be analyzed for this scenario.

The adequate battery size for the 4-hour scenario was 9,846 kWh, which can reduce the system peak by 3.782 MW. For the 6 hour scenario, the battery size was 31,216 kWh, which can reduce the system peak by 7.607 MW.

An example indicative order of magnitude capital costs for implementing distribution scale lithium-ion batteries to meet the requirements is summarized in Table 5-1. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 for the 4-hour and 6-hour scenarios, respectively. The estimate is built based on recent budgetary quotes received for a project of similar nature, and the average cost of $/kW and $/kWh are within the ranges published in [20]. It is to be noted the price is very sensitive for the battery cost, and in this example, the cost is estimated at C$ 390/kWH for Li batteries. Estimates published by various resources suggested decline prices for the LI batteries as the market for storage increases.

Table 5-1 Distribution Scale Battery Installation Cost

Scenario	4-Hour Scenario	6-Hour Scenario
Proposed Capacity Rating	3.75 MW	7.5 MW
Proposed Duration	4 Hrs	6 Hrs
MWH	15	45
Total Energy Storage System Cost		
DC Modules & BMS Equipment (excl. PCS)*	5850000	17550000
General conditions, EPC & Commissioning	2,000,000	2,000,000
Power Conversion System Equipment	750,000	1,500,000
Electric BoS	125,000	250,000
General conditions, EPC & Commissioning	750,000	1,250,000
Misc.	100,000	100,000
Total Cost	9,575,000	22,650,000
Avg. Cost $/KWh	638	503
Avg. Cost $/KW	2553	3020

5.2.2. Customer-Scale Battery Energy Storage

The presented methodology, in this section, aims to determine the level of incentive required for the BES project investment to be profitable, for the customer-scale BES. The concept of a minimum attractive rate of return (MARR) is selected for achieving the objective. If the internal rate of return (IRR), i.e., the rate of return that yields zero present worth value of cash flow, of the project is equal to or higher than the MARR, the project is considered profitable. The income of the BES investment is calculated at different levels of incentives, and the minimum level of incentives is determined. This minimum incentive level is the value that makes the IRR equal to MARR. For accurate economic assessment of the BES project, cash flow is performed. The following procedure is used to calculate the minimum incentives of the BES:

1) Calculate the battery capital cost (Cap) using (1)

$$Cap = [Capitalcost] - [(\frac{Incentives}{kWh}) \times battery\ capacity] \quad (1)$$

2) Calculate the income per year for the project lifetime using (2), considering the BES rated capacity as base power.

$$Inc\ (y) = \sum_{m=1}^{12} \Delta Peak\ of\ month \times demand\ peak\ rate] \quad (2)$$

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (3)

$$C(y) = \frac{Inc\ (y)}{(1 + inflation\ index)^{y}} \quad (3)$$

4) Calculate the minimum incentives/kW of the BES project capacity using (4); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$NPV = Cap - \sum_{y=1}^{N} \frac{C(y)}{(1 + MARR)^{y}} = 0 \quad (4)$$

5.2.1.1 Case Study

For the customer-scale BES, presented in Section #4, the customer with reference number (1323516000) was selected. The maximum load of this customer was 1,013 kW with BES of capacity 129.6kW and 181kW for the 4-hour and 6-hour case, respectively. The technical peak reduction was found to be 72.9 and 82 kW for the 4-hour and 6-hour case, respectively.

The economic analysis presented in the previous procedure is executed based on an average capital cost of $410,391 and $573,155 for the 4-hour and 6-hour case, respectively [21]. The MARR is set to 7%. The income is calculated based on the average regulated price plan for small business in HOL [20]. The inflation rate is set to 2.4% [22], the cash flow is calculated as presented in Table 5-2 and the required incentives to achieve the 7% MARR for the 4-hour and 6-hour cases are $323,065 and $474,928 which means the incentive range between $ 4432-5791 per kW peak reduction. These incentives are significantly high relative to the corresponding savings and are not economically viable. As a result, the customer-scale BES will be excluded from the achievable potential analysis.

Table 5-2 Cash Flow for Customer-Scale BES

	4-Hour Case				6-Hour Case			
Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	410391				573155			
1		7873.2	7718.82	7213.85		8856	8682.35	8114.35
2		8138.95	7822.90	6832.83		9154.92	8799.42	7685.76
3		8404.69	7919.93	6465.02		9453.84	8908.56	7272.04
4		8670.44	8010.15	6110.90		9752.77	9010.04	6873.72
5		8936.19	8093.78	5770.75		10051.68	9104.11	6491.11
6		9201.93	8171.05	5444.72		10350.60	9191.03	6124.37
7		9467.68	8242.18	5132.82		10649.51	9271.04	5773.54
8		9733.43	8307.38	4834.97		10948.43	9344.38	5438.52
9		9999.17	8366.86	4551.02		11247.35	9411.28	5119.11
10		10264.92	8420.81	4280.71		11546.27	9471.97	4815.07
11		10530.66	8469.42	4023.76		11845.19	9526.65	4526.04
12		10796.41	8512.90	3779.83		12144.11	59575.54	4251.66
13		11062.16	8551.41	3548.53		12443.03	9618.86	3991.49
14		11327.9	8585.13	3329.46		12741.95	9656.80	3745.08
15		11593.65	8614.25	3122.20		13040.87	9689.56	3511.94
16		11859.4	8638.93	2926.30		13339.79	9717.31	3291.59
17		12125.14	8659.32	2741.32		13638.71	9740.25	3083.51
18		12390.89	8675.60	2566.80		13937.63	9758.56	2887.21
19		12656.64	8687.90	2402.28		14236.54	9772.40	2702.15
20		12922.38	8696.39	2247.31		14535.46	9781.95	2527.84
PV of Adjusted Income Considering MARR (A)				87325.39	PV of Adjusted Income Considering MARR (A)			98226.09
Capital Cost (B)				410391	Capital Cost (B)			573155
Incentive (B)-(A)				323065	Incentive (B)-(A)			474928
Peak Reduction kW				72.9	Peak Reduction kW			82
Incentive $/KW of peak reduction				4432	Incentive $/KW of peak reduction			5791

5.3. Cost Analysis of DG Measures

The presented methodology, in this section, aims to determine the level of incentive required for the DG project investment to be profitable and to calculate the achievable potential for the DG measures.

The concept of MARR is selected for determining the level of incentives. The income of the DG investment is calculated, and the minimum level of incentives is determined. For accurate economic assessment of the PV DG project, cash flow is performed. The proposed algorithm for the minimum incentive level determination is discussed as detailed below in section 5.3.1 and 5.3.2, while the achievable potential calculation is discussed in section 5.3.3.

5.3.1. PV DGs Installed on Residential Rooftops

The following procedure is used to calculate the minimum incentives of the residential scale PV DGs:

1) Calculate the DG capital cost (Cap) using Equation (5)

$$\mathrm{Cap} = [\mathrm{Capital\ cost} / \mathrm{kW} \times \mathrm{DG\ Capacity}] - [\mathrm{Incentives} / \mathrm{kW} \times \mathrm{DG\ Capacity}] \tag{5}$$

2) Calculate the income per year for the project lifetime using (6), considering the DG rated capacity as base power.

$$\mathrm{Inc}\,(\mathrm{y}) = \sum_{\mathrm{m}=1}^{12} \sum_{\mathrm{hr}=1}^{24} [\mathrm{E_g}(\mathrm{y},\mathrm{m},\mathrm{hr}) \times \mathrm{P_r}(\mathrm{m},\mathrm{hr})] \times \mathrm{N_d}(\mathrm{m}) \tag{6}$$

Where Inc (y) is the DG project income for certain year (y), Eg (y,m,hr) is the DG generated energy at certain hour (hr) at certain month (m) for a certain year, Pr (m, hr) is the time of use (TOU) electricity rates at certain hour at certain month and Nd (m) represents the number of days per month (m).

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (7)

$$\mathrm{C}(\mathrm{y}) = \frac{\mathrm{Inc}\,(\mathrm{y})}{(1 + \mathrm{inflation\ index})^{\mathrm{y}}} \tag{7}$$

4) Calculate the minimum incentives/kW of the DG project capacity using (8); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$\mathrm{NPV} = \mathrm{Cap} - \sum_{\mathrm{y}=1}^{\mathrm{N}} \frac{\mathrm{C}(\mathrm{y})}{(1 + \mathrm{MARR})^{\mathrm{y}}} = 0 \tag{8}$$

Where NPV is the net present value, and N is the project lifetime.

5.3.1.1. Case Study

For the PV DGs installed on the single-family house presented in Section 4, the PV DG installed capacity is 8.68 kW with annual generated energy of 9.231 MWh. This generated energy is still lower than the average annual electricity consumption for a single house (9652 MWh; obtained from Milestone #1 load segmentation report). This means according to the net energy metering, the PV DG will not inject any energy into the grid, and all the generated energy will be used to lower the electricity bill. Based on the average capital cost of 2.53 $/W [23], the economic analysis presented in the previous procedure is executed with a MARR of 7%. The income is calculated based on the generated energy/hr, residential electricity price as per [24], and an inflation rate of 2.4%. The cash flow is calculated as presented in Table 5-3, and the required incentives to achieve the 7% MARR is 9,867$, which means the incentives per installed kW is 1140.76 $/kW.

Table 5-3 Cash Flow for PV Installed on Residential Rooftop

Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	21960.4			
1		1039.20	1018.83	952.17
2		1084.36	1042.26	910.35
3		1131.49	1066.23	870.36
4		1180.66	1090.75	832.13
5		1231.97	1115.83	795.57
6		1285.51	1141.49	760.62
7		1341.37	1167.74	727.21
8		1399.66	1194.60	695.27
9		1460.49	1222.07	664.73
10		1523.96	1250.18	635.53
11		1590.19	1278.93	607.61
12		1659.29	1308.34	580.92
13		1567.98	1212.10	502.98
14		1659.29	1257.54	487.69
15		1659.29	1232.88	446.85
16		1576.23	1148.20	388.94
17		1559.73	1113.90	352.63
18		1551.48	1086.28	321.39
19		1543.22	1059.32	292.91
20		1534.97	1032.99	266.94

5.3.2. PV DGs Installed on Commercial Rooftops

The following procedure is used to calculate the minimum incentives of the commercial-scale PV DGs:

1) Calculate the DG capital cost using (9)

$$Cap = [Capitalcost/\ kW \times DGCapacity] - [Incentives\ /\ kW \times DGCapacity] \quad (9)$$

2) Calculate the income per year for the project lifetime using (10), considering the DG rated capacity as base power.

$$Inc\ (y) = \sum_{m=1}^{12} [E_g(m) \times [A_{WPR}(m)] \quad (10)$$

E_G (m) is the DG generated energy for certain month (m) for a certain year, A_{WPR}(m) is the averaged weight hourly price at certain month m.

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (11)

$$C(y) = \frac{Inc\ (y)}{(1 + inflationindex)^y} \quad (11)$$

4) Calculate the minimum incentives/kW of the DG project capacity using (12); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$NPV = Capcost - \sum_{y=1}^{N} \frac{C(y)}{(1 + MARR)^y} = 0 \quad (12)$$

5.3.2.1. Case Study

For the PV DGs installed on commercial buildings presented in Section 4, the PV DG installed capacity is 58.5 kW with an annual generated energy of 73.79 MWh. This generated energy is still lower than the average annual electricity consumption for a single commercial building. This means according to the net energy metering, the PV DG will not inject any energy into the grid, and all the generated energy will be used to lower the electricity bill. Based on the average capital cost of 2.53 $/W, the economic analysis presented in the previous procedure is executed. The MARR is set to 7%. The income is calculated based on the energy price in Ontario [25], and on the inflation rate of 2.4%, the cash flow is calculated as presented in Table 5-4, and the required incentives to achieve the 7% MARR is $ 129,442 which means the incentives per installed kW is 2200 $/kW.

Table 5-4 Cash Flow for PV Installed on Commercial Building

Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	21960.4			
1		1742.01	1707.85	1596.12
2		1800.81	1730.88	1511.82
3		1859.60	1752.35	1430.44
4		1918.40	1772.31	1352.08
5		1977.20	1790.81	1276.82
6		2036.00	1807.91	1204.69
7		2094.80	1823.65	1135.68
8		2153.60	1838.07	1069.78
9		2212.40	1851.23	1006.95
10		2271.19	1863.17	947.14
11		2329.99	1873.93	890.29
12		2388.79	1883.54	836.32
13		2447.59	1892.07	785.14
14		2506.39	1899.53	736.67
15		2565.19	1905.97	690.81
16		2623.98	1911.43	647.47
17		2682.78	1915.94	606.54
18		2741.58	1919.54	567.92
19		2800.38	1922.27	531.52
20		2859.18	1924.14	497.24

5.3.3. Achievable Potential of PV DGs

The DERs contract capacity, as well as the potential for expansion based on the input data received from the HOL and IESO, is presented in Section 3. The installed DER capacity at Kanata-Marchwood was given as 1.1498 MW, and it is forecasted to be at the same level in 2023 based on the current DERs programs and incentives offered in Ontario. Given the capital cost of the DERs as 2.53 \$/W, the total cost of the installed capacity is \$ 2,908,994. The installed capacity (1.1498 MW) would reduce the summer peak demand by 0.3603 MW as illustrated in Section 3, and hence the unit cost of peak reduction associated with the PV DGs is estimated as follows:

$$\text{Unit cost}\left(\frac{\$}{\text{kW}}\right) = \frac{\text{Incremental life cost}}{\text{Summer peak demand savings per unit (kW)}} = \frac{2{,}908{,}994}{360.3059} = 8073.67\ \$/\text{kW} \qquad (13)$$

5.4. Findings and Observations

The following can be observed from the achievable potential and cost analysis by sector, subsectors, and end use:

- The total achievable potential reduction for CDM was estimated at 6,454.91 kW, the residential sector accounts for 481.31 kW, while the commercial sector accounts for 5972.96 kW.
- For the residential sector, the largest achievable potential was estimated for the single-family subsector.
- For the commercial sector, the largest achievable potential was estimated for office subsector.
- At the residential sector end-use level, lighting items showed the largest achievable potential, while cooking, refrigeration, and ventilation showed the lowest achievable potential.
- At the commercial sector end-use level, lighting items represented the largest achievable potential, while cooking and miscellaneous commercial showed the lowest achievable potential.
- For commercial-scale BES, the required incentive levels were estimated between $ 4432-5791 per kW of peak reduction, which are significantly high relative to the corresponding savings. Accordingly, the customer-scale BES was excluded from the achievable potential analysis.
- For utility-scale BES, the budgetary cost for implementing this project was estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- In addition to the peak reduction considered in this study, the utility-scale BES can provide flexibility and operational benefits by providing ancillary services such as providing back up power, voltage, and frequency support. The economic benefits of ancillary services were not considered in this study due to the lack of market regulation that can be used to generate revenues corresponding to these ancillary services.
- For residential and commercial PV rooftop, the incentives per installed kW were estimated at 1140.76 $/kW and 2200 $/kW.

6. Scenario Analysis

This section presents the analysis of the impact of incentives variations on the achievable potential identified in section 5 in order to estimate the new achievable potential and determine the combinations of technical feasible CDM and DER measures that can meet the technical requirement for given incentive levels and avoided costs.

The incentive level of each measure was determined based on the IESO libraries. The obtained incentive levels and the sources of these values were referenced in the workbook submitted to IESO. Then, incentive cost ($/kW) for each measure was determined as described in (1).

$$Incentives\ cost\ (\frac{\$}{kW}) = \frac{Incentives\ provided\ by\ IESO}{Summer\ peak\ demand\ savings\ per\ unit\ (kW)} \quad (1)$$

A cost curve is constructed based on the peak demand reduction cost of all the CDM measures, under the achievable potential scenario in this section. The curve shows each measure as a step in the curve, with the horizontal length of each step indicating the peak demand reduction of the measure and its height above the horizontal axis shows how much it costs per kW ($/kW) of reduction. Measures are sorted according to their incentive cost ($/kW), where the measures with low incentive cost come first in the curve. The advantage of developing a cost curve is that the overall cost-effective potential can be estimated using one graph, as illustrated in Figure 6-1 for the CDM and DER measures.

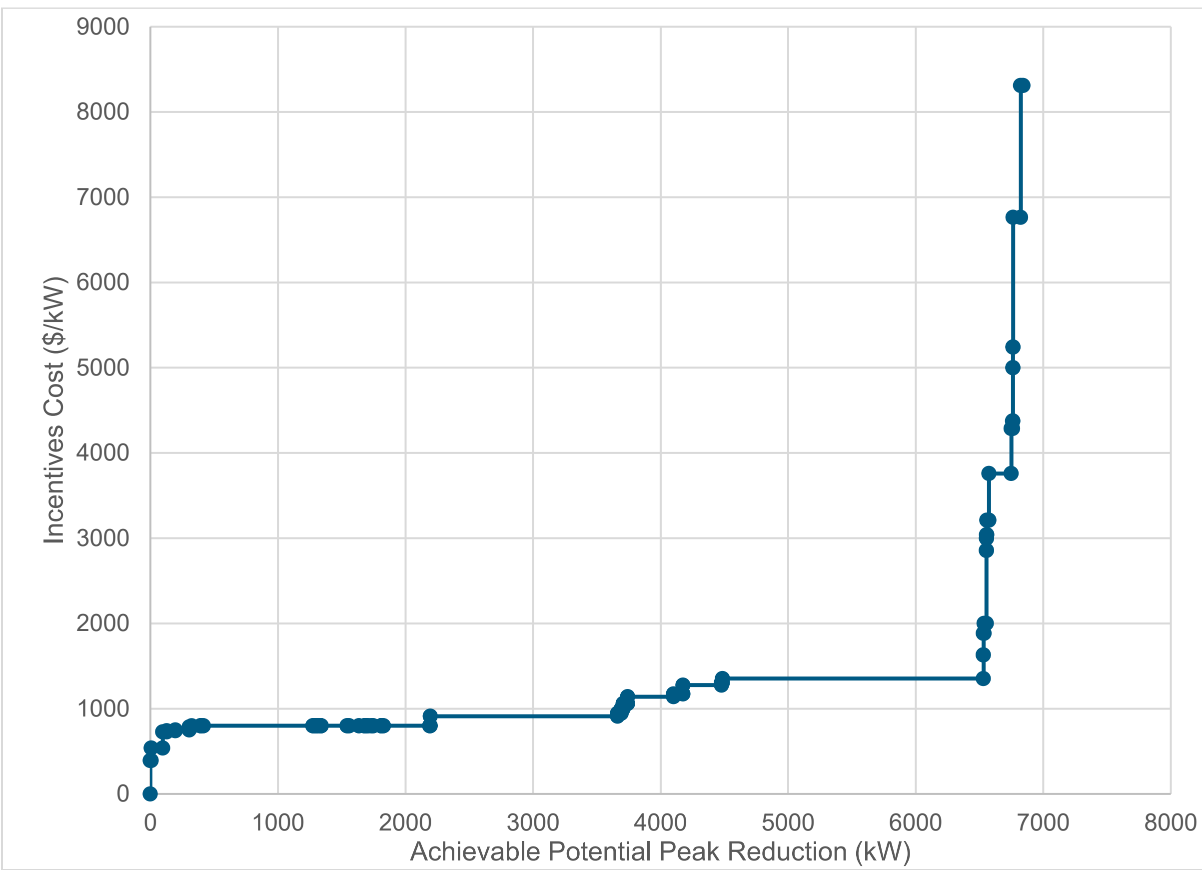

Figure 6-1 Cost Curve of CDM and DER Measures

6.1. Impact of Incentives Variation on Achievable Potential

The sensitivity analysis was conducted to study the impact of incentives variations on the achievable potential based on the price elasticity technique. Where the price elasticity is a primary measure of demand or supply sensitivity to changes in price. The price elasticity values were used to establish the adjustment factor to be applied to the base case modelled savings estimates.

The following methodology was used to access the impact on the achievable potential due to variation in incentives rates:

1- Incentive rates were changed by a certain percentage (+/-) for each measure category (e.g., lighting control products, advanced power bars, etc.).
2- The value of the incentive cost is then calculated based on (2).

$$Incentives\ cost\ (\frac{\$}{kW}) = \frac{Incentives\ provided\ by\ IESO}{Summer\ peak\ demand\ savings\ per\ unit\ (kW)} \quad (2)$$

3- The savings factor adjustment was determined based on the price elasticity values for the residential and commercial sectors. This factor was applied to the base case modelled savings estimates using the formula described in (3).

$$Savings\ Factor\ Adjustment = 1 + Price\ Elasticity\ Value\ \times Incentive\ Change\ \% \quad (3)$$

Where the price elasticity is a primary measure of demand or supply sensitivity to changes in price, an elasticity value of 1.0 would indicate a product that is perfectly elastic, while a value of 0 would mean that the product is inelastic and hence changes in prices have no effect on demand or supply [19] and [26].

4- The project team considered ranges from 0.426-0.46 and from 0.25-0.302 for the price elasticity in the commercial and residential sectors, respectively [19], [26]. The price elasticity of the DERs is assumed to be in the range of 0.25-0.302.
The price elasticity values were based on methodology on a collection of EIA [27] Form 861 data for individual utilities and on panel regression analysis of utility customer supply of demand response capacity as a function of utility incentive payments.
5- The achievable potential estimations were revised based on the incentive level and price elasticity value.

6.1.1. Results and Discussions

The methodology described in the previous section is applied to the Kanata-Marchwood technically feasible measures. The factors required for estimating the achievable potential corresponding to variations in the incentive rates; (i.e., the incentive cost of each measure and the achievable potential of each measure) are determined, as illustrated in the previous section. It should be noted that the incentive levels of all measures are assumed to be equally increased. However, the IESO has the capability to provide the incentive level of each measure independently in the updatable excel sheet.

6.1.1.1. Residential Sector

The impact of incentive rate variations on the achievable potential peak reduction is estimated for each competition group of the residential subsector/ end-use, and the total achievable potential peak reduction is determined for each subsector and end-use. Figure 6-2 presents the increase in the achievable potential summer peak reduction, assuming incentive increases of 5%, 10%, 20%, and 40%. For residential sector, the elasticity estimates suggest that increasing the amount of each product's incentive by 5%, 10%, 20%, and 40%, would increase the total achievable potential by 1.24-1.49 %, 2.44-2.93 %, 4.76-5.69 %, and 9.09-10.78 %, for price elasticity ranging from 0.25-0.302. In other words, increasing the incentive rates by 5%, 10%, 20%, and 40% resulted in an increase in the achievable potential to a value ranging from 487.71 kW- 488.96 kW, 493.73-496.24 kW, 505.77-501.78 kW, and 528.86-539.88 kW, respectively, for price elasticity ranging from 0.25-0.302.

Figure 6-3 to 6-6 present the achievable potential summer peak reduction per end-use for price elasticity of 0.25 and 0.302, assuming incentive increases of 5%, 10%, 20%, and 40, respectively.

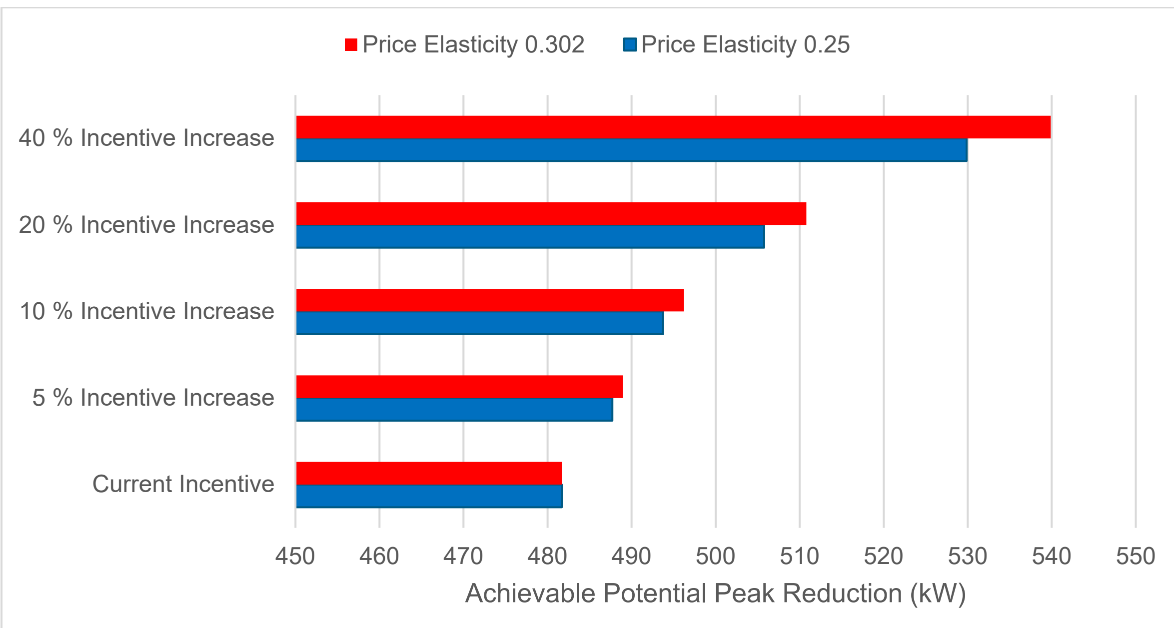

Figure 6-2 Impact of Incentives Variations on Residential Sector Achievable Potential

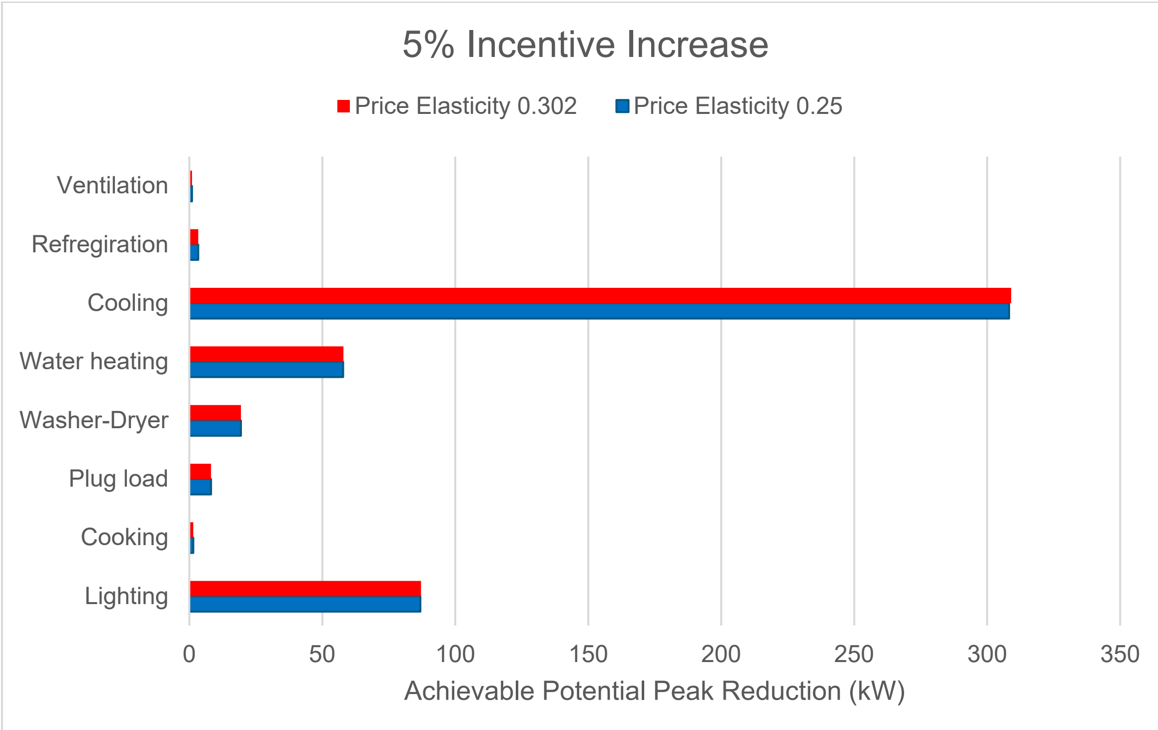

Figure 6-3 Impact of 5% Incentives Increase on Achievable Potential Per End-Use

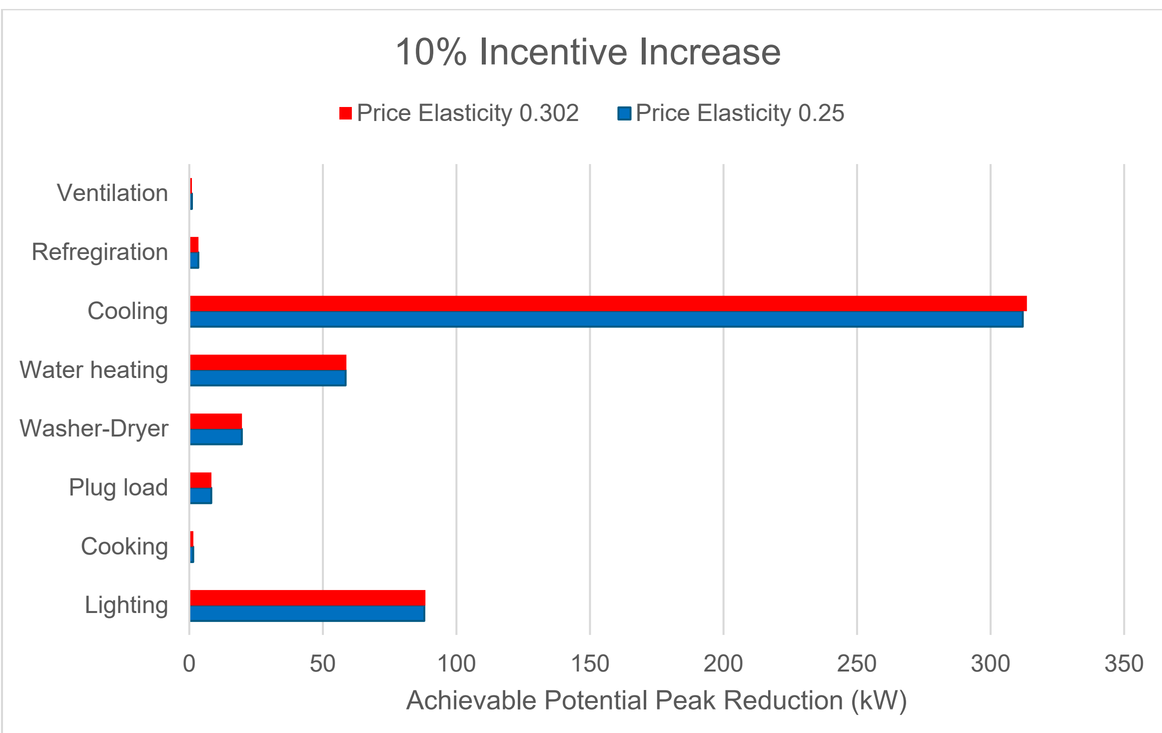

Figure 6-4 Impact of 10% Incentives Increase on Achievable Potential Per End-Use

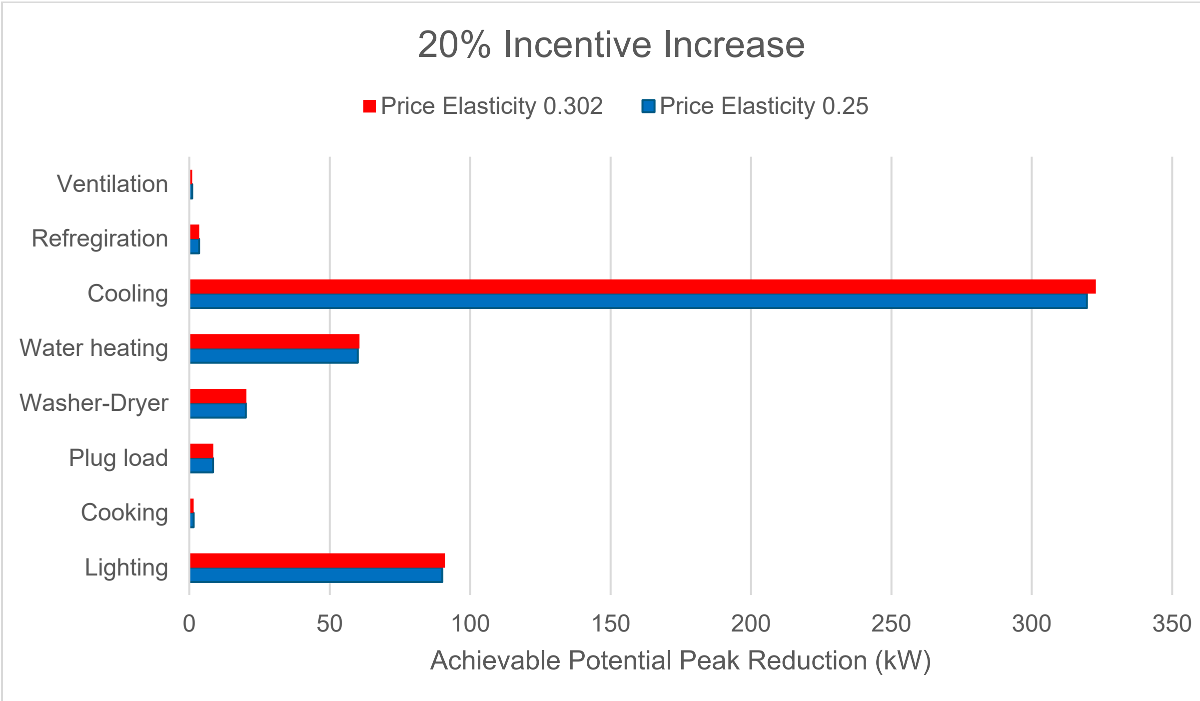

Figure 6-5 Impact of 20% Incentives Increase on Achievable Potential Per End-Use

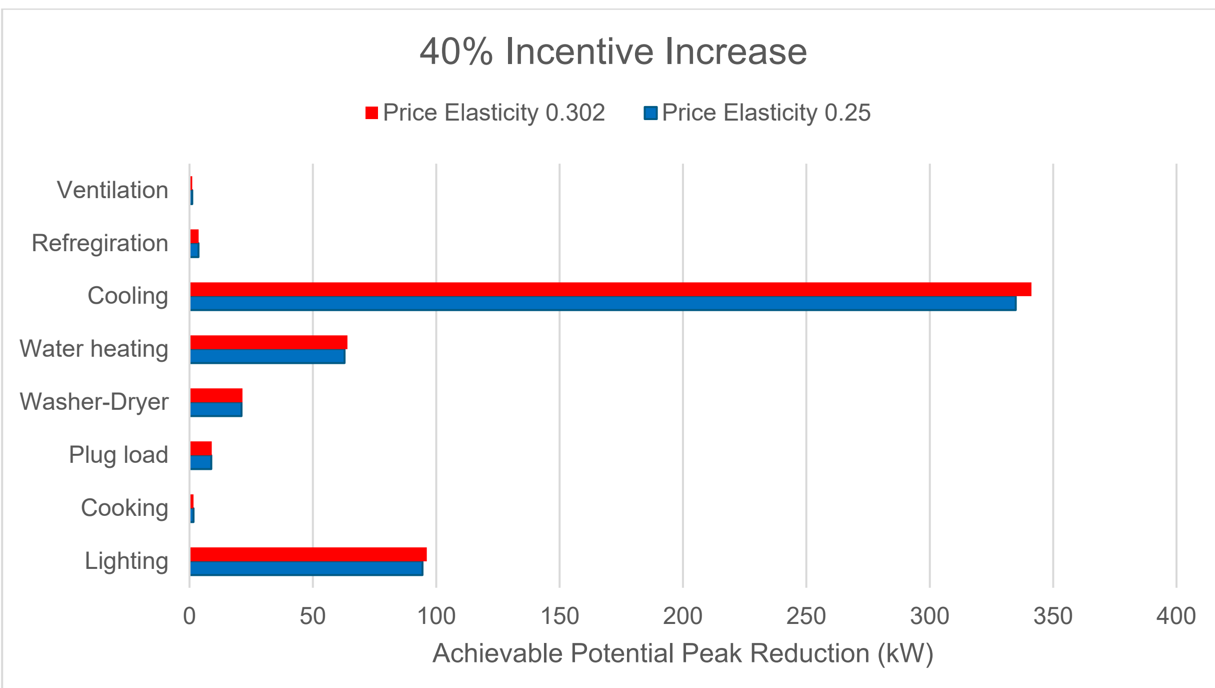

Figure 6-6 Impact of 40% Incentives Increase on Achievable Potential Per End-Use

6.1.1.2. Commercial Sector

The impact of incentive rate variations on the achievable potential peak reduction is estimated for each competition group of the commercial subsector/ end-use, and the total achievable potential peak reduction is estimated for each subsector and end-use. Figure 6-7 presents the increase in the achievable potential summer peak reduction, assuming incentive increases of 5%, 10%, 20%, and 40%. For commercial sector, the elasticity estimates suggest that increasing the amount of each product's incentive by 5%, 10%, 20%, and 40%, would increase the total achievable potential by 2.09-2.25 %, 4.09-4.40 %, 7.85-8.43 %, and 14.56-15.54 %, for price elasticity ranging from 0.426-0.46. In other words, increasing the incentive rates by 5%, 10%, 20%, and 40% resulted in an increase in the achievable potential to a value ranging from 6100.18 kW- 6100.33 kW, 6227.41-6247.72 kW, 6481.86-6522.47 kW, and 6990.75-7071.98 kW, respectively, for price elasticity ranging from 0.426-0.46.

Figures 6-8 to 6-11 present the achievable potential summer peak reduction per end-use for price elasticity of 0.426 and 0.46, assuming incentive increases of 5%, 10%, 20%, and 40, respectively

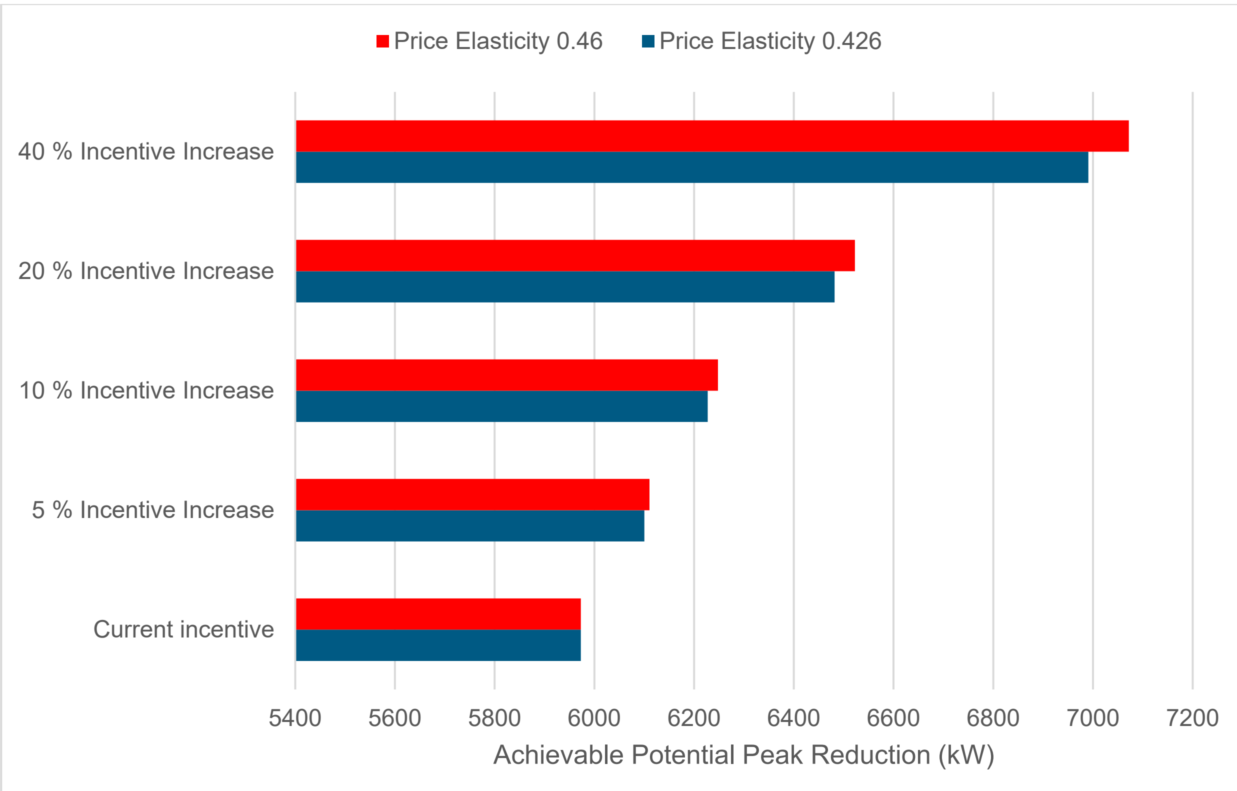

Figure 6-7 Impact of Incentives Variations on Commercial Sector Achievable Potential

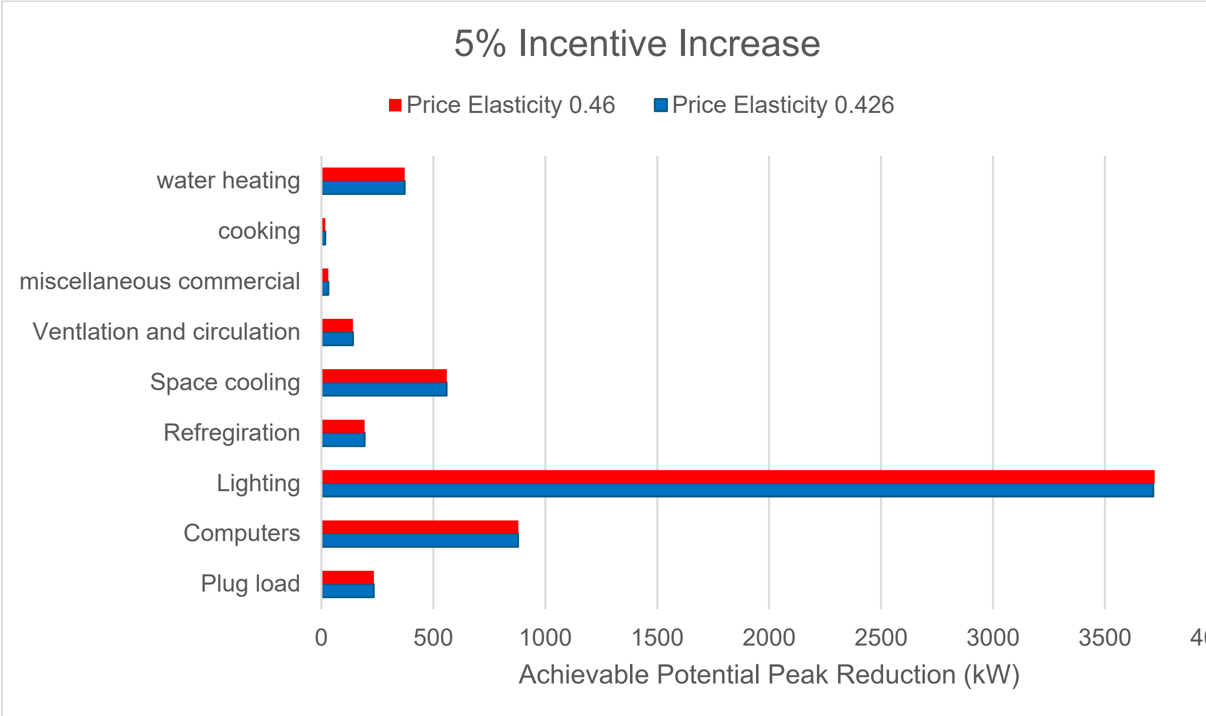

Figure 6-8 Impact of 5% Incentives Increase on Achievable Potential Per End-Use

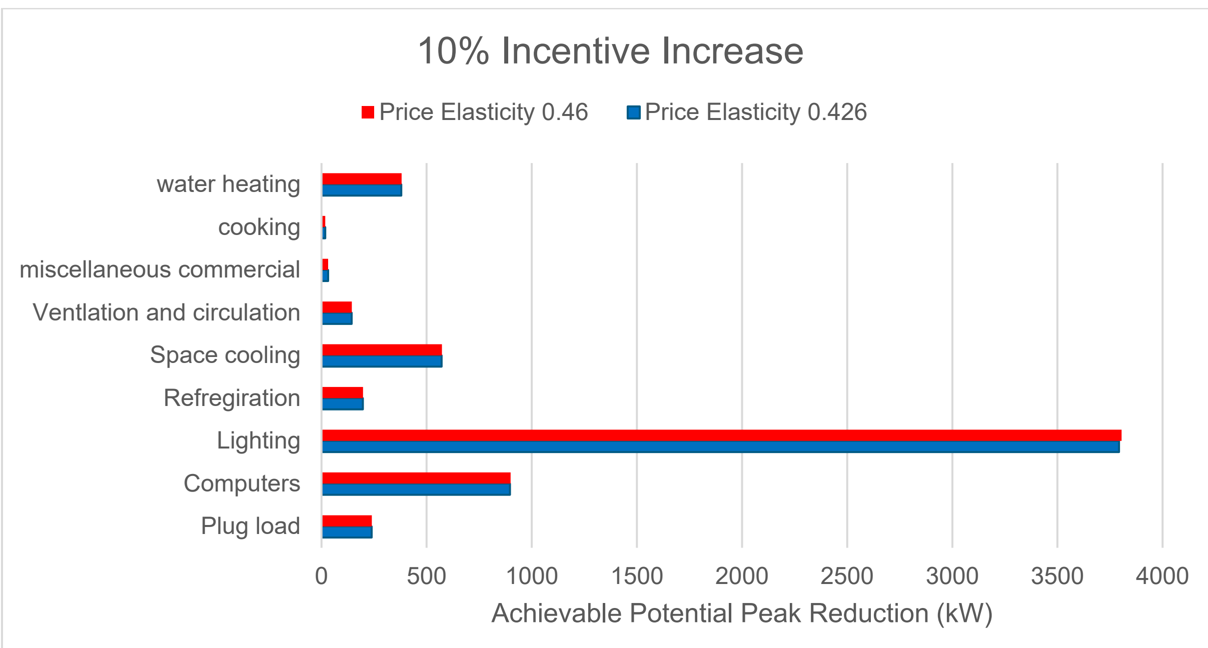

Figure 6-9 Impact of 10% Incentives Increase on Achievable Potential Per End-Use

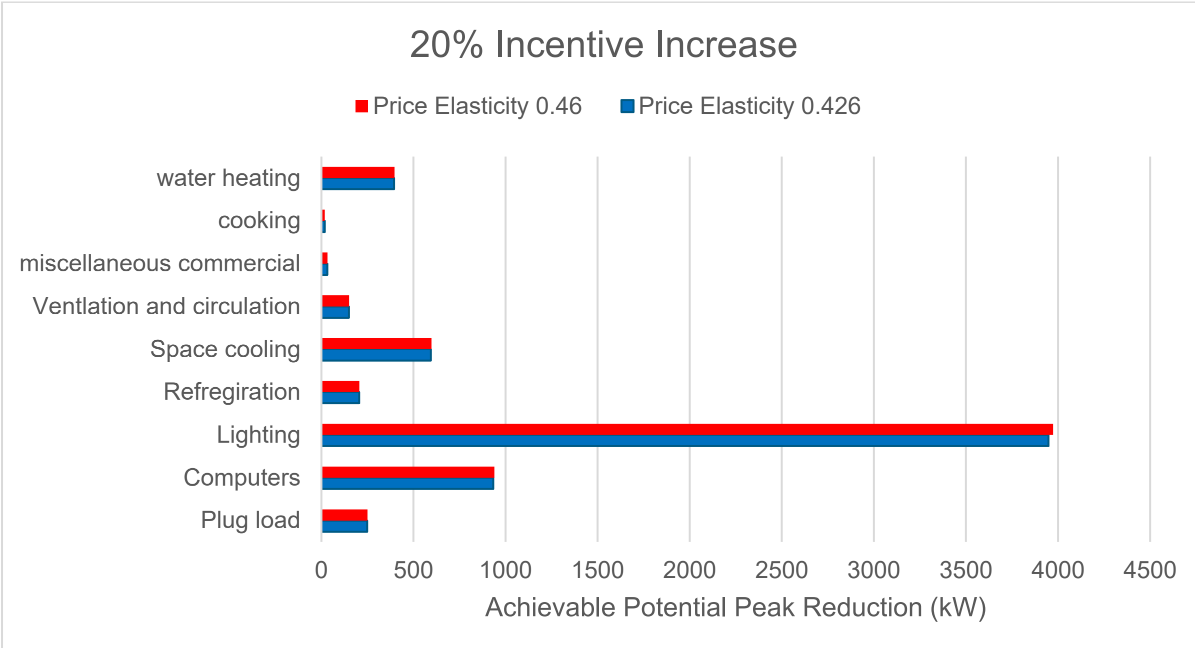

Figure 6-10 Impact of 20% Incentives Increase on Achievable Potential Per End-Use

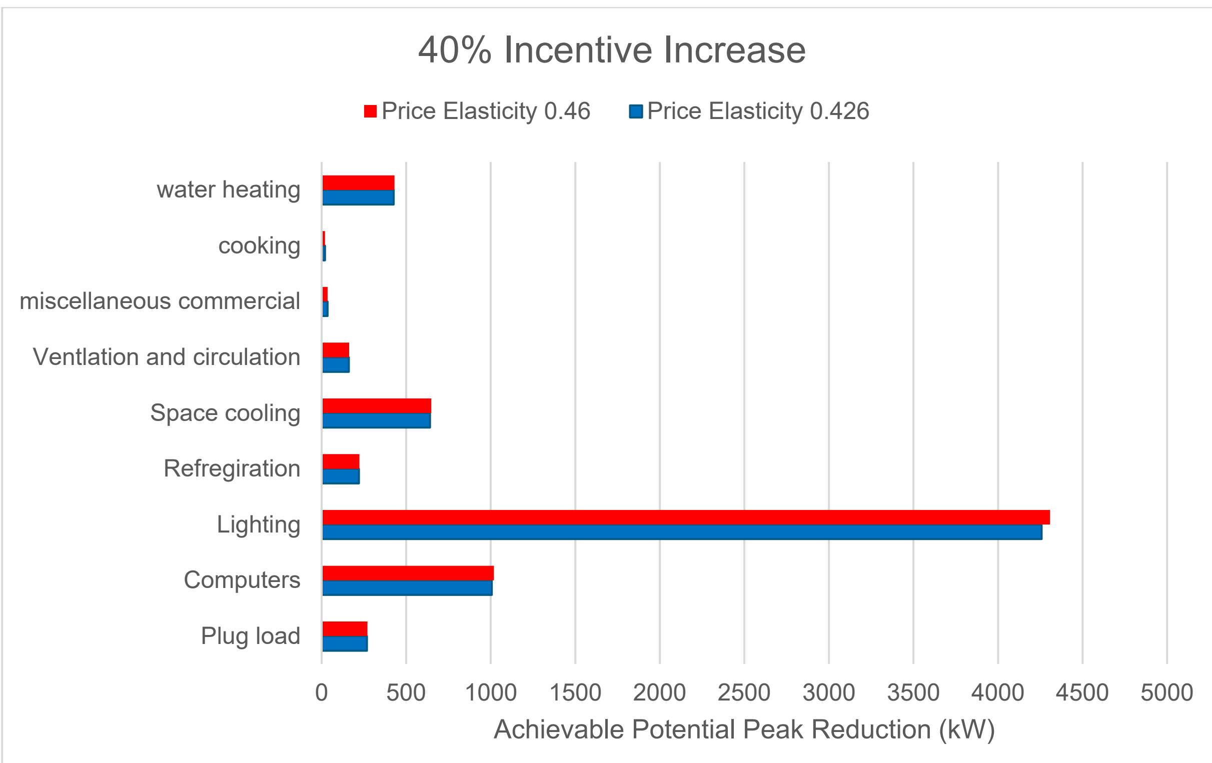

Figure 6-11 Impact of 40% Incentives Increase on Achievable Potential Per End-Use

6.1.1.3. DER

The impact of incentive rate variations on the achievable potential peak reduction is estimated for the DERs contract capacity based on the input data received from HOL in milestone #1. The installed capacity would reduce the summer peak demand (achievable potential) by 360.3 kW, as illustrated in Milestone # 3 report. Figure 6-12 presents the increase in the achievable potential summer peak reduction, assuming incentive increases of 5%, 10%, 20%, and 40%. For DERs, the elasticity estimates suggest that increasing the amount of each product's incentive by 5%, 10%, 20%, and 40%, would increase the total achievable potential by 1.24-1.49 %, 2.44-2.93 %, 4.76-5.69 %, and 9.09-10.78 %. In other words, increasing the incentive rates by 5%, 10%, 20%, and 40% resulted in an increase in the achievable potential to a value ranging from 364.804 kW- 365.741 kW, 369.308-371.181 kW, 378.315-382.32 kW, and 396.33-403.824 kW, respectively.

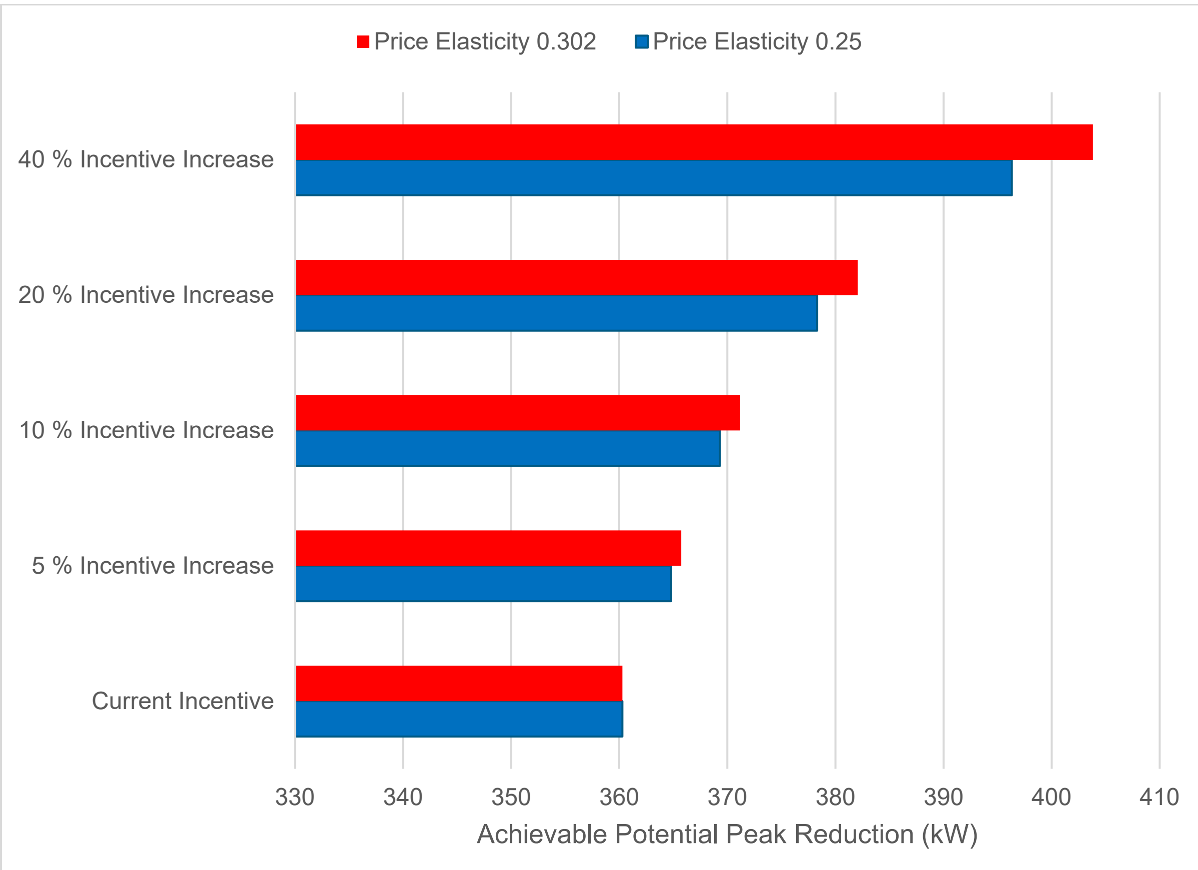

Figure 6-12 Impact of Incentives Variations on DERs Achievable Potential

6.2. Budget

Based on the analysis conducted in section 6.1, the achievable potential and the corresponding budget are estimated for various incentive levels, including current incentive levels, 5 % increase, 10 % increase, 20 % increase, and 40 % increase, as given in Figure 6-13. Where the horizontal axis represents the total estimated achievable potential in kW up to year 2023, while the vertical axis represents the total budget provided in the form of incentives (excluding program administrative costs) for participants up to year 2023.

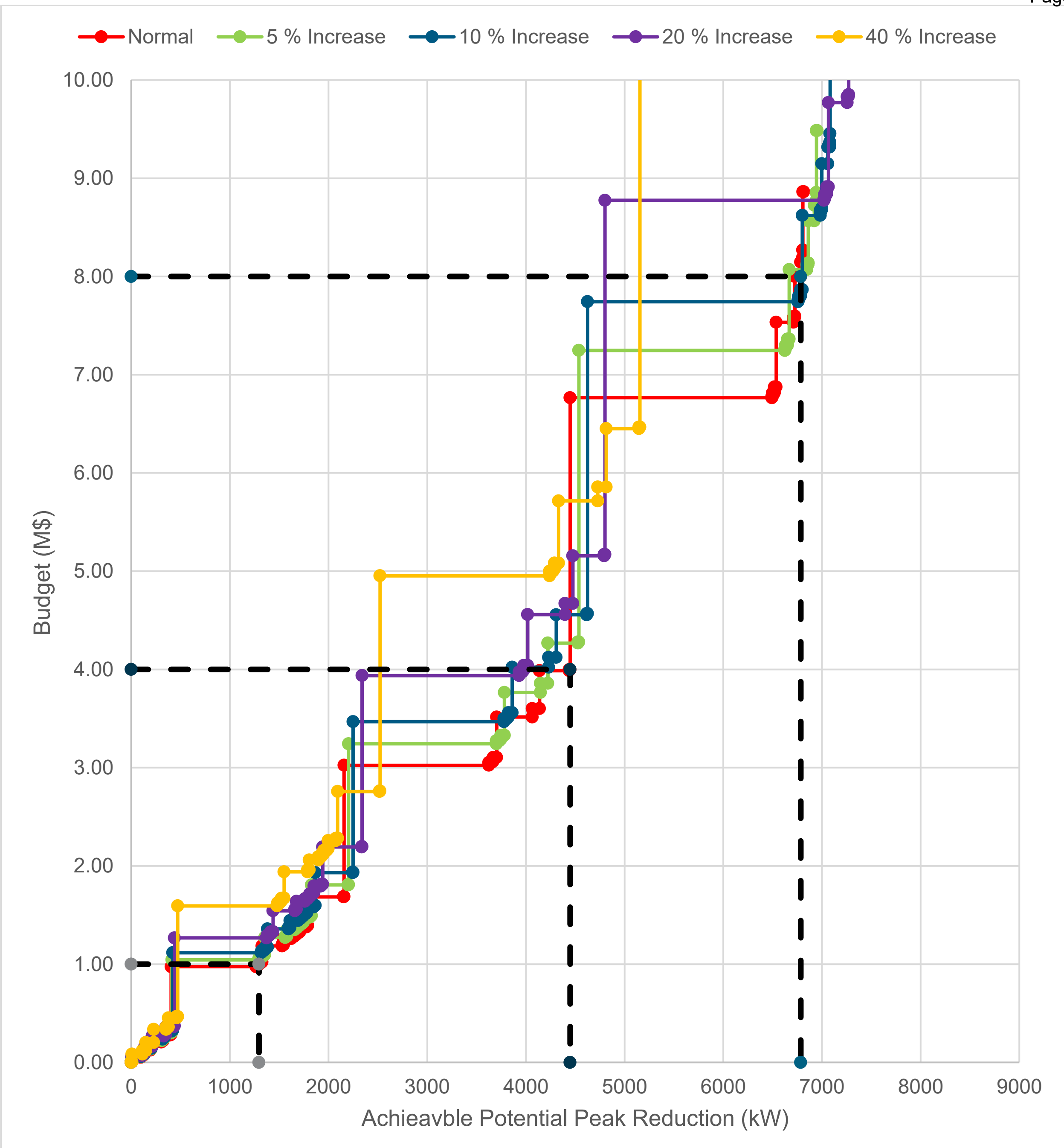

Figure 6-13 Achievable potential up to the year 2023 versus budget for various incentive levels

Three possible budget scenarios, up to the year 2023, are then considered (1 M$, 4 M$, and 8 M$). For each budget scenario, the achievable potential is estimated at the various incentive levels provided in Figure 6-13, and the incentive level providing the maximum achievable potential is considered.

The achievable potential and best incentive level for each of the three scenarios are summarized in table 6-1.

Table 6-1 Achievable Potential for different budget scenarios

Scenario	Incentive	Selected Incentive level	Achievable Potential up to the year 2023 (kW)
1	1 M$	Current	1294.95
2	4 M$		4448.27
3	8 M$		6785.48

According to Table 6-1, the current incentive levels provided by IESO yields the maximum peak reduction for most of the studied scenarios. Therefore the IESO current incentive levels are appropriate.

The total achievable potential for the three budget scenarios at different years is estimated in table 6-2, and the list of measures corresponding to each of the three scenarios is given in Appendix B.

It is worth noting that higher achievable potential is reachable with the consideration of utility-scale energy storage. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.

Table 6-2 Achievable Potential for different budget scenarios

Budget Scenario	Achievable Potential (kW) up to year :			
	2020	2021	2022	2023
1	605.78	846.10	1090.53	1294.95
2	2871.13	3483.41	3994.14	4448.27
3	3882.80	4955.56	5937.02	6785.48

6.3. Avoided Costs

Avoided costs are the “anticipated marginal cost” of energy or capacity or both that the utility would have had to pay if it built a plant to generate that much power. In this study, the avoided costs are avoided energy costs and avoided capacity costs.

6.3.1. Avoided Energy Costs

Avoided energy costs account for variable generation costs, including the cost of fuel and variable Operation and maintenance (O&M) for power plants.

The avoided energy costs are calculated according to the following steps:

Step 1: Calculate the net energy savings at the generator level

Step 2: Energy saving is multiplied by the on-peak, off-peak, and shoulder pricing as per IESO reference [28]. The average energy costs for each year are given in table 6-3 [28].

Table 6-3 Avoided Cost of Energy Production

Year	Avoided Cost of Energy Production ($/MWh)					
	Winter			Summer		
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak
2020	27	26	24	24	23	22
2021	30	30	32	23	23	27
2022	28	26	24	25	25	23
2023	32	31	33	26	28	27

Table 6-4 Avoided energy cost (including line losses)

Budget Scenario	Avoided energy cost ($)				
	2020	2021	2022	2023	Total
1	123,311.78	145,316.53	161,403.79	190,935.57	620,967.67
2	423,586.15	499,174.27	554,435.34	655,879.43	2,133,075.18
3	646,146.80	761,450.44	845,746.78	1,000,491.63	3,253,835.65

6.3.2. Avoided Capacity Costs

Avoided capacity costs account for the reduction in coincident peak demand capacity, including avoided generation capacity (i.e., capital and fixed O&M required to build new generation), transmission, and distribution capacity costs.

The avoided capacity costs are calculated according to the following steps:

Step 1: Calculate the net annual peak demand reduction at the generator level

Step 2: Multiply the peak demand savings by the generation capacity cost to estimate the generation capacity cost. The generation capacity cost at each year is given in table 6-5 [28]

Table 6-5 Generation Capacity Costs

Year	Generation Capacity Cost ($/kW-year)
2020	62
2021	0
2022	104
2023	142

The avoided generation capacity cost is given in table 6-6.

Table 6-6 Avoided Generation capacity cost

Budget Scenario	Avoided Generation Capacity Cost ($)				
	2020	2021	2022	2023	Total
1	37,558.32	0	113,415.57	183,883.23	334,857.12
2	178,010.19	0	415,390.07	631,654.09	1,225,054.34
3	240,733.59	0	617,450.36	963,537.81	1,821,721.76

The avoided distribution capacity cost is assumed to be 160,000 $ per deferral year.

According to the coincident peak forecast for the Summer season developed in section 4.1.3 by considering the median and extreme weather conditions, the summer peak is estimated to reach 107 MW and 115 MW for the median and extreme weather conditions, respectively. The combined LTR rating of the two stations is 88.5 MW, which leads to a gap of 18.5 MW and 26.5 MW. Accordingly, the maximum achievable potential that can be obtained from the three budget scenarios (i.e. provided in table 6-1) represents only 25 % - 30 % of the MW gap. In conclusion, the CDM programs will not be able to meet reduce the peak demand to the desired level and the deferral of the substation cannot be justified. In this case, the avoided transmission capacity cost is zero.

On the other hand, the certainty of some load growth, such as (Broccolini Business Park) and (550 Innovation (Ciena)) should be checked annually due to the high required demand. If these projects were not implemented, the MW gap would reduce significantly, and the achievable potential associated with the CDM programs would be able to reduce the peak demand to the desired level. Based on the data provided by HOL, the cost of building the station is estimated at 36,000,000 $, while the distribution upgrades cost 4,000,000 $. Consequently, the avoided transmission capacity and distribution capacity is estimated based on 4 % interest rate which is equal to 1,144,000 and 160,000, respectively, per deferral year.

The avoided capacity costs for the three budget scenarios are summarized in table 6-7.

Table 6-7 Avoided capacity cost

Budget Scenario	Avoided Generation Capacity Cost up to the year 2023 ($)	Avoided Distribution Capacity Cost ($)	Avoided Transmission Capacity Cost ($)
1	334,857.12	160,000 per deferral year	1,144,000 per deferral year
2	1,225,054.34		
3	1,821,721.76		

6.4. Findings and Observations

The following can be observed from the load forecasts, avoided cost calculation, and achievable potential:

- The maximum achievable peak demand reduction up to 2023 is estimated at 6,785.48 kW (6.78 MW) for an incremental budget of C$ 8,000,000 (excluding program administrative cost).
- The desired peak demand reduction, which represents the gap between the existing summer peak and 2023 forecasted peak is 18.5 MW and 26.5 MW for median and extreme weather conditions forecast, which cannot be achievable from the CDM program.
- The certainty of some load growth, such as (Broccolini Business Park) and (550 Innovation (Ciena)) should be checked annually due to their high required demand, and their exclusion would reduce the gap significantly.
- It is worth noting that higher achievable potential is reachable with the consideration of utility-scale energy storage. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- The avoided costs for budget scenario 3 (C$ 8,000,000) are estimated at C$ 5,075,557.41, in addition to C$ 1,144,000 (transmission capacity cost) for each deferral year, and 160,000 (distribution capacity cost) for each deferral year.

Table 6-8 Budget Scenarios and Avoided Costs Summary – up to 2023

		Scenario 1	Scenario 2	Scenario 3
Incentives (Budget)		1 M$	4 M$	8 M$
Achievable Potential up to year 2023 (kW)		1294.95	4448.27	6785.48
Avoided Costs	Avoided Generation Capacity Cost up to the year 2023 ($)	334,857.12	1,225,054.34	1,821,721.76
	Avoided Distribution Capacity Cost ($)	160,000 for each deferral year		
	Avoided Transmission Capacity Cost ($)	1,144,000 for each deferral year		
	Avoided Energy Cost up to the Year 2023 ($)	620,967.67	2,133,075.18	3,253,835.65

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Appendix A

Definitions and Extracted Data from the Input Database

Table A-9 Residential Subsector Definition

Subsector	Definition
Single family	Single-family, detached and semi-detached households
Row house	Single-family, attached households (e.g., townhouses)
Multi-Unit Residential Building (MURB) low rise	Individually metered units in multi-unit residential buildings less than five stories
Multi-Unit Residential Building (MURB) high rise	Individually metered units in multi-unit residential buildings greater than or equal five stories

Table A-10 Residential Subsector Definition

Subsector	Definition
Office buildings (non-medical)	Office buildings including governmental offices
Medical office buildings	Buildings whose primary business operations include healthcare services (e.g., labs and dialysis centers)
Elementary and/or secondary schools	Elementary and secondary education, apprenticeship, training, and daycare facilities.
Assisted daily/residential care facilities	Home health care facilities and homes for the elderly.
Warehouses Wholesale	Warehouse and wholesale distribution facilities
Hotels, motels or lodges	Overnight accommodation buildings
Hospitals	Inpatient and outpatient health facilities.
Food and beverage stores	Full-service restaurants, caterers, cafeterias, and retail buildings whose primary business operation includes the sale of food.
Non-food retail stores	All retail buildings whose primary business operation does not include the sale of food
Other activity or function	All other activities not specified above (e.g., theaters, sports arena, libraries, etc.)

Appendix B

Table B-11 List of CDM Measures for a Corresponding Budget (Incentives)

Sector	End-Use	Competition group	Measure	Cumlative Budget (Incentives) in $
Residential	Water heating	Hot Water-Insulation	PIPE WRAP : Per 3' Pipe Wrap (different ratings)	2,902.89
Commercial	Refrigeration	Walk-in	ECM MOTORS FOR EVAPORATOR FANS (REFRIGERATOR WALK-IN)	51,379.97
Residential	Water heating	Water heater	(Water, solar and natural gas) water Heater	74,401.20
Commercial	Plug Load	Vending M/C	BEVERAGE VENDING MACHINE CONTROLS	125,067.88
Commercial	Lighting	lighting	Refrigerated display case LED	206,208.56
Commercial	Refrigeration	Cabinet	ENERGY STAR® REFRIGERATOR: Glass Door (≥ 15 cu.ft. to < 30 cu.ft.)	221,506.77
Commercial	Plug Load	Other plug loads	Smart Strip Plug outlets	277,841.95
Commercial	Plug Load	Washer-plug load	electric hot water heater, electric and gas dryers	286,008.84
Commercial	Computers	Computers	NETWORK PC POWER MANAGEMENT SOFTWARE	973,966.74
Commercial	Refrigeration	Pipes	installation of insulation on bare Cooler suction pipes	978,320.33
Commercial	Refrigeration	strip curtain	Strip curtains for walk-in coolers or Freezers	991,961.20
Commercial	Refrigeration	Gasket	DOOR GASKETS FOR WALK-IN AND REACH-IN Coolers	994,389.45
Commercial	Refrigeration	Control	Anti-sweat heat (ASH) and temprature adjustment controls - Cooler/Freezer	997,502.39
Commercial	Refrigeration	Night covers	Vertical Night Covers	1,004,819.67
Commercial	Refrigeration	Refrigeration	Refrigeration Optimization	1,020,848.06
Commercial	Refrigeration	Insulation	Suction Pipe Insulation Freezer/Refrigerator	1,022,600.78
Commercial	Space Cooling	Chillers	Energy efficient Air-cooled chiller: different ratings	1,185,519.89
Commercial	Space Cooling	Room AC	Energy efficient RAC (with louvered sides): different ratings	1,197,657.85
Commercial	Space Cooling	Space Cooling	Chilled Water Optimization	1,259,227.74
Commercial	Space Cooling	Economizer	HVAC Optimization&outside air economizer	1,278,858.39
Commercial	Space Cooling	Space Cooling	air curtains	1,279,214.24
Commercial	Space Cooling	Insulation	Duct Insulation, R8	1,286,090.33
Commercial	Space Cooling	Roof treatment	Adding reflective (White) roof treatment or a green roof	1,297,850.64

Commercial	Ventilation and Circulation	Ventilation and circulation	Air Handler with Dedicated Outdoor Air Systems	1,318,154.92
Commercial	Ventilation and Circulation	Ventilation and circulation	CO Sensors for parking garage exhaust fans	1,328,987.86
Commercial	Ventilation and Circulation	Ventilation and circulation	Demand Control Kitchen Ventilation	1,379,783.23
Commercial	Miscellaneous Commercial	Visc commercial	CEE Tier 2/Energy Star Clothes Washers	1,379,893.20
Commercial	Miscellaneous Commercial	VSD	VSD Air Compressor	1,379,908.08
Commercial	Cooking	Dishwasher	ENERGY STAR Dishwasher	1,382,190.69
Commercial	Cooking	Cooking	High Efficiency Induction Cooking	1,393,437.95
Commercial	Water Heating	water heater	Efficient electric resistance water heater- Different Ratings & heat pump water heater	1,684,570.33
Commercial	Space Cooling	Space Cooling	ECM MOTORS FOR HVAC APPLICATION (FAN-POWERED VAV BOX)	1,687,387.05
Commercial	Lighting	indoor screw in	LED RECESSED DOWNLIGHTS- Different Ratings	3,024,412.18
Commercial	Miscellaneous Commercial	VFD	VFD on Pumps	3,052,572.40
Residential	Water heating	Showerhead	different showerhead	3,066,893.21
Commercial	Ventilation and Circulation	Ventilation and circulation	Variable Frequency Drive (VFD)	3,104,272.86
DERs	Solar PV Rooftop	Solar PV Rooftop	Solar PV Rooftop	3,515,288.69
Commercial	Plug Load	Ice M/C	ENERGY STAR® ICE MACHINES- Different Ratings	3,601,651.24
Residential	Cooling	Central AC	SEER 18 CAC	3,987,323.60
Residential	Lighting	light control	DIMMER SWITCH, light timer and Motion sensor	3,997,785.17
Commercial	Lighting	control	OCCUPANCY SENSORS: Switch Plate and fixture Mounted	6,766,000.63
Residential	Cooling	Space cooling control	Smart Thermostat	6,766,434.58
Residential	Water heating	Aerator	EFFICIENT AERATORS: Kitchen - (different ratings)	6,776,280.52
Residential	Lighting	Screw-in lamps	ENERGY STAR® QUALIFIED INDOOR LIGHT FIXTURE - Hard wired- Different Ratings	6,812,268.93
Residential	Cooking	Wall Oven	SmartBurner Intelligent Cooking System	6,816,417.54
Residential	Cooling	Thermal Envelope	Weather tripping door frame	6,816,909.47

Residential	Cooling	Room AC	ENERGY STAR® ROOM AIR CONDITIONER- Different Ratings	6,822,570.94
Residential	Washer Dryer	Dryer	ENERGY STAR Clothes Dryers, drying rack and gas clothes dryer	6,874,910.64
Commercial	Space Cooling	Packaged AC	UNITARY AIR-CONDITIONING UNIT- Different Ratings	7,533,610.56
Commercial	Refrigeration	Residential	Multi-Residential In Suite Appliance	7,579,540.37
Residential	Washer Dryer	Washer	ENERGY STAR Clothes Washers- Different Ratings	7,589,933.74
Residential	Ventilation	Screw-in lamps	ENERGY STAR® CEILING FAN	7,590,680.80
Residential	Ventilation	Dehumidifier	ENERGY STAR® DEHUMIDIFIER	7,596,185.35
Residential	Lighting	Screw-in lamps	ENERGY STAR® LED BULBS - (Different ratings)	7,999,713.07
Commercial	Lighting	outdoor screw in	LED EXTERIOR AREA LIGHTS: LED fixture different ratings	8,147,586.89
Residential	Washer Dryer	Dishwasher	Energy star dishwasher	8,152,880.33
Residential	Refrigeration	Refrigerator	ENERGY STAR® Refrigerator- Different Ratings	8,189,061.66
Residential	Cooling	Other Cooling	Ducted ASHP w/baseline having Cooling	8,189,540.18
Residential	Refrigeration	Freezers	ENERGY STAR® FREEZER- Different Ratings	8,269,073.80
Residential	Plug Load	Television	ENERGY STAR® Most Efficient TV (Different ratings)	8,862,912.48

Appendix C

SNC-Lavalin has submitted the following reports as part of the deliverables.

Description	Report Name	Revision Number
Milestone 1	660803_LAPS_Hydro Ottawa_Final Report_Milestone_1.pdf	00
Milestone 2	660803_LAPS_Hydro Ottawa_Final Report_Milestone_2.pdf	03
Milestone 3	660803_LAPS_Hydro Ottawa_Final Report_Milestone_3.pdf	00
Milestone 4	UPDATABLE_EXCEL_Model_R1.xlsm	NA

Hydro Ottawa Local Achievable Potential (LAP) Study

Local Load Characterization

Milestone #1 Report

SLI PROJECT NO.: 660803

00	Final Report	05/06/2019	MA	TA	TA
PA	Issued for Information	04/14/2019	MA	TA	TA
REV.	**DESCRIPTION**	**DATE**	**PRPD**	**CHKD**	**APPRD**
			SNC-Lavalin		

SUMMARY

This is the first milestone report of the study entitled "Hydro Ottawa Local Achievable Potential (LAP) Study" which commenced on Dec. 7, 2018. This study, undertaken at the request of Hydro Ottawa Ltd, Ontario, is conducted by SNC-Lavalin Inc. Toronto, Canada, as the Consultant.

The objective of Milestone #1 of this study is to determine the local load characterization for Kanata North area served by Kanata and Marchwood MTS.

The project team developed the sector and subsector energy load profiles for the Kanata North area which serves prominently residential and commercial/ sectors. For each sector, the energy share distributions were estimated, and then each sector was segmented by subsectors (i.e., building type). Also, the team developed the end-use profiles for each sector. The end-use profiles from the IESO's recent achievable potential studies as well as NRCAN residential and commercial end-use surveys were used to develop the end-use profiles for this study.

The project team compared the total reported (actual) annual consumptions for Kanata and Marchwood MTS both with the total consumptions determined from the bottom-up analysis to determine the gap and to calculate the calibration factor. After performing the calibration, the annual consumption for each feeder was obtained by calibrating the feeder's consumption obtained from the analysis.

Based on the base year residential demand, the forecasted number of residential buildings, and the forecasted energy intensities, the team determined the residential forecast for Kanata and Marchwood MTS. Also, the team carried out the commercial forecast for Kanata and Marchwood MTS using the base year load consumption, the area forecast of commercial subsectors, and the forecasted energy intensities for commercial subsectors. Furthermore, the project team developed the end-use residential and commercial forecasts for Kanata and Marchwood MTS.

Based on the input data received from HOL and the IESO, the project team identified the historical participation of the loads in the Conservation and Demand Side Management (CDM) programs and the existing Distributed Energy Resources (DERs) as well as the potential for expansion. HOL and IESO provided the complete list of existing DERs, the total contract capacity of the DERs at Kanata-Marchwood area, and the forecasted effective capacities of the DERs and the CDM.

CONTENTS

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List of acronyms

APS	Achievable Potential Study
CDM	Conservation and Demand Management
DB	Dun & Bradstreet Database
DER	Distributed Energy Resources
EUF	End-Use Forecasting
EUI	Energy Use Intensity
HOL	Hydro Ottawa Ltd
IESO	Independent Electricity System Operator
kWh	Kilo Watt hour
LAP	Local Achievable Potential
MPAC	Municipal Property Assessment Corporation
MURB	Multi-Unit Residential Building
NRCAN	Natural Resources Canada
OEB	Ontario Energy Board
SCIEU	Survey of Commercial and Institutional Energy Use
SHEU	Survey of Household Energy Use
sq. ft.	Square feet

1 Introduction

This report provides the methodology and the complete analyses of milestone #1 that aims to determine the local load characterization for the Kanata North area served by Kanata and Marchwood MTS. This progress report is summarizing the following:

- Market segmentation of the load of Kanata and Marchwood MTS,
- End-use segmentation of the residential and commercial sectors,
- Reference case forecast: 2018-2040 of Kanata and Marchwood MTS load segmented to sectors, subsectors, and end-use,
- Survey of existing area DERs, and
- Summary of local historical participation in CDM programs.

2 Methodology

The project team followed the approach presented in [1-2] to develop a unique profile by conducting the following tasks:

- Segmentation of Kanata North area customers by sector, by subsector and by end use,
- Calibration of the obtained profile to changes in sales and customer forecasts, and
- Determine the existing DERs in the area and the local historical participation in CDM programs.

2.1 Segmentation by sector and by subsectors

The energy share distributions for the residential and commercial/institutional sectors are determined, and then each sector is segmented by subsectors (i.e., building type). Table 2-1 summarizes the sectors and subsectors used in the study. This classification is aligned with the IESO's End-Use Forecasting (EUF) model for planning purposes.

Table 2-1 Sectors and Subsectors

Sector	Residential	Commercial
Subsector	• Single family • Row house • Multi-unit Residential Building - low rise • Multi-unit Residential Building - high rise	• Office buildings (non-medical) • Medical office buildings • Elementary and/or secondary schools • Assisted daily/residential care facilities • Warehouses wholesale • Hotels, motels or lodges • Hospitals • Food and beverage stores • Non-food retail stores • Other activity or function

2.1.1 Residential buildings

The residential sector buildings are subdivided to four categories based on the definition presented in Table A-1. Kanata-Marchwood area residential buildings characteristics are used to develop the local area residential load segmentation as follows;

- The number of residential units by subsector is determined based on the google earth files [3] provided by HOL.
- The counted number of a residential building is calibrated to the number given by HOL for each feeder.
- The energy use intensity (annual kWh consumption/ unit) is derived from the NRCAN residential building SHEU database [4] and adjusted to the average EUI reported in the OEB yearbook [5].
- The total residential estimated annual consumption is compared and calibrated to the actual residential consumption provided by HOL.

2.1.2 Commercial Sector

The commercial sector buildings are subdivided to ten categories based on the definition presented in Table A-2. Kanata-Marchwood area commercial buildings characteristics are used to develop the local area commercial load segmentation as follows;

- The square footage area of commercial buildings by subsector is determined based on Dun & Bradstreet database [6], MPAC database [7], Hemson Data [8], and google earth files [3] provided by IESO and HOL.
- The energy use intensity (annual kWh consumption/ unit) is derived from commercial building SCIEU database [9].
- The total annual electricity consumption (kWh) for public sector facilities is determined by the Public Sector database [10]
- The total commercial estimated annual consumption is compared and calibrated to the actual commercial annual consumption provided by HOL to determine the commercial load segmentation that represents the actual load segmentation for Kanata-Marchwood local area.

2.2 Segmentation by end use

End-use profiles are to be developed for each sector, and Table 2-2 provides a summary of the end uses for the residential and commercial sectors. End-use profiles from the IESO's recent achievable potential studies [2] as well as NRCAN residential and commercial end-use surveys are used to develop the end-use profiles for this study.

Table 2-2 End Uses per Sector

Sector	Residential	Commercial
End uses	Lighting Plug Load Space Heating Space Cooling Ventilation and Circulation Domestic Hot Water Refrigeration Washer/ Dryer/ Dishwashers Cooking Dehumidifiers Miscellaneous	Lighting Space Cooling Ventilation Space Heating Domestic Hot Water Cooking Refrigeration Computer Equipment Other Plug Loads Miscellaneous

2.3 Calibration Methodology

The total reported (actual) annual consumptions for Kanata and Marchwood MTS are compared with the total consumptions determined from the bottom-up analysis to determine the gap and to calculate the calibration factor. After performing the calibration, the annual consumption for each feeder is obtained by calibrating the feeder's consumption obtained from the analysis.

The methodology used for calibration is discussed as follows;

1- The actual annual consumption for each feeder is obtained using the feeders' hourly consumption data provided by HOL.
2- The total actual consumptions should be reduced by a factor of 17 % to represent the share of street lighting and a factor of 3 % to represent the system losses
3- Based on the bottom-up methodology, the annual consumptions for all subsectors and sectors are estimated. Then, the estimated annual consumption for each station is determined as the total sum for all sectors consumptions per station.
4- The reported metered annual consumptions for residential, commercial, and industrial customers are compared to the estimated consumptions.
5- The calibration factor, for each sector, is calculated as the ratio between the total actual annual consumption for the sector divided by the total bottom-up estimated annual consumption for the sector.

6- The calibration factor is then used to modify the bottom-up estimated consumption; i.e., the calibration factor is multiplied times the bottom-up estimation to determine an estimation that is matching the actual annual consumptions.

2.4 Adjust Kanata North load Profile to Changes in Sales and Customer Forecasts

SNC requested all the anticipated changes on load trend from HOL, and HOL declared that no fuel switching is anticipated. Thus, the project team use the findings of the Hemson study, the official community plan for Kanata North [11], and NRCAN surveys to develop the load forecast over the study period.

2.5 Participation in CDM and DER program

From the input data from HOL and IESO, the existing DERs, and the potential for expansion, the participation of DER in Kanata North area identified. Moreover, the historical participation of the loads in the CDM programs are assessed.

3 Load Segmentation for Base Year and Reference Case Forecast

3.1 Kanata MTS load segmentation for Base Year (2018) by Sector/ Subsector

The methodology presented in section 2 is applied to Kanata premises that consist of five feeders named 624F1, 624F2, 624F3, 624F5, 624F6. This section presents the analysis performed for the five feeders presented in Figure 3-1. These feeders' service areas are covering residential and commercial loads as well as one large industrial load located at feeder 624F2.

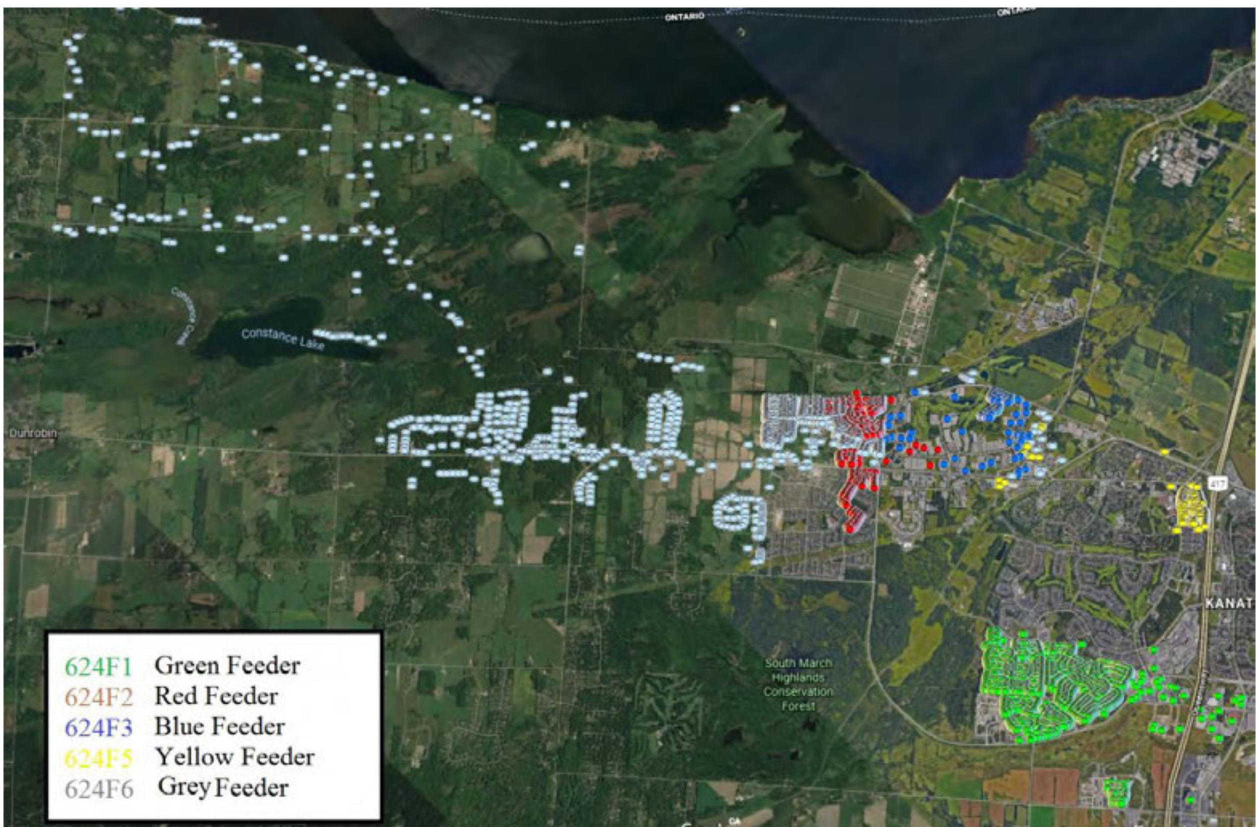


Figure 3-1 Kanata MTS service area

3.1.1 Kanata MTS Residential load segmentation

The residential sector buildings are subdivided to four subsectors based on the definition presented in Table A-1, the number of residential buildings in each subsector is counted using Google Earth files provided by HOL and adjusted using the total residential building number provided by HOL; Table 3-1 summarizes the number of buildings in each subsector for each of the five feeders.

Table 3-1 Residential Subsectors Premises, Kanata MTS

Residential building type	Single family	ROW	Low rise	High rise	Total
Number of units / Subsector for feeder 624F1	1596	924	192	0	2712
Number of units / Subsector for feeder 624F2	458	387	0	0	845
Number of units / Subsector for feeder 624F3	111	169	94	194	568
Number of units / Subsector for feeder 624F5	22	81	0	0	103
Number of units / Subsector for feeder 624F6	652	945	0	0	1597
Number of units / Subsector for Kanata MTS	2839	2506	286	194	5825

The NRCAN residential building (SHEU) database is used to determine the energy intensity per premise; Table 3-2 summarises the energy intensities for all residential subsectors in Ontario. The methodology discussed in section 2 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each subsector are obtained. Then, the average estimated kWh per residential customer is calculated using the total residential consumption and the total number of residential buildings; the average estimated kWh per customer for Kanata MTS is 7,732 kWh which is close to the actual kWh per residential customer reported in the OEB yearbook (i.e., 7,537 kWh). Thus, no calibration is needed. A summary of the total residential consumption for Kanata MTS service area is presented in Table 3-3.

Table 3-2 Residential Subsectors Energy Intensity [9]

Residential building type	Single family	ROW	Low rise	High rise
Annual Total Energy intensity (eMWh/household)	38.74571	26.55473	8.176108	9.575353
Annual Electricity intensity (MWH/household)	9.652535	6.090792	4.812586	5.118794
Natural Gas intensity (eMWh/household)	24.56966	20.32247	3.317058	4.36854
Other Energy intensity (eMWh/household)	4.52353	0.141473	0.046468	0.088023

Table 3-3 Total Residential Subsectors Energy Consumptions for Kanata MTS

Residential building type	Single Family	ROW	Low Rise	High Rise	Total
Annual Electricity consumptions (MWh)	27,404	15,264	1,376	993	45,037
Annual Natural gas consumptions (eMWh)	69,753	50,928	949	848	122,478
Annual Other energy consumptions (eMWh)	12,842	354	13	17	13,227
Total Annual Energy consumptions (eMWh)	109,999	66,546	2,338	1,858	180,741

3.1.2 Kanata MTS Commercial load segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, and activity of all commercial buildings located at each of the five feeders of Kanata MTS. The energy intensities for all commercial subsectors are obtained using the NRCAN commercial building SCIEU database and summarized in Table A-3. The methodology discussed in section 2 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each commercial subsector are obtained; a summary of the total commercial consumption for Kanata MTS service area is presented in Table 3-4.

Table 3-4 Commercial Subsectors Energy Consumption, Kanata MTS

Commercial Subsector	Annual Electricity Consumption (MWh)	Annual Natural gas Consumption (eMWh)
Office buildings (non-medical)	90,018	52,672
Medical office buildings	3,135	2,270
Elementary and/or secondary schools	1,416	2,124
Assisted daily/residential care facilities	1,197	1,246
Warehouses Wholesale	5,106	6,768
Hotels, motels or lodges	3,003	3,386
Hospitals	0	0
Food and beverage stores	13,653	5,407
Non-food retail stores	11,414	9,983
Other activity or function	5,282	6,200

3.1.3 Kanata MTS Industrial Load segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, number of employees, and primary activity of all industrial buildings located at Kanata MTS service area. One industrial building is found at feeder 624F2 as shown in Table 3-5. The total annual energy, annual electricity consumption, and the annual Natural gas consumption for the industrial building are obtained based on the methodology described in section 2.1.3; the obtained results are presented in Table 3-6.

Table 3-5 Industrial Facilities located at Kanata MTS

Feeder	Company Name	Address	Activity	Square Footage	Employees
624F2	ASTENJOHNSON, INC	1243 TERON RD	Fibre, Yarn and Thread Mills	120, 181	37

Table 3-6 Industrial Subsectors Total Energy Consumption for Kanata MTS

Subsector	Electricity Consumption (MWh)
Miscellaneous industrial	3,150

3.2 Marchwood MTS load segmentation for Base Year (2018) by Sector/ Subsector

The methodology discussed in section 2 is applied to Marchwood premises that consist of four feeders named MWDF1, MWDF2, MWDF3, and MWDF4. This section presents the analysis performed for the four feeders presented in Figure 3-2. These feeders' service areas are covering different residential, commercial, and industrial loads.

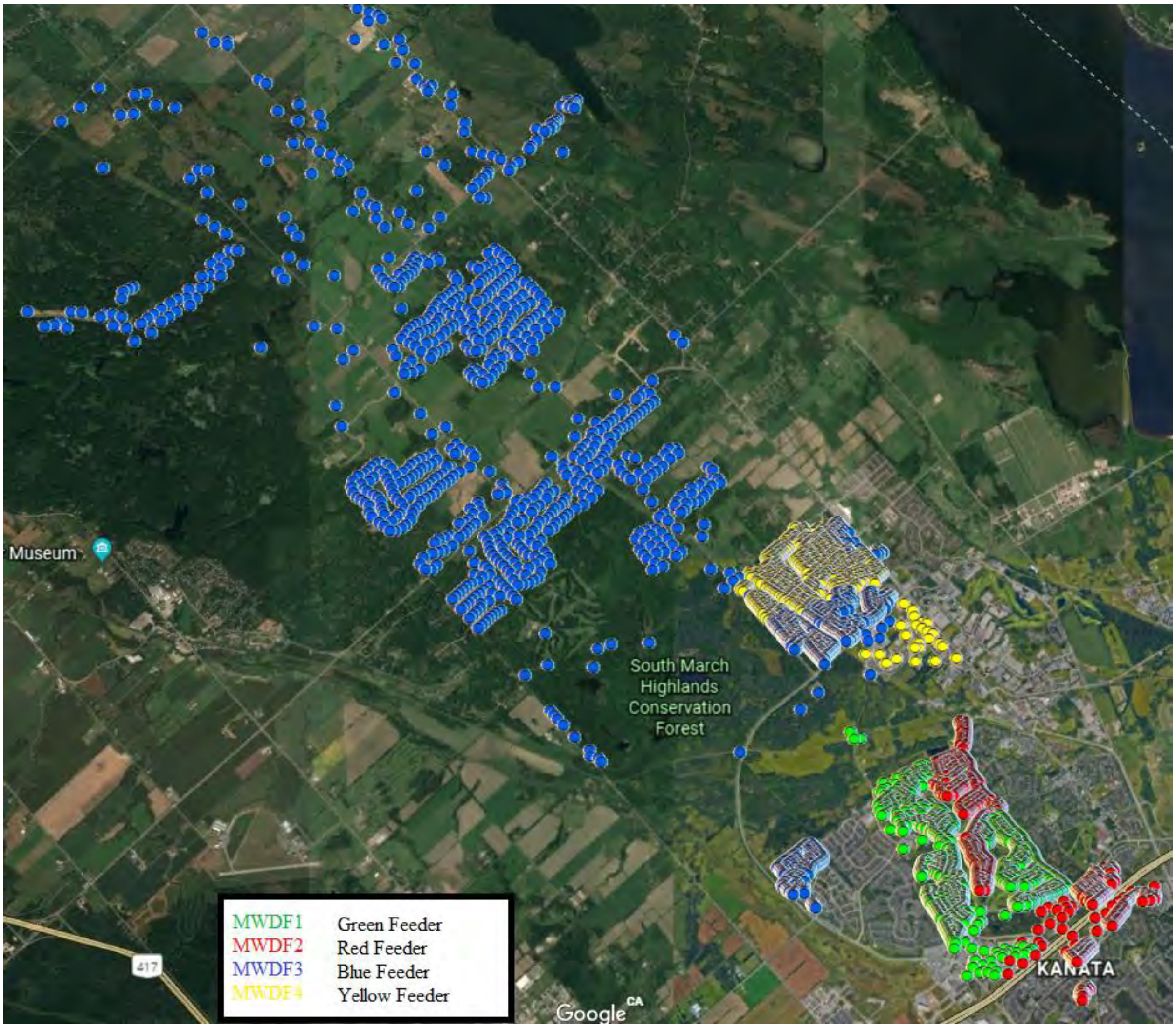


Figure 3-2 Marchwood MTS service area

3.2.1 Marchwood MTS Residential load segmentation

The residential sector buildings are subdivided to four subsectors based on the definition presented in Table 2-1, the number of residential buildings in each subsector is counted using Google Earth files provided by HOL; Table 3-7 summarizes the number of buildings in each subsector for each of the four feeders.

Table 3-7 Residential Subsectors Premises, Marchwood MTS

Residential Building Type	Single Family	ROW	Low Rise	High Rise	Total
Number of premises / subsector for feeder MWDF1	1076	649	62	0	1787
Number of premises / subsector for feeder MWDF 2	584	696	0	739	2019
Number of premises / subsector for feeder MWDF3	1435	889	86	0	2410
Number of premises / subsector for feeder MWDF4	1192	348	0	0	1540
Number of premises / subsector for Marchwood MTS	4287	2582	148	739	7756

The NRCAN residential building (SCEU) database is used to determine the energy intensity per premise as summarized in Table 3-2. The total annual energy, annual electricity consumption, and the annual Natural gas consumption for each subsector are obtained. Then, the average estimated kWh per residential customer is calculated using the total residential consumption and the total number of residential buildings; the average estimated kWh per customer for Kanata MTS is 7,802 kWh which is very close to the actual kWh per residential customer reported in the OEB yearbook (i.e., 7,537 kWh). Thus, no adjustment for the used EUIs needed. A summary of the total residential consumption for Marchwood MTS service area is presented in Table 3-8.

Table 3-8 Total Residential Subsectors Energy Consumptions for Marchwood MTS

Residential Building Type	Single Family	ROW	Low Rise	High Rise	Total
Annual electricity consumptions (MWh)	41,381	15,726	712	3,783	41,381
Annual natural gas consumptions (eMWh)	105,330	52,473	491	3,228	105,330
Annual other energy consumptions (eMWh)	19,393	365	7	65	19,393
Total annual energy consumptions (eMWh)	166,103	68,564	1,210	7,076	166,103

3.2.2 Marchwood MTS Commercial load segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, and activity of all commercial buildings located at each of the four feeders of Marchwood MTS. The energy intensities for all commercial subsectors are obtained using the NRCAN commercial building SCIEU database. The methodology described in section 2 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each commercial subsector are obtained; a summary of the total commercial consumption for Marchwood MTS service area is presented in Table 3-9.

Table 3-9 Commercial Subsectors Energy Consumption, Marchwood MTS

Commercial Subsector	Annual Electricity Consumption (MWh)	Annual Natural Gas Consumption (eMWh)
Office buildings (non-medical)	31,555	18,532
Medical office buildings	2,475	1,792
Elementary and/or secondary schools	3,477	5,215
Assisted daily/residential care facilities	3,818	3,973
Warehouses Wholesale	1,498	1,986
Hotels, motels or lodges	3,205	3,614
Hospitals	0	0
Food and beverage stores	12,607	4,903
Non-food retail stores	13,690	11,662
Other activity or function	3,766	4,421

3.2.3 Marchwood MTS Industrial Load segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, number of employees, and primary activity of all industrial buildings located at Marchwood MTS service area. The data search shows that no industrial buildings are located at Marchwood service area.

3.3 Calibrated Load Segmentation for Base Year

The calibration methodology described in section 2.3 is applied to determine the calibration factor for each sector. The actual annual consumption for Kanata and Marchwood MTS is obtained using the data provided by HOL; this consumption is reduced by a factor of 17 % to represent the share of street lighting and a factor of 3 % to represent the system losses (obtained from 2017 OEB Yearbook [5]) as shown in Tables 3-10 and 3-11.

Table 3-10 Actual and estimated consumptions for Kanata MTS

Kanata		Consumptions (kWh)
Actual consumptions	with street lighting	321,700,199
	without street lighting	267,011,165
	without street lighting & losses	259,000,830
Estimated consumptions	Residential	45,036,520
	Commercial	189,328,355
	Industrial	3,150,000
	Total	237,514,875
Gap		-21,485,955

Table 3-11 Actual and estimated consumptions for Marchwood MTS

Marchwood		Consumptions (kWh)
Actual consumptions	with street lighting	178,540,075
	without street lighting	148,188,262
	without street lighting & losses	143,742,614
Estimated consumptions	Residential	63,520,491
	Commercial	85,020,705
	Industrial	0
	Total	148,541,196
Gap		4,798,582

The reported metered KWh for residential customers is compared to the bottom-up estimation, and the results are closely matched. Thus, the estimated annual consumption for residential sector is kept without calibration. Then, the calibration factor is calculated, for the commercial and industrial sectors, as the ratio between the total actual annual consumption for commercial and industrial sectors divided by the total bottom-up estimated annual consumption for commercial and industrial sectors (Table 3-12).

Table 3-12 Calibration Factor Calculation

	Kanata	Marchwood	Sum	Sum of commercial and Industrial
Total actual (kWh)	259,000,830	143,742,614	402,743,445	294,186,433
Total estimated (kWh)	237,514,875	148,541,196	386,056,071	277,499,060
Calibration Factor	= (294,186,433 / 277,499,060) =1.06013			

3.3.1 Calibrated Load Segmentation by sector/sub-sector

The obtained calibration factor is used to modify the estimated consumption for each feeder; i.e., the calibration factor is multiplied times the bottom-up estimation of each feeder to determine a bottom-up estimation that is matching the actual annual consumptions. Table 3-13 and Table 3-14 show the total estimated electrical consumptions (after calibration) for Kanata and Marchwood respectively. Moreover, Tables B-1 to B-13 shows the detailed estimated electrical consumption for each feeder for each sector/ subsector.

Table 3-13 Estimated consumptions (kWh) for Kanata MTS after calibration

Kanata	624F1	624F2	624F3	624F5	624F6	Total
Residential	21,957,355	6,777,998	3,546,205	705,710	12,049,252	45,036,520
Commercial	35,437,231	52,884,403	7,694,143	75,889,460	28,808,356	200,713,593
Industrial	0	3,339,425	0	0	0	3,339,425
Total	57,394,587	63,001,826	11,240,347	76,595,170	40,857,608	249,089,538

Table 3-14 Estimated consumptions for Marchwood MTS after calibration

Marchwood	MWDF1	MWDF2	MWDF3	MWDF4	Total
Residential	16,556,027	13,659,061	19,679,985	13,625,418	63,520,491
Commercial	31,584,597	20,260,960	10,979,980	27,307,879	90,133,415
Industrial	0	0	0	0	0
Total	48,140,624	33,920,021	30,659,965	40,933,296	153,653,906

3.4 End-Use Load segmentation for Base Year

3.4.1 Kanata End-Use segmentation

Based on the end-uses profiles provided by IESO for the residential and commercial sectors, the project team developed the end-use load segmentation for As per discussion with HOL, only one industrial building is located at Kanata- Marchwood area; thus, the project team performs the load segmentation for the residential and commercial buildings. The Kanata area. The end-use classification was performed using the calibrated annual consumption of the loads.

A. Kanata Residential End-Use segmentation

The end-use segmentations for Kanata MTS are developed for the residential sector and subsectors. Kanata residential end-use segmentation for the residential sector is presented in Figure 3-3, while Kanata residential end-use segmentations for the single house, Row, Low-rise, and High-rise subsectors are presented in Figures B-1, B-2, B-3, and B-4 respectively.

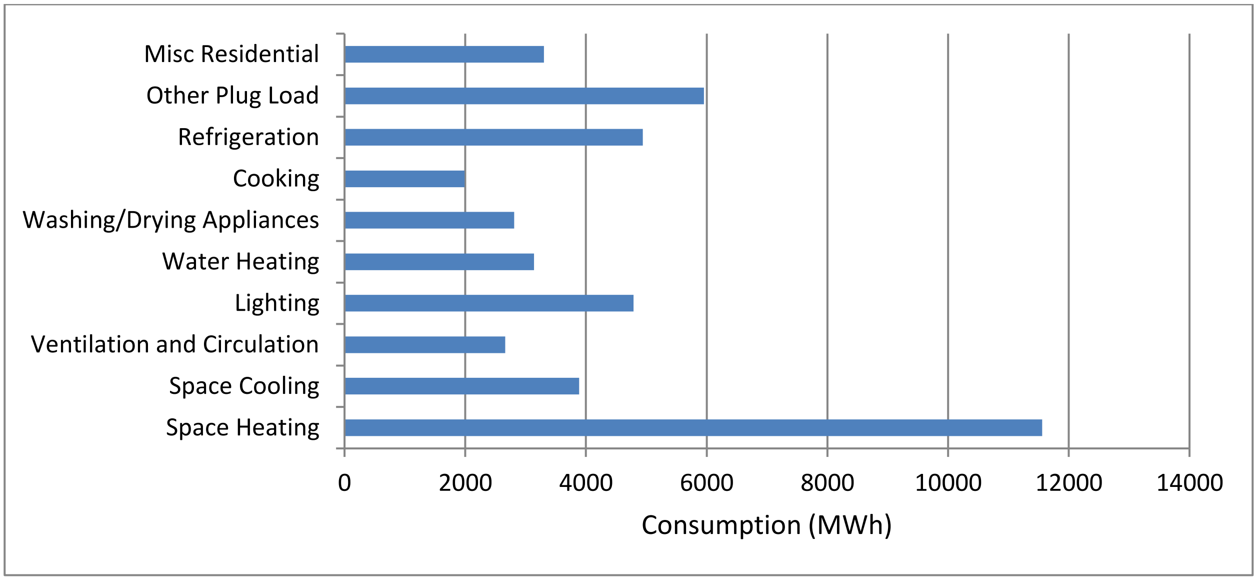


Figure 3-3 End-use Segmentation for Residential Sector, Kanata MTS

B. Kanata Commercial End-Use segmentation

Based on the end-uses profiles provided by IESO for the commercial sectors, the project team developed the end-use load segmentation for Kanata. The end-use segmentation for the commercial sector is presented in Figures 3-4. Moreover, the end-use segmentations for all commercial subsectors are presented in Figures B-5 to B-13.

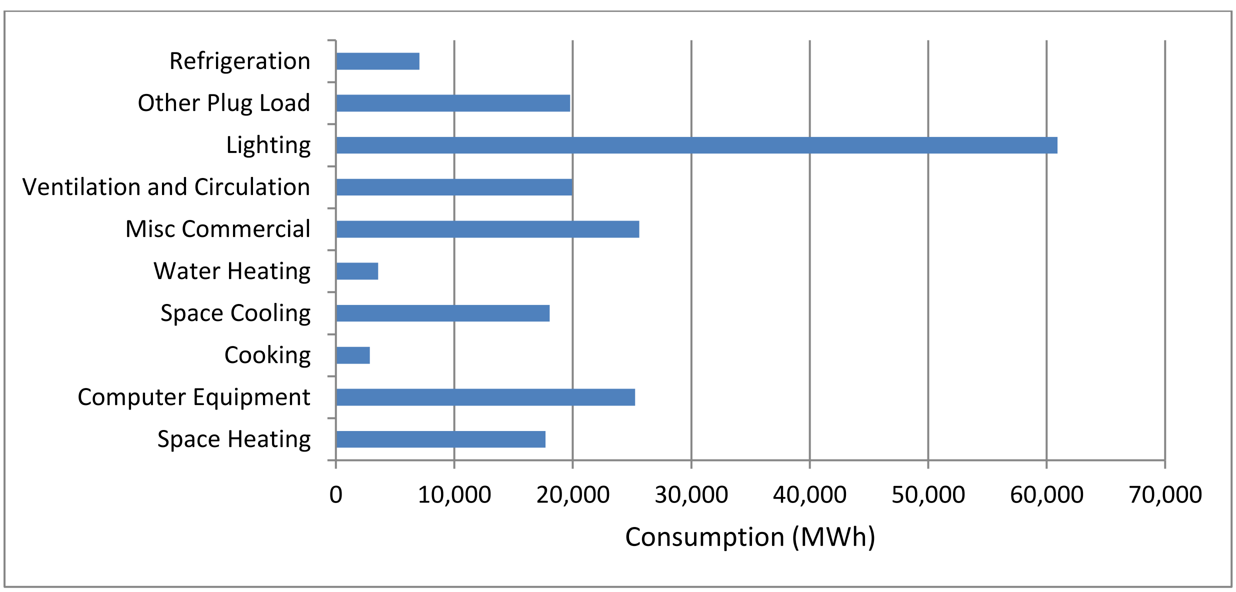


Figure 3-4 End-use Segmentation for Commercial Sector, Kanata MTS

3.4.2 Marchwood MTS End-Use Load segmentation

A. Marchwood Residential End-Use segmentation

The end-use segmentations for Marchwood MTS are developed for the residential sector and subsectors. The residential end-use segmentation is presented in Figure 3-5, while subsector residential end-use segmentations for the single house, Row, Low-rise, and High-rise are presented in Figures B-14, B-15, B-16, and B-17 respectively.

B. Marchwood Commercial End-Use segmentation

Based on the end-uses profiles provided by IESO for the commercial sectors, the project team developed the end-use load segmentation for Marchwood. The end-use segmentation for the commercial sector is presented in Figures 3-6. Moreover, the end-use segmentations for all commercial subsectors are presented in Figures B-17 to B-25.

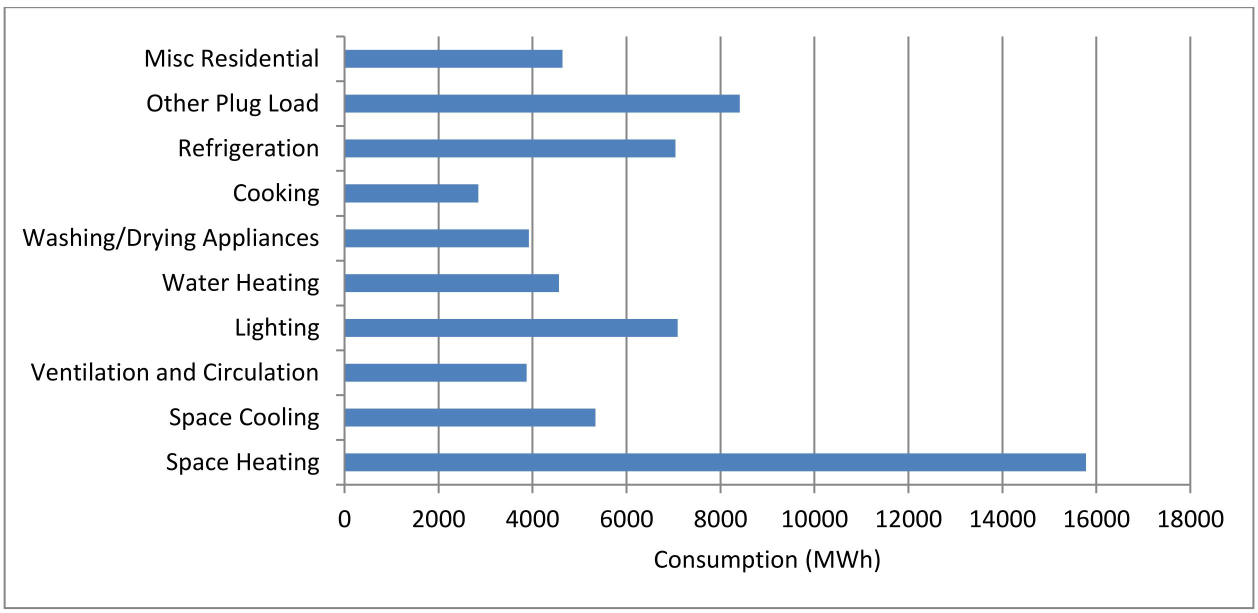


Figure 3-5 End-use Segmentation for Residential Sector, Marchwood MTS

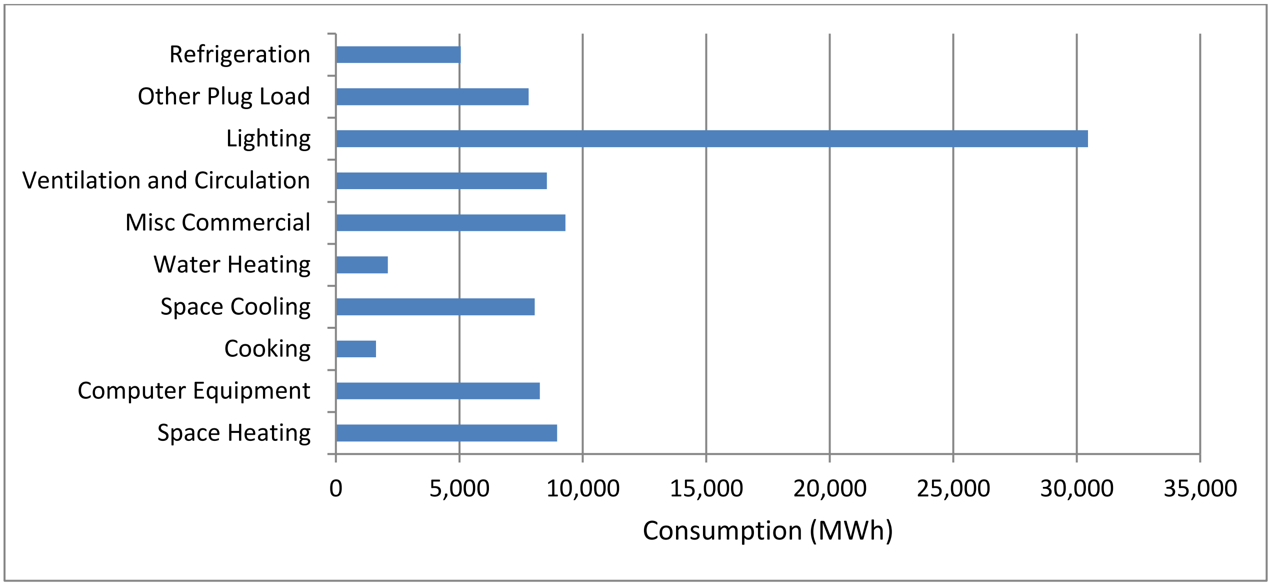


Figure 3-6 End-use Segmentation for Commercial Sector, Marchwood MTS

3.5 Reference Case Forecast: 2019-2040

3.5.1 Residential Forecast

The project team carried out a forecast for the expected number of residential buildings and energy intensity over the forecast period with respect to the base year. The NRCAN historical data for the number of residential buildings and energy intensity presented in Tables A-4 and A-5 were used to develop the forecast. The official community plan for Kanata North [11] show that the potential distribution for residential units over the planning period (i.e., 2018 to 20131) is as shown in Tables 3-15. The official residential building plan for Kanata North is used to calibrate the residential building forecast. The calibrated residential building forecasts for the four residential subsectors are presented in Table B-14, and the residential energy intensity forecasts are presented in Table B-15.

Table 3-15 Potential Unit Distribution for Kanata North [11]

UNIT TYPE	Potential Unit Distribution
Single Detached	960 Units
Apartments	527 Units
Street Townhouses and other ground oriented multiple dwelling	1477 Units

Based on the base year residential demand, the calibrated forecasts of residential buildings number, and the forecasted energy intensities, the residential forecast for Kanata and Marchwood MTS are obtained. Complete results for the residential forecast for Kanata MTS and Marchwood MTS are introduced in Tables B- 16 and B-17 respectively. Moreover, the residential subsectors consumptions for the base year are compared to the short-term forecasted consumptions (i.e., 2023) and the long-term forecasted consumptions (i.e., 2040). The comparison results are presented in Figures 3-7 and 3-8 for Kanata and Marchwood MTS respectively. Furthermore, the project team developed the end-use residential forecasts for Kanata and Marchwood MTS as shown in Figures 3-9 and 3-10 respectively.

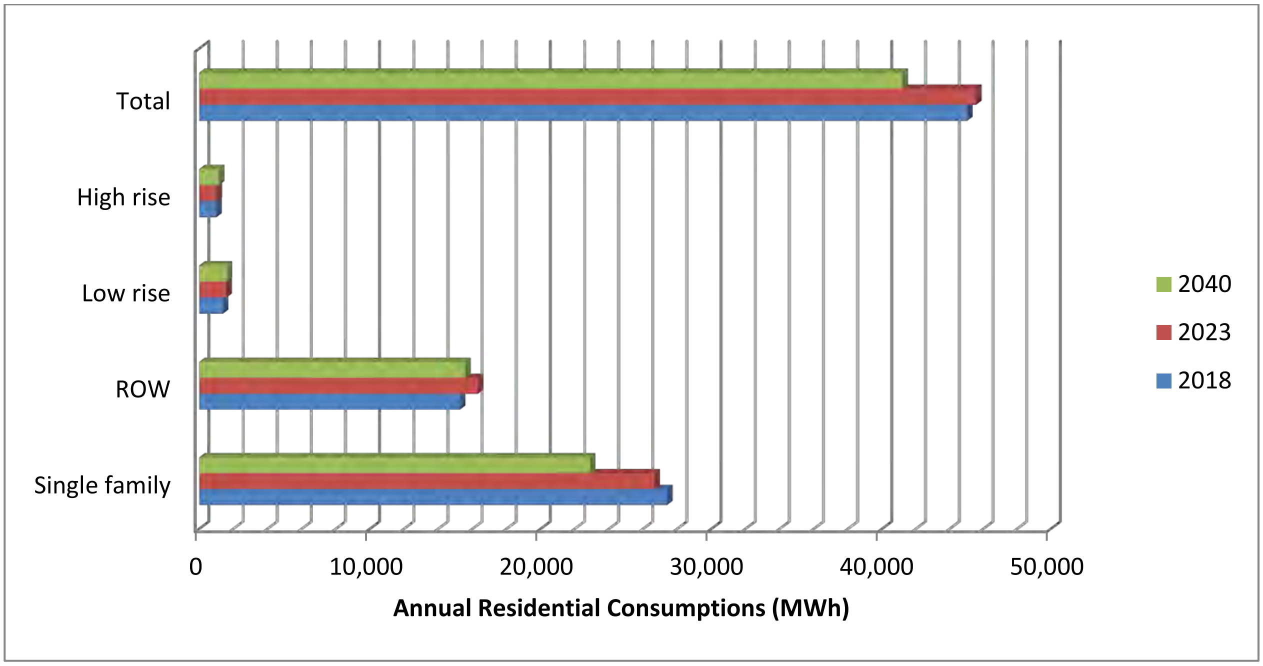


Figure 3-7 Residential sector load forecast, Kanata MTS

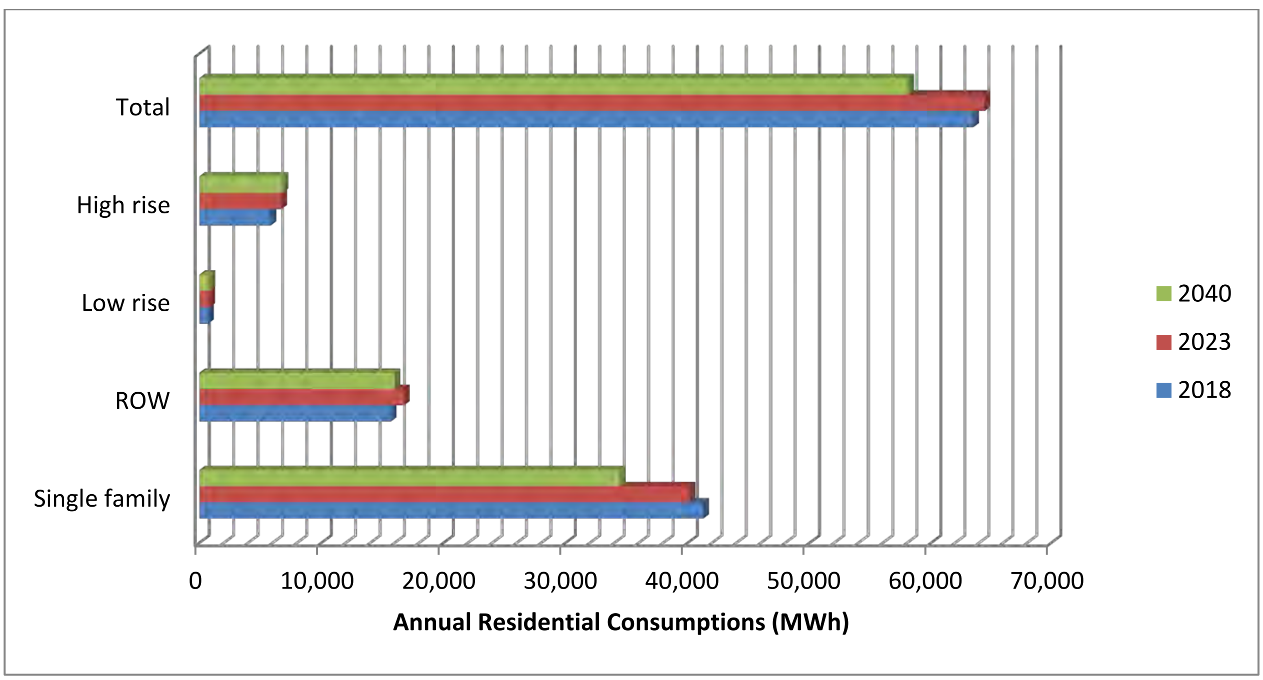


Figure 3-8 Residential sector load forecast, Marchwood MTS

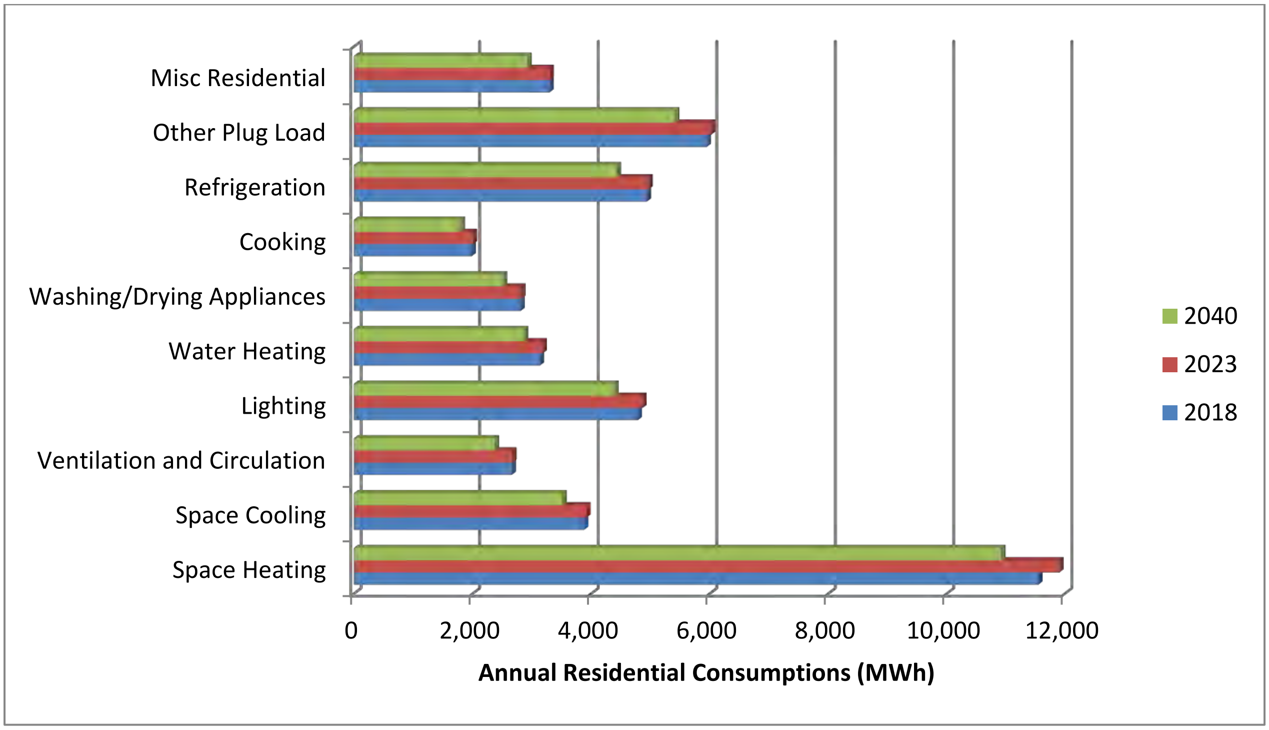


Figure 3-9 Residential load forecast by end-use, Kanata MTS

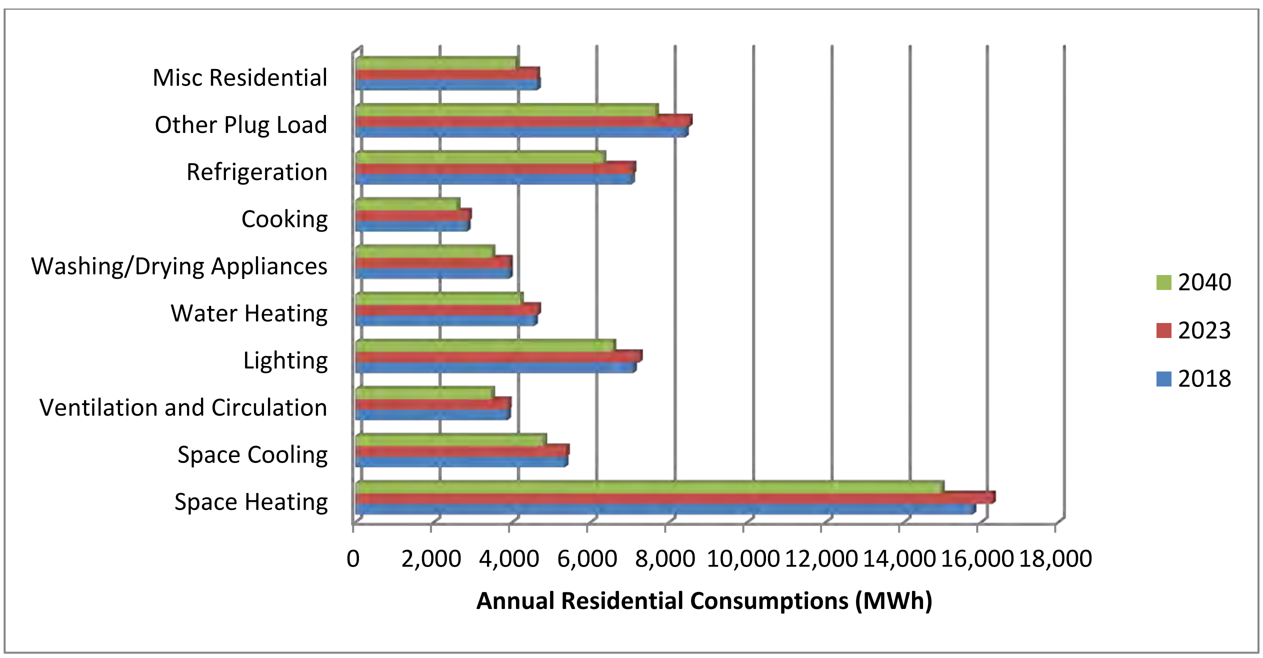


Figure 3-10 Residential load forecast by end-use, Marchwood MTS

3.5.2 Commercial Forecast

The project team developed the forecast of the square footage of the commercial subsectors at Kanata and Marchwood MTS using the base-year commercial sector estimation as well as Hemson study provided by IESO. Also, the project team developed a forecast for the energy intensity for each commercial subsector based on NRCAN historical energy intensities for commercial subsectors.

The project team carried out the commercial forecast for Kanata and Marchwood MTS based on the base year commercial load consumption, the area forecast of commercial subsectors, and the forecasted energy intensities for commercial subsectors. The complete results for the residential forecast for Kanata MTS and Marchwood MTS are introduced in Tables B- 18 and B-19 respectively. Moreover, the commercial subsectors consumptions for the base year are compared to the short-term forecasted consumptions (i.e., 2023) and the long-term forecasted consumptions (i.e., 2040). The comparison results are presented in Figures 3-11 and 3-12 for Kanata and Marchwood MTS respectively. Furthermore, the project team developed the end-use residential forecasts for Kanata and Marchwood MTS as shown in Figures 3-13 and 3-14 respectively.

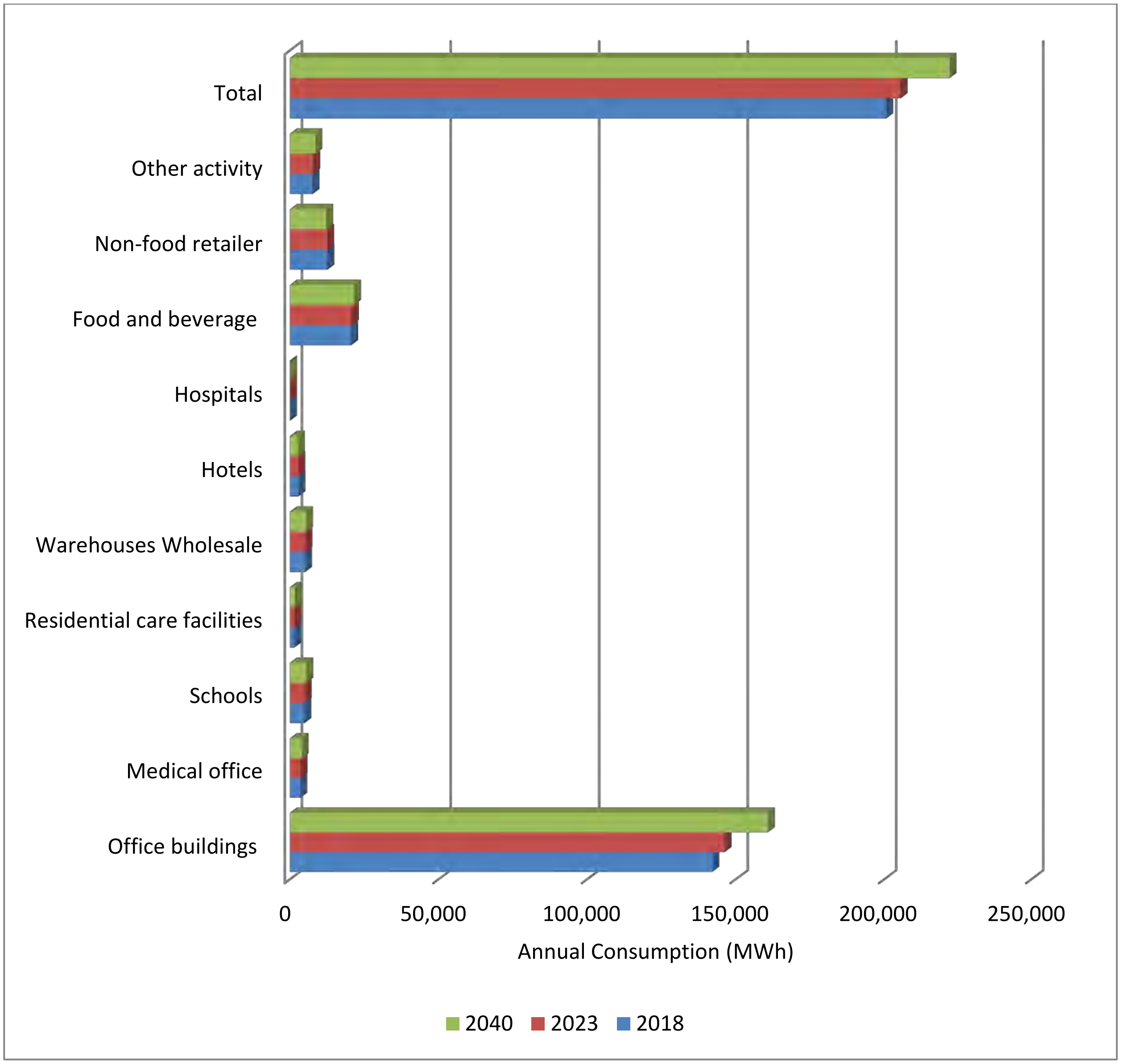


Figure 3-11 Commercial sector load forecast, Kanata MTS

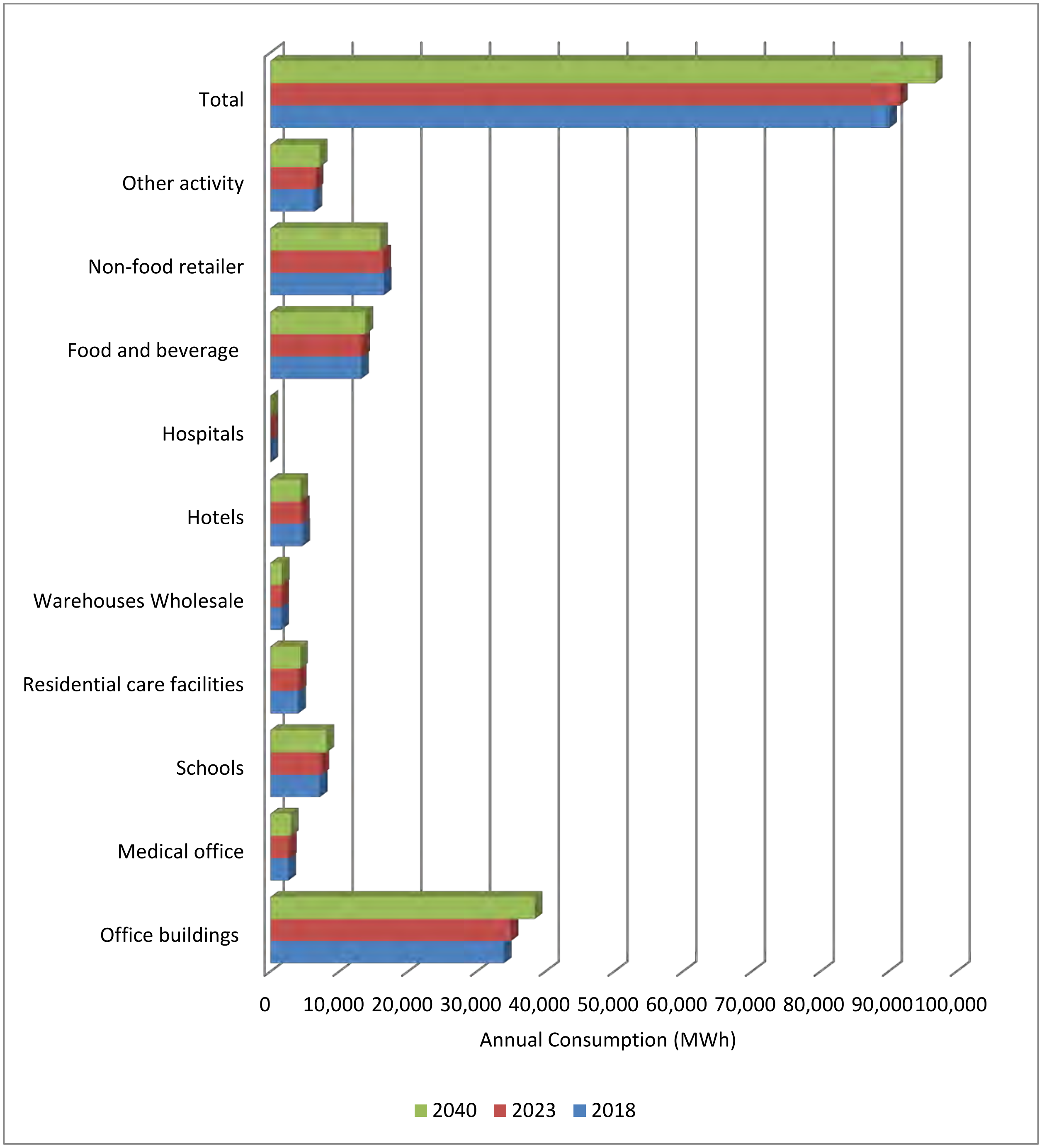


Figure 3-12 Commercial sector load forecast, Marchwood MTS

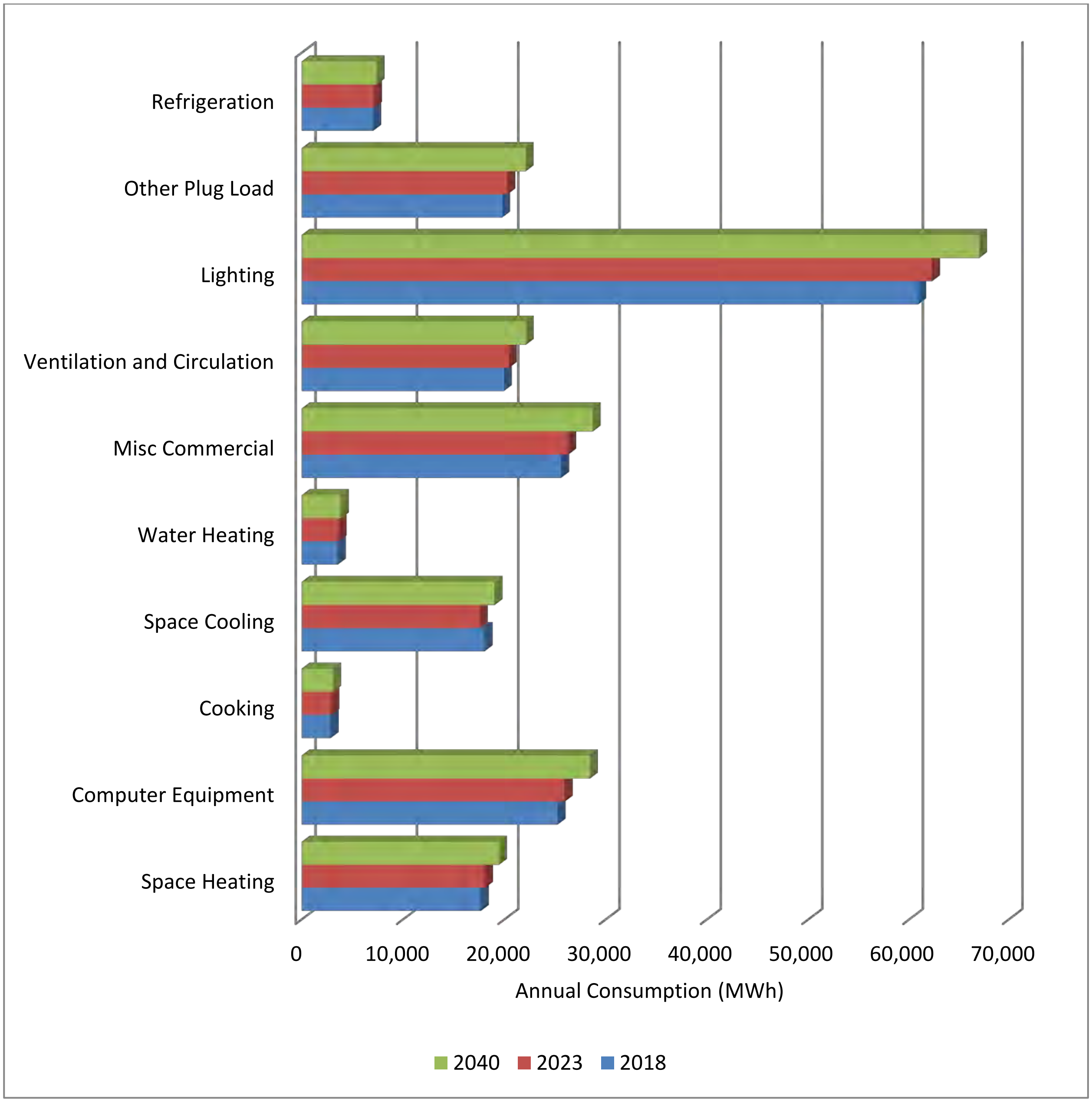


Figure 3-13 Commercial load forecast by end-use, Kanata MTS

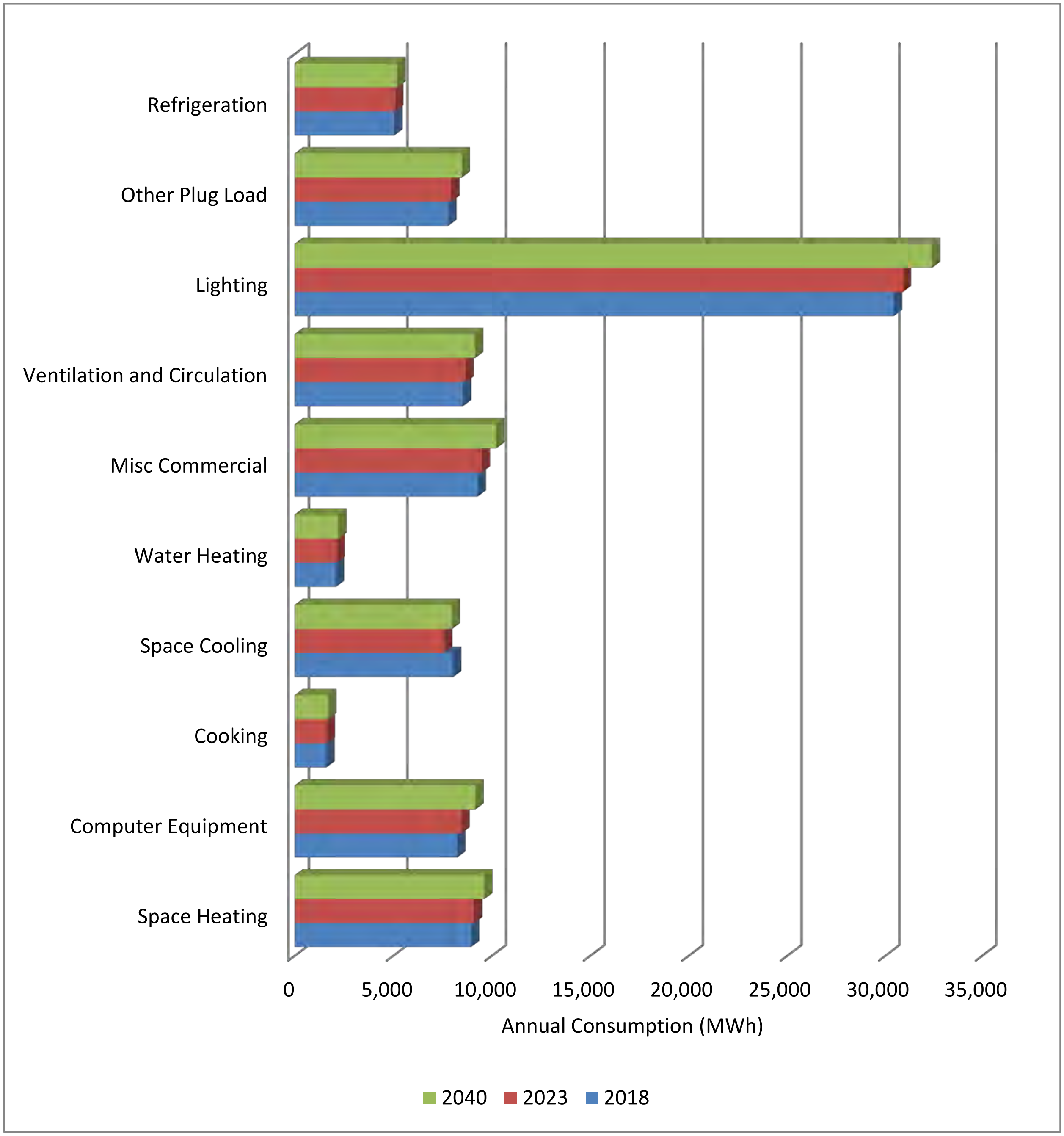


Figure 3-14 Commercial load forecast by end-use, Marchwood TS

3.5.3 Aggregated Forecast

The project team determined the aggregated commercial and residential forecast of Kanata-Marchwood area; illustrated in Figure 3-15. When compared to the base year of 2018, the total aggregated load forecast for 2040 estimates a total increase in electricity consumption of 4% from 402,743 MWh in 2018 to 418,971 MWh in 2040. The commercial section is expected to provide the largest increase in electricity use, rising from 290,847 MWh in 2018 to 319,038 MWh (9.7 % increase). The residential sector electricity consumption is expected to show a decrease from 108,557 MWh in 2018 to 99,309 MWh in 2040 (8.51 % decrease). The industrial forecast is assumed to be constant over the forecasting period as one industrial building only exists at Kanata-Marchwood area.

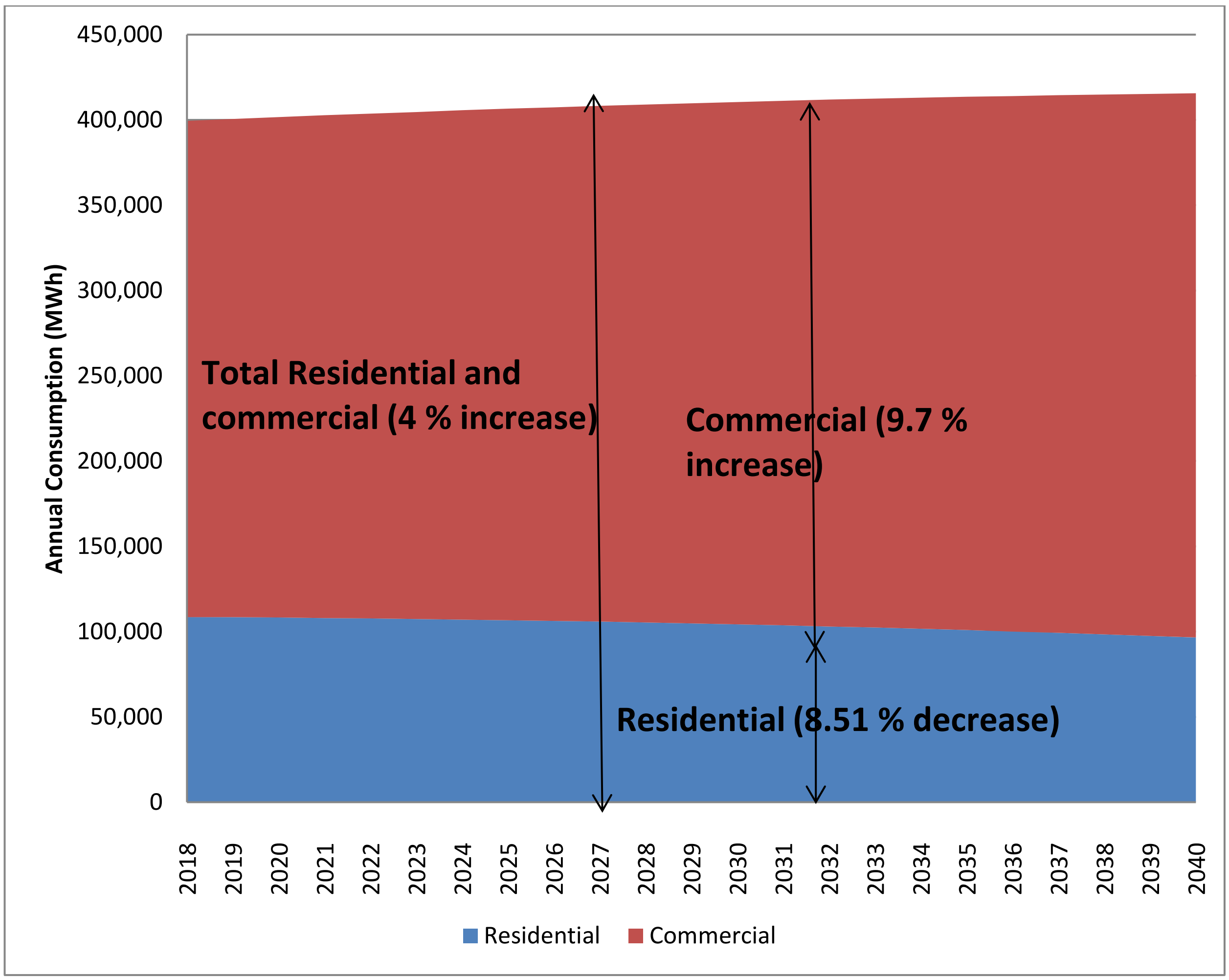


Figure 3-15 Kanata-Marchwood forecast (2018-2040) by sector

3.5.4 Observations

The following can be observed from the 2018-2040 load forecasts by sector, subsectors, and end use:

- The largest decrease in electricity consumption in the residential sector is expected to occur in the single-family subsector (16.25% decrease from 2018 to 2040).
- The electricity consumption of ROW subsector is expected to increase up to the year 2026 (7 % increase from 2018 to 2026), and then the ROW consumption will fall for the remaining forecasted years (4.67% decrease from 2018 to 2040).
- The electricity consumption of low-rise and high-rise subsectors is expected to increase over the forecasted period (16.67% increase for low-rise and high-rise)
- At the end-use level, all residential end-use items are expected to decrease in electricity use.
- Increased electricity usage is expected for all commercial subsectors, except for non-food retailers and hotels that are expected to decrease in electricity use (3.28 decrease for non-food retailers and 6.36 decrease for hotels).
- At the end-use level, all commercial end-use items are expected to increase in electricity use. Lighting shows the largest increase, while cooking, space cooling, water heating, and refrigeration show the lowest increase.

3.6 Participation in CDM and DER program

Based on the input data received from the HOL and IESO, the project team identified the historical participation of the loads in the CDM programs and the existing DERs as well as the potential for expansion. The complete list of existing DERs at Kanata-Marchwood area is presented in Table 3-15. Moreover, the total contract capacity of the DERs at Kanata-Marchwood area is presented in Table 3-16. The forecasted effective capacities of the DERs and the CDM are presented in Table 3-17.

Table 3-16 Existing Energy Resources Facilities at Kanata-Marchwood

Station	Feeder	Capacity (KW)	Fuel Type
Kanata MTS	624F1	400	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	2.5	Solar PV
Kanata MTS	624F1	500	Solar PV
Kanata MTS	624F1	8	Solar PV
Kanata MTS	624F5	250	Solar PV
Kanata MTS	624F1	40	Solar PV
Kanata MTS	624F2	5120	Battery
Marchwood MTS	MWDF1	10	Solar PV
Marchwood MTS	MWDF2	250	Solar PV
Marchwood MTS	MWDF3	65	Solar PV
Marchwood MTS	MWDF1	250	Solar PV
Marchwood MTS	MWDF1	150	Solar PV
Marchwood MTS	MWDF3	297	Solar PV
Marchwood MTS	MWDF2	150	Solar PV
Marchwood MTS	MWDF3	10	Solar PV
Marchwood MTS	MWDF3	100	Solar
Marchwood MTS	MWDF4	990	Battery

Table 3-17 DERs Contract Capacity at Kanata-Marchwood

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	0.2098	0.2098	0.2098	0.2098	0.2098	0.2098	0.2098	0.2098	0.209 8	0.2098	0.2098
Capacity connected to Kanata MTS (MW)	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Capacity connected to Marchwood MTS (MW)	0.2098	0.2098	0.2098	0	0	0	0	0	0	0	0
Capacity connected to Kanata MTS (MW)	0.94	0.94	0.94	0.04	0.04	0.04	0.04	0	0	0	0

Table 3-18 DERs Effective Capacity at Kanata-Marchwood

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Capacity connected to Kanata MTS (MW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Capacity connected to Marchwood MTS (MW)	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Capacity connected to Kanata MTS (MW)	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0

Table 3-19 CDM Effective Capacity at Kanata-Marchwood

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	1.8	2.3	2.6	2.3	2.4	2.6	2.9	3.4	3.8	4.3
Capacity connected to Kanata MTS (MW)	2.3	2.7	3.1	3.2	3.2	3.4	3.9	4.2	4.8	5.4
Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Capacity connected to Marchwood MTS (MW)	4.7	5.2	5.5	5.8	6.1	6.3	6.3	6.3	6.3	6.2
Capacity connected to Kanata MTS (MW)	6.0	6.6	7.1	7.5	7.9	8.0	8.0	8.0	8.0	8.0

List of References

[1] Achievable Potentials Study: Project Plan for Long Term Analysis; http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Achievable-Potential-Study-LDC-Working-Group

[2] Achievable Potentials Study: Project Plan for Short Term Analysis; http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Achievable-Potential-Study-LDC-Working-Group

[3] Google Earth Files for Kanata and Marchwood MTS service area; received from HOL.

[4] Survey of Household Energy Use; Detailed Statistical Report http://oee.nrcan.gc.ca/publications/statistics/sheu/2011/pdf/sheu2011.pdf

[5] Ontario Electricity Board 2017 Yearbook of Electricity Distributors: https://www.oeb.ca/oeb/_Documents/RRR/2017_Yearbook_of_Electricity_Distributors.pdf

[6] Dun & Bradstreet database: database on Kanata and Marchwood commercial and industrial building; received from IESO.

[7] MPAC database: database on Kanata and Marchwood commercial and industrial building; received from IESO.

[8] Hemson Data: database on Ottawa city commercial building forecast; received from IESO.

[9] Survey of Commercial and Institutional Energy Use (SCIEU) - https://www.nrcan.gc.ca/energy/efficiency/17137

[10] Public Sector database: database on an annual consumption of schools, universities, and hospitals https://www.ontario.ca/data/energy-use-and-greenhouse-gas-emissions-broader-public-sector

[11] https://documents.ottawa.ca/sites/default/files/kanata_north_cdp_en.pdf

Appendix A

Definitions and Extracted Data from the Input Database

Table A-1 Residential Subsector Definition

Subsector	Definition
Single family	Single-family, detached and semi-detached households
Row house	Single-family, attached households (e.g., townhouses)
Multi-Unit Residential Building (MURB) low rise	Individually metered units in multi-unit residential buildings less than five stories
Multi-Unit Residential Building (MURB) high rise	Individually metered units in multi-unit residential buildings greater than or equal five stories

Table A-2 Commercial Subsector Definition

Subsector	Definition
Office buildings (non-medical)	Office buildings including governmental offices
Medical office buildings	Buildings whose primary business operations include healthcare services (e.g., labs and dialysis centers)
Elementary and/or secondary schools	Elementary and secondary education, apprenticeship, training, and daycare facilities.
Assisted daily/residential care facilities	Home health care facilities and homes for the elderly.
Warehouses Wholesale	Warehouse and wholesale distribution facilities
Hotels, motels or lodges	Overnight accommodation buildings
Hospitals	Inpatient and outpatient health facilities.
Food and beverage stores	Full-service restaurants, caterers, cafeterias, and retail buildings whose primary business operation includes the sale of food.
Non-food retail stores	All retail buildings whose primary business operation does not include the sale of food
Other activity or function	All other activities not specified above (e.g., theaters, sports arena, libraries, etc.)

Table A-3 Energy Intensity for Commercial Buildings

Primary activity	Building size	Energy intensity GJ/m^2	Electricity/natural gas split (%)
Office buildings (non-medical)	**Total**	**1.12**	**63/37**
	5,000 square feet or less (465 square metres or less)	1.57	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.28	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.08	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.16	
	Over 200,000 square feet (Over 18,580 square metres)	1.09	
Medical office buildings	**Total**	**1.28**	**58/42**
	5,000 square feet or less (465 square metres or less)	1.18	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.06	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.10	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.42	
	Over 200,000 square feet (Over 18,580 square metres)	1.92	
Elementary and/or secondary schools	**Total**	**0.88**	**40/60**
	5,000 square feet or less (465 square metres or less)	0.70	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.33	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	0.91	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	0.84	
	Over 200,000 square feet (Over 18,580 square metres)	0.88	
Assisted daily/residential care facilities	**Total**	**1.30**	**49/51**
	5,000 square feet or less (465 square metres or less)	1.06	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.22	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.28	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.40	

	Over 200,000 square feet (Over 18,580 square metres)	1.14	
Warehouses Wholesale	**Total**	**0.82**	**43/57**
	5,000 square feet or less (465 square metres or less)	0.83	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.00	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	0.90	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	0.74	
	Over 200,000 square feet (Over 18,580 square metres)	0.63	
Hotels, motels or lodges	**Total**	**1.24**	**47/53**
	5,000 square feet or less (465 square metres or less)	1.33	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.28	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.24	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.33	
	Over 200,000 square feet (Over 18,580 square metres)	1.11	
Hospitals	**Total**	**2.44**	**40/60**
	5,001 to 10,000 square feet (466 to 929 square metres)	1.26	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	2.92	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	2.84	
	Over 200,000 square feet (Over 18,580 square metres)	2.37	
Food and beverage stores	**Total**	**1.86**	**72/28**
	5,000 square feet or less (465 square metres or less)	2.64	
	5,001 to 10,000 square feet (466 to 929 square metres)	2.24	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	2.61	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	2.33	
	Over 200,000 square feet (Over 18,580 square metres)	0.71	
Non-food retail stores	**Total**	**1.12**	**54/46**
	5,000 square feet or less (465 square metres or less)	1.37	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.06	

	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.42	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.00	
	Over 200,000 square feet (Over 18,580 square metres)	1.02	
Other activity or function	**Total**	**1.20**	**46/54**
	5,000 square feet or less (465 square metres or less)	1.98	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.29	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.08	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	0.93	
	Over 200,000 square feet (Over 18,580 square metres)	1.07	

Table A-4 Historical Number of Residential Buildings

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998
Single Detached (thousands)	5,854	6,014	6,134	6247	6,346	6,456	6,544	6,614	6,693
Single Attached (thousands)	969	1,010	1,045	1,079	1,110	1,136	1,162	1,188	1,215
Apartments (thousands)	3,380	3,465	3,522	3,581	3,625	3,682	3,733	3,762	3,787
Year	1999	2000	2001	2002	2003	2004	2005	2006	2007
Single Detached (thousands)	6,772	6,864	6,950	7,055	7,165	7,280	7,386	7,490	7,594
Single Attached (thousands)	1,242	1,272	1,298	1,325	1,355	1,391	1,429	1,467	1,503
Apartments (thousands)	3,810	3,834	3,860	3,901	3,954	4,014	4,082	4,146	4,210
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Single Detached (thousands)	7,686	7,759	7,838	7,907	7,976	8,040	8,103	8,156	8,215
Single Attached (thousands)	1,540	1,573	1,604	1,635	1,666	1,699	1,733	1,768	1,802
Apartments (thousands)	4,287	4,358	4,422	4,486	4,553	4,630	4,708	4,802	4,890

Table A-5 Historical Energy Intensity of Residential subsectors

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998
Single Detached, Energy Intensity (GJ/household)	184.2	176.3	175.3	178.7	179.9	172.1	178.7	170.4	157.2
ROW, Energy Intensity (GJ/household)	127.1	122.4	122.2	123.3	124.6	119.1	123.2	118.0	107.2
Apartments, Energy Intensity (GJ/household)	77.5	73.4	74.8	75.1	76.1	73.0	75.4	73.0	67.3
Year	1999	2000	2001	2002	2003	2004	2005	2006	2007
Single Detached, Energy Intensity (GJ/household)	159.4	163.1	154.0	159.9	157.6	154.9	150.2	142.6	151.8
ROW, Energy Intensity (GJ/household)	109.8	112.1	106.7	109.3	109.6	107.6	106.0	100.0	105.9
Apartments, Energy Intensity (GJ/household)	68.7	70.3	66.8	68.4	69.4	69.3	67.1	64.6	68.4
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Single Detached, Energy Intensity (GJ/household)	150.1	143.4	140.1	146.4	138.2	141.8	144.3	136.8	126.9

ROW, Energy Intensity (GJ/household)	105.1	100.0	97.7	101.5	95.8	99.4	101.7	97.1	89.5
Apartments, Energy Intensity (GJ/household)	67.7	65.6	63.7	66.4	63.5	66.0	67.7	65.0	60.8

Appendix B
Detailed Estimation for Kanata-Marchwood

Table B-1 Residential Subsector Energy Consumptions for Kanata Feeders

Feeder #	Residential building type	Single family	ROW	Low rise	High rise
624F1	Annual Electricity consumptions (MWh)	15,405	5,628	924	0
624F2	Annual Electricity consumptions (MWh)	4,421	2,357	0	0
624F3	Annual Electricity consumptions (MWh)	1,071	1,029	452	993
624F5	Annual Electricity consumptions (MWh)	212	493	0	0
624F6	Annual Electricity consumptions (MWh)	6,293	5,756	0	0
Total	Annual Electricity consumptions (MWh)	27,404	15,264	1,376	993

Table B-2 Commercial Subsectors Energy Consumption, Feeder 624F1

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	14,527	2,623,735
Medical office buildings	145	8,429
Elementary and/or secondary schools	611	60,870
Assisted daily/residential care facilities	0	0
Warehouses Wholesale	2,054	226,601
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	7,888	158,598
Non-food retail stores	9,272	564,522
Other activity or function	941	64,539

Table B-3 Commercial Subsectors Energy Consumption, Feeder 624F2

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	39,901	2,082,994
Medical office buildings	0	0
Elementary and/or secondary schools	0	0
Assisted daily/residential care facilities	845	75,000
Warehouses Wholesale	2,071	117,597
Hotels, motels or lodges	2,848	167,436
Hospitals	0	0
Food and beverage stores	6,260	133,040
Non-food retail stores	556	26,500
Other activity or function	404	28,413

Table B-4 Commercial Subsectors Energy Consumption, Feeder 624F3

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	2,145	101,874
Medical office buildings	125	5,000
Elementary and/or secondary schools	2,889	300,000
Assisted daily/residential care facilities	0	0
Warehouses Wholesale	200	17,709
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	474	10,732
Non-food retail stores	0	0
Other activity or function	1,862	152,813

Table B-5 Commercial Subsectors Energy Consumption, Feeder 624F5

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	67,729	3,374,230
Medical office buildings	241	13,832
Elementary and/or secondary schools	127	8,719
Assisted daily/residential care facilities	559	32,579
Warehouses Wholesale	536	49,762
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	3,366	65,291
Non-food retail stores	921	48,055
Other activity or function	2,409	190,969

Table B-6 Commercial Subsectors Energy Consumption, Feeder 624F6

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	17,849	883,368
Medical office buildings	2,977	137,226
Elementary and/or secondary schools	1,209	126,880
Assisted daily/residential care facilities	68	4,780
Warehouses Wholesale	244	23,327
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	2,589	52,472
Non-food retail stores	1,868	112,481
Other activity or function	2,004	112,995

Table B-7 Commercial Subsectors Energy Consumption, Kanata MTS

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	142,151	9,066,201
Medical office buildings	3,488	164,487
Elementary and/or secondary schools	4,836	496,469
Assisted daily/residential care facilities	1,471	112,359
Warehouses Wholesale	5,107	434,996
Hotels, motels or lodges	2,848	167,436
Hospitals	0	0
Food and beverage stores	20,578	420,133
Non-food retail stores	12,617	751,558
Other activity or function	7,620	549,729

Table B-8 Residential Subsectors Energy Consumptions for Each Feeder, Marchwood MTS

Feeder #	Residential building type	Single family	ROW	Low rise	High rise
MWDF1	Annual Electricity consumptions (MWh)	10,290	3,910	298	2,058
MWDF2	Annual Electricity consumptions (MWh)	5,637	4,239	0	3,783
MWDF3	Annual Electricity consumptions (MWh)	13,851	5,415	414	0
MWDF4	Annual Electricity consumptions (MWh)	11,506	2,120	0	0
Total	Annual Electricity consumptions (MWh)	41,284	15,684	712	5,841

Table B-9 Commercial Subsectors Energy Consumption, Feeder MWDF1

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	1,485	57,977
Medical office buildings	2,301	104,548
Elementary and/or secondary schools	3,509	367,000
Assisted daily/residential care facilities	0	
Warehouses Wholesale	34	1,670
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	8,690	152,745
Non-food retail stores	14,759	837,260
Other activity or function	806	13,444

Table B-10 Commercial Subsectors Energy Consumption, Feeder MWDF2

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	2,502	124,541
Medical office buildings	323	19,204
Elementary and/or secondary schools	408	40,969
Assisted daily/residential care facilities	3,920	213,173
Warehouses Wholesale	256	24,198
Hotels, motels or lodges	4,637	273,441
Hospitals	0	0
Food and beverage stores	4,498	105,976
Non-food retail stores	1,110	55,249
Other activity or function	2,607	198,948

Table B-11 Commercial Subsectors Energy Consumption, Feeder MWDF3

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	5,624	291,611
Medical office buildings	0	0
Elementary and/or secondary schools	2,552	262,209
Assisted daily/residential care facilities	0	0
Warehouses Wholesale	139	13,100
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	0	0
Non-food retail stores	0	0
Other activity or function	2,665	209,580

Table B-12 Commercial Subsectors Energy Consumption, Feeder MWDF4

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	24,353	1,229,529
Medical office buildings	0	0
Elementary and/or secondary schools	726	65,720
Assisted daily/residential care facilities	127	7,761
Warehouses Wholesale	1,142	183,280
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	0	0
Non-food retail stores	623	39,769
Other activity or function	337	23,695

Table B-13 Commercial Subsectors Energy Consumption for Marchwood MTS

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	33,964	1,703,658
Medical office buildings	2,624	123,752
Elementary and/or secondary schools	7,195	735,898
Assisted daily/residential care facilities	4,047	220,934
Warehouses Wholesale	1,571	222,248
Hotels, motels or lodges	4,637	273,441
Hospitals	0	0
Food and beverage stores	13,188	258,721
Non-food retail stores	16,493	932,278
Other activity or function	6,416	445,667

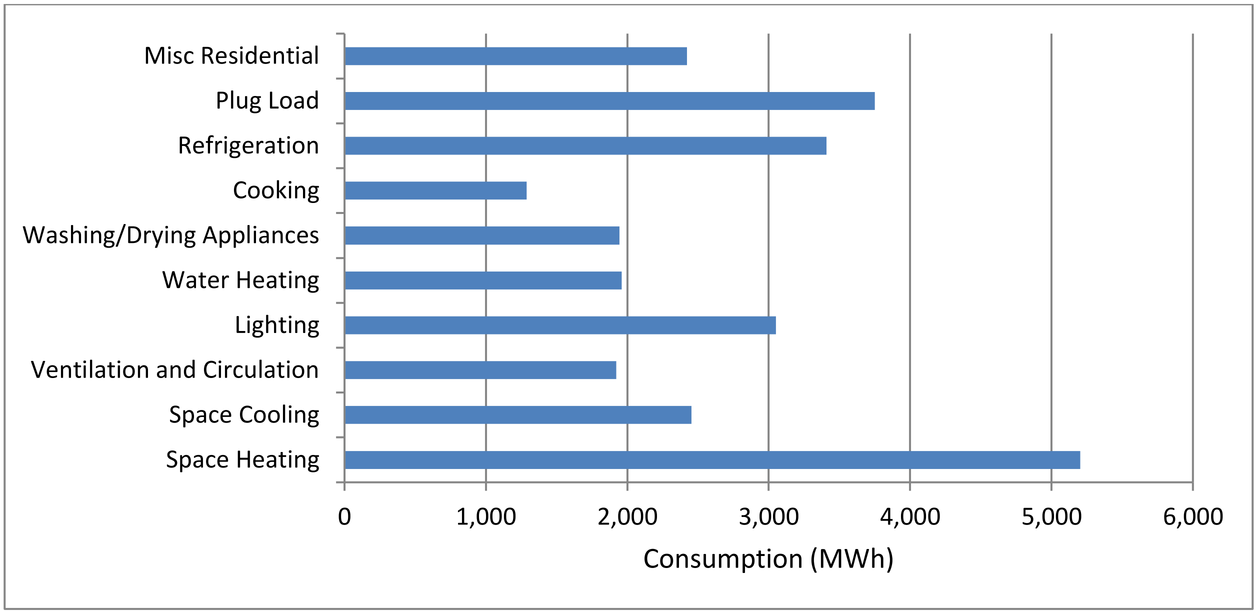


Figure B-1 End-use Segmentation for Single Family, Kanata MTS

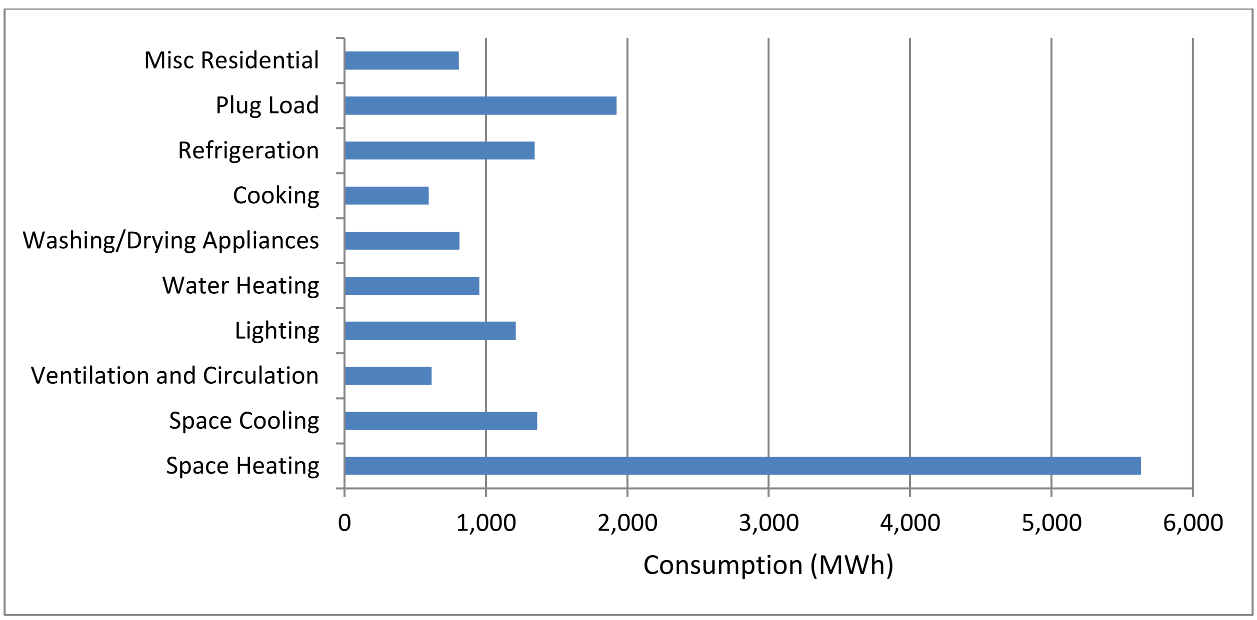


Figure B-2 End-use Segmentation for ROW, Kanata MTS

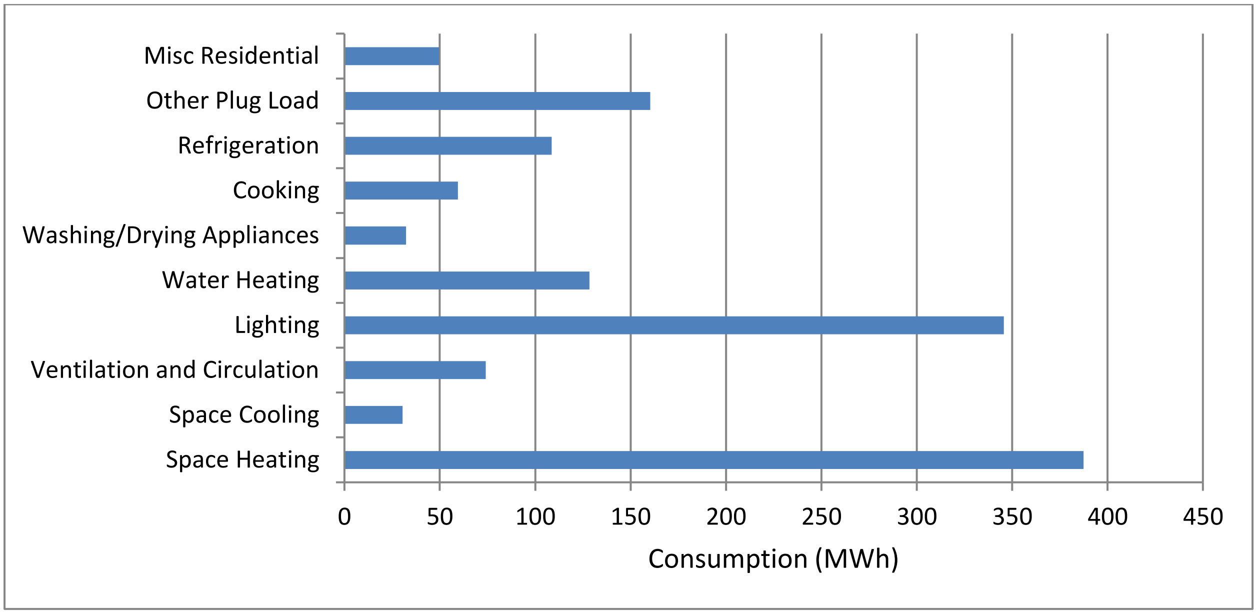


Figure B-3 End-use Segmentation for Low-Rise, Kanata MTS

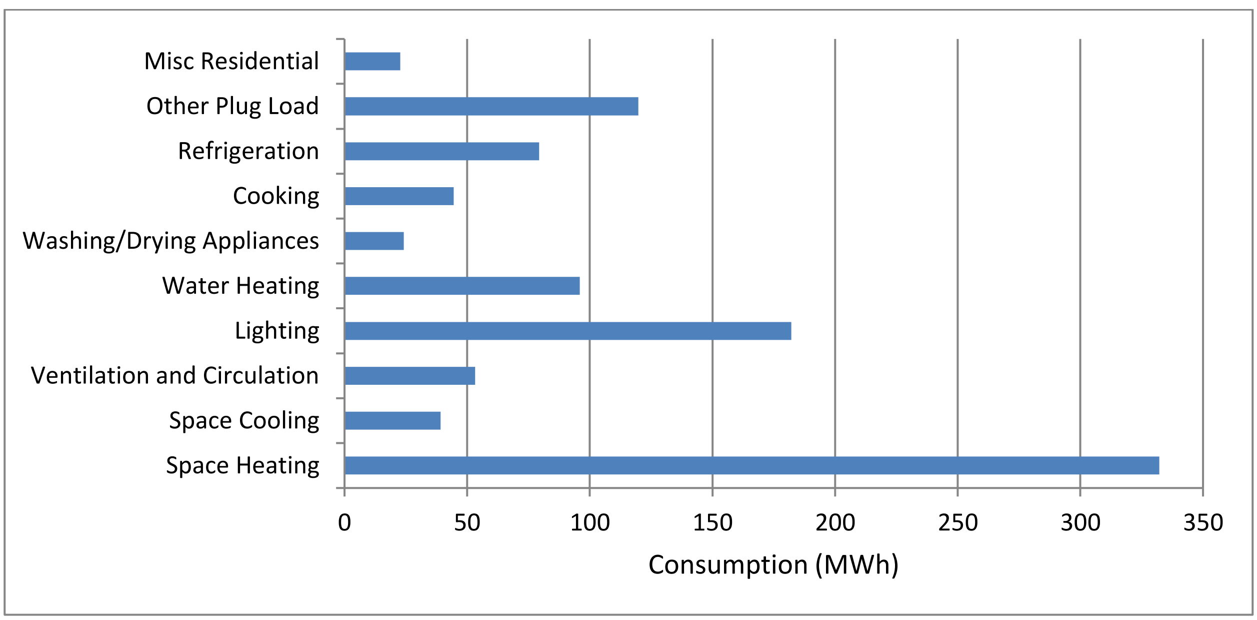


Figure B-4 End-use Segmentation for High-Rise, Kanata MTS

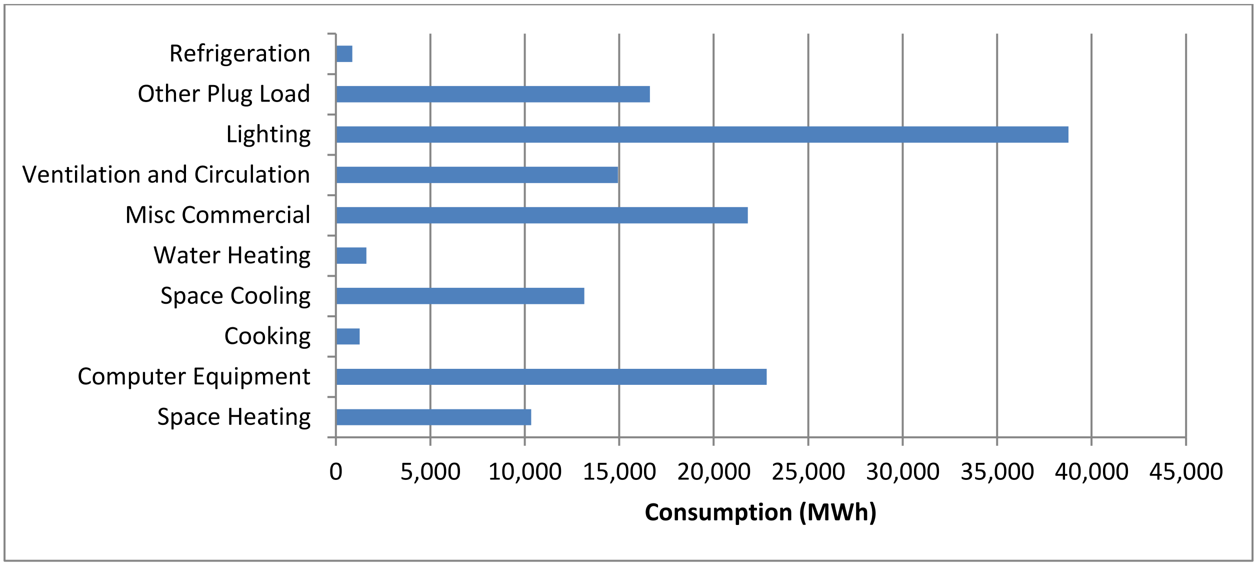


Figure B-5 End-use Segmentation for Office Buildings, Kanata MTS

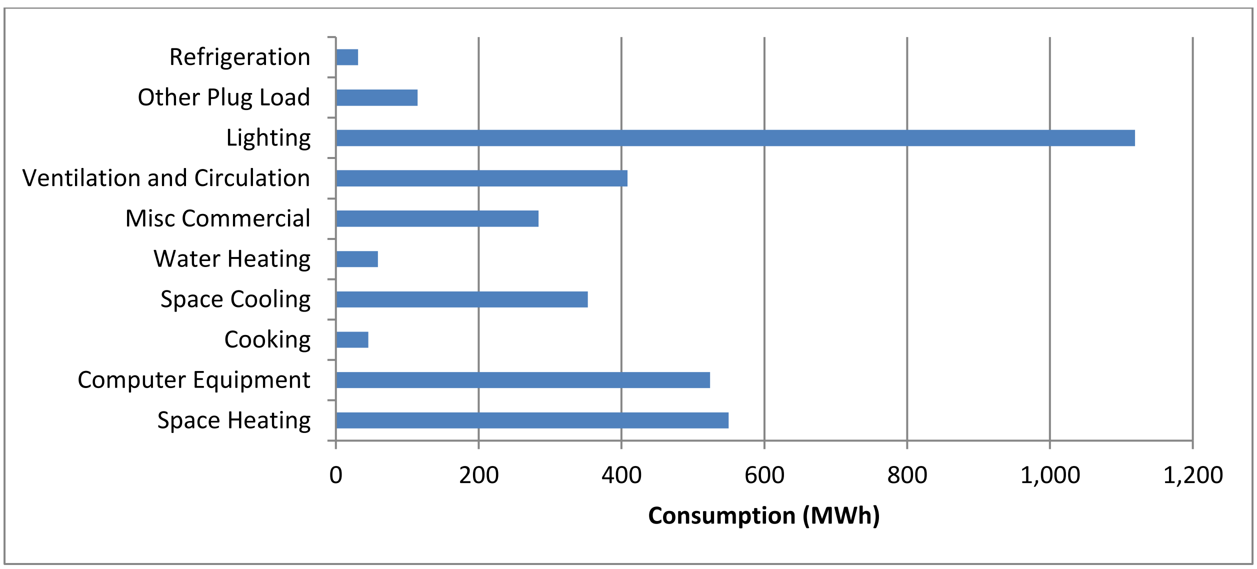


Figure B-6 End-use Segmentation for Medical Office Buildings, Kanata MTS

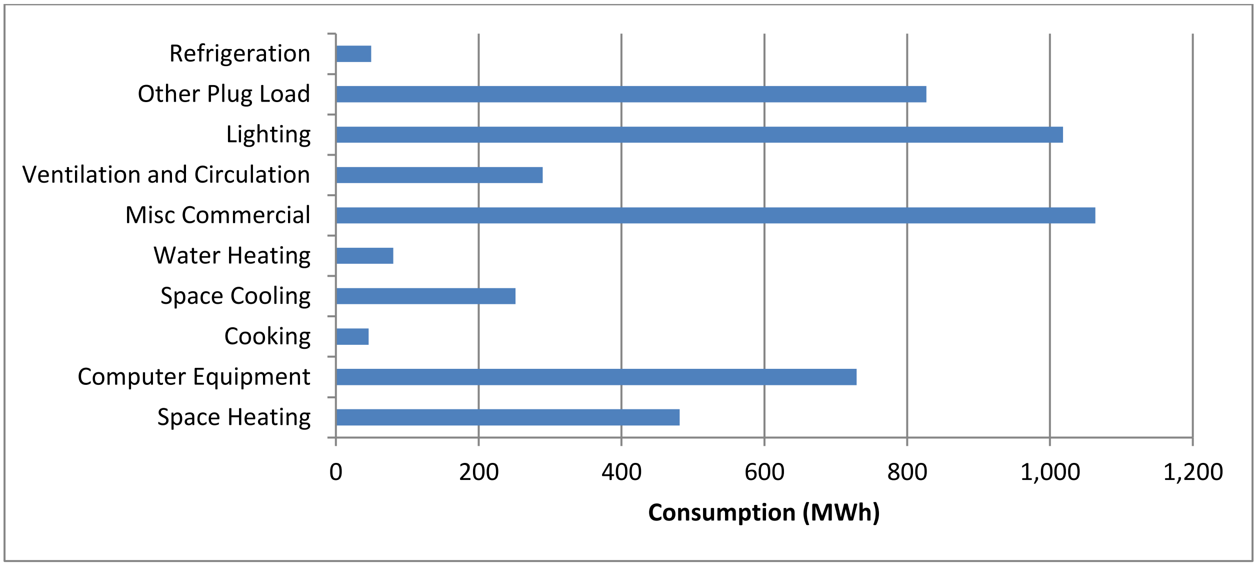


Figure B-7 End-use Segmentation for School, Kanata MTS

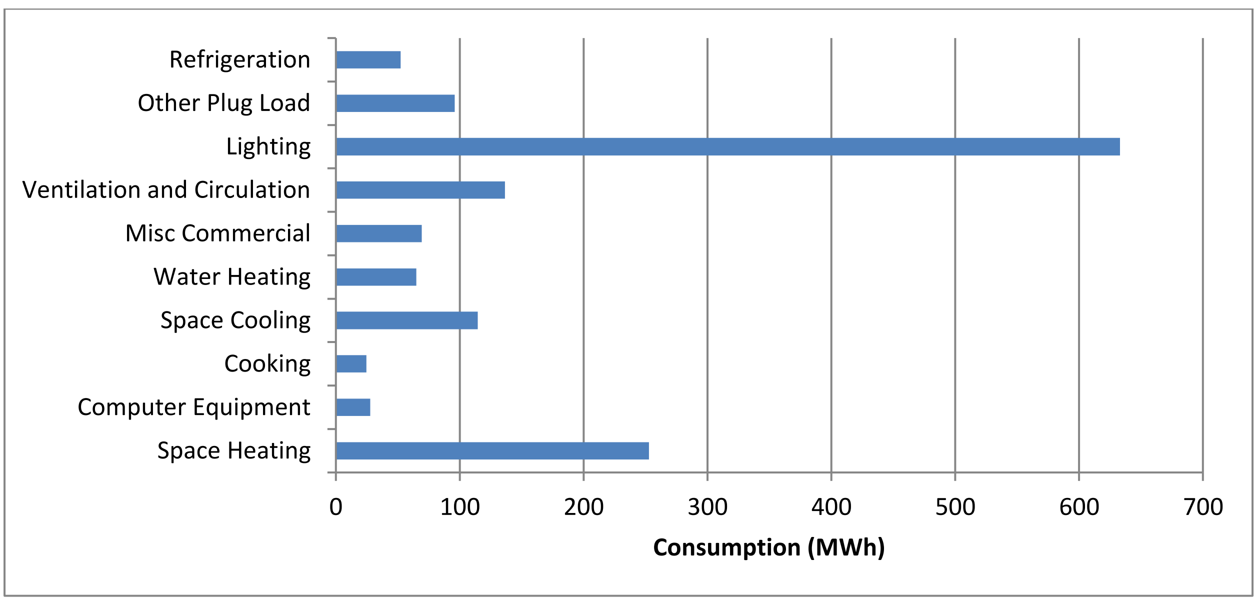


Figure B-8 End-use Segmentation for Residential Care, Kanata MTS

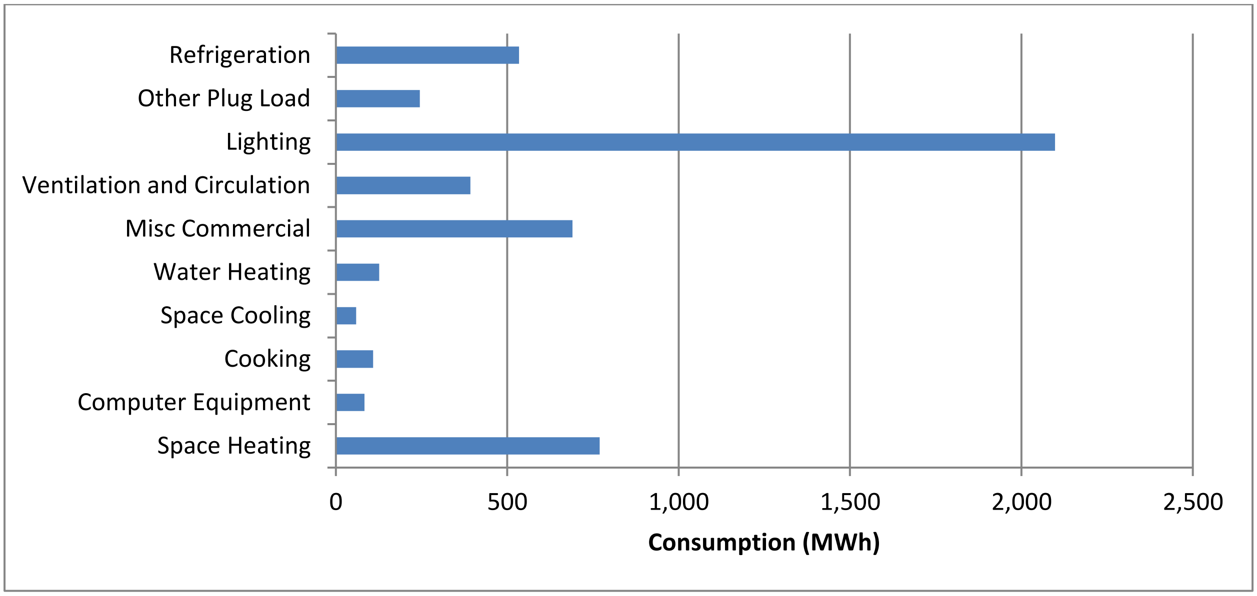


Figure B-9 End-use Segmentation for Warehouse Wholesale, Kanata MTS

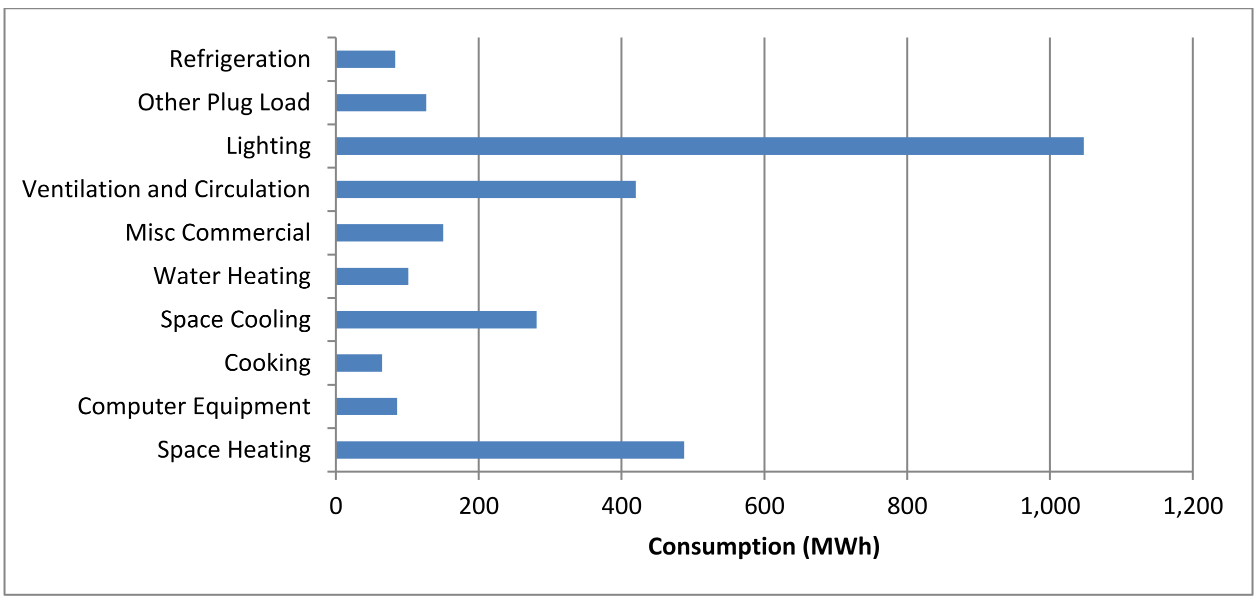


Figure B-10 End-use Segmentation for Hotels, Kanata MTS

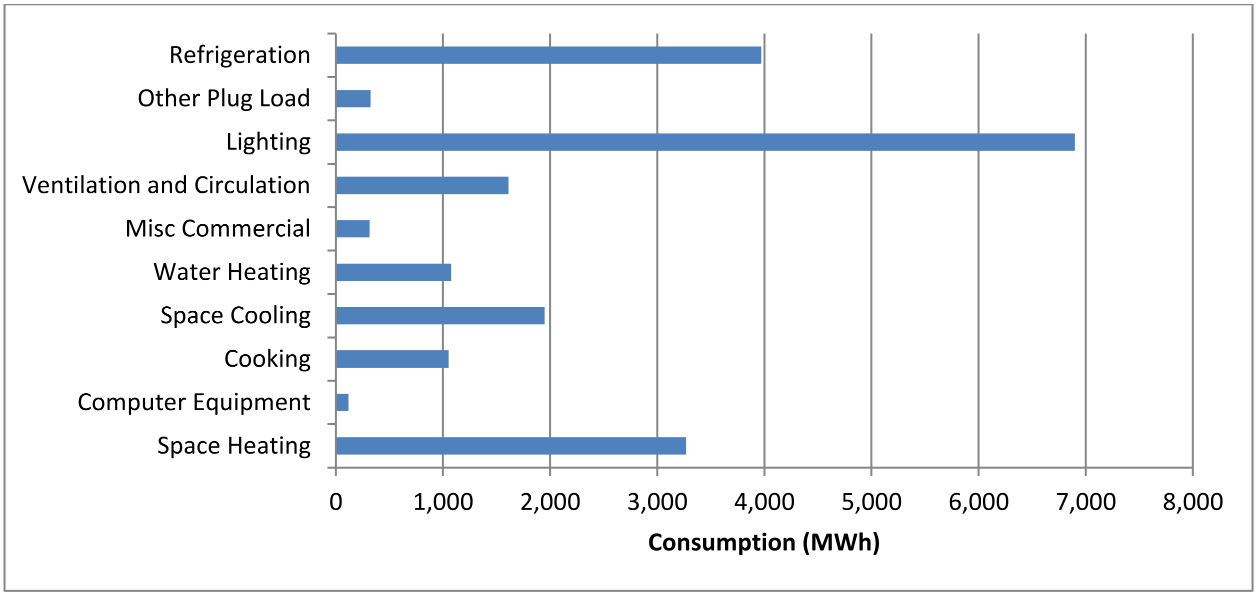


Figure B-11 End-use Segmentation for Food and Beverage Stores, Kanata MTS

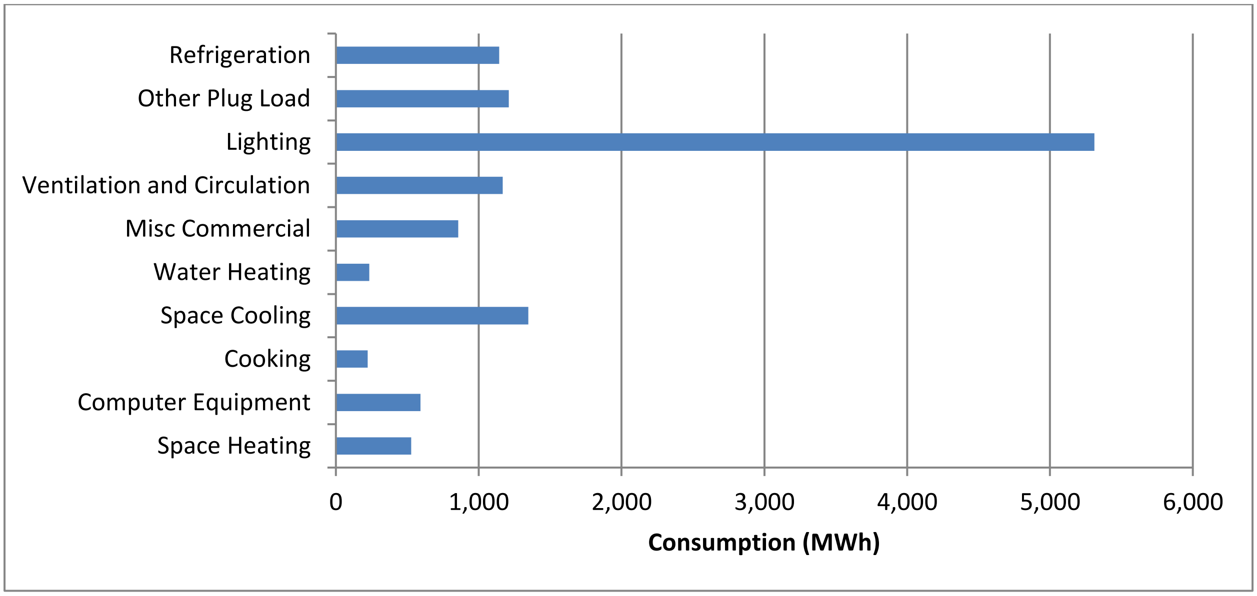


Figure B-12 End-use Segmentation for Non-Food retail Stores, Kanata MTS

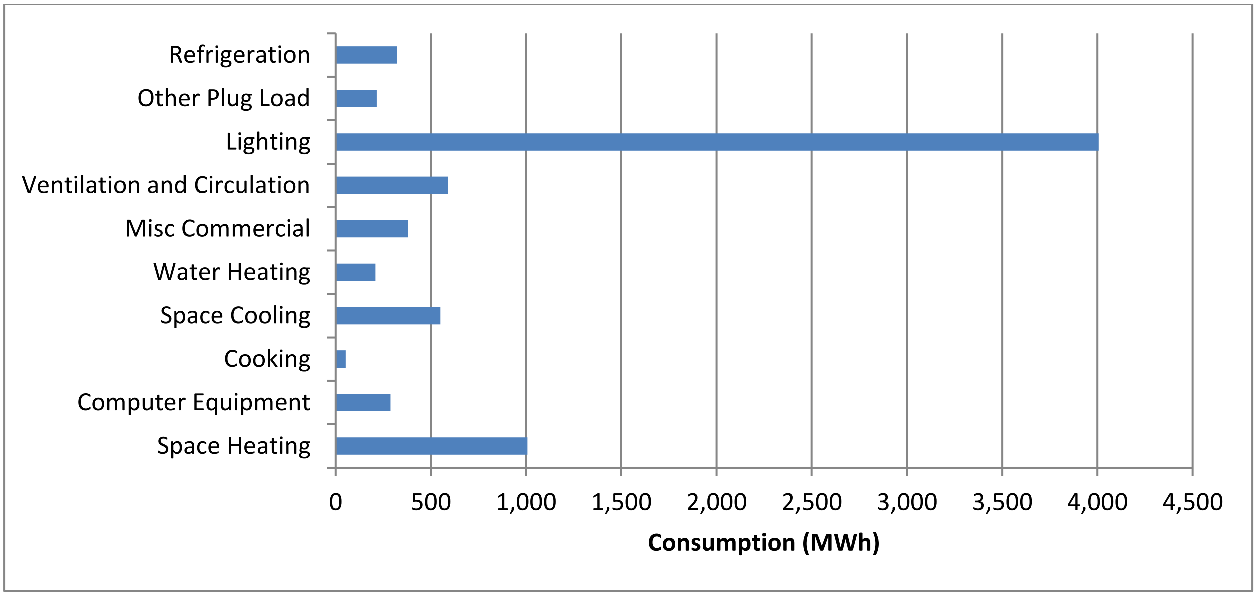


Figure B-13 End-use Segmentation for Other Commercial, Kanata MTS

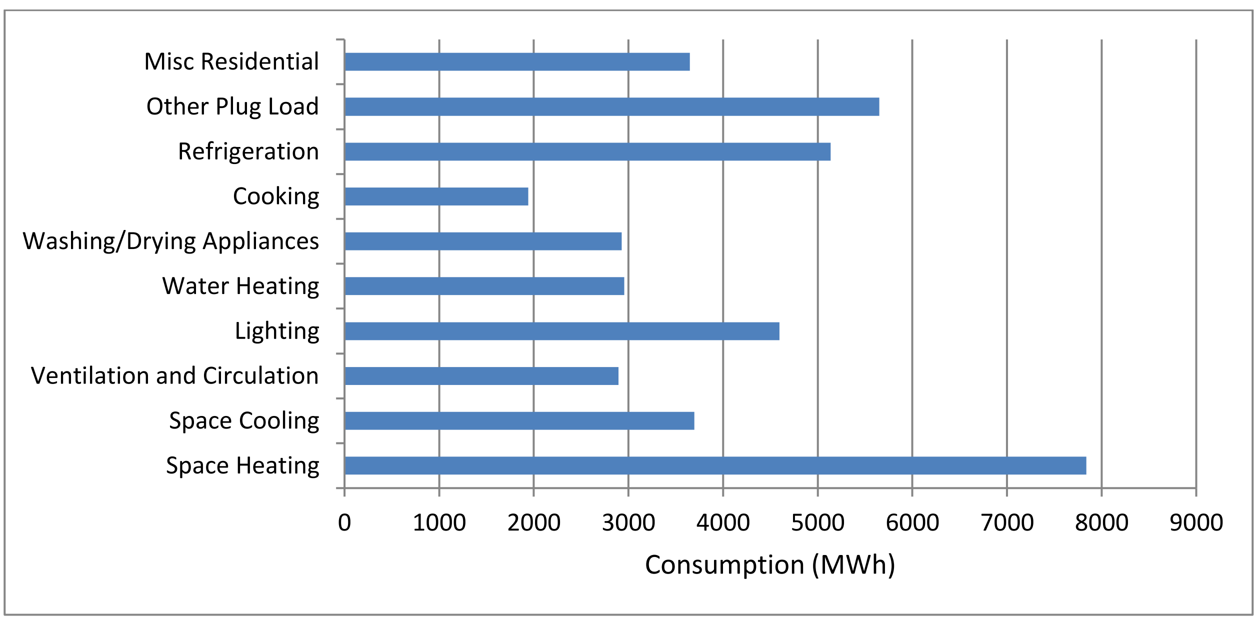


Figure B-14 End-use Segmentation for Single Family, Marchwood MTS

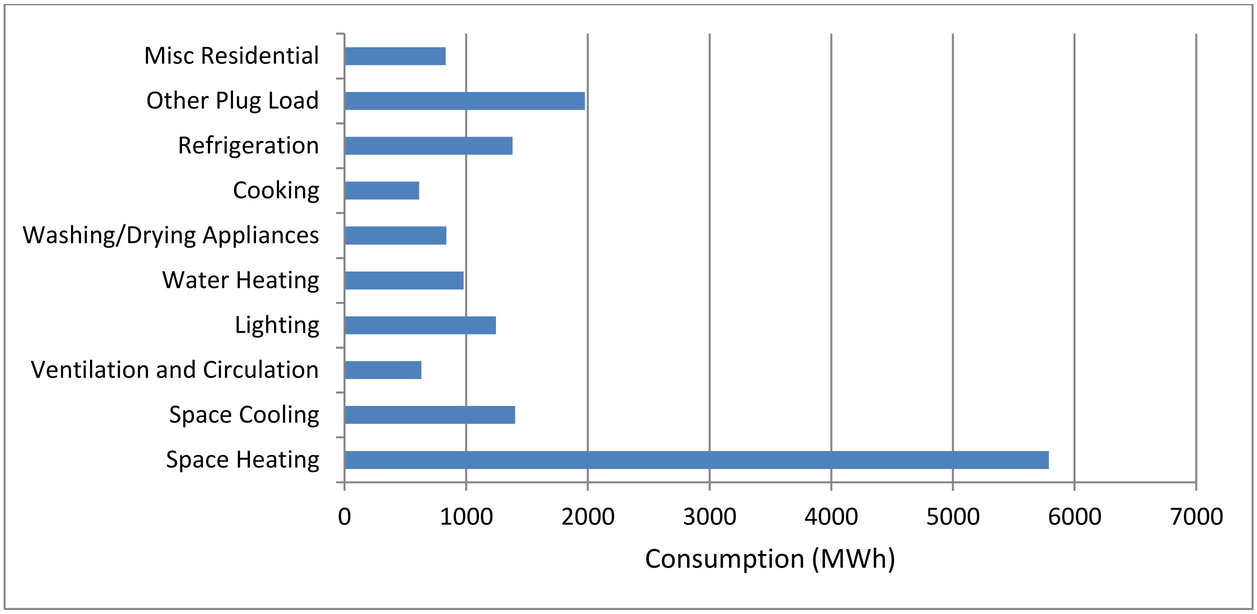


Figure B-15 End-use Segmentation for ROW, Marchwood MTS

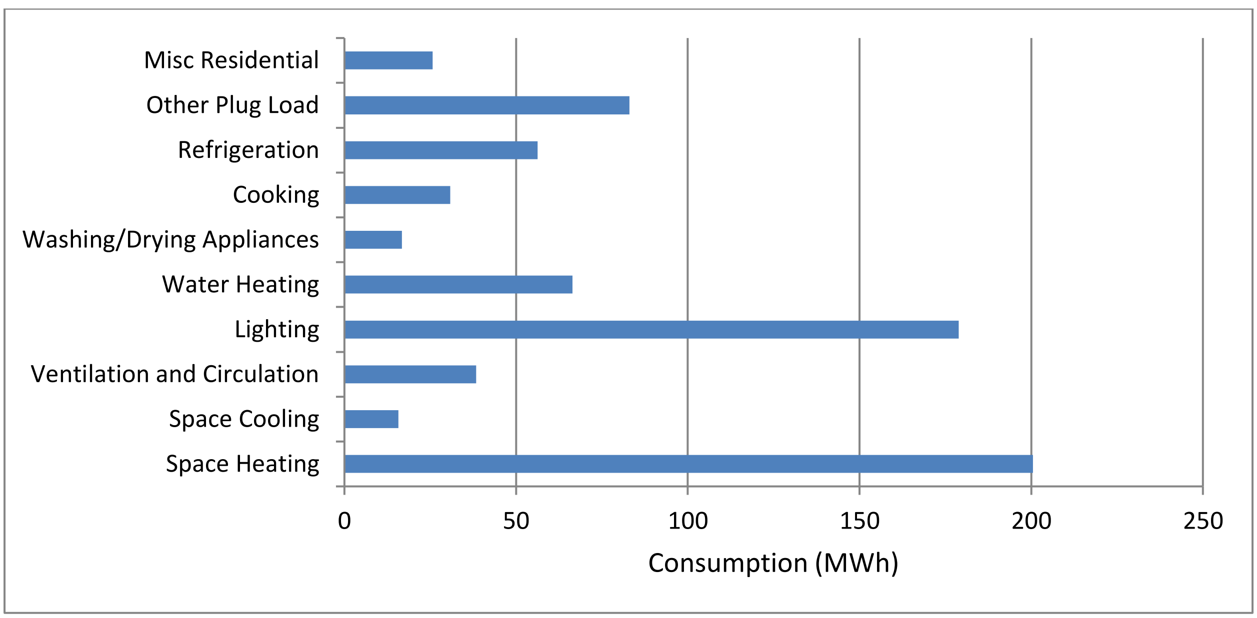


Figure B-16 End-use Segmentation for Low-Rise, Marchwood MTS

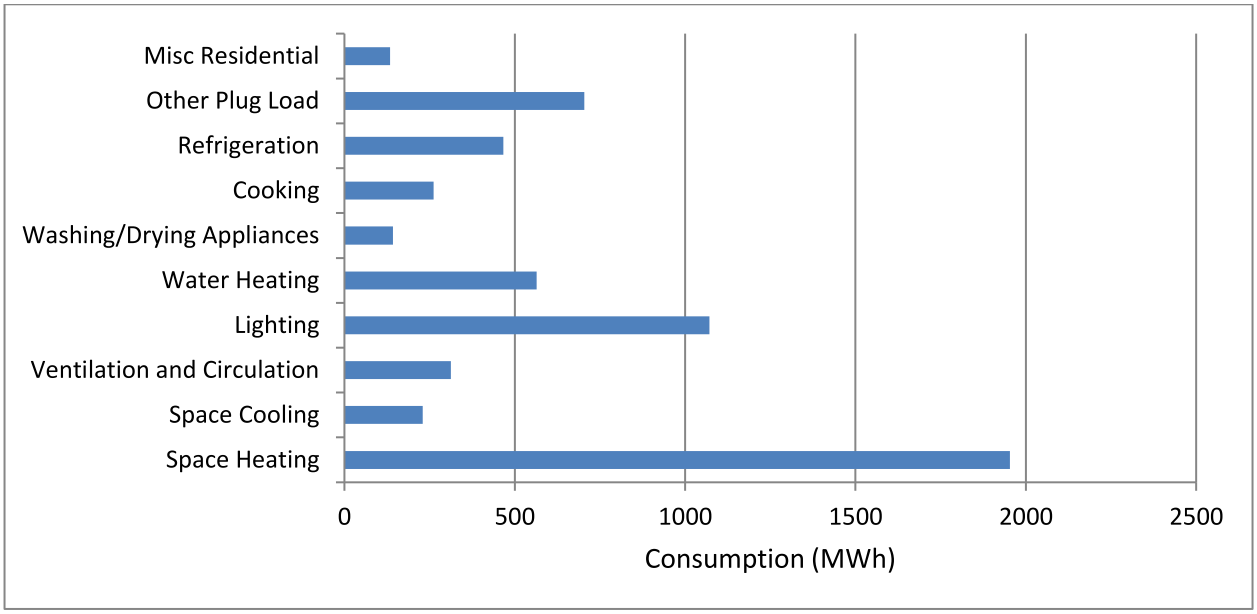


Figure B-17 End-use Segmentation for High-Rise, Marchwood MTS

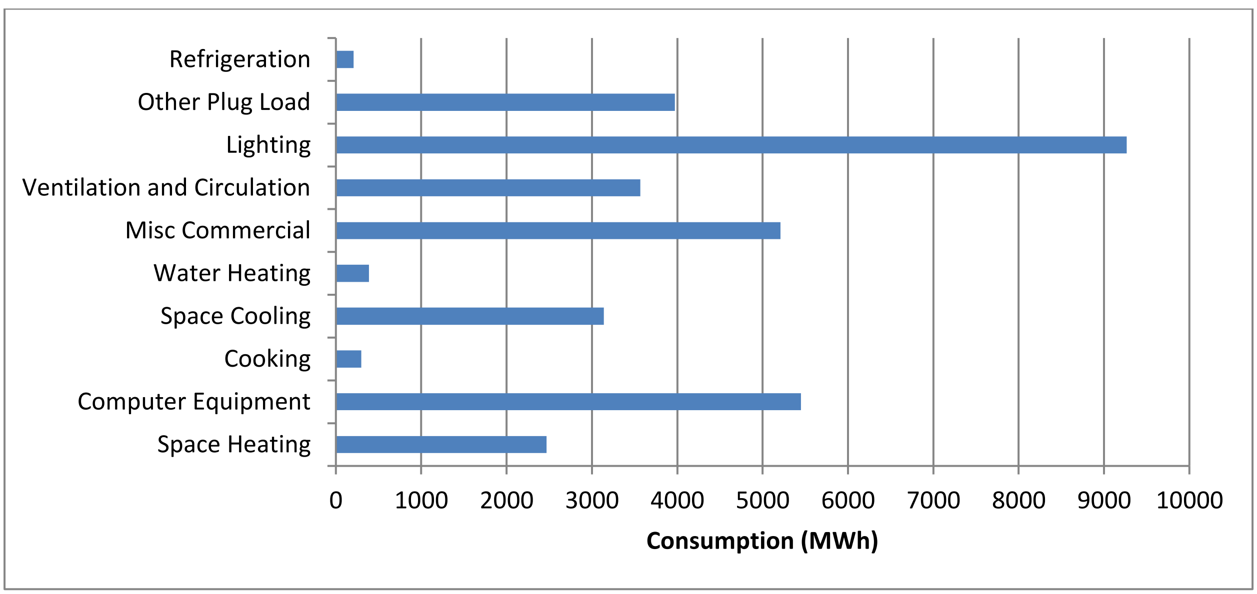


Figure B-18 End-use Segmentation for Office Buildings, Marchwood MTS

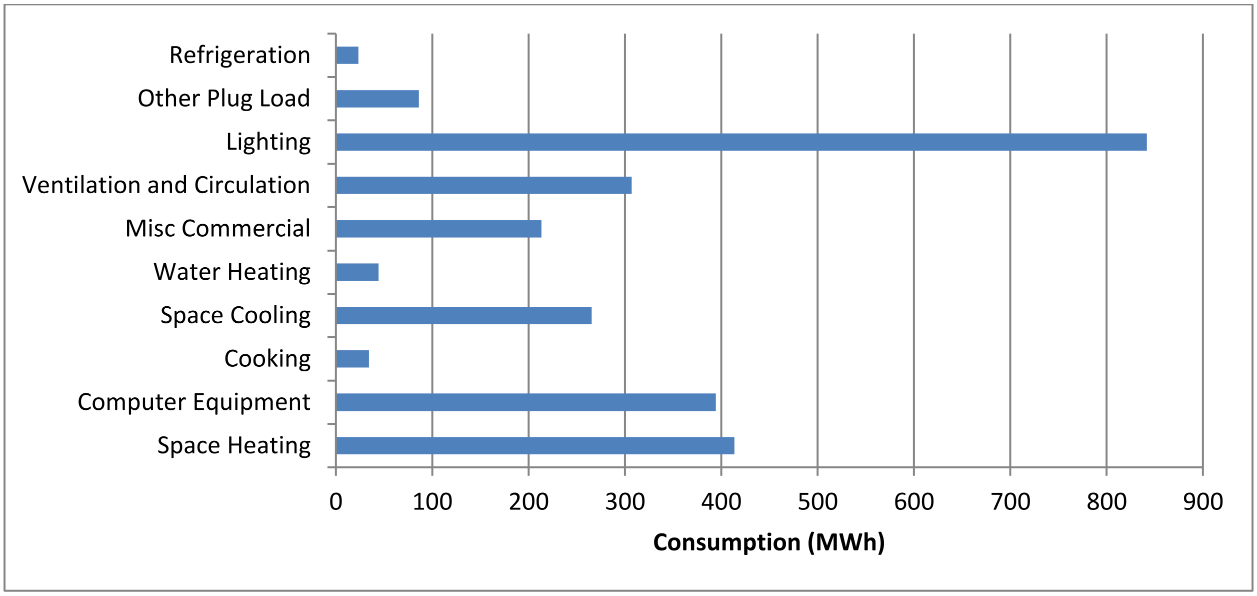


Figure B-19 End-use Segmentation for Medical Office Buildings, Marchwood MTS

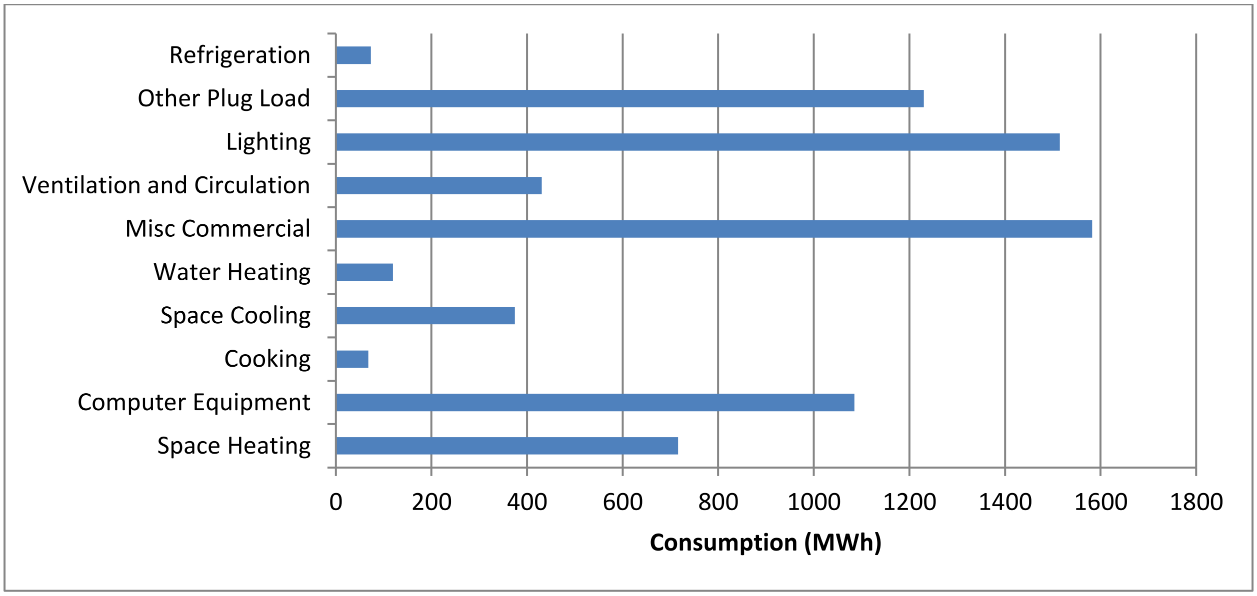


Figure B-20 End-use Segmentation for Schools, Marchwood MTS

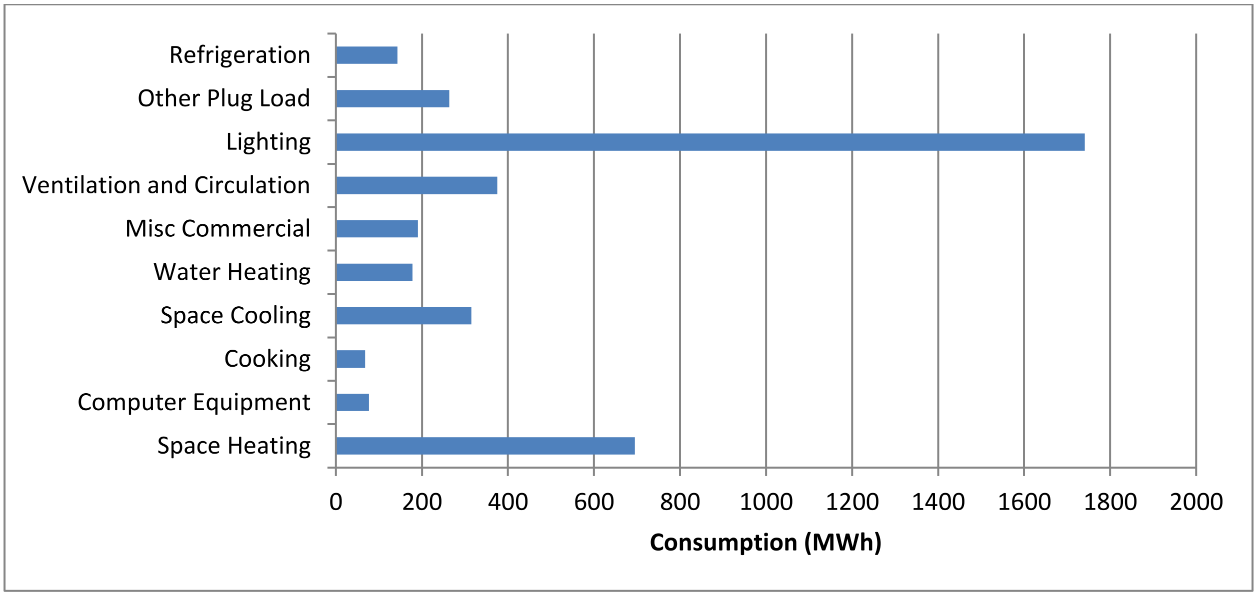


Figure B-21 End-use Segmentation for Residential Care Facilities, Marchwood MTS

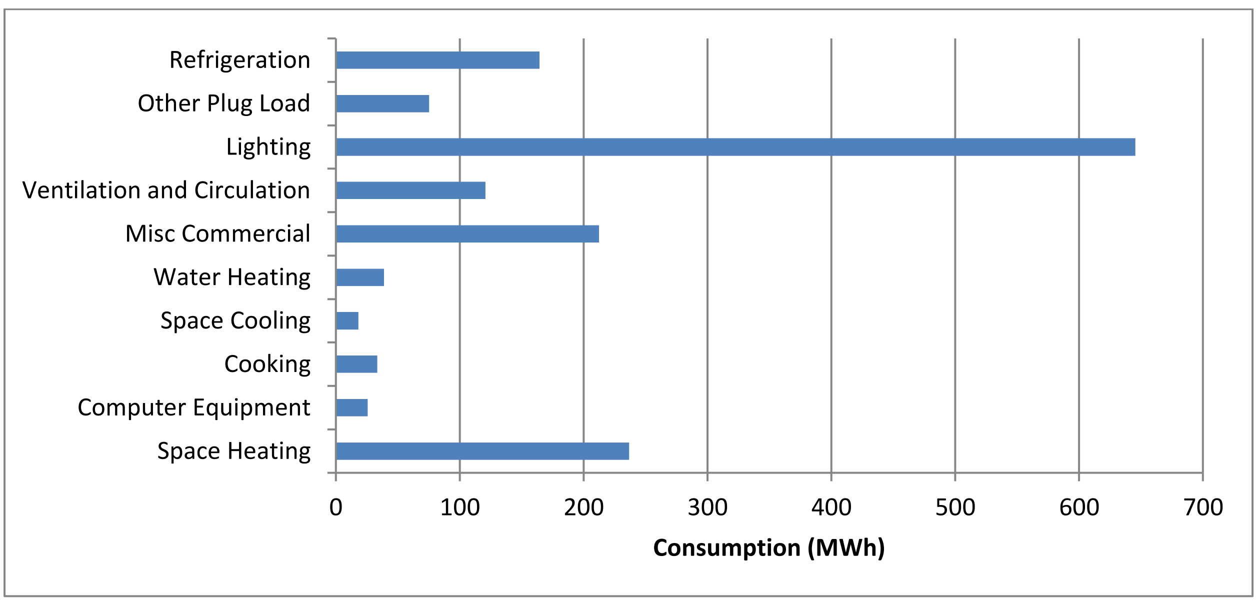


Figure B-22 End-use Segmentation for Warehouses Wholesale, Marchwood MTS

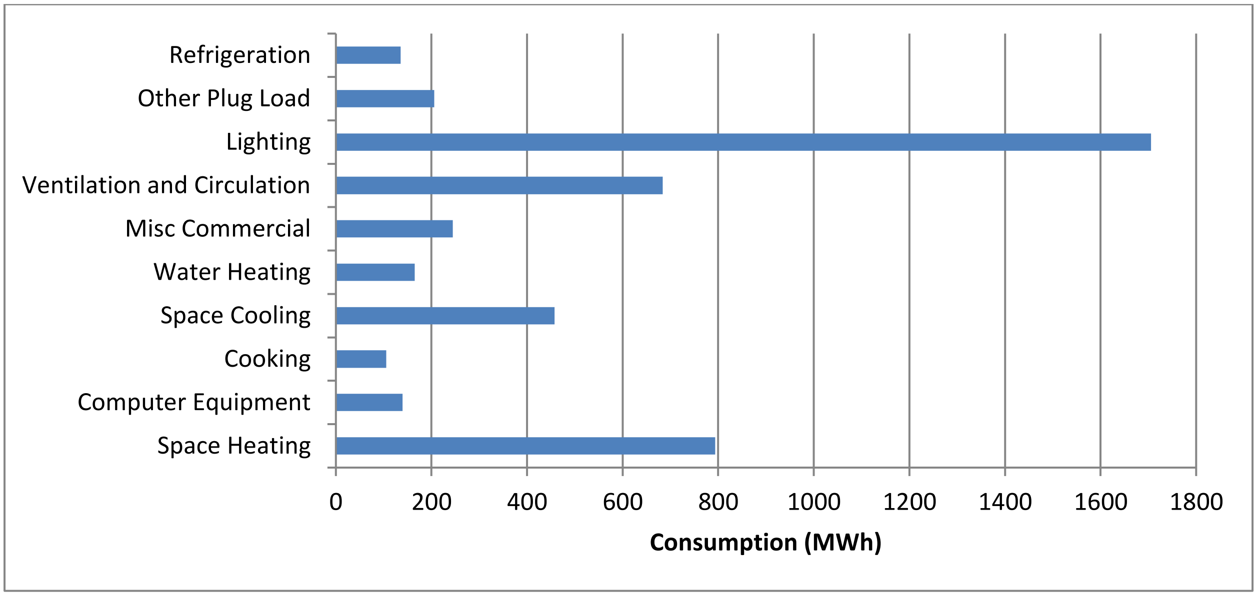


Figure B-23 End-use Segmentation for Hotels, Marchwood MTS

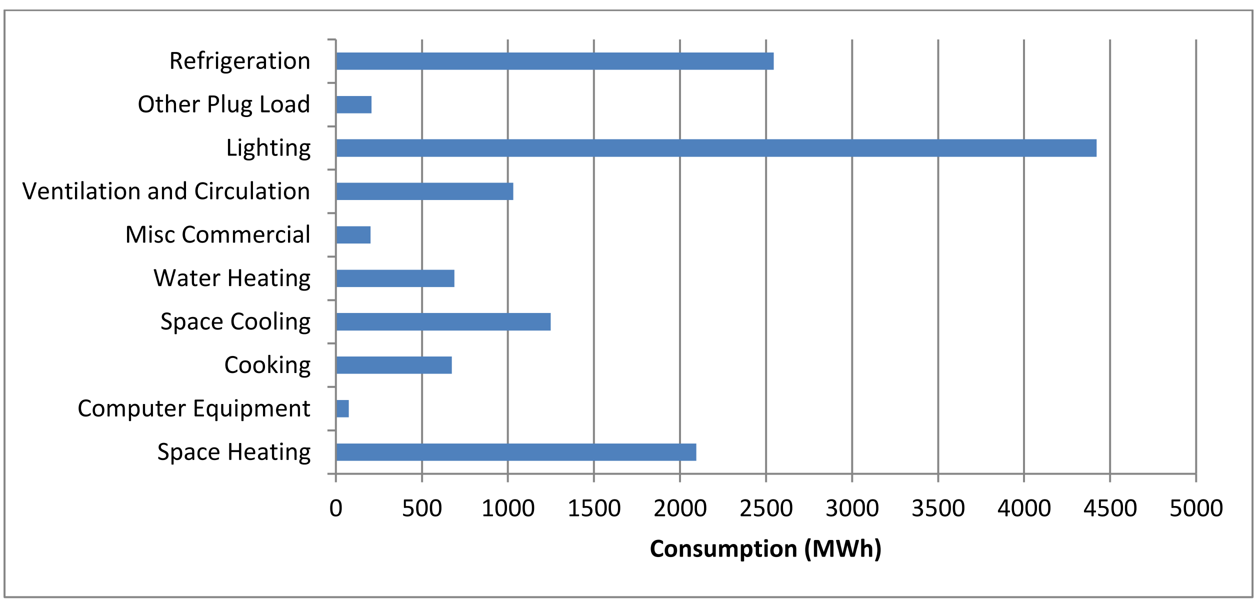


Figure B-24 End-use Segmentation for Food and Beverage Stores, Marchwood MTS

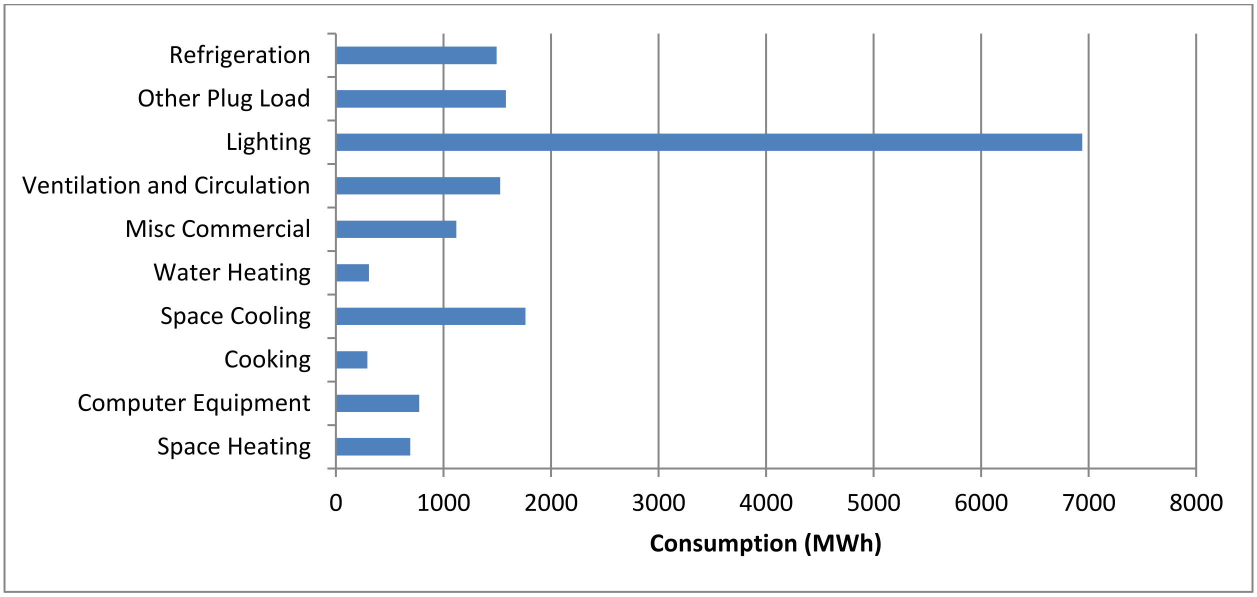


Figure B-25 End-use Segmentation for Non-Food Retail Stores, Marchwood MTS

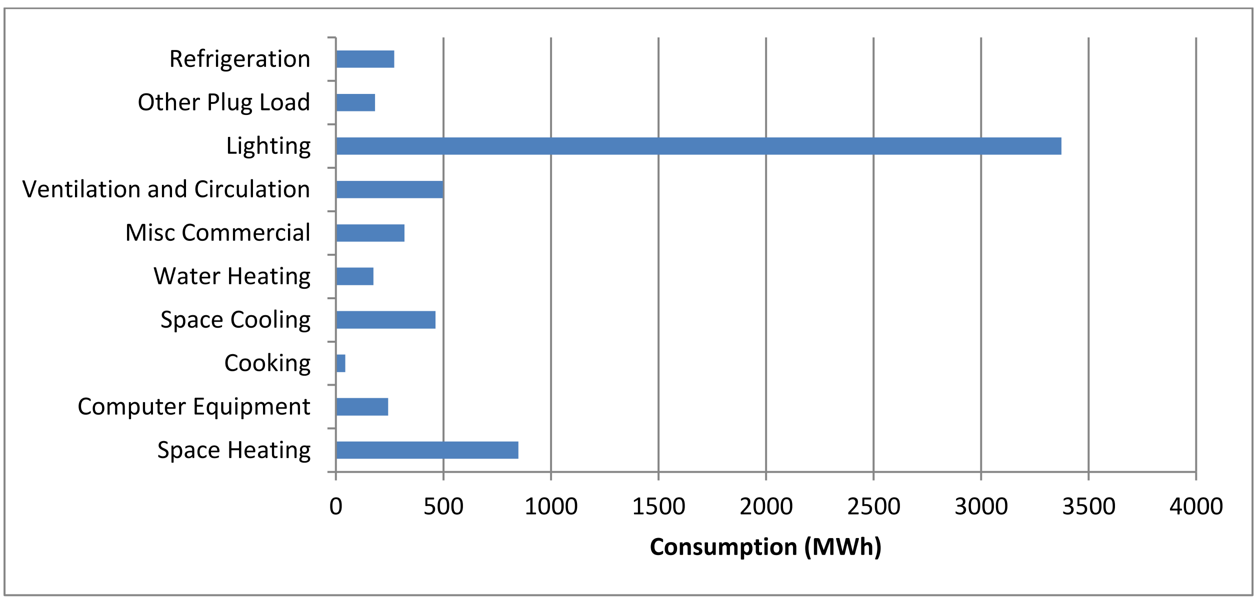


Figure B-26 End-use Segmentation for Other Commercial, Marchwood MTS

Table B-14 Number of Building Forecast with respect to 2018

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Single Detached w.r.t base year	1.006925	1.01759	1.028255	1.03892	1.049586	1.060251	1.070916	1.081581	1.092246	1.102912	1.113577
Single Attached w.r.t base year	1.074709	1.092708	1.110706	1.128705	1.146703	1.164702	1.1827	1.200698	1.218697	1.236695	1.254694
Apartments w.r.t base year	1.147382	1.159926	1.17247	1.185014	1.197558	1.210101	1.222645	1.235189	1.247733	1.260277	1.272821
Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Single Detached w.r.t base year	1.124242	1.134907	1.145572	1.156238	1.166903	1.177568	1.188233	1.198899	1.209564	1.220229	1.230894
Single Attached w.r.t base year	1.272692	1.290691	1.308689	1.326688	1.344686	1.362685	1.380683	1.398682	1.41668	1.434679	1.452677
Apartments w.r.t base year	1.285365	1.297908	1.310452	1.322996	1.33554	1.348084	1.360628	1.373172	1.385715	1.398259	1.410803

Table B-15 Energy Intensity Forecast with respect to 2018

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Single Detached w.r.t base year	0.985	0.971	0.956	0.941	0.927	0.912	0.898	0.883	0.868	0.854	0.839
Single Attached w.r.t base year	0.986	0.973	0.959	0.946	0.932	0.919	0.905	0.892	0.878	0.865	0.851
Apartments w.r.t base year	0.992	0.984	0.976	0.969	0.961	0.953	0.945	0.937	0.929	0.921	0.913
Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Single Detached w.r.t base year	0.824	0.810	0.795	0.780	0.766	0.751	0.737	0.722	0.707	0.693	0.678
Single Attached w.r.t base year	0.838	0.824	0.811	0.797	0.783	0.770	0.756	0.743	0.729	0.716	0.702
Apartments w.r.t base year	0.906	0.898	0.890	0.882	0.874	0.866	0.858	0.851	0.843	0.835	0.827

Table B-16 Annual Consumption Forecast for Residential Subsectors, Kanata MTS

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Single Detached (MWh)	27,190	27,069	26,941	26,804	26,658	26,504	26,341	26,169	25,989	25,801	25,604
ROW (MWh)	16,182	16,227	16,265	16,295	16,318	16,334	16,342	16,343	16,336	16,322	16,300
Low Rise (MWh)	1,567	1,571	1,576	1,580	1,584	1,587	1,590	1,593	1,596	1,598	1,600
High Rise (MWh)	1,130	1,134	1,137	1,140	1,142	1,145	1,147	1,149	1,151	1,153	1,155
Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Single Detached (MWh)	25,398	25,184	24,961	24,730	24,490	24,242	23,985	23,719	23,445	23,162	22,871
ROW (MWh)	16,271	16,235	16,191	16,139	16,081	16,014	15,941	15,860	15,771	15,675	15,572
Low Rise (MWh)	1,602	1,604	1,605	1,606	1,607	1,607	1,608	1,608	1,607	1,607	1,606
High Rise (MWh)	1,156	1,157	1,158	1,159	1,159	1,160	1,160	1,160	1,160	1,159	1,159

Table B-17 Annual Consumption Forecast for Residential Subsectors, Marchwood MTS

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Single Detached (MWh)	40,961	40,781	40,587	40,380	40,160	39,928	39,683	39,424	39,153	38,869	38,572
ROW (MWh)	16,627	16,674	16,713	16,744	16,768	16,784	16,792	16,793	16,786	16,771	16,749
Low Rise (MWh)	811	813	815	817	819	821	823	824	826	827	828
High Rise (MWh)	6,649	6,668	6,686	6,703	6,719	6,734	6,748	6,760	6,772	6,782	6,791
Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Single Detached (MWh)	38,263	37,940	37,604	37,256	36,895	36,520	36,133	35,733	35,320	34,895	34,456
ROW (MWh)	16,719	16,682	16,637	16,584	16,523	16,455	16,380	16,296	16,205	16,107	16,001
Low Rise (MWh)	829	830	831	831	832	832	832	832	832	831	831
High Rise (MWh)	6,805	6,811	6,815	6,819	6,821	6,822	6,822	6,820	6,818	6,814	6,805

Table B-18 Annual Consumption (MWh) Forecast for Commercial Subsectors, Kanata MTS

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Office buildings	134,861	135,637	136,416	137,198	137,982	138,769	139,559	140,351	141,146	141,944	142,744
Medical office	3,309	3,328	3,347	3,366	3,385	3,405	3,424	3,443	3,463	3,482	3,502
Schools	4,589	4,616	4,644	4,671	4,699	4,726	4,754	4,782	4,809	4,837	4,865
Residential care facilities	1,393	1,397	1,402	1,407	1,411	1,416	1,420	1,424	1,429	1,433	1,437
Warehouses Wholesale	4,832	4,846	4,861	4,875	4,889	4,903	4,917	4,931	4,945	4,958	4,971
Hotels	2,679	2,673	2,666	2,659	2,652	2,644	2,637	2,630	2,622	2,615	2,607
Hospitals	0	0	0	0	0	0	0	0	0	0	0
Food and beverage stores	19,463	19,516	19,567	19,618	19,667	19,716	19,764	19,810	19,856	19,901	19,945
Non-food retail	11,888	11,875	11,862	11,848	11,834	11,819	11,803	11,788	11,771	11,754	11,737
Other activity	7,226	7,265	7,303	7,342	7,381	7,420	7,459	7,497	7,536	7,575	7,615
Total	190,24	191,15	192,06	192,98	193,90	194,81	195,73	196,65	197,57	198,49	199,42
Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Office buildings	143,546	144,352	145,159	145,970	146,782	147,597	148,415	149,235	150,057	150,882	151,709
Medical office	3,522	3,542	3,561	3,581	3,601	3,621	3,641	3,661	3,681	3,702	3,722
Schools	4,893	4,920	4,948	4,976	5,003	5,031	5,059	5,086	5,114	5,142	5,169
Residential care facilities	1,441	1,445	1,449	1,453	1,457	1,461	1,465	1,469	1,472	1,476	1,479
Warehouses Wholesale	4,984	4,997	5,010	5,022	5,035	5,047	5,059	5,071	5,082	5,094	5,105
Hotels	2,599	2,591	2,583	2,575	2,567	2,559	2,550	2,541	2,533	2,524	2,515
Hospitals	0	0	0	0	0	0	0	0	0	0	0
Food and beverage stores	19,987	20,029	20,069	20,108	20,146	20,183	20,219	20,253	20,286	20,318	20,349
Non-food retail	11,719	11,701	11,682	11,662	11,642	11,622	11,600	11,579	11,556	11,534	11,510
Other activity	7,654	7,693	7,732	7,771	7,811	7,850	7,889	7,928	7,968	8,007	8,047
Total	200,34	201,26	202,19	203,11	204,04	204,97	205,89	206,82	207,75	208,67	209,60

Table B-19 Annual Consumption (MWh) Forecast for Commercial Subsectors, Marchwood MTS

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Office buildings	134,861	135,637	136,416	137,198	137,982	138,769	139,559	140,351	141,146	141,944	142,744
Medical office	3,309	3,328	3,347	3,366	3,385	3,405	3,424	3,443	3,463	3,482	3,502
Schools	4,589	4,616	4,644	4,671	4,699	4,726	4,754	4,782	4,809	4,837	4,865
Residential care facilities	1,393	1,397	1,402	1,407	1,411	1,416	1,420	1,424	1,429	1,433	1,437
Warehouses Wholesale	4,832	4,846	4,861	4,875	4,889	4,903	4,917	4,931	4,945	4,958	4,971
Hotels	2,679	2,673	2,666	2,659	2,652	2,644	2,637	2,630	2,622	2,615	2,607
Hospitals	0	0	0	0	0	0	0	0	0	0	0
Food and beverage stores	19,463	19,516	19,567	19,618	19,667	19,716	19,764	19,810	19,856	19,901	19,945
Non-food retail	11,888	11,875	11,862	11,848	11,834	11,819	11,803	11,788	11,771	11,754	11,737
Other activity	7,226	7,265	7,303	7,342	7,381	7,420	7,459	7,497	7,536	7,575	7,615
Total	190,20	191,13	192,08	192,93	193,90	194,88	195,77	196,67	197,58	198,49	199,42

Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Office buildings	143,546	144,352	145,159	145,970	146,782	147,597	148,415	149,235	150,057	150,882	151,709
Medical office	3,522	3,542	3,561	3,581	3,601	3,621	3,641	3,661	3,681	3,702	3,722
Schools	4,893	4,920	4,948	4,976	5,003	5,031	5,059	5,086	5,114	5,142	5,169
Residential care facilities	1,441	1,445	1,449	1,453	1,457	1,461	1,465	1,469	1,472	1,476	1,479
Warehouses Wholesale	4,984	4,997	5,010	5,022	5,035	5,047	5,059	5,071	5,082	5,094	5,105
Hotels	2,599	2,591	2,583	2,575	2,567	2,559	2,550	2,541	2,533	2,524	2,515
Hospitals	0	0	0	0	0	0	0	0	0	0	0
Food and beverage stores	19,987	20,029	20,069	20,108	20,146	20,183	20,219	20,253	20,286	20,318	20,349
Non-food retail	11,719	11,701	11,682	11,662	11,642	11,622	11,600	11,579	11,556	11,534	11,510
Other activity	7,654	7,693	7,732	7,771	7,811	7,850	7,889	7,928	7,968	8,007	8,047
Total	200,34	201,26	202,19	203,11	204,04	204,97	205,89	206,82	207,75	208,67	209,60

Hydro Ottawa Local Achievable Potential (LAP) Study

Identification of technically feasibly measures for addressing local area needs

Milestone #2 Report

SLI PROJECT NO.: 660803

3	Final Report	07/23/2019	EH	HA	TA
2	Issued for Review	07/03/2019	MA	HA	TA
1	Issued for Comments	06/13/2019	MA	HA	TA
0	Issued for Information	05/22/2019	MA	HA	TA
REV.	**DESCRIPTION**	**DATE**	**PRPD**	**CHKD**	**APPRD**
			SNC-Lavalin		

SUMMARY

This is the report for the second milestone of the study entitled "Hydro Ottawa Local Achievable Potential (LAP) Study," which commenced on Dec. 7, 2018. This study, undertaken at the request of Hydro Ottawa Ltd, Ontario, is conducted by SNC-Lavalin Inc. Toronto, Canada, as the Consultant.

The objective of Milestone #2 of this study is to identify the technically feasible measures for addressing local area needs.

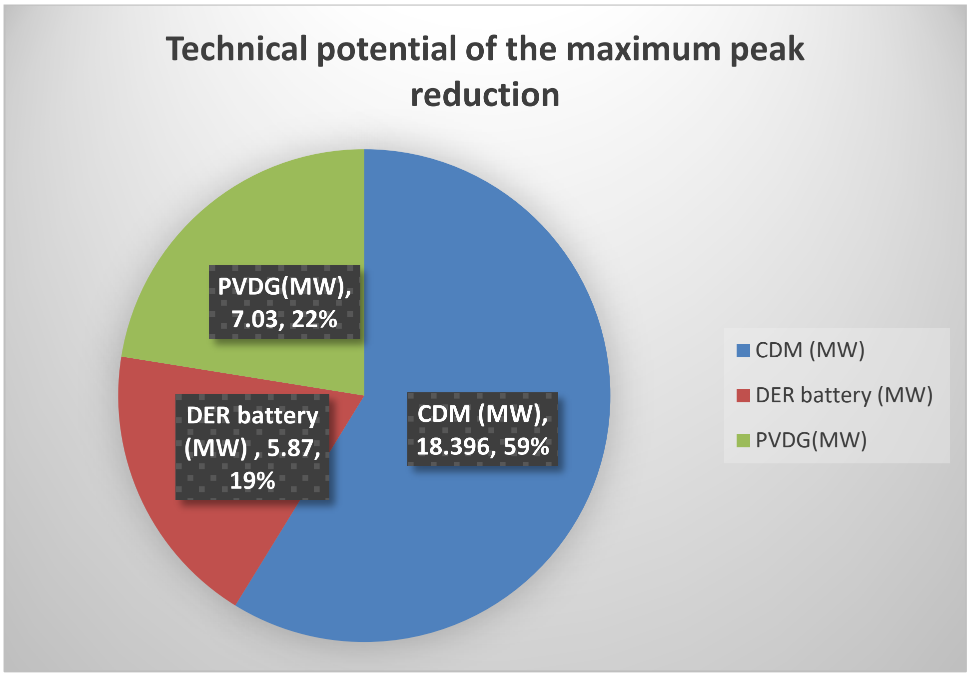
The project team collected data on the conservation and demand management (CDM) measures; the 2018 and 2019 IESO's Measure and Assumption lists (MAL) represent the basis for the measure research. In addition, the list of measures of the 2016's APS provided by the IESO for Ottawa is also included [1]. The integration of the additional measures achieved extra peak reduction of an additional 12% of the maximum peak reduction of the CDM. Moreover, other CDM measures from North American Jurisdictions (outside existing MAL), that could be rolled into the market quickly are added to the CDM list of measures used. For each measure, the team calculated the annual energy consumption saving as well as the peak demand savings. The team screened the available measures to determine the shortlisted measures that are addressing the summer peak demand at the Kanata North area; three screening stages are followed to exclude the measures that are not suitable for addressing the local area needs;

- Exclude measures of subsectors that are not existing in Kanata North area (e.g., hospitals, colleges, agribusiness,)
- Exclude measures that are no longer offered in 2018 and 2019 IESO list of measures.
- Exclude measures that have no impact on summer peak demand (e.g., space heating measures).

The team calculated the maximum potential for peak demand reduction for each measure based on the local area load segmentation developed in milestone #1, the number of equipment per subsector, the consumption of the total equipment as a percentage of the end-use consumption, and the fraction of equipment that is energy efficient. Finally, the team estimated the aggregated technical potential for peak reduction for all the CDM measures.

In addition to the CDM measures, the project team conducted an analysis to study the impact of the Distributed Energy Resources (DER) on Kanata-Marchwood summer peak; the analysis is categorized into load shifting using battery energy storage system and renewable-based distributed generation. The technical potential for peak reduction of the battery energy storage is calculated on the utility-scale and on the large customers-scale. Moreover, the technical potential of photovoltaic roof-top distributed generation mounted on the residential and commercial buildings is calculated. Based on the calculated technical potentials for the CDM and DER measures, the total technical potential for the peak reduction of Kanata North area is calculated.

The results presented in Figure ES-1 show that the maximum technical potential of the peak reduction due to the CDM program is 18.396 MW, for the DER battery the maximum reduction is 5.87MW for the 6 hours scenario. In addition, the technical potential of the photovoltaic PV Distributed generators DG is 7.03 MW.



ES-1 Percentage contribution of each of the technical potential on peak reduction

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List of acronyms

APS	Achievable Potential Study
CDM	Conservation and Demand Management
DER	Distributed Energy Resources
DG	Distributed Generation
HOL	Hydro Ottawa Ltd
HR	High Rise
IESO	Independent Electricity System Operator
kWh	Kilowatt-hour
LAP	Local Achievable Potential Study
LR	Low Rise
MAL	IESO's Measure and Assumption lists

1 Introduction

This report provides the methodology and the complete analyses of milestone #2 that aims to identify the technically feasible measures for addressing local area needs. This report is summarizing the following;

- Peak load analysis for Kanata North area,
- The collected list of CDM measures,
- The screening criterion and the shortlisted CDM measures mapped to sectors, subsectors, end-use, and competition groups,
- The technical potential of the shortlisted CDM measures,
- The technical potential of load shifting using battery energy storage,
- The technical potential of residential and commercial roof-top photovoltaic DER, and
- Summary of the total technical potential of the CDM and DER measures.

2 Peak Load Analysis for Kanata North Area

The project team carried out an analysis, based on the historical, forecasted, and current load profiles received from HOL, to determine the peak loading conditions for Kanata and Marchwood MTS.

2.1 Historical Peak Load Analysis

Based on the data received from HOL, the historical peak loading was analyzed, Figure 2-1 shows the coincidental combined peak load for the years 2012 to 2016 for Kanata MTS and Marchwood MTS. Kanata MTS contains 2 X 41.7 MVA transformers and Marchwood MTS has 2 X 33 MVA transformers. Thus, the combined N-1 ratings for the two stations is 74.7 MVA. The limited-time ratings (LTR) for Kanata MTS is 54.5 MVA, and for Marchwood, MTS is 34 MVA; thus, the combined LTR for the two stations is 88.5 MVA. It worth noting that all the maximum peak loading occurred at the Summer Season for all these years. The highest historical coincidental loading occurred in 2016 with a summer peak of 105.2 MW, while the winter coincidental peak load for this year was 77 MW. This historical data analysis shows that the Summer peak is always greater than the Winter peak for all available historical data. In addition, the Summer peak exceeded the combined LTR for the two stations over the historical years.

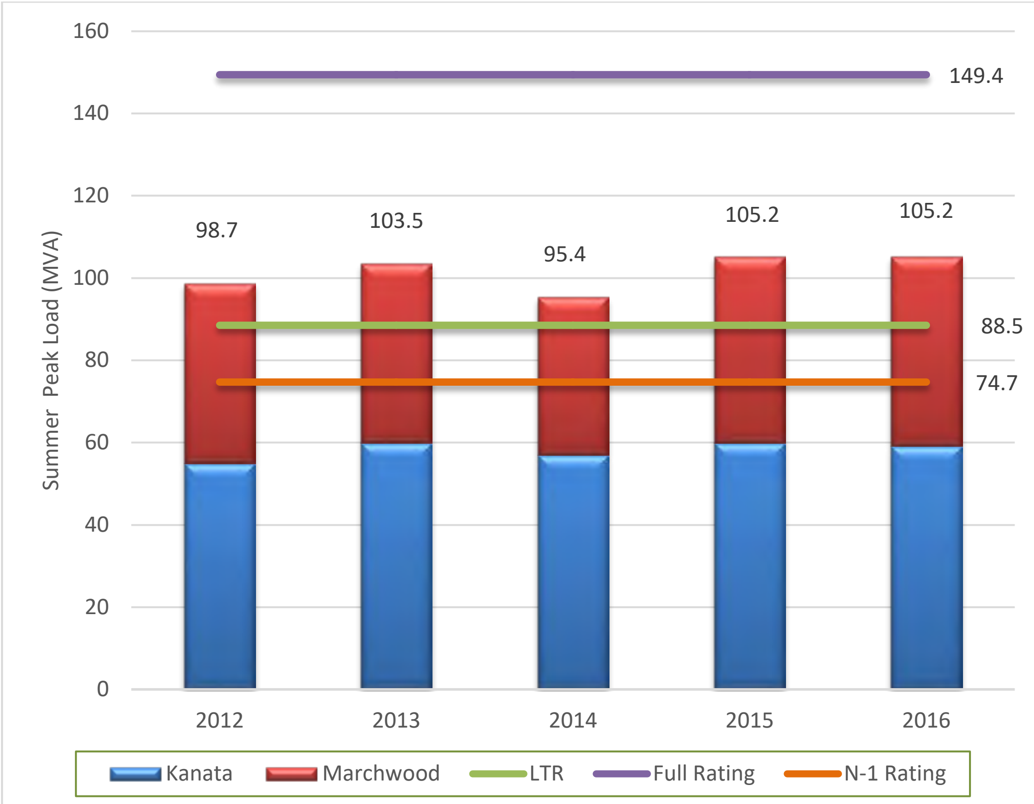

Figure 2-1 Historical Peak Loading for Kanata-Marchwood

2.2 Peak Load Forecast (Median Weather Condition)

The coincident peak loading forecasts for the summer season is estimated based on the noncoincidental peak demand provided by HOL and by using the diversity factor estimated using 2018 coincidental and noncoincidental peak demand. Tables A-1 and A-2 show the Summer peak loading forecast for the median weather for Kanata MTS and Marchwood MTS (received from HOL). The Summer peak is expected to exceed the combined LTR rating of the two stations (i.e., 88.5 MVA). ***We recommend reviewing the bulk load forecast of (Broccolini Business Park) and (550 Innovation (Ciena) as those two specific loads combined represent about 14 MVA of the forecast load growth. It would be beneficial to review how the assumptions used in reaching out this estimate and if Conservation and Demand Side measures are being considered in the development phase.***

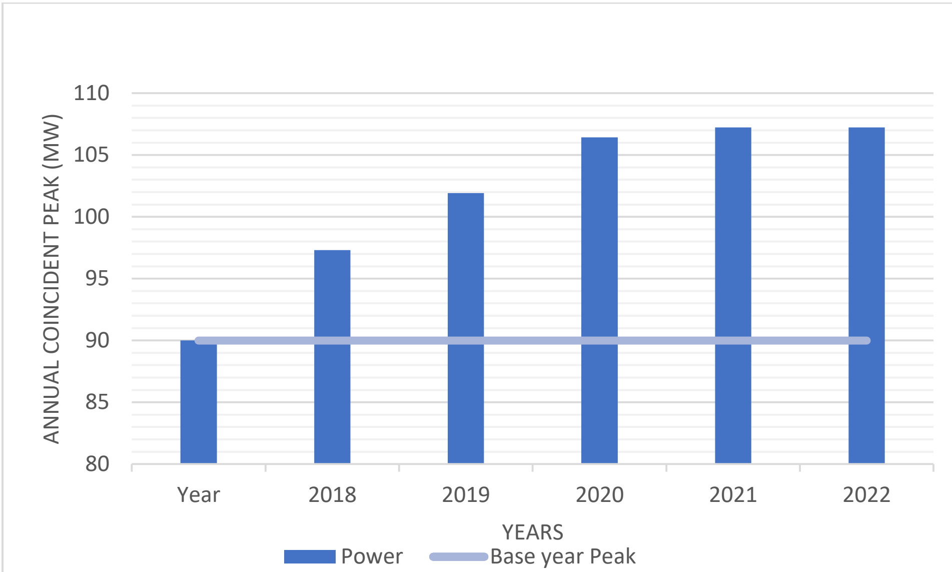

Figure 2-2 Forecasted Coincident Peak Loading for Kanata-Marchwood, Median Weather

2.3 Peak Load forecast (Extreme Weather Condition)

The coincident peak loading forecasts for the Summer season considering the extreme weather conditions is presented in Figure 2-2. The forecast was estimated using data provided by HOL and 2018 diversity factors.

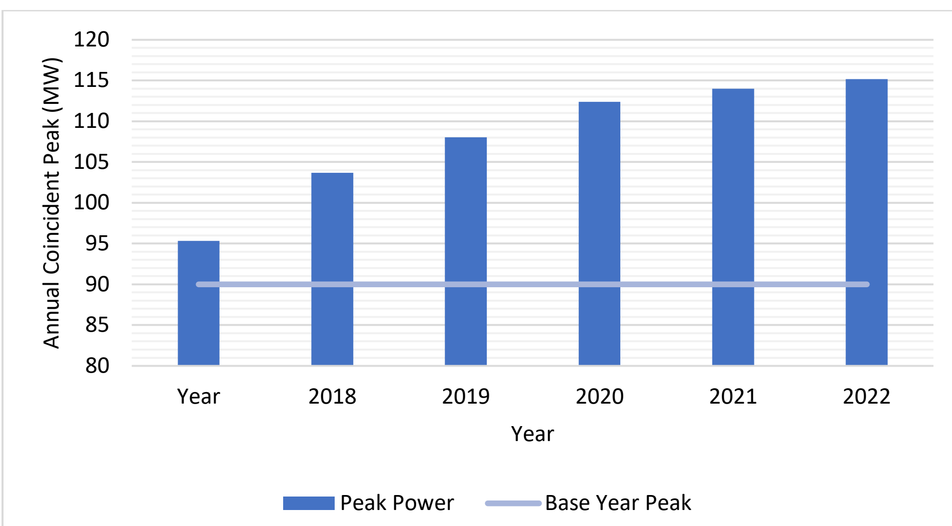

Figure 2-3 Forecasted Coincident Peak Loading for Kanata-Marchwood, Extreme Weather

2.4 Base Year Peak Load

Based on the feeder hourly loading profiles for years 2017 and 2018, the project team performed an analysis to determine the chronological loading curve for the Winter and Summer seasons. The chronological loading curves, for the peak day, for the Winter and Summer seasons are determined; Figure 2-2 shows the chronological loading curve for the summer peak. The highest peak loading during the summer was reached on July 5th, while for the Winter Season the highest peak was reached on January 5th. The winter peak is 14.7% less compared to Summer, and the total number of days for the Winter season where the peak loading exceeded the planning ratings are ten days, while this number increased to 52 days in the Summer Season. Based on this analysis, the Winter Peak will not be analyzed given the available data and the large difference between winter and summer peak. Therefore, non-wire solutions should be addressing the Summer peak to lower this peak below the planning ratings of the two stations.

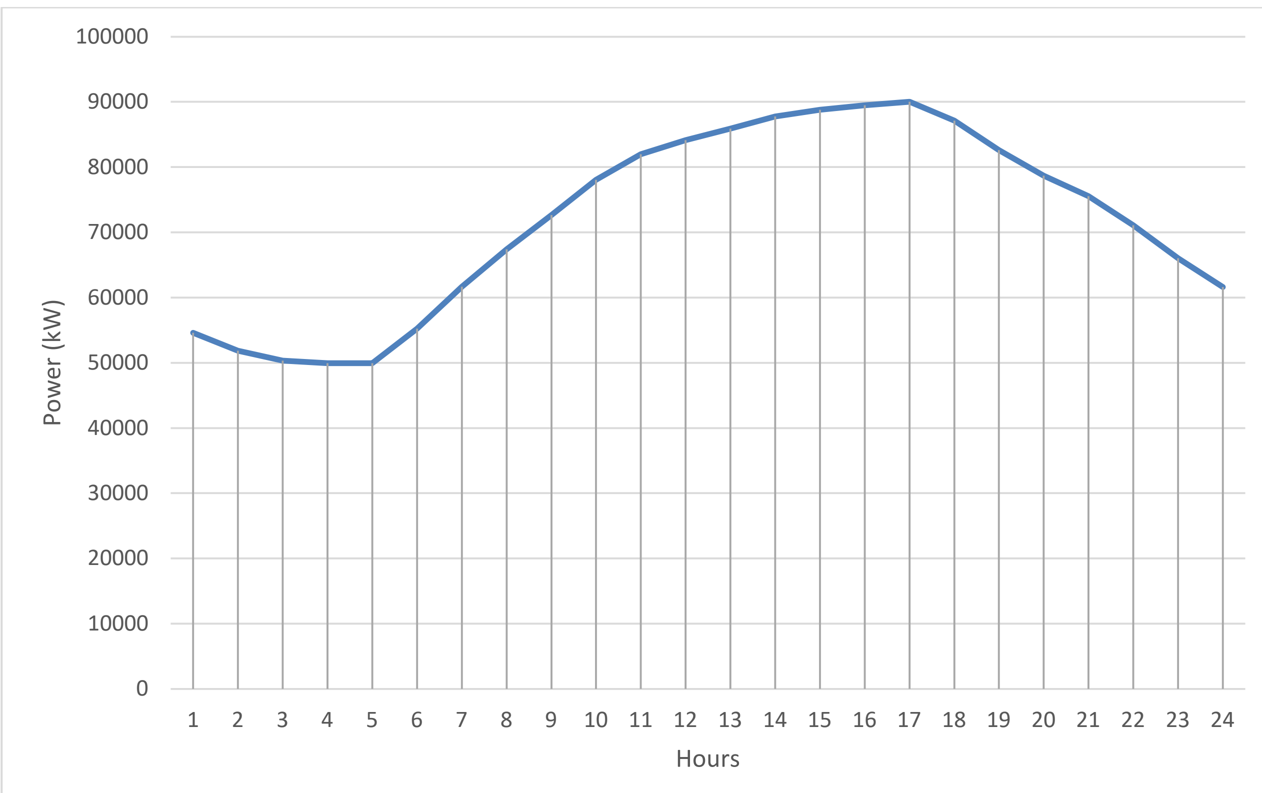

Figure 2-**3** Peak Coincident Loading Day for the Base Year for Kanata-Marchwood, Summer Season Year 2018

3 Technical Potential of CDM Measures

The technical potential scenario estimates the saving potential when all technically feasible non-wire solutions are implemented at their full technical potential. This saving potential is the maximum potential that is not considering the economics of the measures nor customer adoption. This section presents the methodology followed for shortlisting the available CDM measures in Ontario and for calculating the technical potential of these measures.

3.1 Methodology

The main project rationale is to determine the potential solutions to lower the summer peak demand in Kanata-Marchwood area. The achievable potential of Summer peak load reduction would allow for more efficient use of existing facilities and infrastructure and differ or eliminate the need for a new station. Based on HOL plan, the new station (new Kanata North) is planned to be in service in 2026. Therefore, the presented study focuses on the short-term technical potential scenarios that may differ or eliminate the need for the new station.

Since the presented study is targeting the short-term technical potential, the commercially available measures existing in the current CDM programs in Ontario are included in the CDM list of measures. Therefore, the 2018 and 2019 IESO's Measure and Assumption (M&A) lists represent the basis for the measure research. In addition, the list of measures of the 2016's APS provided by the IESO for Ottawa is also included. Moreover, other CDM measures from nearby jurisdictions, that could be rolled into market quickly are added to the CDM list of measures used. The market adoption of the additional measures will be evaluated in milestone #3 to assess their impact on short-term load reduction.

The methodology of the CDM analysis is summarized as follows;

1- The project team collected data on the available conservation measures from IESO's MAL, the 2016's APS, and from other North American Jurisdictions [2]-[5].
2- The team screened the measures to determine the measures that are addressing the summer peak demand at Kanata North area; three screening stages are followed to exclude the measures that are not suitable for addressing the local area needs (a sample of excluded measures are presented in Table A-3);
    - Exclude measures of subsectors/end uses not available in Kanata area (e.g., hospitals, colleges, agribusiness, etc.)
    - Exclude measures that are no longer offered in 2018 and 2019 IESO list of measures.
    - Exclude measures that have no impact on summer peak demand (e.g., space heating measures)
3- For each measure, compared to the base case equipment, the consumption, annual energy saving, and peak demand reduction are determined.

4- The measures are categorized by sectors and subsectors first, and then further categorization by end-use was done.

5- For each end-use, the competition groups will be developed. For example, for the lighting residential end-use, the competition groups will be indoor (screw-in lamps and lighting control), outdoor, and common area lighting. The obtained measures will be mapped to the competition groups/ end-use/ subsector/ sector. Table A-4 and Table A-5 present the list of residential and commercial CDM measures used classified by competition group.

6- For each measure in each competition group, the team collected data on:
- The fraction of equipment that is energy efficient
- The number of equipment per subsector, and the consumption of the total equipment as a percentage of end-use consumption.

7- The maximum potential for peak demand reduction for each measure is calculated as follows;

$$Potential\ of\ measure = Total\ number\ of\ base\ equipment\ \times (1 - energy\ efficient\ factor) \times measure\ peak\ reduction$$

Where;

$Total\ number\ of\ base\ equipment$: is the total number of base case equipment (non-efficient); this number is obtained for each subsector/end-use using the base case energy consumption per subsector/ end-use (obtained from milestone #1), the base case equipment share (i.e. consumption of the measure as a portion from the end-use consumption), and the annual energy consumption of the base case equipment.

$energy\ efficient\ factor$: is the fraction of equipment that is already energy efficient.

8- The aggregated measure savings potential for each competitive group is determined; double-count of potential savings is avoided by limiting the total adoption to 100% within each measure competition group.

3.2 Mapping of CDM Measures

The measure competition groups were developed for each subsector/end-use separately. Each competition group consolidates similar measures that could be an alternative to each other. For example, the competition groups for the space cooling end-use are a thermal envelope, space cooling control, room/window air conditions, and central AC. The measures in each competition group are alternatives to each other, while a measure from the room AC group cannot compete with measures of the central AC group. The complete list of competition groups mapped to subsectors, and end-use are presented in Table 3-1 and 3-2 for residential and commercial sectors, respectively. The subsectors mentioned in Table 3-2 are an office, medical office, hotels, residential care, non-food retailers, food retailers, schools, warehouse wholesale, and other commercials.

Table 3-1 Residential Sector Competition Groups

End-use	Competition Groups
Indoor Lighting	Screw-in lamps, light control
Outdoor Lighting	Screw-in lamps, light control
Common Area Lighting	Screw-in lamps, light control
Cooking	Wall Oven
Refrigeration	Refrigerators, Freezers
Space Cooling	Control, Thermal Envelope, Room AC, Central AC, Other Cooling
Water Heating	Pipe Insulation, Showerhead, Water heater, Aerator
Plug Loads	Dehumidifiers, Televisions, Water cooler, office equipment
Washer Dryer	Washing Machines, Dryers, Dishwashers

Table 3-2 Commercial Sector Competition Groups

End-use	Competition Groups
Subsector Lighting	Screw-in lamps, light control
Subsector space cooling	Packaged AC units, Chillers, Room AC
Subsector refrigeration	Residential size refrigerators, Walk-in refrigerators, Cabinet, pipes insulation, strip curtain, Gasket.
Subsector plug loads	Ice machine, Vending machine
Subsector computers	Computers
Subsector Domestic Hot Water	Water heater

3.3 Results and Discussion

The methodology described in section 3.1 is applied to the Kanata-Marchwood load profile developed in milestone #1, the year 2023 forecasted load, forecasted number of residential units and forecasted commercial areas were used to determine the technical potential, due to CDM measures, for this year. The factors required for calculating the technical potential; (i.e., the measure share, the energy-efficient factor, and the total number of equipment per household or square footage) are obtained from the residential survey provided by IESO and the commercial CDM data provided by HOL. The missed values or fractions are completed using NRCAN residential and commercial surveys [6]-[7] and EIA's Commercial Buildings Energy Consumption Survey (CBECS) [8]. Samples for the analysis and results for some CDM measures are presented in Appendix B. Moreover, an example of the calculations of the technical potential for peak reduction savings for one of the additional collected measures (Electric chillers) is presented in Appendix B.

3.3.1 Residential Sector

The technical potential peak reduction is calculated for each competition group of the residential subsector/ end-use, and the total technical potential peak reduction is calculated for each subsector and end-use. The total residential summer peak reduction in 2023 was estimated to be 4.713 MW. Figure 3-1 shows the technical potential Summer peak reduction for each subsector; the largest technical potential was estimated for the single-family subsector, which accounts for 62.725 % of the total peak reduction in 2023. Figures 3-2 to 3-5 show the reductions per residential end-use for each subsector.

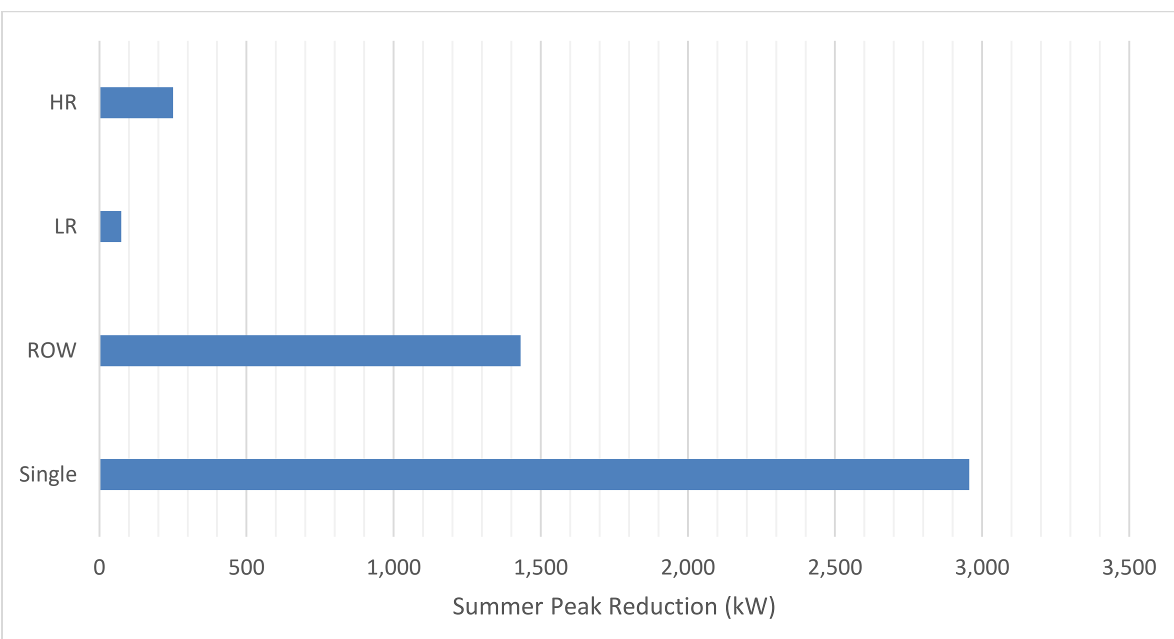

Figure 3-1 Technical Potential Peak Reduction by Residential Subsector in 2023

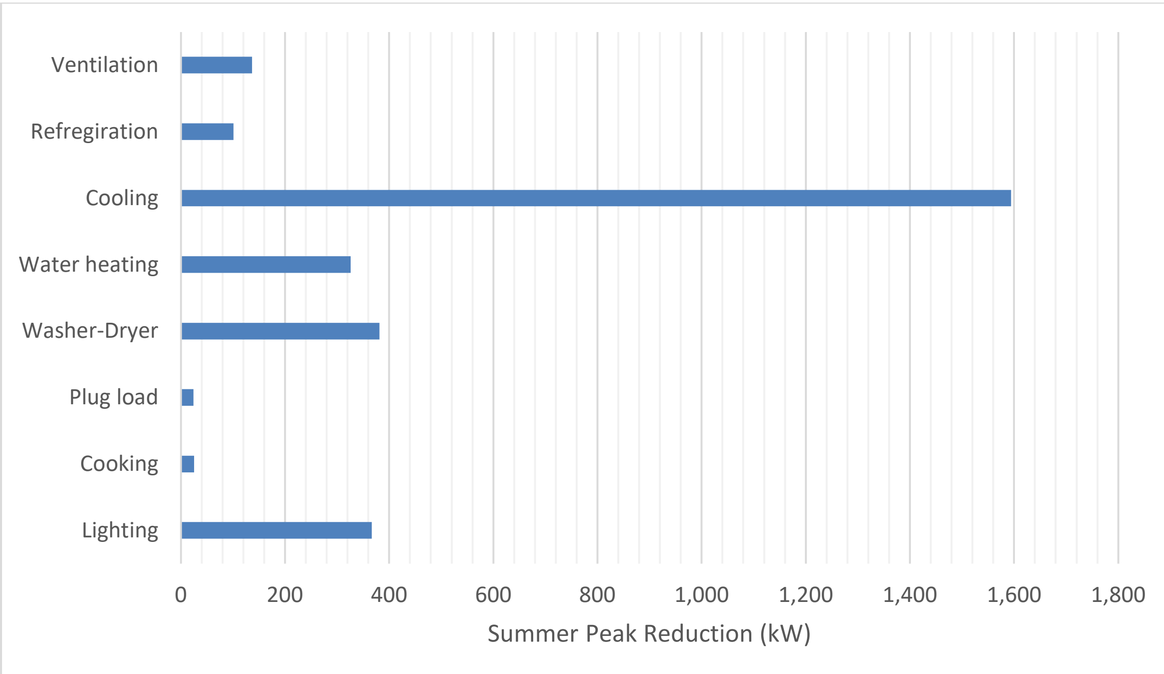

Figure 3-2 Technical Potential Peak Reduction by End-use in 2023, Single-family

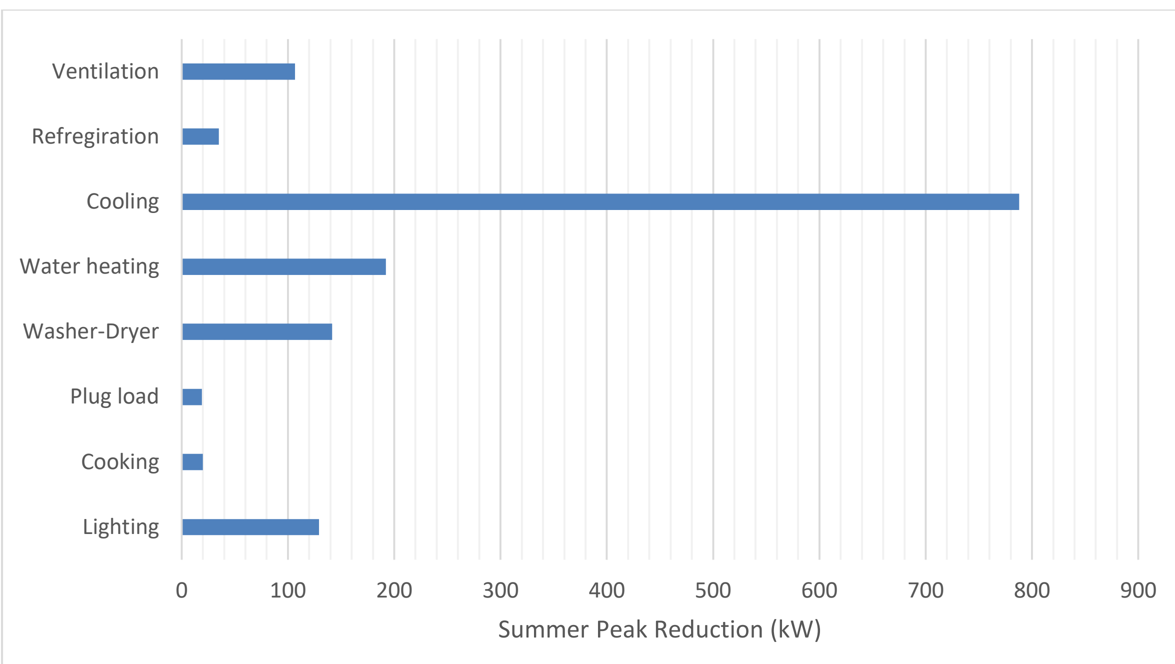

Figure 3-3 Technical Potential Peak Reduction by End-use in 2023, ROW

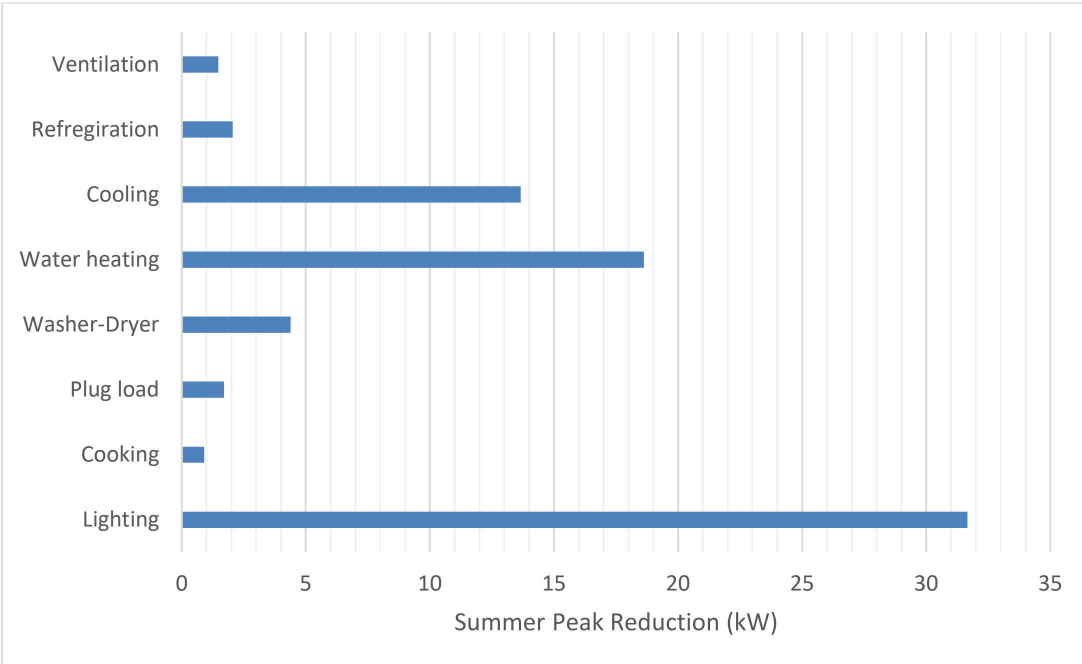

Figure 3-4 Technical Potential Peak Reduction by End-use in 2023, Low Rise

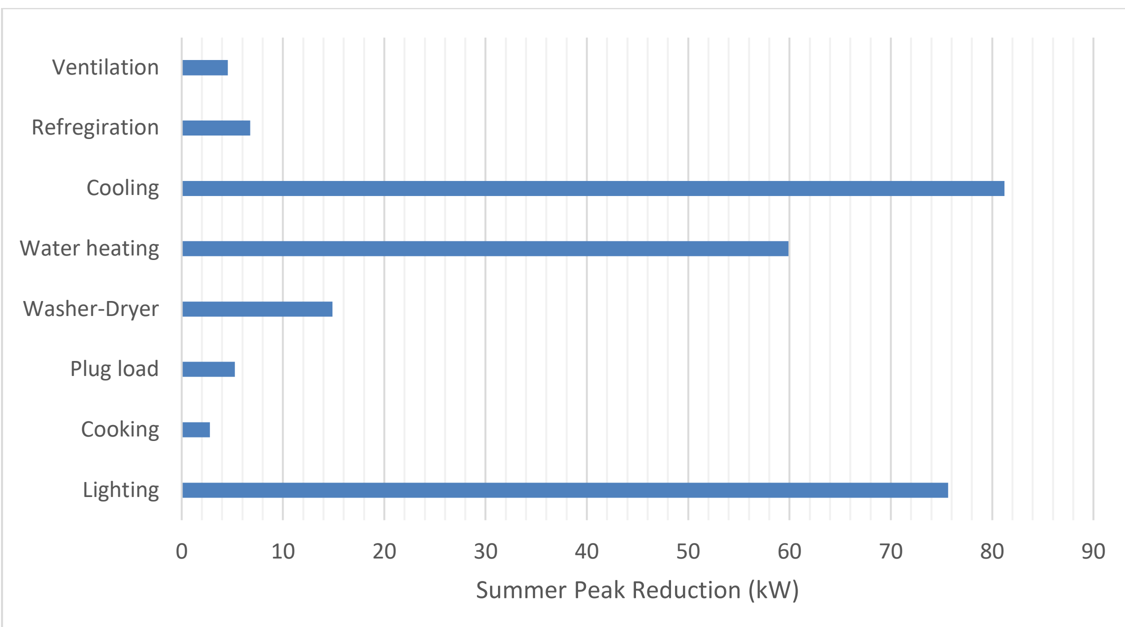

Figure 3-5 Technical Potential Peak Reduction by End-use in 2023, Low Rise

3.3.2 Commercial Sector

The technical potential peak reduction is calculated for each competition group of the commercial subsector/ end-use, and the total technical potential peak reduction is calculated for each subsector and end-use. The total commercial summer peak reduction in 2023 was estimated to be 12.217 MW. Figure 3-6 shows the technical potential Summer peak reduction for each subsector; the largest technical potential was estimated for the office subsector, which accounts for 63.6 % of the total peak reduction in 2023 followed by the food stores subsector that accounts for 11.15%. Figures 3-7 shows the total reductions per commercial end-use; the lighting end-use accounts for the largest peak reductions of 58.17% of the total reductions.

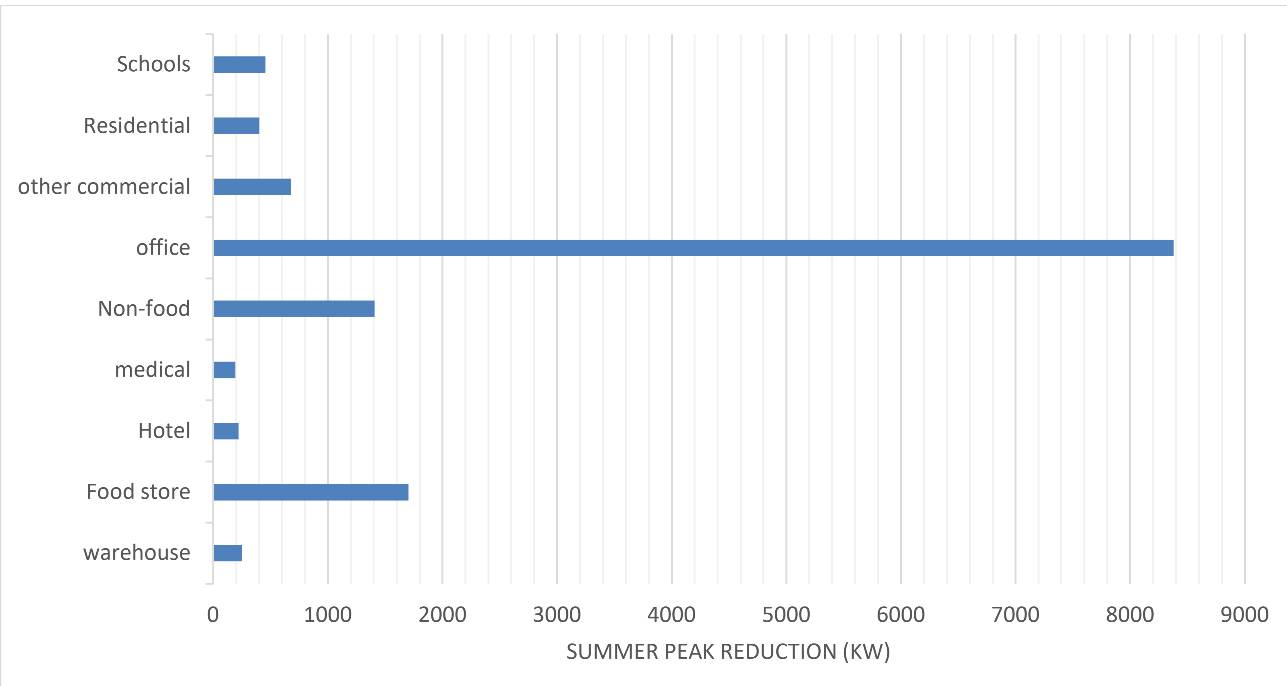

Figure 3-6 Technical Potential Peak Reduction by Commercial Subsectors in 2023

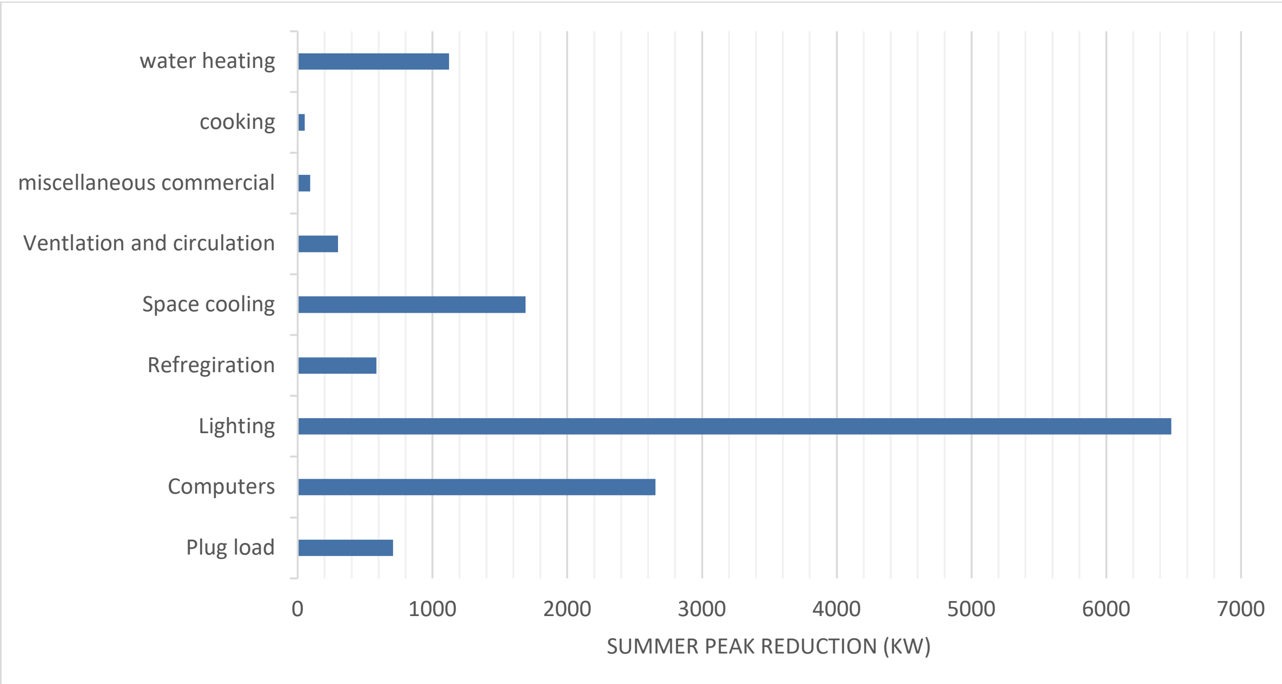

Figure 3-7 Technical Potential Peak Reduction by End-use, Commercial Sector

3.4 CDM Peak Reduction portfolio

The total technical potential reduction in 2023 was calculated to be 18,396 MW; the residential sector accounts for 26% while the commercial sector accounts for 74 %. As only one industrial building is located at Kanata-Marchwood, and there is no plan for expansion, the industrial sector CDM measures were not included in the shortlisted measures. In addition, the street lighting does not contribute to the Summer Peak reduction as the peak hour coincides with the daytime.

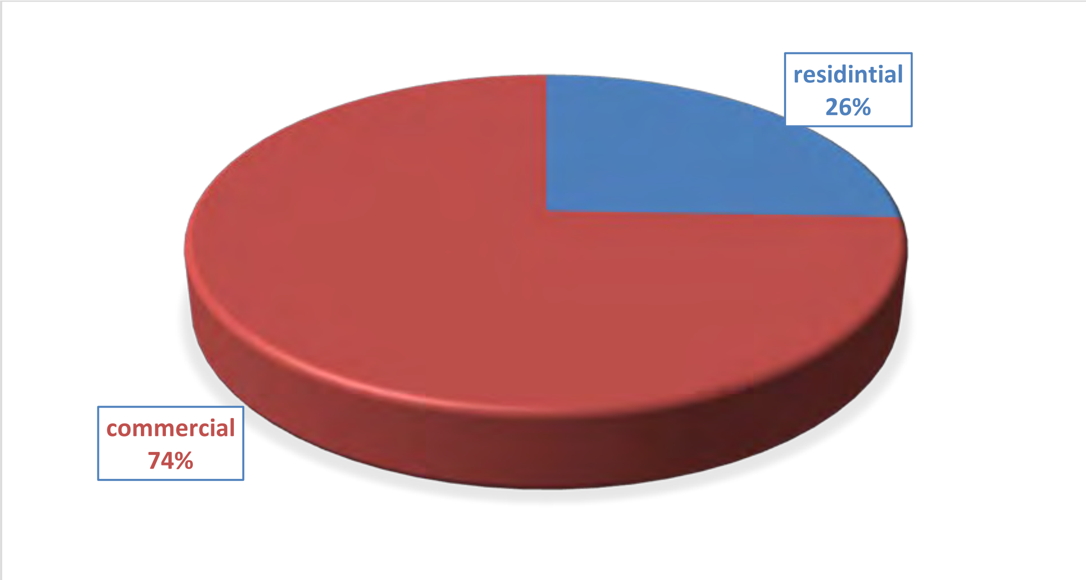

Figure 3-8 Total Technical Potential of CDM measures

3.6 Impact of the additional measures on the peak reduction

the Additional measures of APS 2016 provided by IESO shows have increased the commercial, technical peak reduction by 12% compared to the previously considered measures. The following charts show comparison between the peak reduction classified per the end-use and then by sector.

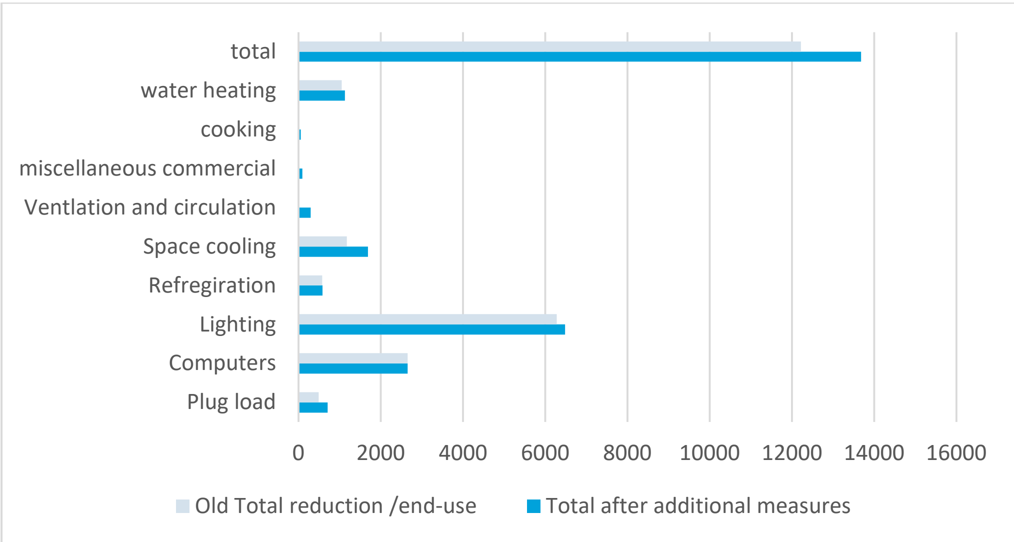

Figure 3-9 Impact of the additional measures on the end-use Kanata 2023

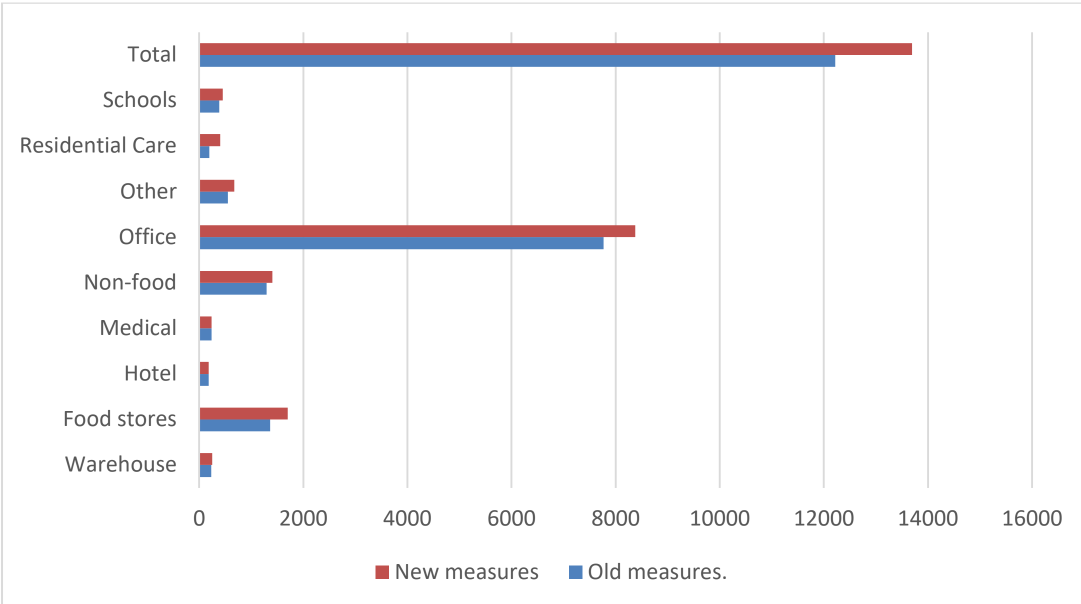

Figure 3-9 Impact of the additional measures on the sectors Kanata 2023

4 Technical Potential of Load Shifting Measures

The project team conducted an analysis to study the impact of load shifting on Kanata-Marchwood summer peak. One important measure to perform the load shifting is the time of use (TOU) pricing, HOL already adopted the TOU pricing for the Regulated Price Plan (RPP) customers. Most of the residential customers and the small commercial customers (i.e. 50kW to 1000 kW) are RPP customers. The larger commercial customers (i.e. Wholesale Market Participants (WMP)) purchase electricity through the IESO directly. Therefore, the TOU pricing is implicitly included in the wholesale energy prices. Thus, the project team concluded that the TOU pricing measure is already applied in Kanata North area, and no additional load shifting could be achieved using it.

The project team analyzed the possibility of load shifting using the battery energy storage system. This analysis was performed for two scenarios; i.e. utility-scale and large customers-scale. The load shifting analysis determined the technical potential of using a battery owned by HOL and installed at the substation. Moreover, the technical potential for installing batteries owned by large customers greater than 1000 KW was also determined.

4.1 Utility-Scale Battery Energy Storage

The total system peak is analyzed as shown in Figure 4-1, and the potential for peak reduction using substation scale battery storage is determined. Two scenarios are studied; i.e. batteries that are capable of discharging for 4 or 6 hours. The adequate battery size for the 4 hours scenario is 7,609 kWh, and this battery can reduce the system peak by 2.922 MW (shaving the peak from 90.05 MW to 87.113 MW). For the 6 hours scenario, the battery size is 24,125 kWh, and this battery can reduce the system peak by 5.87 MW. The economic potential of these proposed battery capacities will be assessed in milestone #3.

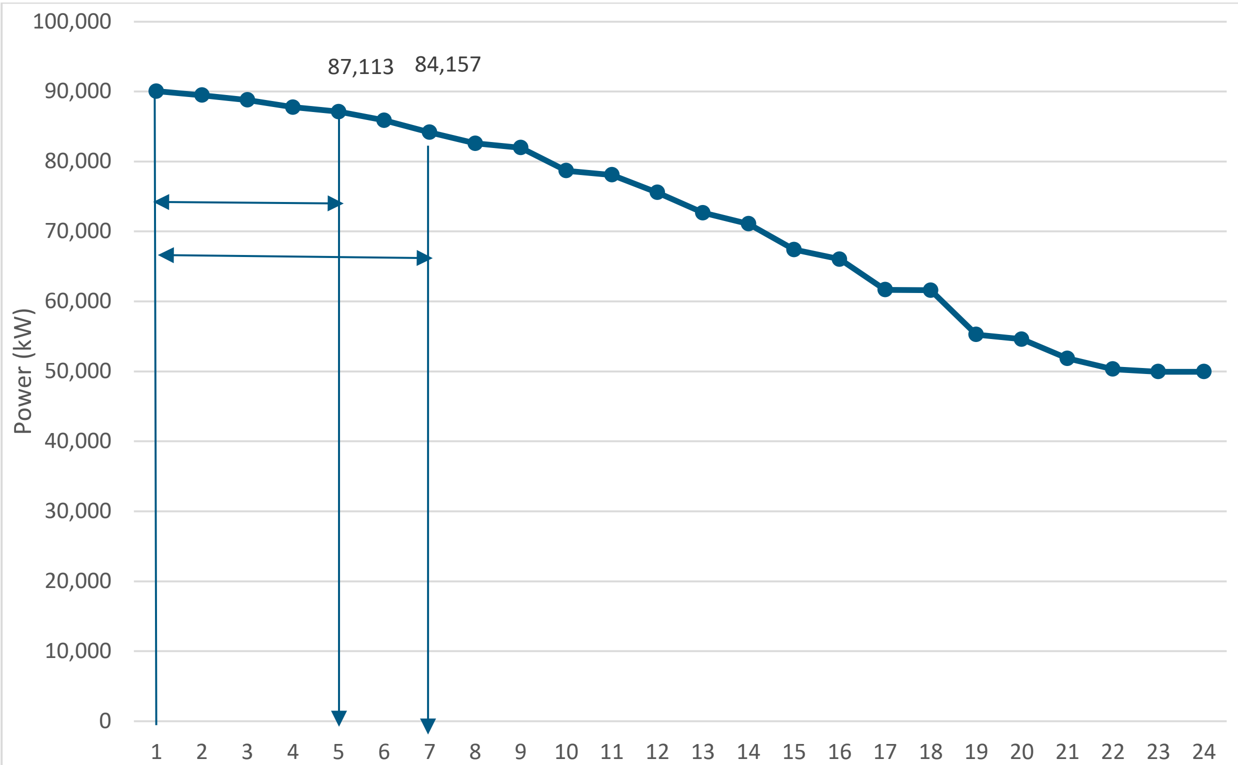

Figure 4-1 Load Duration Curve of the Summer Peak Day

4.2 Customer-Scale Battery Energy Storage

The potential for peak reduction using customer scale battery storage is determined. Two scenarios are studied; i.e. batteries that are capable of discharging for 4 or 6 hours. The adequate battery size for the 4 hours and 6 hours scenarios are determined for the large customers greater than 1000kW. The corresponding technical potentials of peak reduction for these batteries are obtained. Table 4-1 shows the customer meter reference number and the adequate battery sizes for both scenarios as well as the technical potential of these batteries. The total technical potential peak reduction for the 4-hour battery is 746 kW, while for the 6-hour battery, the reduction is 1,186 kW.

Table 4-1 Technical Potential of Large Customer Batteries

Meter Data Reference Number	Customer Maximum Load (kW)	Four Hours Scenario		Six Hours Scenario	
		Battery Capacity (kWh)	Technical Potential for Peak Reduction (kW)	Battery Capacity (kWh)	Technical Potential for Peak Reduction (kW)
1064575000	2,077	52.92	21.6	78.48	25.92
1323516000	1,013	129.6	72.9	181.08	82.08
2261516000	1,655	35.46	13.86	194.22	44.28
2313175000	2,173	166.88	69.44	327.6	100.24
2589675000	1,597	142.56	52.2	467.64	106.38
3948590255	2,278	62.04	19.92	141.36	34.32
5430710301	1,230	33.72	17.52	77.88	25.32
5649575000	1,479	75.24	29.76	263.52	65.04
6445807039	1,050	102.24	32.94	171	45.18
7489675000	1,055	68.13	27.45	121.5	36.99
8079416000	1,967	57.6	21.96	242.82	54.18
9046027318	2,098	15.48	6.3	55.08	12.96
9098675000	3,396	400.76	173.88	689.13	245.97
9771025037	1,097	31.32	17.16	34.8	17.76
9858616000	1,105	198.96	60.48	368.28	93.96
9866575000	3,594	40.079	25.32	97.68	36.54
9951516000	1,053	26.46	10.26	42.3	12.96
9982475000	8,273	227.67	91.41	545.73	145.95

5 Technical Potential of DG Measures

The Project team studied the impact of roof-top small-scale PV DGs located at residential and commercial buildings on the system peak. The team used helioscope software to determine the optimal distribution of the PV panels. The software utilized the actual solar irradiances at Kanata North area to develop the daily profile of the PV DG output power and the DG capacity. The minimum daily power profile for the Summer season was used to determine the technical potential for the Summer peak reduction using the PV DGs.

5.1 Technical Potential of Commercial DGs

One large commercial building located at Terry Fox Dr. is selected (shown in Figure 5-1) to determine the technical potential per square footage. The optimal PV module distribution is developed as shown in Figure 5-2 and the minimum Summer day output powers are obtained as presented in Fig 5-3. The results show that this PV DG can reduce the summer peak by 12.2 kW.

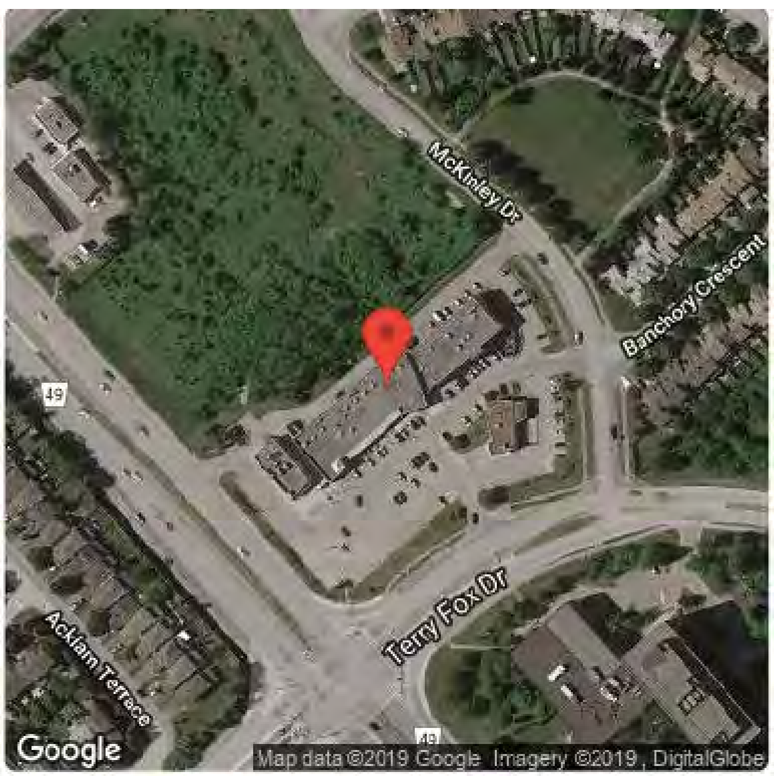

Figure 5-1 Location of the Selected Commercial Building

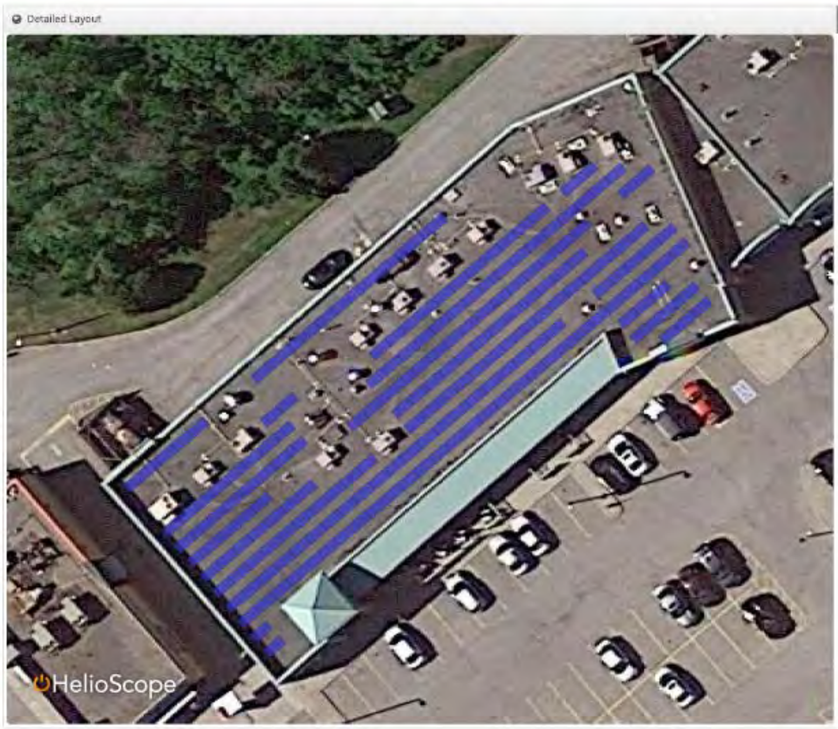

Figure 5-2 Layout of the PV arrays, Commercial Building

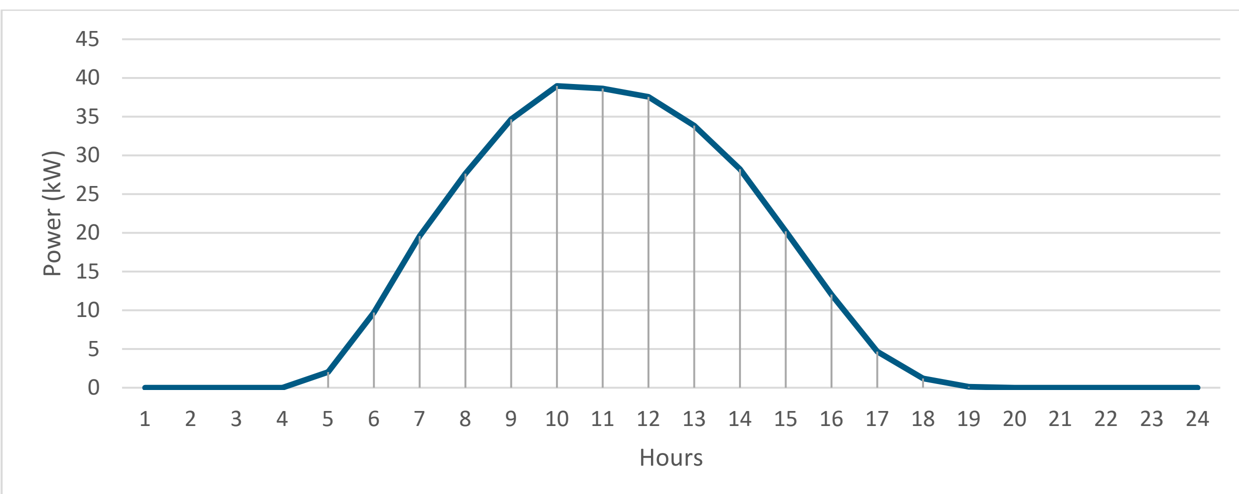

Figure 5-3 Minimum Hourly Output Power for a Summer Day, Commercial Building

The square area of the roof of the selected building is 13,788 square feet. The total square area of the roofs at Kanata North are obtained using MPAC data and adjusted using the square footage forecast developed in milestone #1. The total square footage forecasted in the year 2023 is found to be 7,945,730 square feet. Therefore, the total technical potential for peak reduction using roof-top PV DGs, mounted on commercial buildings, is 7.03 MW.

5.2 Technical Potential of Residential DGs

The same procedure is applied for the residential buildings, two houses were selected; one single-family house and one ROW house. Helioscope was used to determine the optimal PV module distribution. Figures 5-4 shows the optimal PV module distribution for the selected single-family house.

Figure 5-4 Layout of the PV arrays, Single-Family House

The minimum Summer day output powers are obtained as presented in Figure 5-5 and 5-6 for the single family and the ROW house respectively. The results show that the PV DG mounted on the single-family house reduced the Summer peak by 2.732 kW and that of the ROW house reduced the Summer peak by 1.793 kW.

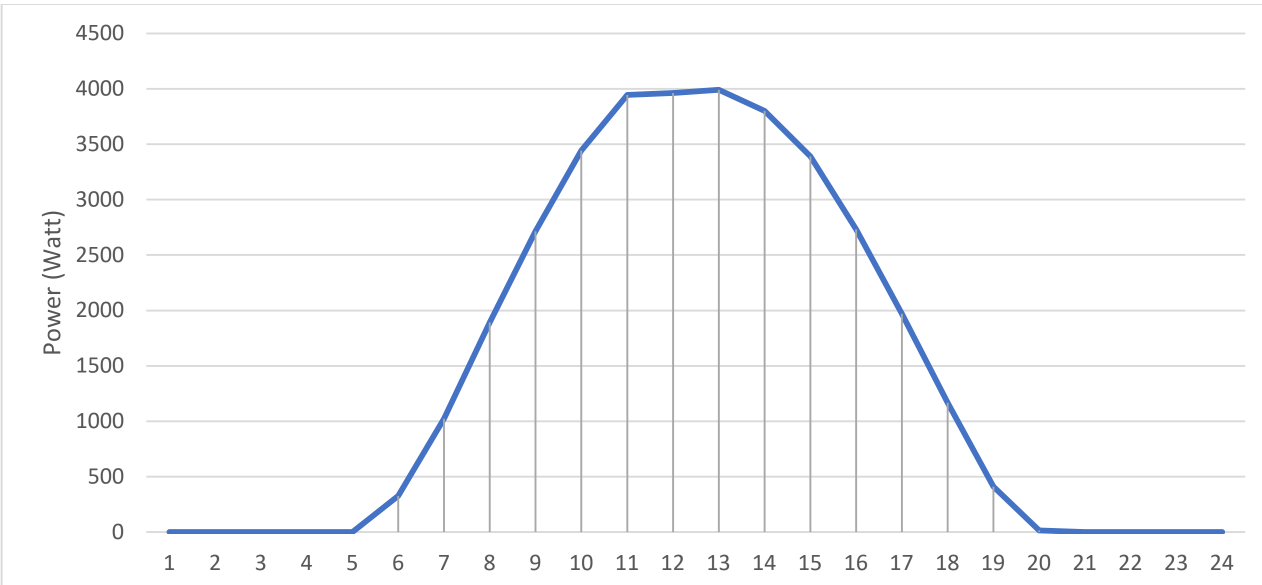

Figure 5-5 Minimum Hourly Output Power for a Summer Day, Single-Family House

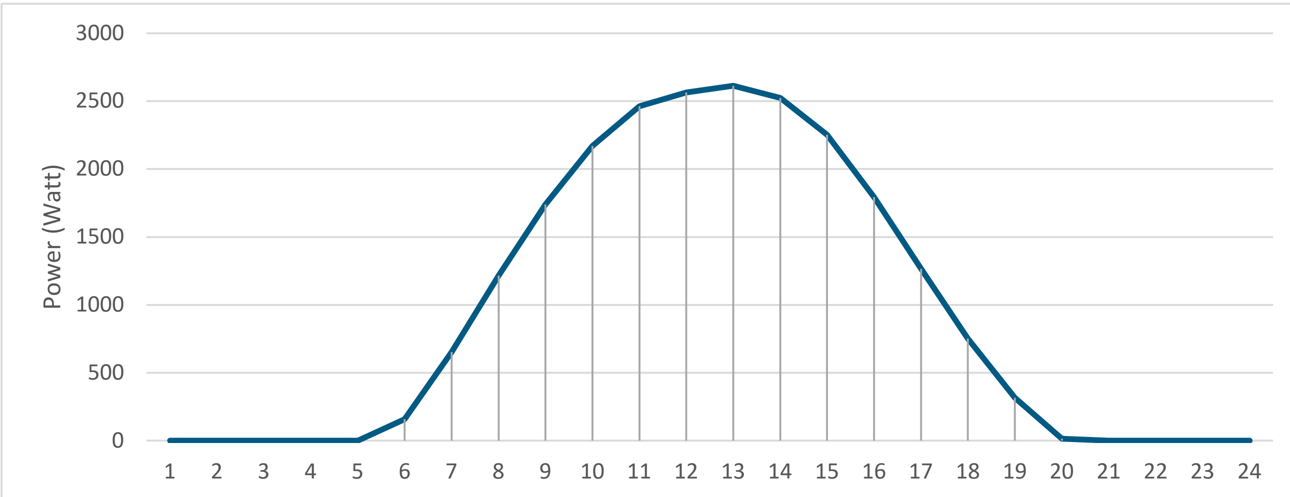

Figure 5-6 Minimum Hourly Output Power for a Summer Day, ROW House

To calculate the total technical potential for peak reduction for all residential buildings, the residential building forecast developed in milestone #1 was used. The total forecasted single-family houses in 2023 are 7,468 houses and the forecasted RO housed in 2023 are 5,826 houses. Therefore, the total technical potential for peak reduction using roof-top PV DGs is 20.4 MW for the single-family and 10.446 MW for the ROW. Therefore, the total technical potential of peak reduction for the residential sector is 30.84 MW and the total technical potential of the DER is 37.87 MW.

List of References

[1] APS 2016' Data provided by IESO

[2] Mid-Atlantic- Technical Reference Manual- Version 5; Available Online: https://neep.org/sites/default/files/resources/Mid-Atlantic_TRM_V5_FINAL_5-26-2015.pdf

[3] State of Ohio Energy Efficiency Technical Reference Manual; Available Online: http://s3.amazonaws.com/zanran_storage/amppartners.org/ContentPages/2464316647.pdf

[4] State of Pennsylvania- Technical Reference Manual; Available Online: https://neep.org/sites/default/files/resources/1333318.pdf

[5] Introduction to Technical Reference Manuals for Kentucky Energy Efficiency Programs; Available Online: https://emp.lbl.gov/publications/introduction-technical-reference

[6] Survey of Household Energy Use; Detailed Statistical Report http://oee.nrcan.gc.ca/publications/statistics/sheu/2011/pdf/sheu2011.pdf

[7] Survey of Commercial and Institutional Energy Use (SCIEU) - https://www.nrcan.gc.ca/energy/efficiency/17137

[8] https://www.eia.gov/consumption/commercial/reports/2012/lighting/

Appendix A

Table A-1 Connected Load Forecast for Kanata MTS

Year		2018	2019	2020	2021	2022	2023	2024	2025
Forecasted Peak Demand (MVA)		65.9	68.8	72.6	75.8	76.9	78.1	78.5	78.9
Added Load (MVA)	TOTAL (MVA)	0.3	3.3	7.1	10.2	11.4	12.5	12.9	13.3
	Kanata North CDP	0.0	0.0	0.0	0.5	0.9	1.3	1.7	2.1
	Beaverbrook Volt Conv.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	124 Battersea	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	469 Terry Fox	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	1136 Maritime	0.0	0.7	1.5	1.5	1.5	1.5	1.5	1.5
	15 Frank Nighbor Place - Com	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Richardson Ridge Phase 2C	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	20 Frank Nighbor PLl (CampMart Kanata)	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Brocollini Business Park Development	0.0	1.0	4.0	6.1	6.1	6.1	6.1	6.1
	471 Terry Fox	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6
	777 Silver Seven	0.0	0.0	0.0	0.0	0.8	1.5	1.5	1.5

Table A-2 Connected Load Forecast for Marchwood MTS

Year		2018	2019	2020	2021	2022	2023	2024	2025
Forecasted Peak Demand (MVA)		55.7	61.4	65.9	67.4	68.9	69.9	70.9	71.9
Added Load (MVA)	TOTAL (MVA)	6.0	11.7	16.1	17.6	19.1	20.1	21.1	22.1
	5050 Innovation (Ciena)	1.6	5.0	8.0	8.0	8.0	8.0	8.0	8.0
	Kanata North CDP	0.0	0.0	0.0	0.0	0.0	1.0	2.0	3.0
	Katimavik Voltage Conversion	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0
	1100 Canadian Shield	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
	KNL Stage 9	0.0	0.0	0.5	1.0	1.5	1.5	1.5	1.5
	Best Western Hotel	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Richardson Ridge Phase 3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Timberwalk Retirement Home	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Kanata Town Centre	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	Kanata North Elementary School	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Ottawa Retirement Residence	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	5100 Kanata Commercial	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Minto Arcadia	1.0	2.0	3.0	4.0	4.0	4.0	4.0	4.0

Table A-3 Sample of Measures Excluded from Measure List

INITIATIVE	END-USE	CONSERVATION MEASURE	MEASURE DESCRIPTION	BASE MEASURE	FIRST YEAR DEMAND SAVINGS (KW)	FIRST YEAR ENERGY SAVINGS (KWH)	SUMMER PEAK DEMAND SAVINGS (KW)	REASON FOR EXCLUSION
Home Assistance Program (HAP)	Miscellaneous	HEAVY DUTY PLUG-IN TIMERS	Car Block Heater Timer	No timer on the car block heater	-	239.1	0	No impact on summer peak
Home Assistance Program (HAP)	Controls for Space Cooling and Heating - Residential	PROGRAMMABLE THERMOSTAT	Baseboard Heaters	Non-programmable thermostats installed on baseboard heaters	122.2	0	11	No impact on summer peak
Direct Install Pilot	Water Heating - Residential	Shower Start Ladybug	Showerhead adapter	Showerhead with Flow Rate = 7.57 L/min	78	0.008	10	Not offered in recent programs
Retrofit	Lighting - University Colleges	HIGH PERFORMANCE MEDIUM BAY T8 FIXTURES	Four-lamp High Performance T-8 fixtures (32W)	250 Watt Metal Halide	514.3	0.068	15	PSP-Business-University_Colleges-Subsector is not existing

Table A-4 Residential CDM Measures

CONSERVATION MEASURE	Competition group	Source
ENERGY STAR® QUALIFIED LED BULBS - General Purpose LED- Different ratings	Screw-in lamps	IESO's Measures
ENERGY STAR® QUALIFIED INDOOR LIGHT FIXTURE - Hard wired- Different Ratings	Screw-in lamps	IESO's Measures
ENERGY STAR® CEILING FAN	Screw-in lamps	IESO's Measures
ENERGY STAR® QUALIFIED LED BULBS- Different Ratings	Screw-in lamps	IESO's Measures
ENERGY STAR® QUALIFIED LED BULBS - SPECIALTY- Different Ratings	Screw-in lamps	IESO's Measures
≤11W ENERGY STAR® Qualified LED A Shape (60W) (minimum 600 Lumen output) (Formerly: 7W – 11W ENERGY STAR® Qualified LED A Shape)	Screw-in lamps	IESO's Measures
≤11W ENERGY STAR® Qualified LED MR 16 (minimum 400 Lumen output) (Formerly: 7W – 12W ENERGY STAR® Qualified LED MR 16 GU 5.3 Base)	Screw-in lamps	IESO's Measures
≤14W ENERGY STAR® Qualified LED A Shape (75W) (minimum 800 Lumen output) (Formerly:10W – 14W ENERGY STAR® Qualified LED A Shape)	Screw-in lamps	IESO's Measures
≤16W ENERGY STAR® Qualified LED PAR 20 (minimum 600 Lumen output) (Formerly: 8W – 12W ENERGY STAR® Qualified LED PAR 20)	Screw-in lamps	IESO's Measures
≤16W ENERGY STAR® Qualified LED PAR30 & PAR38 (minimum 600 Lumen output) (Formerly: 8W – 12W ENERGY STAR® Qualified LED PAR 30)	Screw-in lamps	IESO's Measures
≤23W ENERGY STAR® Qualified LED A Shape (100W) (minimum 1600 Lumen output) (Formerly: 17W – 23W ENERGY STAR® Qualified LED A Shape)	Screw-in lamps	IESO's Measures
≤23W ENERGY STAR® Qualified LED PAR (minimum 1100 Lumen output) (Formerly: 14W – 18W ENERGY STAR® Qualified LED PAR 38)	Screw-in lamps	IESO's Measures
≤6W ENERGY STAR® Qualified LED MR 16 / PAR 16 (minimum 250 Lumen output) (Formerly:7W – 10W ENERGY STAR® Qualified LED MR 16 / PAR 16 - GU 10 Base)	Screw-in lamps	IESO's Measures
LED Downlight with Light Output >600 and <800 lumens (Retrofit Measure List)	Screw-in lamps	IESO's Measures
LED Downlight with Light Output >800 lumens (Retrofit Measure List)	Screw-in lamps	IESO's Measures
DIMMER SWITCH (HARD-WIRED)	light control	IESO's Measures
LIGHTING TIMERS (HARD-WIRED, INDOOR)	light control	IESO's Measures
MOTION SENSORS (HARD-WIRED, INDOOR)	light control	IESO's Measures
Smart Burner Intelligent Cooking System	Wall Oven	IESO's Measures
ENERGY STAR® FREEZER- Different Ratings	Freezers	IESO's Measures
ENERGY STAR® REFRIGERATOR - Different Ratings	Refrigerators	IESO's Measures
SMART THERMOSTAT	Space cooling control	IESO's Measures
WEATHERSTRIPPING (DOOR FRAME)	Thermal Envelope	IESO's Measures
ENERGY STAR® ROOM AIR CONDITIONER- Different Ratings	Room AC	IESO's Measures
SEER 18 CAC	Central AC	IESO's Measures
Cold-climate Ductless ASHP w/baseline having Cooling	Other Cooling	IESO's Measures
Ducted ASHP w/baseline having Cooling	Other Cooling	IESO's Measures
Cold-climate Duct ASHP w/baseline having Cooling	Other Cooling	IESO's Measures
Cold-climate Ductless ASHP w/baseline having Cooling	Other Cooling	IESO's Measures
PIPE WRAP : Per 3' Pipe Wrap (5/8" Pipe)	Hot Water- Insulation	IESO's Measures
PIPE WRAP: Per 3' Pipe Wrap (1/2" Pipe)	Hot Water- Insulation	IESO's Measures

PIPE WRAP: Per 3' Pipe Wrap (3/4" Pipe)	Hot Water- Insulation	IESO’s Measures
EFFICIENT SHOWERHEAD (Low-flow)	Showerhead	IESO’s Measures
EFFICIENT SHOWERHEAD (HANDHELD)	Showerhead	IESO’s Measures
EFFICIENT SHOWERHEAD (STANDARD)	Showerhead	IESO’s Measures
Shower Start Ladybug	Showerhead	IESO’s Measures
Water Heater Blanket	Water heater	IESO’s Measures
Solar water heater	Water heater	North America
ENERGY STAR natural gas or propane water heater	Water heater	North America
EFFICIENT AERATORS: Bathroom - Flow Rate ≤ 3.8 L/min	Aerator	IESO’s Measures
EFFICIENT AERATORS: Kitchen - Flow Rate < 5.7 L/min	Aerator	IESO’s Measures
ENERGY STAR Clothes Washers- Different Ratings	Washer	IESO’s Measures
Energy star dishwasher	Dishwasher	North America
ENERGY STAR Clothes Dryers	Dryer	IESO’s Measures
Indoor Clothes Drying Rack, Retractable Clotheslines	Dryer	IESO’s Measures
Gas clothes dryer	Dryer	North America
ENERGY STAR® DEHUMIDIFIER	Dehumidifiers	IESO’s Measures
< 20" ENERGY STAR® Most Efficient TV	Television	North America
20 < 30" ENERGY STAR® Most Efficient TV	Television	North America
30 < 40" ENERGY STAR® Most Efficient TV	Television	North America
40 < 50" ENERGY STAR® Most Efficient TV	Television	North America
50 < 60" ENERGY STAR® Most Efficient TV	Television	North America
> 60" ENERGY STAR® Most Efficient TV	Television	North America
ENERGY STAR Water Coolers	Water Cooler	North America
Energy Star Computer	Office Equipment	North America
Energy Star Monitor	Office Equipment	North America
Energy Star Copier	Office Equipment	North America
Energy Star Fax	Office Equipment	North America
Energy Star Printer	Office Equipment	North America

Table A-5 Commercial CDM Measures

CONSERVATION MEASURE	Competition group	Source
LED RECESSED DOWNLIGHTS- Different Ratings	Indoor Screw-in	IESO’s
LED REFLECTOR (FLOOD/SPOT) LAMP PIN & SCREW BASE	Indoor Screw-in	IESO’s
ENERGY STAR LED DECORATIVE BLUB(E12 CANDELABRA BASE)	Indoor Screw-in	IESO’s
LED TUBE RE-LAMP	Indoor Screw-in	IESO’s
INTEGRAL LED RETROFIT KIT	Indoor Screw-in	IESO’s
INTEGRAL LED TROFFERS / LINEAR AMBIENT FIXTURE	Indoor Screw-in	IESO’s
ENERGY STAR® LED OMNIDIRECTIONAL A LAMPS- Different Ratings	Indoor Screw-in	IESO’s
LED EXIT SIGN	Indoor Screw-in	IESO’s
REFRIGERATED DISPLAY CASE LED FIXTURE - HORIZONTAL	Indoor Screw-in	IESO’s
REFRIGERATED DISPLAY CASE LED FIXTURE - VERTICAL INSTALLATION	Indoor Screw-in	IESO’s
LED EXTERIOR AREA LIGHTS: LED fixture (≤30W)	Outdoor- Screw-in	IESO’s
LED EXTERIOR AREA LIGHTS: LED fixture (>30W to ≤60W)	Outdoor- Screw-in	IESO’s
LED EXTERIOR AREA LIGHTS: LED fixture (>60W to ≤120W)	Outdoor- Screw-in	IESO’s
LED EXTERIOR AREA LIGHTS: LED fixture (>120W to ≤200W)	Outdoor- Screw-in	IESO’s
LED EXTERIOR AREA LIGHTS: LED fixture (≤530W)	Outdoor- Screw-in	IESO’s
OCCUPANCY SENSORS: Switch Plate Mounted	Control	IESO’s
OCCUPANCY SENSORS: Fixture Mounted Occupancy Sensor (High Bay) for fixtures	Control	IESO’s
UNITARY AIR-CONDITIONING UNIT- Different Ratings	Packaged AC	IESO’s
Energy efficient Air-cooled chiller: < 150 tons	Chillers	North
Energy efficient Air-cooled chiller: > 150 tons to < 300 tons	Chillers	North
Energy efficient Water-cooled positive displacement chiller: < 75 tons	Chillers	North
Energy efficient Water-cooled positive displacement chiller: 75 < and > 150 tons	Chillers	North
Energy efficient Water-cooled positive displacement chiller: 150 < and > 300 tons	Chillers	North
Energy efficient Water-cooled positive displacement chiller: 300 < and > 600 tons	Chillers	North
Energy efficient Water-cooled centrifugal Chiller: < 300 tons	Chillers	North
Energy efficient Water-cooled centrifugal Chiller: 300 < and > 600 tons	Chillers	North
Energy efficient Water-cooled centrifugal Chiller: > 600 tons	Chillers	North
Energy efficient RAC (with louvered sides): < 6000 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 6000-7999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 8000-10999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 11000-13999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 14000-19999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 20000-24999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): > 25000 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): < 6000 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 6000-7999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 8000-10999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 11000-13999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 14000-19999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 20000-24999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): > 25000 BTU/hr	Room AC	North
Efficient electric resistance water heater- Different Ratings	Water heater	North
Heat Pump- Different Ratings	Water heater	North
NETWORK PC POWER MANAGEMENT SOFTWARE	Computer Software	IESO’s
Multi-Residential In Suite Appliance	Residential size	IESO’s
ECM MOTORS FOR EVAPORATOR FANS (REFRIGERATOR WALK-IN)	Walk-in refrigerators	IESO’s
ENERGY STAR® REFRIGERATOR: Glass Glass Door (< 15 cu.ft.)	Cabinet	IESO’s
ENERGY STAR® REFRIGERATOR: Glass Door (≥ 15 cu.ft. to < 30 cu.ft.)	Cabinet	IESO’s

ENERGY STAR® REFRIGERATOR: Glass Door (≥ 30 cu.ft. to < 50 cu.ft.)	Cabinet	IESO's
ENERGY STAR® REFRIGERATOR: Glass Door (≥ 50 cu.ft.)	Cabinet	IESO's
ENERGY STAR® REFRIGERATOR: Solid Door (< 15 cu.ft.)	Cabinet	IESO's
ENERGY STAR® REFRIGERATOR: Solid Door (≥ 15 cu.ft. to < 30 cu.ft.)	Cabinet	IESO's
ENERGY STAR® REFRIGERATOR: Solid Door (≥ 50 cu.ft.)	Cabinet	IESO's
ENERGY STAR® FREEZER: Glass Door (< 15 cu.ft.)	Cabinet	IESO's
ENERGY STAR® FREEZER: Glass Door (≥ 15 cu.ft. to < 30 cu.ft.)	Cabinet	IESO's
ENERGY STAR® FREEZER: Glass Door (≥ 30 cu.ft. to < 50 cu.ft.)	Cabinet	IESO's
ENERGY STAR® FREEZER: Glass Door (≥ 50 cu.ft.)	Cabinet	IESO's
installation of insulation on bare Cooler suction pipes	Pipes insulation	North
Strip curtains for walk-in coolers or Freezers	Strip Curtain	North
DOOR GASKETS FOR WALK-IN AND REACH-IN Coolers	Gasket	North
ENERGY STAR® ICE MACHINES- Different Ratings	Ice machine	IESO's
BEVERAGE VENDING MACHINE CONTROLS	Vending Machine	IESO's
Electric hot water heater, electric dryer	Washer-plug load	North
Electric hot water heater, gas dryer	Washer-plug load	North
ENERGY STAR Dishwasher	cooking	APS 2016
High-Efficiency Induction Cooking	cooking	APS 2016
Refrigerated Display Case LED	lighting	APS 2016
CEE Tier 2/Energy Star Clothes Washers	Misc. commercial	APS 2016
VFD on Pumps	Misc. commercial	APS 2016
VSD Air Compressor	Misc. commercial	APS 2016
VSD Air Compressor	Misc. commercial	APS 2016
Smart Strip Plug Outlets	other plug loads	APS 2016
Vertical Night Covers	refrigeration	APS 2016
Temperature Adjustment in Commercial Freezers	refrigeration	APS 2016
Suction Pipe Insulation Freezer/Refrigerator	refrigeration	APS 2016
Refrigeration Optimization	refrigeration	APS 2016
Refrigeration Commissioning	refrigeration	APS 2016
Anti-sweat heat (ASH) controls - Cooler/Freezer	refrigeration	APS 2016
Adding reflective (White) roof treatment or a green roof	Space cooling	APS 2016
Air Curtains	Space cooling	APS 2016
Duct Insulation, R8	Space cooling	APS 2016
Chilled Water Optimization	Space cooling	APS 2016
ECM MOTORS FOR HVAC APPLICATION (FAN-POWERED VAV BOX)	Space cooling	APS 2016
HVAC Optimization	Space cooling	APS 2016
Outside Air Economizer	Space cooling	APS 2016
Air Handler with Dedicated Outdoor Air Systems	Vent. & Circ.	APS 2016
CO Sensors for parking garage exhaust fans	Vent. & Circ.	APS 2016
Demand Control Kitchen Ventilation	Vent. & Circ.	APS 2016
Variable Frequency Drive (VFD)	Vent. & Circ.	APS 2016
Air Handler with Dedicated Outdoor Air Systems	water heating	APS 2016
CO Sensors for parking garage exhaust fans	water heating	APS 2016
Demand Control Kitchen Ventilation	water heating	APS 2016
Variable Frequency Drive (VFD)	water heating	APS 2016

Appendix B

The methodology presented in section 3.1 is applied to the collected CDM measures; this section presents examples for the calculations of the technical potential of the peak demand reduction. One example is for the peak reduction within the competition group dehumidifier- Residential single-family. First, the number of forecasted single-family units on the year 2023 is determined using the residential forecast developed in milestone #1. Secondly, the penetration of dehumidifiers for single-family subsector is determined from the HOL residential survey provided by IESO. Then, the ratio of energy star dehumidifiers to the total number of dehumidifiers in the single-family subsector is used to determine the energy efficient factor; this ratio was obtained from the residential survey. Finally, the measure summer peak reduction developed in IESO's MAL was used for the calculation of the total peak reduction as presented in the following equation.

$$Potential\ of\ dehumidifier\ measu = Total\ number\ of\ single\ family\ units \times dehumidifier\ penetration\ share \times (1 - energy\ efficient\ factor) \times measure\ peak\ reduction$$

$= 7468.85\ \times 27.6\,\%\ \times (100 - 21.7\%) \times 0.078\ kW$=125.9 kW

The same procedure is repeated for all measures lying in the competition group as shown in Table B-1; then, the total technical potential for the peak reduction from this group is obtained by assuming 100% adoption of the CDM measure. It should be noted that the exact adoption rate will be used in Milestone #3 to determine the achievable potential for peak reduction.

Table B-1 Dehumidifier competition group- Residential Single Family

CONSERVATION MEASURE	MEASURE DESCRIPTION	BASE MEASURE	SUMMER PEAK DEMAND SAVINGS (KW)	Base measure Share	Number of residential units	Energy Efficient Factor	Savings (KW)
ENERGY STAR® DEHUMIDIFIER	Dehumidifier Replacement (ENERGY STAR Qualified 21.3 - 25.4 l/day)	Non-Energy Star® Dehumidifier	0.064	27.60%	7468.85	21.7 %	103
ENERGY STAR® DEHUMIDIFIER	Dehumidifier Replacement (ENERGY STAR Qualified 14.2 - 21.2 l/day)	Non-Energy Star® Dehumidifier	0.078	27.60%	7468.85	21.7 %	125.90
ENERGY STAR® DEHUMIDIFIER	Dehumidifier Replacement (ENERGY STAR Qualified 25.5 - 35.5 l/day)	Non-Energy Star® Dehumidifier	0.059	27.60%	7468.85	21.7 %	95

Electric Chiller Example

This section presents the procedure used for the estimation of the savings associated with installing high-efficiency electric chillers as compared to conventional chillers. The peak demand reduction for chillers is calculated using one of the following equations; based on the chiller type;

a) Efficiency ratings in EER

$$\Delta kW_{peak} = Tons_{ee} \times 12 \times (\frac{1}{EER_{base}} - \frac{1}{EER_{ee}}) \times CF$$

b) Efficiency ratings in kW/Ton

$$\Delta kW_{peak} = Tons_{ee} \times \left(\frac{kW}{ton_{base}} - \frac{kW}{ton_{ee}}\right) \times CF$$

The definition and description of each variable are given in table B-2.

Table B-2 Chillers Parameters Definitions

Term	Description	Unit
$Tons_{ee}$	The capacity of the chiller	Tons
EER_{base}	Energy efficiency ratio of the baseline chiller	$\frac{Btu/hr}{W}$
$\frac{kW}{ton_{base}}$	Design rated efficiency of the baseline chiller	$\frac{kW}{ton}$
EER_{ee}	Energy efficiency ratio of the efficient chiller	$\frac{Btu/hr}{W}$
$\frac{kW}{ton_{ee}}$	Design rated efficiency of the efficient chiller	$\frac{kW}{ton}$
CF	Demand Coincidence Factor	Decimal

The rated capacities and efficiencies of the baseline chiller and the energy efficient chillers depend on the chiller type and size. This data, as well as the demand coincidence factor, are gathered from several North American distribution utilities. Table B-3 show a sample of the collected data for different chillers types and ratings. Moreover, the average demand coincidence factors (collected from different North American cities) for some commercial subsectors are presented in Table B-4. Finally, a sample of the calculated demand reductions for different commercial subsectors and chiller types are presented in Table B-5.

Table B-3 Electric Chiller Baseline Efficiencies

Chiller Type	Size	BaseLine Chiller	Energy Efficient Chiller
Air Cooled Chillers	< 150 tons	12.5 EER	15 EER
	> = 150 tons	12.75 EER	14.45 EER
Water Cooled	< 75 tons	0.630 kW/ton	0.62 kW/ton
	> = 75 tons and < 150 tons	0.615 kW/ton	0.6 kW/ton
	> = 150 tons and < 300 tons	0.580 kW/ton	0.46 kW/ton
	> = 300 tons	0.540 kW/ton	0.46 kW/ton
Water Cooled Centrifugal Chiller	< 300 tons	0.596 kW/ton	0.47 kW/ton
	> = 300 tons and < 600 tons	0.549 kW/ton	0.38 kW/ton
	> = 600 tons	0.539 kW/ton	0.38 kW/ton

Table B-4 Chiller Demand CFs

Building type	Average Demand Coincidence Factor
Education - Community College	0.408571
Education - Secondary College	0.145714
Education – University	0.375714
Health/medical – Hospital	0.497143
Health/medical – Nursing Home	0.258571
Lodging – Hotel	0.655714
Manufacturing – Bio/Tech	0.512857
Office – Large	0.307143
Office - Small	0.281429
Retailers	0.474286

Table B-5 Sample of the Chillers Calculations

END-USE	CONSERVATION MEASURE	MEASURE DESCRIPTION	BASE MEASURE	FIRST YEAR DEMAND SAVINGS (KW)	SUMMER PEAK DEMAND SAVINGS (KW)	EFFECTIVE USEFUL LIFE (YEAR)
Space Cooling-School	Energy efficient Air-cooled chiller	< 150 tons	Standard Air-cooled chiller	12.0	1.749	20.0
Space Cooling-School	Energy efficient Air-cooled chiller	> 150 tons to < 300 tons	Standard Air-cooled chiller	25.0	3.645	20.0
Space Cooling-School	Energy efficient Water-cooled positive displacement chiller	< 75 tons	Standard Water-cooled positive displacement chiller	0.4	0.055	20.0
Space Cooling-School	Energy efficient Water-cooled positive displacement chiller	75 < and > 150 tons	Standard Water-cooled positive displacement chiller	1.7	0.246	20.0
Space Cooling-School	Energy efficient Water-cooled positive displacement chiller	150 < and > 300 tons	Standard Water-cooled positive displacement chiller	27.0	3.934	20.0
Space Cooling-School	Energy efficient Water-cooled positive displacement chiller	300 < and > 600 tons	Standard Water-cooled positive displacement chiller	36.0	5.246	20.0
Space Cooling-School	Energy efficient Water-cooled centrifugal Chiller	< 300 tons	Standard Water-cooled centrifugal Chiller	25.4	3.694	20.0
Space Cooling-School	Energy efficient Water-cooled centrifugal Chiller	300 < and > 600 tons	Standard Water-cooled centrifugal Chiller	76.1	11.082	20.0
Space Cooling-School	Energy efficient Water-cooled centrifugal Chiller	> 600 tons	Standard Water-cooled centrifugal Chiller	95.4	13.901	20.0
Space Cooling-Large office	Energy efficient Air cooled chiller	< 150 tons	Standard Air cooled chiller	12.0	3.686	20.0

Space Cooling-Large office	Energy efficient Air cooled chiller	> 150 tons to < 300 tons	Standard Air cooled chiller	25.0	7.683	20.0
Space Cooling-Large office	Energy efficient Water cooled positive displacement chiller	< 75 tons	Standard Water cooled positive displacement chiller	0.4	0.115	20.0
Space Cooling-Large office	Energy efficient Water cooled positive displacement chiller	75 < and > 150 tons	Standard Water cooled positive displacement chiller	1.7	0.518	20.0
Space Cooling-Large office	Energy efficient Water cooled positive displacement chiller	150 < and > 300 tons	Standard Water cooled positive displacement chiller	27.0	8.293	20.0
Space Cooling-Large office	Energy efficient Water cooled positive displacement chiller	300 < and > 600 tons	Standard Water cooled positive displacement chiller	36.0	11.057	20.0
Space Cooling-Large office	Energy efficient Water-cooled centrifugal Chiller	< 300 tons	Standard Water-cooled centrifugal Chiller	25.4	7.786	20.0
Space Cooling-Large office	Energy efficient Water cooled centrifugal Chiller	300 < and > 600 tons	Standard Water cooled centrifugal Chiller	76.1	23.358	20.0
Space Cooling-Large office	Energy efficient Water-cooled centrifugal Chiller	> 600 tons	StandardWater-cooled centrifugal Chiller	95.4	29.301	20.0

Hydro Ottawa Local Achievable Potential (LAP) Study

Market Analysis of the Feasible Measures

Milestone #3 Report

SLI PROJECT NO.: 660803

00	Final Report	09/11/2019	AS	HA	TA
PB	Issued for Comments	07/25/2019	AS	HA	TA
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REV.	**DESCRIPTION**	**DATE**	**PRPD**	**CHKD**	**APPRD**
			SNC-Lavalin		

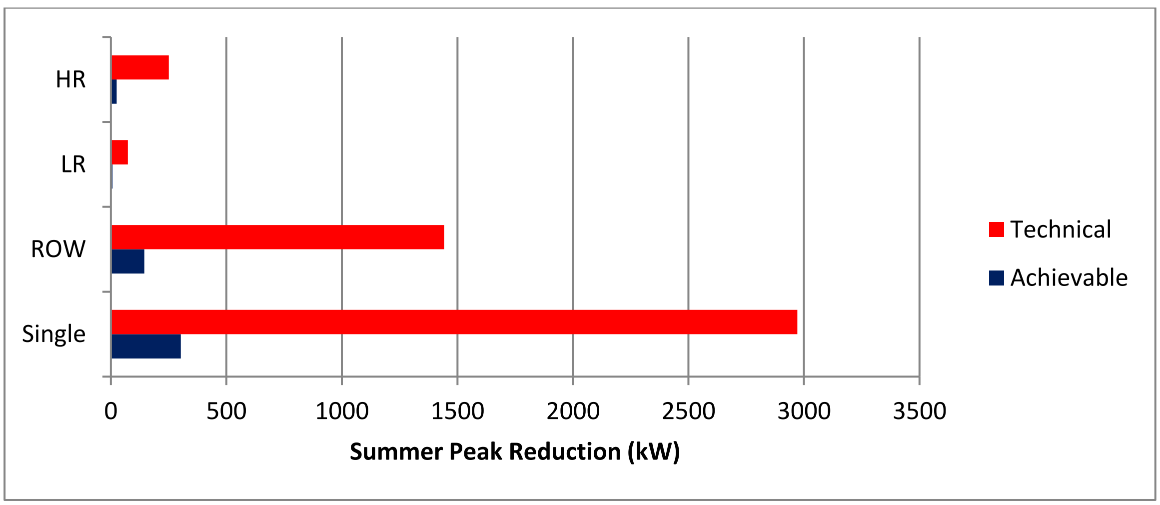
EXECUTIVE SUMMARY

The objective of Milestone #3 of this study is to determine the achievable potential of the technically feasible measures. For each measure, the project team conducted the analysis through the determination of the measure unit cost ($/kW), measure peak demand reduction, and the number of units. The project team ranked the measures in terms of their unit cost in ascending order to determine the measures with significant potential.

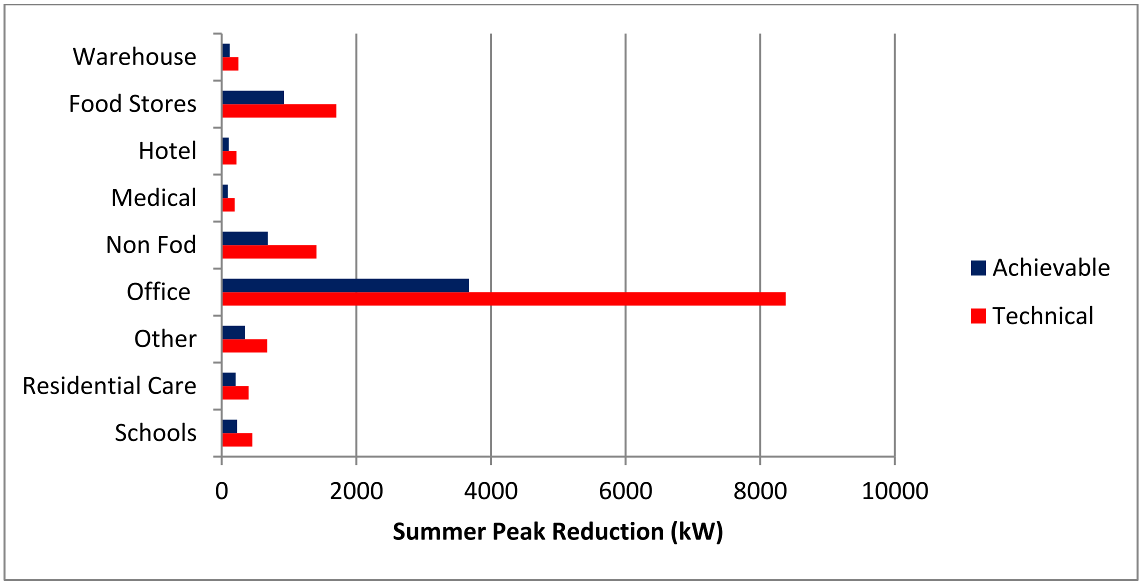
The team reviewed the HOL customer and business participation in the CDM programs to estimate the bass diffusion equations parameters. Then, the team developed the adoption curve for each measure based on the historical participation in CDM programs and the estimated value of the bass diffusion equation parameters. The project team estimated the aggregated achievable potential for peak reduction for all the CDM measures based on the developed adoption curves.

Based on the calculated achievable potentials for the CDM and DER measures, the total achievable potential for the peak reduction of Kanata North area is estimated at 6491.88kW. This reduction is mainly coming from CDM measures.

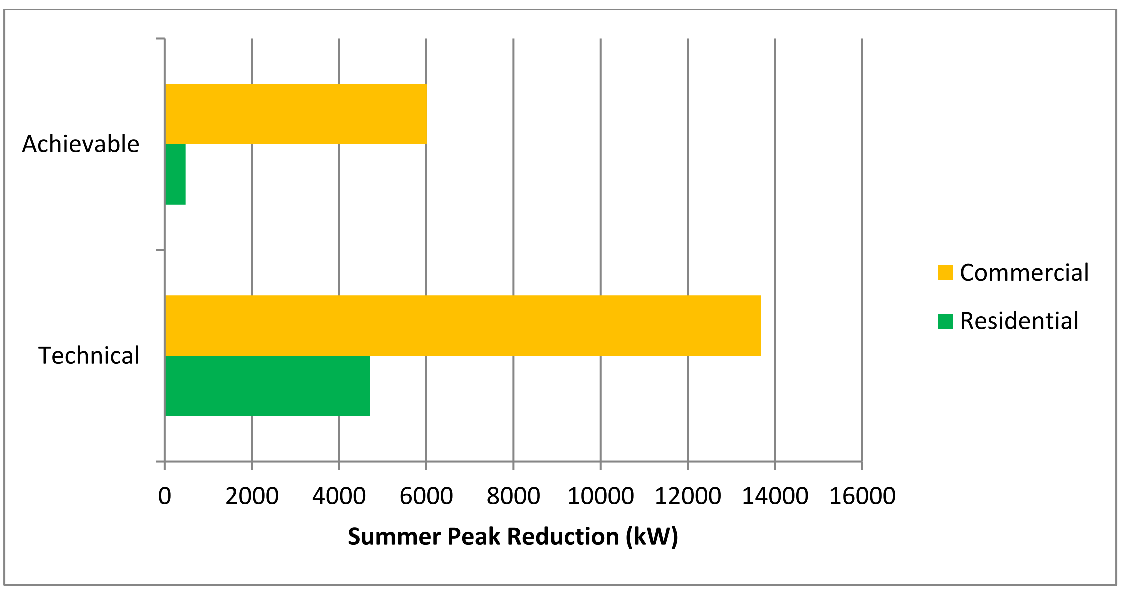
Figure ES-1, ES-2, and ES-3 show the estimated values for the achievable potential vs. technical potential of the residential and commercial measures.



ES-1 Technical and Achievable Potential Peak Reduction by Residential Subsector in 2023



ES-2 Technical and Achievable Potential Peak Reduction by Commercial Subsectors in 2023



ES-3 Total Technical and Achievable Potential Peak Reduction in 2023

The team conducted a cost analysis to study the impact of the Distributed Energy Resources (DER) on Kanata-Marchwood summer peak; the analysis is categorized into load shifting using battery energy storage (BES) system and renewable-based distributed generation. The analysis reveals the following:

- For commercial-scale battery storage, the required incentives levels are estimated between $5570-6930 per kW of peak reduction
- For utility-scale energy storage, the budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW
- For residential PV rooftop, the incentives per installed kW are 1140.76 $/kW. This incentive level would provide the minimum attractive rate of return of 7%
- For commercial PV rooftop, the incentives per installed kW are 2200 $/kW. This incentive level would provide the minimum attractive rate of return of 7%

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List of acronyms

APS	Achievable Potential Study
BES	Battery Energy Storage
CDM	Conservation and Demand Management
DER	Distributed Energy Resources
DG	Distributed Generation
HOL	Hydro Ottawa Ltd
HR	High Rise
IESO	Independent Electricity System Operator
kWh	Kilowatt-hour
LAP	Local Achievable Potential Study
LR	Low Rise

1 Introduction

In Milestone #2, the technical potential was estimated assuming the implementation of all the feasible non-wire solutions. The market analysis and the adoption rate of the non-wire feasible solutions were not considered in the analysis of Milestone #2. In this report, we present the market analysis of the technically feasible measures identified in Milestone #2 to calculate the achievable potential for addressing local area needs.

2 Achievable Potential of CDM Measures

The achievable potential is estimated using the technical potential determined in Milestone #2 after considering the cost of the measures and customer adoption.

Based on HOL plan, the new station (new Kanata North) is planned to be in service in 2029. Therefore, the presented study focuses on short-term achievable potential scenarios. This section shows the methodology followed for calculating the achievable potential of the CDM measures.

2.1 Methodology

Assessing achievable potential requires: calculating the technical potential of the CDM measures (identified in Milestone #2), calculating the cost-effectiveness of each measure (see sample calculation in Appendix A) and estimating the rate at which cost-effective measures could be adopted over time. The following key items were considered and addressed in developing the methodology:

1- Historical performance of programs in HOL.
2- Development of adoption curves.
3- Mapping of measures to the adoption curves.

The development of the achievable potential scenario is accomplished by estimating the adoption curves of the technically feasible measures. The adoption curves are developed to estimate the achievable annual participation in each measure using the equation derived by the bass diffusion, the historic program participation and launch period of the program [1].

The steps implemented in developing the adoption curves are:

1- Measures categorized by sectors and subsectors first, and then further categorized by end-use was done
2- For each end-use, the competition groups were developed. The obtained measures were mapped to the competition groups/ end-use/ subsector/ sector. Tables 3-1 and 3-2 present the list of the used residential and commercial CDM measures classified by competition group.
3- The values of p, q, and m parameters in the bass diffusion equation were developed using statistical analysis of Ontario historic program participation data as provided by HOL.
4- Market adoption curves were aligned with the availability of historic program participation data.
5- The adoption curves were developed using the bass diffusion equations and historic program participation.

6- Measures were mapped to the adoption curves.

7- The achievable potential for peak demand reduction for each measure was calculated as follows:

$$Achievable potential of measure = \frac{Technical potential of measure \times \text{number of } adopters at year\ 2023}{eligible\ population}$$

8- The aggregated measure savings potential for each competitive group was determined; double-count of potential savings was avoided by limiting the total adoption to 100% within each measure competition group.

A demonstrative example is shown in Appendix A for the calculation of the Achievable Potential of Deep Freezer measure in the residential sector.

2.1.1 Mapping of CDM Measures

The measure competition groups were developed for each subsector/end-use separately. Each competition group consolidates similar measures that could be an alternative to each other. For example, the competition groups for the space cooling end-use area thermal envelope, space cooling control, room/window air conditions, and central AC. The measures in each competition group are alternatives to each other. The complete list of competition groups mapped to subsectors and end-use are presented in Table 2-1 and 2-2 for residential and commercial sectors, respectively. The subsectors mentioned in Table 2-2 are in offices, medical offices, hotels, residential care, non-food retailers, food retailers, schools, warehouse wholesale, and other commercials.

Table 2-1 Residential Sector Competition Groups

End-use	Competition Groups
Indoor Lighting	Screw-in lamps, light control
Outdoor Lighting	Screw-in lamps, light control
Common Area Lighting	Screw-in lamps, light control
Cooking	Wall Oven
Refrigeration	Refrigerators, Freezers
Space Cooling	Control, Thermal Envelope, Room AC, Central AC, Other Cooling
Water Heating	Pipe Insulation, Showerhead, Water heater, Aerator
Plug Loads	Dehumidifiers, Televisions, Water cooler, office equipment
Washer Dryer	Washing Machines, Dryers, Dishwashers

Table 2-2 Commercial Sector Competition Groups

End-use	Competition Groups
Subsector Lighting	Screw-in lamps, light control
Subsector space cooling	Packaged AC units, Chillers, Room AC
Subsector refrigeration	Residential size refrigerators, Walk-in refrigerators, Cabinet, pipes insulation, strip curtain, Gasket.
Subsector plug loads	Ice machine, Vending machine
Subsector computers	Computers
Subsector ventilation and circulation	Ventilation and circulation
Subsector miscellaneous commercial	Visc commercial
Subsector Domestic Hot Water	Water heater

2.2 Data provided by HOL and IESO

HOL provided historical participation in CDM programs for the years 2006 – 2018 for the residential sector and from 2015 – 2019 for the commercial sector. According to the residential sector data provided by HOL, the historical participation in all CDM programs from 2006 – 2014 is zero except for Central Air Conditioner (CAC) measures. However, the data for the years 2016 - 2018 is not consistent and not accurate; a sample of the historical participation for some measures is presented in Table 2-3.

IESO provided historical participation in CDM programs for the years 2015 – 2019 for the commercial sector. The data for the years 2015 - 2019 does not reveal a consistent trend.

A sample of historical participation is presented in Table 2-3 and Table 2-4.

Table 2-3 Historical Participation Provided by HOL

Measure / Year	2011-2014	2015	2016	2017	2018
Energy star qualified fixtures	0	3743	41	8102	7726
Freezer	0	352	0	0	0

Table 2-4 Historical Participation Provided by IESO

Program	2015	2016	2017	2018	2019
Save on energy small business lighting program	662	54	530	278	176
Save on energy retrofit program	109	192	6,108	741	-

2.2.1 Assumptions

Due to the inconsistency of the data provided by HOL and IESO and since the historical participation in CDM programs four consecutive years at least are needed to estimate the bass diffusion equation parameters, the following assumptions are made in the development of the adoption curves:

1- The CDM programs for both residential and commercial sectors were launched in 2011 [2].
2- The historical participation of the CDM-HOL residential programs for the year 2015 is considered consistent and accurate and used in the analysis to estimate the ultimate number of adopters in the residential sector
3- Due to the deficiency in data, the remaining parameters were in adopted form [2].

2.3 Results and Discussion

The methodology described in section 3.1 is applied to the Kanata-Marchwood technically feasible measures developed in Milestone #2. The factors required for calculating the achievable potential (i.e., the technical potential, the historical participation in CDM programs, and the unit cost of each measure); are determined as illustrated in section 2.1 and 3.1. Sample for the analysis implemented in the development of the adoption curves for CDM measure is presented in Appendix A.

2.3.1 Residential Sector

The achievable potential peak reduction is calculated for each competition group of the residential subsector/ end-use, and the total achievable potential peak reduction is calculated for each subsector and end-use. Figure 2-1 shows the technical and achievable potential summer peak reduction for each subsector; the largest achievable potential was estimated for the single-family subsector, which accounts for 63.13% of the total peak reduction in 2023. Figures 2-2 to 2-5 show the reductions per residential end-use for each subsector. The total achievable residential summer peak reduction in 2023 was estimated to be 480.31 kW, which accounts for 10.22% compared with the technical potential of the residential measures that had a value of 4.7 MW.

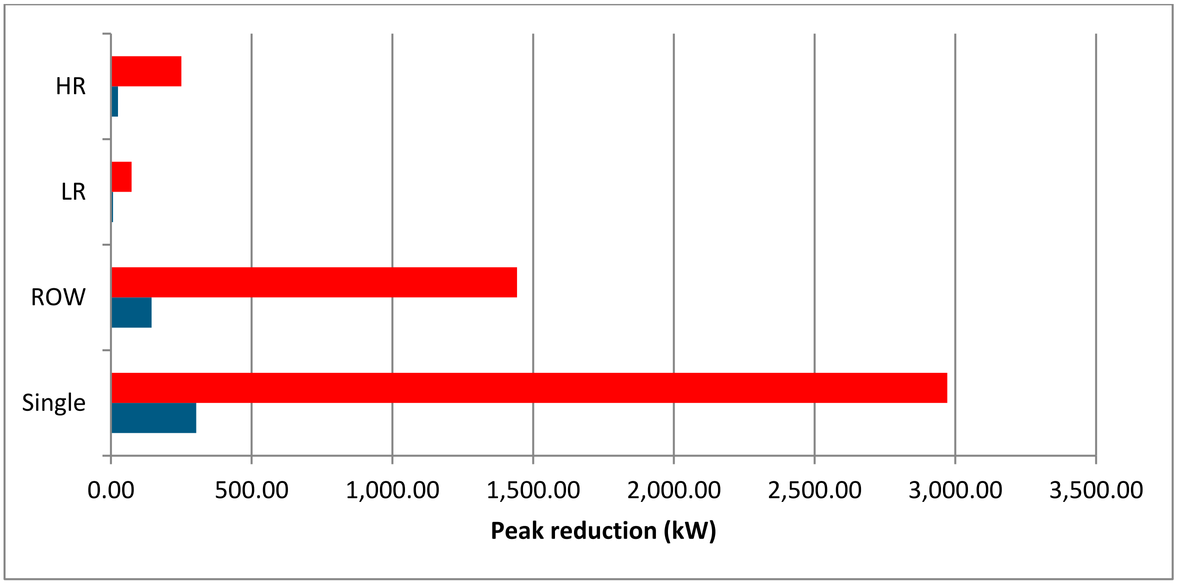

Figure 2-1 Technical and Achievable Potential Peak Reduction by Residential Subsector in 2023

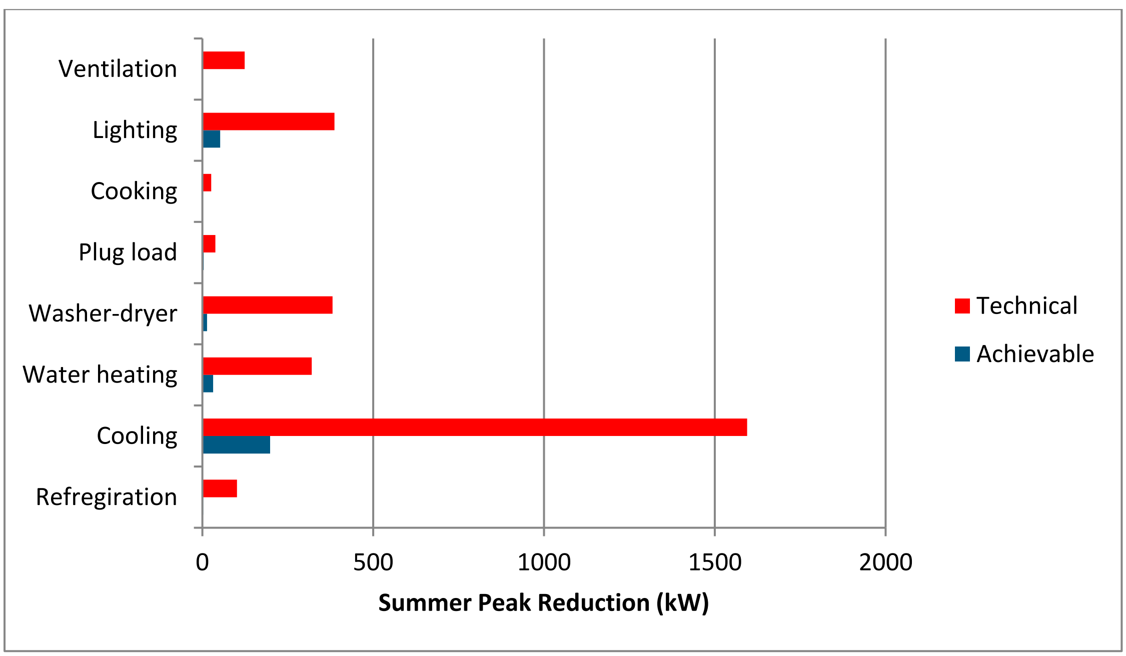

Figure 2-2 Technical and Achievable Potential Peak Reduction by End-use in 2023, Single-family

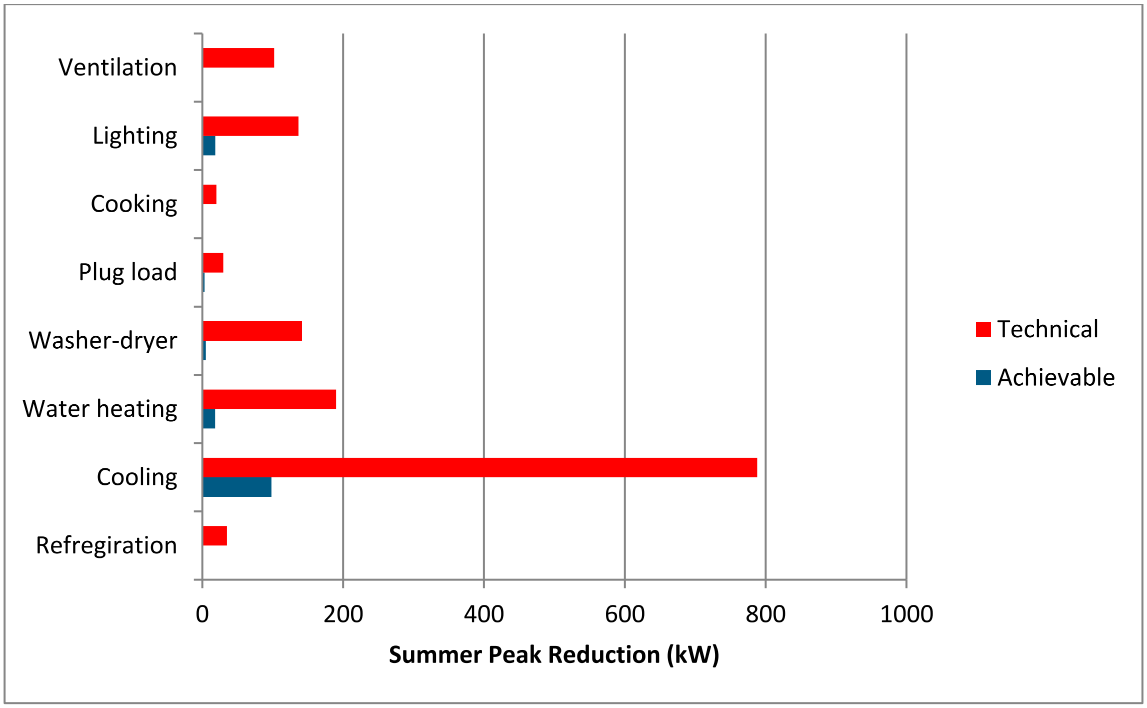

Figure 2-3 Technical and Achievable Potential Peak Reduction by End-use in 2023, Row

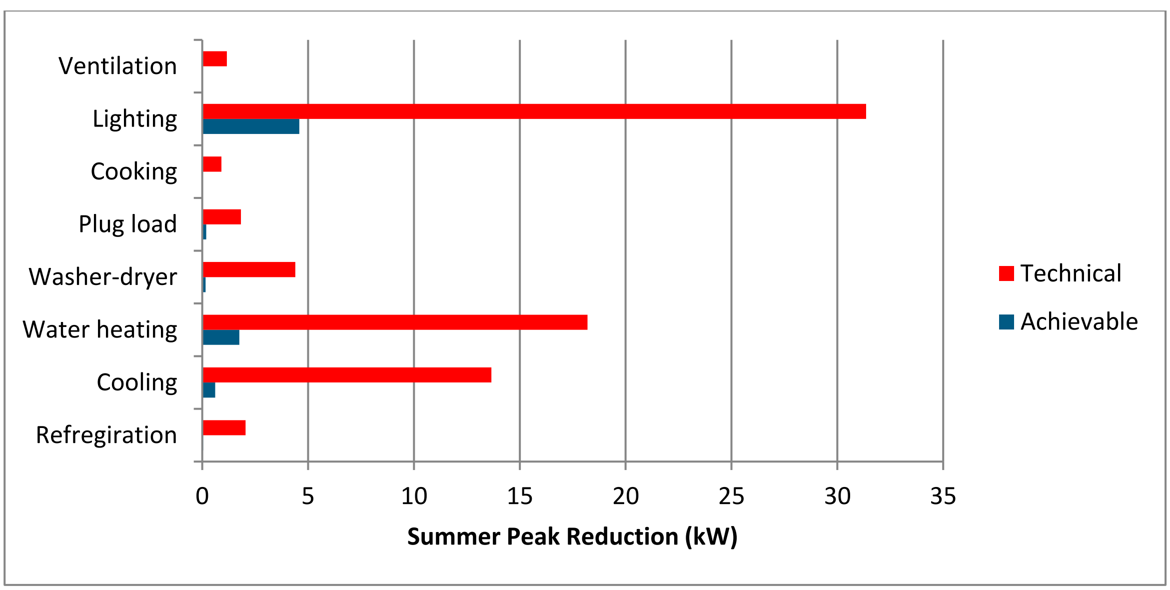

Figure 2-4 Achievable Potential Peak Reduction by End-use in 2023, Low Rise

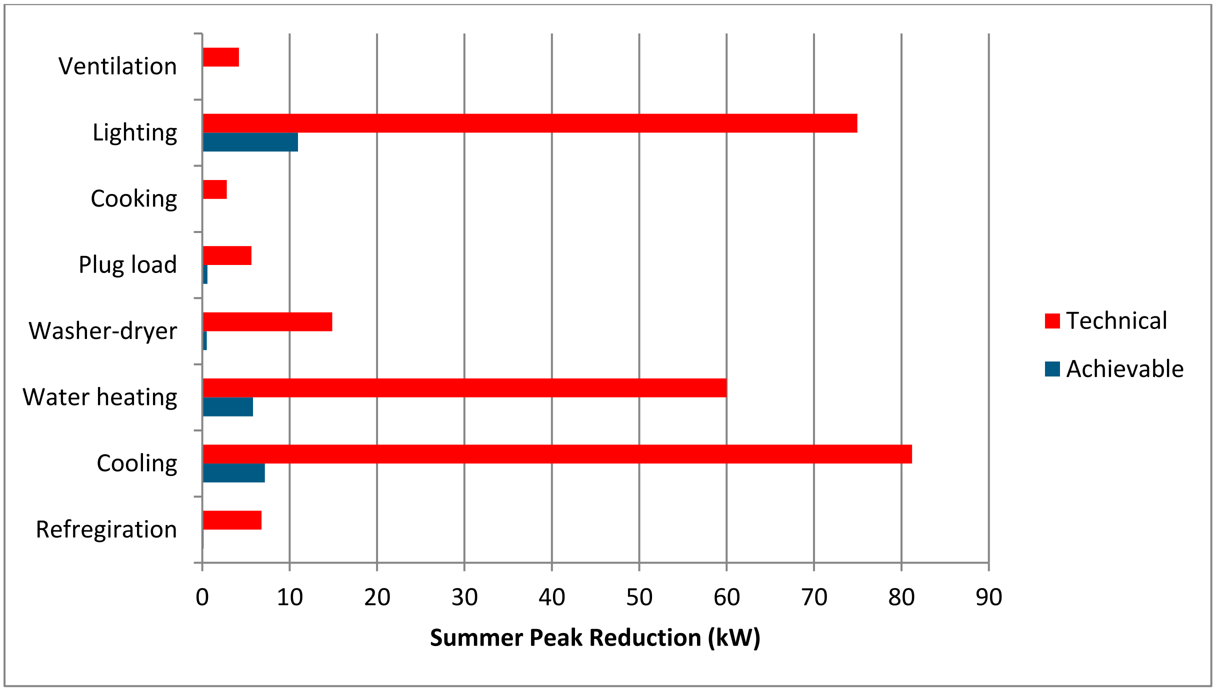

Figure 2-5 Achievable Potential Peak Reduction by End-use in 2023, High Rise

2.3.2 Commercial Sector

The achievable potential peak reduction is calculated for each competition group of the commercial subsector/ end-use, and the total achievable potential peak reduction is calculated for each subsector and end-use. Figure 2-6 shows the technical and achievable potential summer peak reduction for each subsector; the largest achievable potential was estimated for the office subsector, which accounts for 57.58 % of the total peak reduction in 2023 followed by the food stores subsector that accounts for 14.48%. Figure 2-7 shows the total reductions per commercial end-use; the lighting end-use represents the largest peak reductions of 60.51% of the total reductions. The total achievable commercial summer peak reduction in 2023 was estimated to be 6011.57 kW.

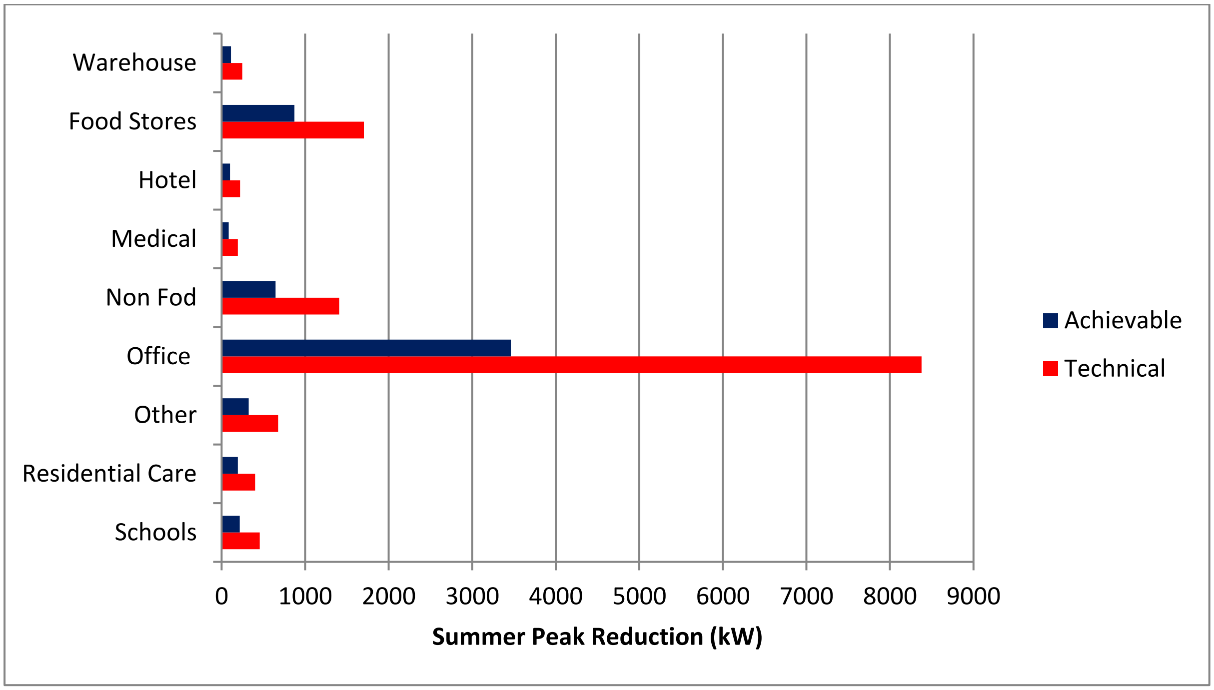

Figure 2-6 Technical and Achievable Potential Peak Reduction by Commercial Subsectors in 2023

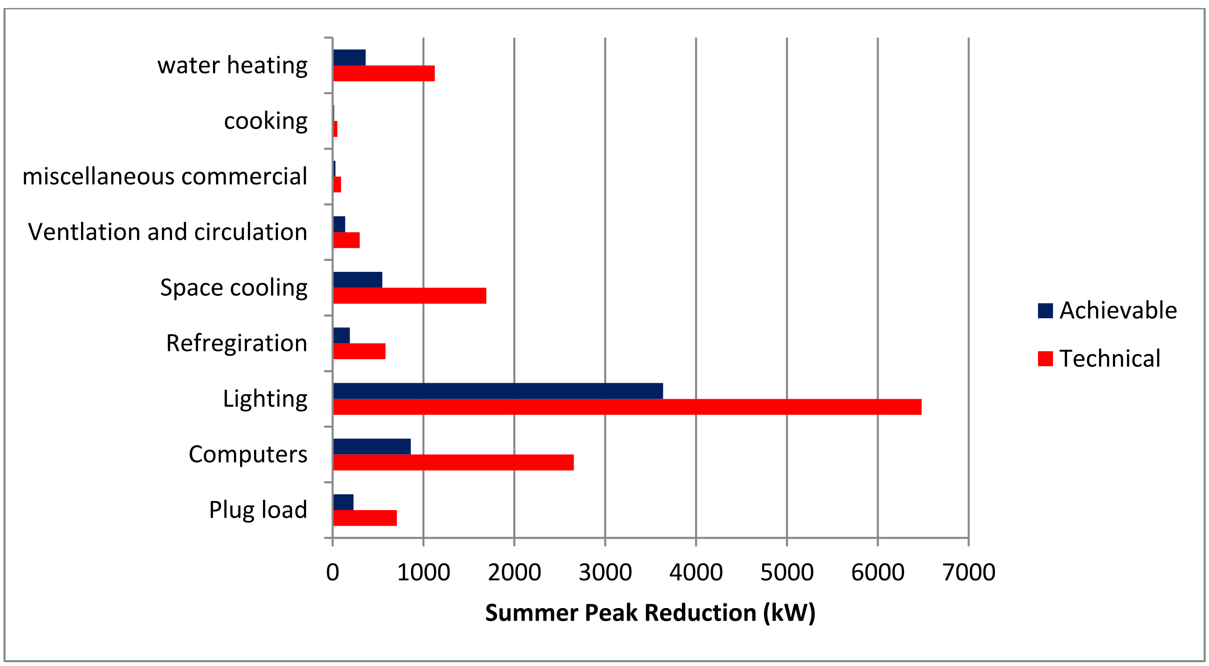

Figure 2-7 Technical and Achievable Potential Peak Reduction by End-use, Commercial Sector

3 Cost Analysis of Load Shifting Measures

The project team analyzed the possibility of load shifting using the Battery Energy Storage (BES) system. This analysis was performed for two scenarios; i.e., utility-scale and large customers-scale. In Milestone #2, the technical potential for using a battery owned by HOL and installed at the substation was determined. Moreover, the technical potential for installing batteries owned by large customers greater than 1000 kW was also determined. For each scenario, two cases were studied; i.e., batteries that are capable of discharging for 4 or 6 hours. In this section, the cost analysis for the BES is analyzed as will be illustrated in the next subsections.

3.1 Customer-Scale Battery Energy Storage

The presented methodology, in this section, aims to determine the level of incentive required for the BES project investment to be profitable, for the customer-scale BES. The concept of a minimum attractive rate of return (MARR) is selected for achieving the objective. If the internal rate of return (IRR), i.e., the rate of return that yields zero present worth value of cash flow, of the project is equal to or higher than the MARR, the project is considered profitable. The income of the BES investment is calculated at different levels of incentives, and the minimum level of incentives is determined. This minimum incentive level is the value that makes the IRR equal to MARR. For accurate economic assessment of the BES project; cash flow is performed. The following procedure is used to calculate the minimum incentives of the BES:

1) Calculate the battery capital cost (Cap) using (1)

$$Cap = [Capitalcost] - [(Incentives — kWh) \times batterycapacity] \tag{1}$$

2) Calculate the income per year for the project lifetime using (2), considering the BES rated capacity as base power.

$$Inc\ (y) = \sum_{m=1}^{12} \Delta Peakofmonth \times demandpeakrate] \tag{2}$$

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (3)

$$C(y) = \frac{Inc\ (y)}{(1 + inflationindex)^y} \tag{3}$$

4) Calculate the minimum incentives/kW of the BES project capacity using (4); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$NPV = Cap - \sum_{y=1}^{N} \frac{C(y)}{(1 + MARR)^y} = 0 \tag{4}$$

3.1.1 Case Study

For the customer-scale BES, presented in the Milestone #2 report, the customer with reference number 1323516000 was selected. The maximum load of this customer was 1,013 kW with BES of capacity 129.6kW and 181kW for the 4-hour and 6-hour case, respectively. The technical peak reduction was found to be 72.9 and 82 kW for the 4-hour and 6-hour case, respectively.

The economic analysis presented in the previous procedure is executed based on an average capital cost of $410,391 and $573,155 for the 4-hour and 6-hour case, respectively [3]. The MARR is set to 7%. The income is calculated based on the average regulated price plan for small business in HOL [4]. The inflation rate is set to 2.4% [5], the cash flow is calculated as presented in Table 3-1 and the required incentives to achieve the 7% MARR for the 4-hour and 6-hour cases are $406,102 and $568,330 which means the incentive range between $ 5570-6930 per kW peak reduction. These incentives are significantly high relative to the corresponding savings and are not economically viable. As a result, the customer-scale BES will be excluded from the achievable potential analysis as discussed with HOL and IESO in the meeting held on July 4th, 2019.

Table 3-1 Cash Flow for Customer-Scale BES

	4-Hour Case				6-Hour Case			
Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	410391				573155			
1		386.66	379.08	354.28		434.93	426.40	398.50
2		399.73	384.19	335.57		449.61	432.15	377.46
3		412.76	388.96	317.50		464.29	437.51	357.14
4		425.82	393.39	300.11		478.97	442.49	337.58
5		438.87	397.49	283.41		493.65	447.11	318.79
6		451.92	401.29	267.40		508.33	451.38	300.77
7		464.97	404.78	252.08		523.01	455.31	283.54
8		478.02	407.98	237.45		537.69	458.91	267.09
9		491.07	410.91	223.51		552.37	462.20	251.41
10		504.12	413.56	210.23		567.05	465.18	236.47
11		517.17	415.94	197.61		581.73	467.86	222.28
12		530.22	418.08	185.63		596.41	470.27	208.80
13		543.28	419.97	174.27		611.09	472.39	196.03
14		556.33	421.63	163.51		625.77	474.26	183.92
15		569.38	423.06	153.33		640.45	475.86	172.48
16		582.43	424.27	143.71		655.13	477.23	161.65
17		595.48	425.27	134.63		669.81	478.35	151.43
18		608.53	426.07	126.06		684.49	479.25	141.79
19		621.58	426.67	117.98		699.17	479.93	132.71
20		634.63	427.09	110.37		713.85	480.40	124.15
PV of Adjusted Income Considering MARR (A)				4288.65	PV of Adjusted Income Considering MARR (A)			4824
Capital Cost (B)				410391	Capital Cost (B)			573155
Incentive (B)-(A)				406102	Incentive (B)-(A)			568330
Peak Reduction kW				72.9	Peak Reduction kW			82
Incentive $/KW of peak reduction				5570	Incentive $/KW of peak reduction			6930

3.2 Utility-Scale Battery Energy Storage

The total system peak for the year 2023 was analyzed in Milestone #2, and the potential for peak reduction using substation-scale battery storage was determined for the 4-hour and 6-hour batteries. For utility-scale BES, no incentives will be provided since the BES is owned by HOL, and hence, only the economic analysis will be analyzed for this scenario.

The adequate battery size for the 4 hour scenario was 9,846 kWh, which can reduce the system peak by 3.782 MW. For the 6 hour scenario, the battery size was 31,216 kWh, which can reduce the system peak by 7.607 MW.

An example indicative order of magnitude capital costs for implementing distribution scale lithium-ion batteries to meet the requirements is summarized in Table 3-2. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 for the 4-hour and 6-hour scenarios, respectively. The estimate is built based on recent budgetary quotes received for a project of similar nature, and the average cost of $/kW and $/kWh are within the ranges published in [3]. It is to be noted the price is very sensitive for the battery cost and in this example the cost is estimated at C$ 390/kWH for Li batteries.

Estimates published by various resources suggested decline price for the LI batteries as the market of storage increase.

Table 3-2 Distribution Scale Battery Installation Cost

Scenario	4-Hour Scenario	6-Hour Scenario
Proposed Capacity Rating	3.75 MW	7.5 MW
Proposed Duration	4 Hrs	6 Hrs
MWH	15	45
Total Energy Storage System Cost		
KWh Driven		
DC Modules & BMS Equipment (excl. PCS)*	5850000	17550000
General conditions, EPC & Commissioning	2,000,000	2,000,000
KW Driven		
Power Conversion System Equipment	750,000	1,500,000
Electric BoS	125,000	250,000
General conditions, EPC & Commissioning	750,000	1,250,000
Misc.	100,000	100,000
Total Cost	9,575,000	22,650,000
Avg. Cost $/KWh	638	503
Avg. Cost $/KW	2553	3020

Assuming the cost of Li-Battery is 390CAD/KWh

4 Economic Analysis of DG Measures

The presented methodology, in this section, aims to determine the level of incentive required for the DG project investment to be profitable and to calculate the achievable potential for the DG measures.

The concept of MARR is selected for determining the level of incentives. The income of the DG investment is calculated, and the minimum level of incentives is determined. For accurate economic assessment of the PV DG project; cash flow is performed. The proposed algorithm for the minimum incentive level determination is discussed as detailed below in section 4-1 and 4-2, while the achievable potential calculation is discussed in section 4-3.

4.1 PV DGs installed on residential rooftops

The following procedure is used to calculate the minimum incentives of the residential scale PV DGs:

1) Calculate the DG capital cost (Cap) using Equation (5)

$$\mathrm{Cap} = [\mathrm{Capital\ cost}/\ \mathrm{kW} \times\ \mathrm{DG\ Capacity}] - [\mathrm{Incentives}\ /\ \mathrm{kW} \times \mathrm{DG\ Capacity}] \tag{5}$$

2) Calculate the income per year for the project lifetime using (7), considering the DG rated capacity as base power.

$$\mathrm{Inc}\ (\mathrm{y}) = \sum_{\mathrm{m}=1}^{12} \sum_{\mathrm{hr}=1}^{24} [\mathrm{E_g}(\mathrm{y}, \mathrm{m}, \mathrm{hr}) \times \mathrm{P_r}(\mathrm{m}, \mathrm{hr})]\ \times\ \mathrm{N_d}(\mathrm{m}) \tag{6}$$

Where Inc (y) is the DG project income for certain year (y), Eg (y,m,hr) is the DG generated energy at certain hour (hr) at certain month (m) for a certain year, Pr (m, hr) is the time of use (TOU) electricity rates at certain hour at certain month and Nd (m) represents the number of days per month (m).

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (7)

$$\mathrm{C}(\mathrm{y}) = \frac{\mathrm{Inc}\ (\mathrm{y})}{(1 + \mathrm{inflation\ index})^{\mathrm{y}}} \tag{7}$$

4) Calculate the minimum incentives/kW of the DG project capacity using (8); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$\mathrm{NPV} = \mathrm{Cap}\ - \sum_{\mathrm{y}=1}^{\mathrm{N}} \frac{\mathrm{C}(\mathrm{y})}{(1 + \mathrm{MARR})^{\mathrm{y}}} = 0 \tag{8}$$

Where NPV is the net present value, and N is the project lifetime.

4.1.1 Case Study

For the PV DGs installed on the single-family house, presented in the Milestone #2 report, the PV DG installed capacity is 8.68 kW with annual generated energy of 9.231 MWh. This generated energy is still lower than the average annual electricity consumption for a single house (9652 MWh; obtained from Milestone #1 load segmentation report). This means according to the net energy metering, the PV DG will not inject any energy to the grid, and all the generated energy will be used to lower the electricity bill. Based on the average capital cost of 2.53 $/W [6], the economic analysis presented in the previous procedure is executed with a MARR of 7%. The income is calculated based on the generated energy/hr, residential electricity price as per [7], and an inflation rate of 2.4%. The cash flow is calculated as presented in Table 4-1, and the required incentives to achieve the 7% MARR is 9,867$, which means the incentives per installed kW is 1140.76 $/kW.

Table 4-1 Cash Flow for PV Installed on Residential Rooftop

Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	21960.4			
1		1039.20	1018.83	952.17
2		1084.36	1042.26	910.35
3		1131.49	1066.23	870.36
4		1180.66	1090.75	832.13
5		1231.97	1115.83	795.57
6		1285.51	1141.49	760.62
7		1341.37	1167.74	727.21
8		1399.66	1194.60	695.27
9		1460.49	1222.07	664.73
10		1523.96	1250.18	635.53
11		1590.19	1278.93	607.61
12		1659.29	1308.34	580.92
13		1567.98	1212.10	502.98
14		1659.29	1257.54	487.69
15		1659.29	1232.88	446.85
16		1576.23	1148.20	388.94
17		1559.73	1113.90	352.63
18		1551.48	1086.28	321.39
19		1543.22	1059.32	292.91
20		1534.97	1032.99	266.94

4.2 PV DGs installed on commercial buildings

The following procedure is used to calculate the minimum incentives of the commercial-scale PV DGs:

1) Calculate the DG capital cost using (9)

$$Cap = [Capitalcost/\, kW \times DGCapacity] - [Incentives\, /\, kW \times DGCapacity] \tag{9}$$

2) Calculate the income per year for the project lifetime using (10), considering the DG rated capacity as base power.

$$Inc\ (y) = \sum_{m=1}^{12} [E_g(m) \times [A_{WPR}(m)] \tag{10}$$

$E_G(m)$ is the DG generated energy for certain month (m) for a certain year, $A_{WPR}(m)$ is the averaged weight hourly price at certain month m.

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (11)

$$C(y) = \frac{Inc\ (y)}{(1 + inflationindex)^y} \tag{11}$$

4) Calculate the minimum incentives/kW of the DG project capacity using (12); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$NPV = Capcost - \sum_{y=1}^{N} \frac{C(y)}{(1 + MARR)^y} = 0 \tag{12}$$

4.2.1 Case Study

For the PV DGs installed on commercial buildings, presented in Milestone #2 report, the PV DG installed capacity is 58.5 kW with annual generated energy of 73.79 MWh. This generated energy is still lower than the average annual electricity consumption for a single commercial building. This means according to the net energy metering, the PV DG will not inject any energy to the grid, and all the generated energy will be used to lower the electricity bill. Based on the average capital cost of 2.53 $/W, the economic analysis presented in the previous procedure is executed. The MARR is set to 7%. The income is calculated based on the energy price in Ontario [7], and on the inflation rate of 2.4%, the cash flow is calculated as presented in Table 4-2, and the required incentives to achieve the 7% MARR is $ 129,442 which means the incentives per installed kW is 2200 $/kW.

Table 4-2 Cash Flow for PV Installed on Commercial Rooftop

Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	21960.4			
1		1742.01	1707.85	1596.12
2		1800.81	1730.88	1511.82
3		1859.60	1752.35	1430.44
4		1918.40	1772.31	1352.08
5		1977.20	1790.81	1276.82
6		2036.00	1807.91	1204.69
7		2094.80	1823.65	1135.68
8		2153.60	1838.07	1069.78
9		2212.40	1851.23	1006.95
10		2271.19	1863.17	947.14
11		2329.99	1873.93	890.29
12		2388.79	1883.54	836.32
13		2447.59	1892.07	785.14
14		2506.39	1899.53	736.67
15		2565.19	1905.97	690.81
16		2623.98	1911.43	647.47
17		2682.78	1915.94	606.54
18		2741.58	1919.54	567.92
19		2800.38	1922.27	531.52
20		2859.18	1924.14	497.24

4.3 Achievable Potential of PV DGs

The project team identified the DERs contract capacity as well as the potential for expansion based on the input data received from the HOL and IESO in Milestone #1. The installed DER capacity at Kanata-Marchwood was given as 1.1498 MW, and it is forecasted to be at the same level in 2023 based on the current DERs programs and incentives offered in Ontario. Given the capital cost of the DERs as 2.53 $/W, the total cost of the installed capacity is $ 2,908,994. The installed capacity (1.1498 MW) would reduce the summer peak demand by 0.3603 MW as illustrated in Milestone # 2 report, and hence the unit cost of peak reduction associated with the PV DGs is calculated as follows:

$$\text{Unit cost}\left(\frac{\$}{\text{kW}}\right) = \frac{\text{Incremental life cost}}{\text{Summer peak demand savings per unit (kW)}} = \frac{2{,}908{,}994}{360.3059} = 8073.67\ \$/\text{kW} \qquad (13)$$

5 Cost Curve

The cost curve is constructed based on the unit peak demand reduction cost of all the CDM measures, under the achievable potential scenario.

The curve shows each measure as a step in the curve, with the horizontal length of each step indicating the peak demand reduction of the measure and its height above the horizontal axis indicates how much it costs per unit of reduction. Measures are sorted in order of increasing cost.

The advantage of developing a cost curve is that the overall cost-effective potential can be estimated using one graph as illustrated in Figure 5-1 for the residential CDM measures.

The unit cost of the commercial CDM measures is still under development as we are missing the unit cost associated with the measures of the 2016's APS provided by the IESO. The availability of the unit cost data will be discussed with IESO during the next meeting

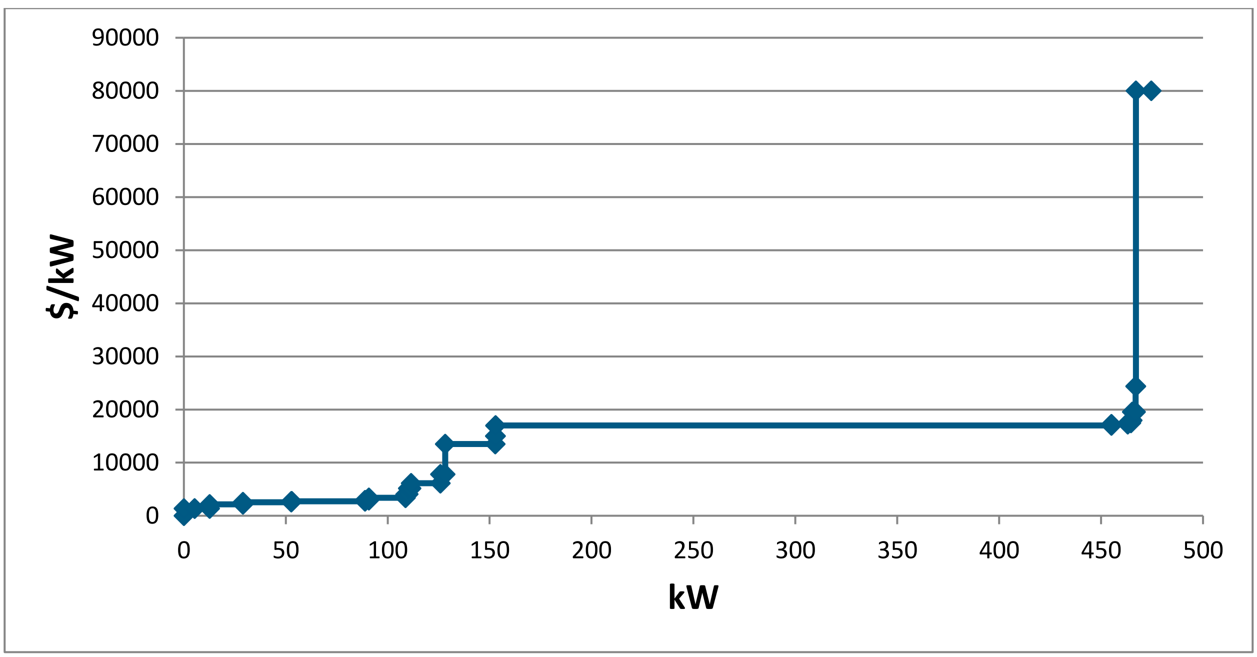

Figure **5-1 Cost Curve of Residential CDM Measures**

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Appendix A

Calculation of Achievable Potential Example

This Appendix presents an example for the calculation of the achievable potential of the peak demand reduction. One example is for the peak reduction within the competition group freezer. Table A-1 and Table A-2 summarize the data obtained from Milestone #2 for the freezer measure.

Table A-1 Freezer Data

Sector	Conservation measure	Summer Peak Demand Reduction (kW)	Base Case kW	Base Case kWh	Incremental Life Cycle Cost ($)
Consumer	Fixture	0.014	0.056	491.25	273.50

Table A-2 Freezer Data

Sector Single	Single	Row	Low Rise	High Rise
Measure Base Share	30.90%	30.10%	16.50%	16.50%
Consumption (MWh)	8313.373	2916.292	189.7909	628.1477
Remaining Factor	65.45%	65.45%	65.45%	65.45%

The kW savings are calculated using Equations A-1

$$\begin{aligned}\text{Savings (kW)} \\ &= \text{Measure Base Share} \times \text{Consumption (MWh)} \times \text{Remaining factor} \times 1000 \\ &\times \text{Summer Peak Demand Savings} \div (\mathit{Base\ Case\ kWh})\end{aligned} \tag{A1}$$

The number of units, the unit cost per kW, and the total cost are calculated using Equation (A2), (A3), and (A4), respectively

$$\begin{aligned}\text{Number of units} &= \frac{\text{Savings (kW)}}{\text{Summer peak demand savings per unit (kW)}} \\ &= \frac{\text{Savings (kWh)}}{\text{Firstyear energy savings per unit (kWh)}}\end{aligned} \tag{A2}$$

$$\text{Unit cost } (\frac{\$}{\text{kW}}) = \frac{\text{Incremental life cost}}{\text{Summer peak demand savings per unit (kW)}} \tag{A3}$$

$$\text{Total cost} = \text{Incremental life cost} \times \text{number of units} \times \text{Summer peak demand savings per unit (kW)} \qquad \text{(A4)}$$

The results are summarized in Table A-3.

Table A-3 Freezer kW savings

	Single	Row	Low Rise	High Rise	Sum
kW savings	47.912304	16.372268	0.5840779	1.9331122	66.8018
Number of units	3422.307	1169.448	41.71985	138.0794	4772
Unit cost ($/kW)	$19,535.71				
Total cost	$936,101.23	$319,878.18	$11,411.60	$37,768.77	$1,305,159.78

The number of eligible populations is determined as follows:

$$\text{Eligible population} = \frac{\text{Number of base units}}{\text{Effective useful life}} \text{(A5)}$$

Table A-4 shows the eligible freezer population estimated using Eq (A5)

Table A-4 Eligible Population of Freezer

	Single-Family	Row	LR	HR	Sum
Eligible Population	475.3821	162.4444	5.795175	19.18019	662.8018628

The actual number of adopters, which is obtained from solving the bass model, the equation given in (A6).

$$n(t) = \frac{dN(t)}{dt} = m\,\frac{p\,(p+q)^2 e^{-(q+p)t}}{(p+q\,e^{-(q+p)t})^2} \qquad (A6)$$

The values of p, q, and m parameters are estimated for each of the adoption curves using statistical analysis of Ontario historic program participation data. After the estimation of p, q, and m, the forecasting of the number of adopters per year is achievable, and hence, the development of the adoption curve, as shown in Figure A-1.

As shown in Figure A-1, the market share at 2023 is 2.28 % of the eligible population; therefore, the achievable potential is given by:

$$Achievable\ Potential = \frac{Technical\ Potential \times Number\ of\ adopters\ at\ 2023}{Eligible\ Population} \tag{A7}$$

$$= \frac{145.1 \times 2.28}{100\%} = 3.319\ kW$$

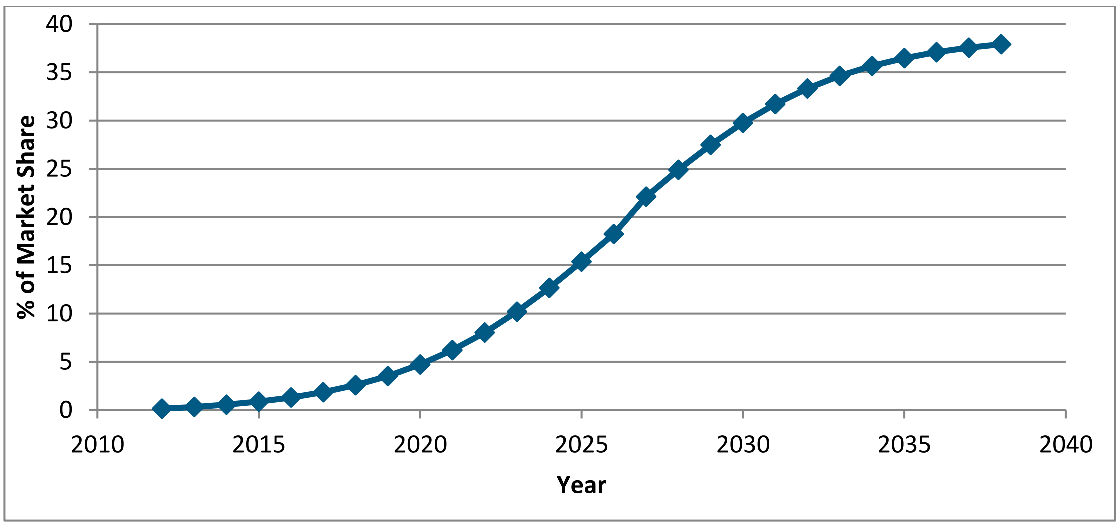

Figure **A-1** Adoption Curve for Freezer Measure

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TECHNOLOGY ROADMAP AND AMI STRATEGY

SUMMARY REPORT

Hydro Ottawa

25 MARCH 2019

BLACK & VEATCH
Building a world of difference.

Table of Contents

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Executive Summary

SUMMARY OF KEY FINDINGS

Black & Veatch's began working with Hydro Ottawa (HOL) in November 2018 to develop the AMI Strategic Plan and Roadmap. Our approach consisted of five main tasks as shown in the below figure.

Figure 1 - Methodology

The key activities are summarized in the table below.

DATE	ACTIVITIES
November 1, 2018	• Project Kick-off • Meetings to review existing IT/OT systems
November 8, 2018	• Executive Leadership Strategy Discussion
November 27 – 28, 2018	• AMI Opportunity Discovery Workshops o Customer Care o Distribution Automation o Market Engagement o Metering
December 6, 2018	• Regulatory Discovery Workshop
January 17, 2019	• AMI Technology & Vendor Overview • Honeywell Discovery Meeting
February 5 – 6, 2019	• Various AMI and communication vendor meetings and demonstrations at DistribuTech with HOL participation
February 22, 2019	• Review of AMI Roadmap & Business Release

Figure 2 - Program Activities

AMI STRATEGY RECOMMENDATIONS

AMI Strategy Framework

Black & Veatch developed a recommended sequence of strategic steps that HOL might take to prudently address the remaining and new opportunities of AMI. The strategic steps (or phases) formed the basis of the Technology Roadmap which are depicted in the strategic framework diagram below.

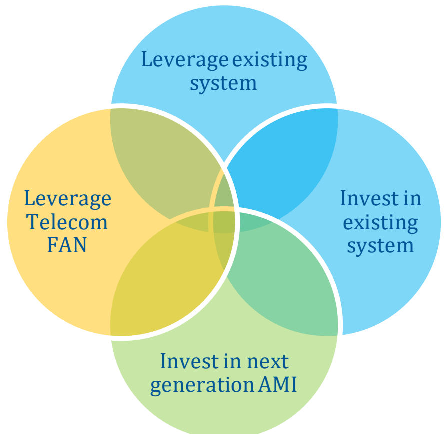


Figure 3 – AMI Strategy Framework

The phases developed were influenced and shaped based on our understanding of several factors:

- Understanding of the current system operation and functionality,
- The desired and prioritized opportunities and requirements discovered in the workshops, and
- The influence of the HOL Telecom Plan.

The AMI related opportunities were mapped to the four identified phases with the exception of those that were already achieved.

Thus, the four key phases of the AMI Roadmap can be characterized as follows:

1. Capabilities that can be enabled with existing Honeywell AMI system (REX1/REX2 meters, existing mesh network nodes, existing backhaul, existing HES) but which require changes to downstream systems	2. Incremental investments in existing AMI system (selective replacement of existing meters or other low volume field devices, network collectors, backhaul, HES) to mitigate obsolescence risks and enable high value capabilities	3. Investment in operational capabilities which may be enabled by the planned FAN network	4. Re-investment in AMI replacement technology to enable benefits dependent on mass meter replacement or other endpoint deployments
• Applications that do NOT require any significant changes to the existing AMI system • Provides capabilities and benefits through downstream system releases	• Upgrade of headend system to mitigate support risk and enable transition to REXU meter to avoid meter production obsolescence • Applications that may require limited replacements of field devices, or upgrades to the existing AMI network and/or head end • Provides high value benefits while bridging to future AMI Solution	• Applications that may be more efficiently addressed by direct communications to endpoints via the planned FAN network • Provides benefits that may be dependent on final Telecom FAN plan	• Applications that require replacement of AMI system, including electric meters or deployment of DA (or other) dedicated network and endpoints • Dependent on meter population depreciation (to avoid stranded assets), Measurement Canada new requirements, AMI vendor strategies, and Final HOL FAN plan

Figure 4 - AMI Strategy Phases

Key dependencies such as the HOL Telecom plan, meter depreciation schedules, and future Meter Canada requirements were factored into the AMI Technology Roadmap timing and implementation sequence.

Additionally, key components of the HOL AMI System are reaching end of life or becoming obsolete due to advances in technology and changing business requirements. The key components include the EnergyAxis headend system v9.x which is scheduled to be at end of support life in Q2 2019, REX2 meters that are near end of production (no date confirmed yet from Honeywell), and REXU replacement meters that would require an upgraded headend system. Thus, mitigating the risk of system obsolescence (i.e. lack of system support) and meter product obsolescence (discontinued production availability) is also an important dependency on the timing and sequencing of the four phases. With these key dependencies considered, the Roadmap logically becomes sequenced in the following strategy:

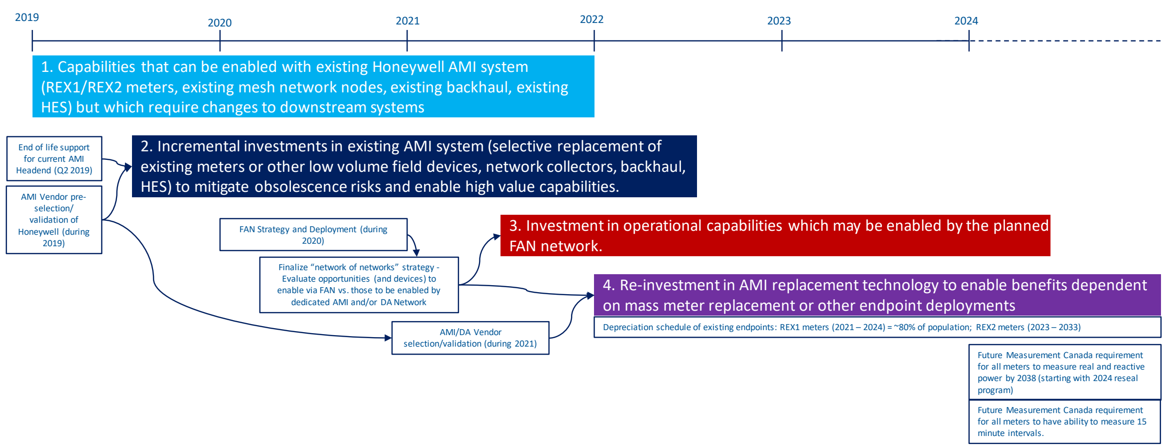


Figure 5 - AMI Strategy Sequence and Timing

Within each phase, opportunities are further described as Business Releases. Additional details on the potential business releases contained within each phase are provided below and further explained in the Recommendation Details section.

Business Release Plan

The functional requirements and IT system impacts that were identified with each opportunity were integrated into logical groupings of system development initiatives (or business releases). These business releases combined related capabilities, enhancements, or synergistic system work efforts to describe likely IT/OT system development efforts required to enable the desired AMI opportunities.

It is important to note that the business releases within each phase are not presented in any particular sequence or order of priority. Thus, each business release within each phase should be evaluated independently and planned for in an appropriate time period.

A summary of the business release plan and systems impacted during each release is shown in the following table.

Business Release 1 - Leverage Existing AMI System		
a. Billing System Enablement b. Data Analytics + Distribution Modeling c. Outage Reporting Metrics d. Customer Usage Analytics + Enhanced Customer Portal e. Forecasting + Rate Design	Analytics Billing System MDMS CSR and Customer Portal	Planning & Forecasting OMS Dispatch / MTU GIS
Business Release 2 - Incremental Investment in Existing AMI System		
a. Enhanced Operational Processes b. Outage Management using AMI Data c. Enhanced Data Analytics d. Customer Portal + In-Home Data Device e. Upgrade AMI Headend	Analytics Billing System CSR and Customer Portal IVR	AMI Headend OMS Dispatch / MTU GIS
Business Release 3 - Alternative FAN / System Communication Technologies		
a. DERMS Implementation b. DA/DMS c. Smart City Sensor Integration d. DERMS and DA Integration	Analytics	DMS DERMS Dispatch / MTU GIS
Business Release 4 - Replacement AMI Solution		
a. AMI Replacement b. Data Analytics + DMS/OMS Enhancements c. Planning & Forecasting d. Enhancements to Billing + MDMS + Customer Portal	Analytics Billing System MDMS CSR and Customer Portal	Planning & Forecasting OMS Dispatch / MTU

Figure 6 - Business Releases by Phase

AMI Roadmap Phases and Business Releases

Phase 1 - Leverage existing investments

Phase 1 is focused on extending the use of data and information already available from HOL's current Honeywell AMI system. It involves enhancements to downstream systems to extract additional value and enable opportunities from the existing AMI solution.

The Phase 1 business releases are focused on expanding upon and enabling the opportunities that can be accomplished using the existing AMI system.

Recommendations for enabling Phase 1 opportunities by business release are shown in the below table.

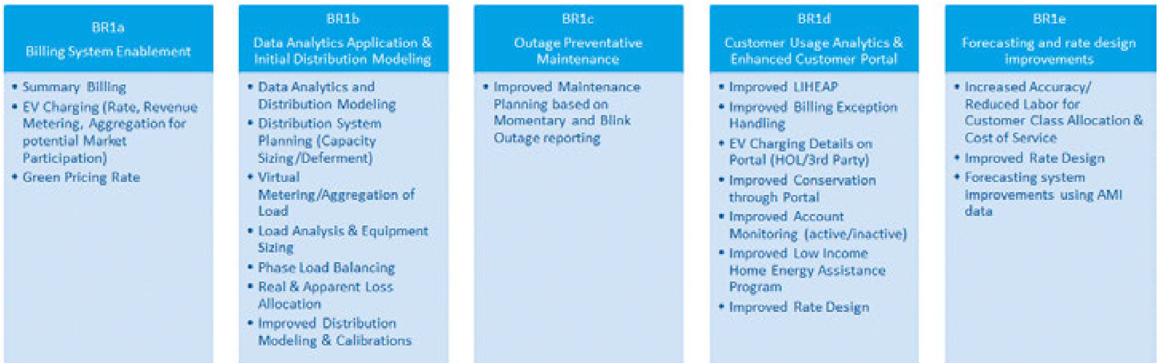


Figure 7 - Phase 1 Business Releases

Phase 2 - Incrementally invest in existing system

Phase 2 is focused on additional opportunities that can be leveraged from the existing Honeywell AMI system through incremental and selective investments to upgrade or enhance the existing system. The AMI Roadmap recommends that HOL conduct an RFI or other appropriate exercise to validate the value of each incremental investment as these may result in short term investments only pending the final solutions from Phase 3 based on the HOL Telecom FAN and/or from Phase 4 which contemplates a complete AMI system replacement.

The Phase 2 business releases are focused on enabling the opportunities that can be accomplished with incremental investments in the AMI infrastructure. These investments include upgrading the AMI headend, replacing the backhaul communications on all collectors to cellular, fiber, or other communication technologies as recommended in the HOL Telecom FAN Plan.

Recommendations for enabling Phase 2 opportunities by business release are shown in the below table.

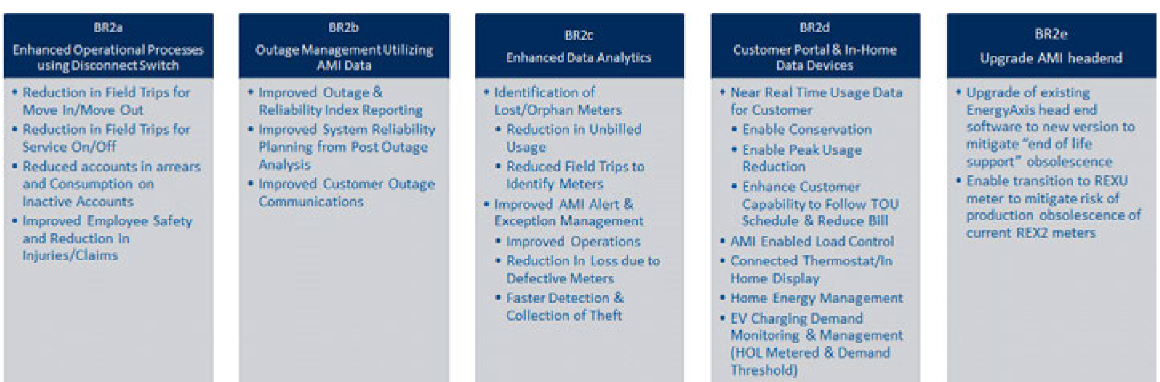


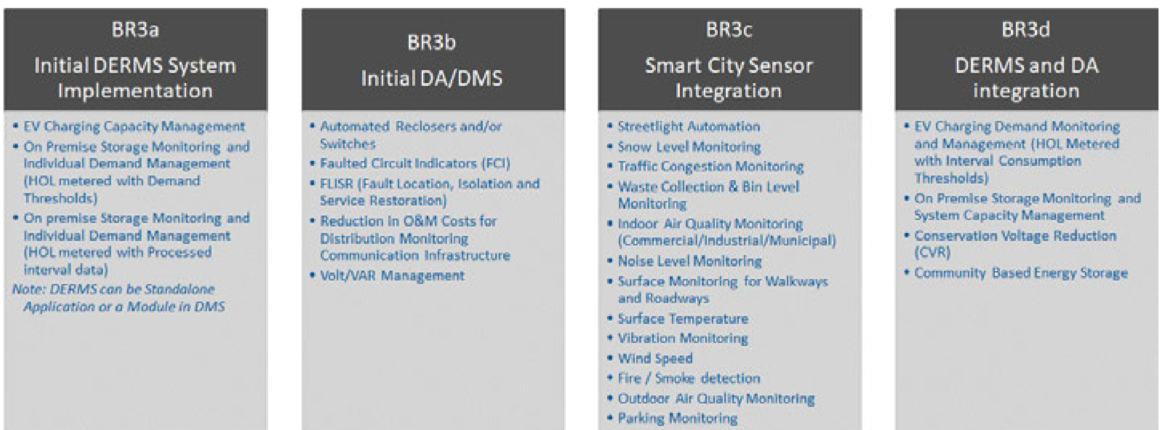
Figure 8 - Phase 2 Business Releases

Phase 3 - Leverage Telecom FAN

Phase 3 is focused on opportunities that may leverage the planned HOL Telecom FAN implementation.

The Phase 3 business releases are focused on enabling smart grid applications such as smart city sensors, distribution automation, volt/var control, EV charging control, distributed energy resource management, demand response and load control. The primary dependency for the opportunities identified in Phase 3 is the plans for the implementation of the Telecom Plan FAN network, the timing of that implementation, and the extent to which the HOL FAN is expected to serve as a backhaul network for AMI and DA systems (i.e. a "network of networks" strategy) or the FAN is expected to serve as the primary network which provides end-to-end connectivity to specific endpoint devices (such as AMI meters, DA devices, in home devices, etc.).

Recommendations for enabling Phase 3 opportunities by business release are shown in the below table.



BR3a Initial DERMS System Implementation	BR3b Initial DA/DMS	BR3c Smart City Sensor Integration	BR3d DERMS and DA integration
• EV Charging Capacity Management • On Premise Storage Monitoring and Individual Demand Management (HOL metered with Demand Thresholds) • On premise Storage Monitoring and Individual Demand Management (HOL metered with Processed interval data) *Note: DERMS can be Standalone Application or a Module in DMS*	• Automated Reclosers and/or Switches • Faulted Circuit Indicators (FCI) • FLISR (Fault Location, Isolation and Service Restoration) • Reduction in O&M Costs for Distribution Monitoring Communication Infrastructure • Volt/VAR Management	• Streetlight Automation • Snow Level Monitoring • Traffic Congestion Monitoring • Waste Collection & Bin Level Monitoring • Indoor Air Quality Monitoring (Commercial/Industrial/Municipal) • Noise Level Monitoring • Surface Monitoring for Walkways and Roadways • Surface Temperature • Vibration Monitoring • Wind Speed • Fire / Smoke detection • Outdoor Air Quality Monitoring • Parking Monitoring	• EV Charging Demand Monitoring and Management (HOL Metered with Interval Consumption Thresholds) • On Premise Storage Monitoring and System Capacity Management • Conservation Voltage Reduction (CVR) • Community Based Energy Storage

Figure 9 - Phase 3 Business Releases

Phase 4 - Invest in next generation AMI

Phase 4 opportunities are based on the potential complete replacement of the AMI solution. It involves upgraded systems, networks, and all meters. Thus, this phase is dependent on the resolution of the HOL Telecom FAN plan, it's ultimate architecture as a reliable communications path to connect directly to all meters and other endpoints or its role as primarily a backhaul network for a new AMI "network within a network". This phase does not pre-assume that the next generation solution will continue to be based on Honeywell technology or another vendors solution. As such, this phase is preceded by a recommended vendor solution validation or selection exercise, with full understanding of the Telecom FAN solution and expected role in HOL's long term AMI system.

The Phase 4 business releases are focused on the opportunities presented from replacing the existing AMI system Applications that require replacement of the AMI system (including electric meters or deployment of DA (or other) dedicated network and endpoints) or transitioning to the next generation Honeywell AMI system to enable smart meter functionality that exists in next generation AMI systems. The primary dependency for the opportunities identified in Phase 4 is the schedule for the depreciation of the existing meter population. This becomes a key dependency to avoid stranded assets. Additionally, the need to comply with new Measurement Canada requirements adds another dependency that will affect the timing of this phase.

Recommendations for enabling Phase 4 opportunities by business release are shown in the below table.

Figure 10 - Phase 4 Business Releases

While all of these capabilities and the subsequent business releases which enable them were deemed to provide incremental value to HOL, the final determination to invest additional funds into any or all of these opportunities should be predicated with a specific and individual business case to validate the ultimate prudency of each investment in time, effort, or capital.

Methodology

Black & Veatch's approach to develop the Hydro Ottawa (HOL) AMI Strategic Plan and Roadmap consisted of five main tasks as shown in the below figure and further described below.

Figure 11 - Methodology

KICKOFF, AND DOCUMENTATION REVIEW

Documentation Review

Black & Veatch conducted an initial kick-off meeting on November 1, 2018 with key stakeholders that are participating in the project. The primary purpose for the meeting was to share the overall project approach and gain an understanding of stakeholders needs and concerns.

Black & Veatch reviewed several key documents that provided insight into system architecture and business strategy. Key documents reviewed include the following:

- HOL Enterprise Architecture Landscape
- Meter to Cash Flow Architecture
- Hydro Ottawa Annual Report, 2017
- Hydro Ottawa Strategic Direction, 2016-2020
- Smart Energy Roadmap for Hydro Ottawa (draft)
- Telecommunications Blueprint and Roadmap, July 2014

This information provided the basis of understanding of the Current State from which Hydro Ottawa would implement AMI and the Strategy Roadmap going forward.

STRATEGY DISCUSSIONS AND ARCHITECTURE REVIEWS

Strategy Roadmap workshop

Black & Veatch conducted a strategy workshop on November 8, 2018 with members from the Hydro Ottawa leadership team including:

- Lance Jeffries - Chief Electricity and Distribution Officer
- Julie Lupinacci - Chief Customer Officer
- Mark Fernandes - Chief Information and Technology Officer
- Adnan Khokhar - Envari, Chief Energy & Infrastructure Services Officer
- Guillaume (Gee) Paradis - Operations Director
- Laurie Heuff – Project Metering Systems Manager

The workshop included a presentation of existing and emerging AMI / smart utility technologies with focus on what other utilities are pursuing. The full presentation is provided in Appendix A. The outcome of the workshop was identifying the main AMI strategic drivers for the leadership team as they might relate to the expected AMI Strategy and Roadmap.

In addition to the kick-off meeting and strategy review workshop, two architecture review sessions were conducted to understand current and planned IT / OT infrastructure and Meter to Cash architecture. Additional discussions were held with the project lead to ensure alignment with approach and gain insight into the AMI strategic drivers.

AMI BENEFITS AND OPPORTUNITIES DISCOVERY

Black & Veatch conducted a series of workshops focused on systematically reviewing an extensive list of potential opportunities from implementing AMI technology. The outcome of the benefits discovery workshops provided a qualified and prioritized list of potential key opportunities for operational efficiencies, business transformation, revenue enhancement, cost management, customer care, or extended business opportunities that may be available to Hydro Ottawa. Black & Veatch utilized our comprehensive *AMI Opportunities* framework to facilitate this assessment.

FUNCTIONAL REQUIREMENTS DEVELOPMENT

Following the benefits discovery workshop, Black & Veatch extended the understandings of the prioritized opportunities into expected key functional capabilities required to enable these goals and benefits. This included identifying those opportunities already achieved, the system elements that would be required to enable each new or expanded opportunity, the relative cost and effort for each, and the extent to which each opportunity might be achievable with the existing HOL AMI system or with incremental improvements to this system.

This included several meetings and discussions with Honeywell to understand the capabilities of the current system and qualify the incremental improvements needed.

The final details of the prioritized opportunities, their functional requirements, prioritization, level of effort, and Roadmap phase were all incorporated into the *AMI Opportunities* framework which is included as Appendix B.

TECHNOLOGY ROADMAP AND BUSINESS RELEASE PLANNING

Roadmap Planning

Based on the understanding of the current system, the desired and prioritized opportunities, and the influence of the HOL Telecom Plan, Black & Veatch developed a recommended sequence of strategic steps that HOL might take to prudently address the remaining and new opportunities of AMI. The strategic steps (or phases) formed the basis of the Technology Roadmap. All of the AMI related opportunities not already achieved were mapped to the four identified phases of the technology roadmap to identify what can be accomplished throughout the roadmap steps and what dependencies impact the timing and implementation of each step.

Business Release Planning and Sequencing

The functional requirements and IT system impacts that were identified with each opportunity (within each Roadmap phase) were then integrated into a logical sequence of system development steps (or business releases). These business releases combined related capabilities enhancements or synergistic system work efforts to describe likely IT/OT system development efforts required to enable the desired opportunities beyond strict AMI investments. The business release plan is included in Appendix C.

Key Findings

CURRENT STATE ASSESSMENT

Hydro Ottawa Enterprise Strategies

Strategic Direction 2016-2020

Black & Veatch reviewed the HOL Strategic Direction 2016-2020 document to identify key initiatives that may influence or be influenced by AMI technologies. This review revealed the following items that should be considered within the AMI Roadmap:

The Strategic Direction identifies three key drivers of change for HOL, all of which may be influenced by or drive changes in AMI technology strategy. These include:

1. Cost
2. Technology
3. Public policy and regulation relating to energy

Clearly stated within the Strategic Direction was that customer centrality represents the single most important change in the fundamentals of the utilities business:

- *"Customer focus has been the key driver of Hydro Ottawa's business strategy over the past several years, and will continue to be our focus over the next five years"*
- *"HOL will focus on positioning customers to be much more active participants in the power system and the power market"*

More specifically, this Strategic Direction foresees that HOL will enable the following customer-oriented capabilities (some of which are specifically addressed in the AMI Roadmap):

- Prosumers – Producers and Consumers of energy
- Sellers of consumption reduction – Automated Demand Response
    a. Aggregators – enabling "Set and forget" automated DR
- Distributed energy, DR, Energy Management
- EV infrastructure

The Strategic Direction portrays that these changes are most likely to occur according to the following expected sequence of adopters:

1. Large Businesses and Institutions
2. Farms and warehouses
3. Residential - slower to adopt, particularly where the upfront costs are high
    a. New subdivisions and high-rise apartments – distributed generation, micro-grids, EV infrastructure energy efficiency (Key driver will be government standards that emerge to encourage or require this)

Finally, the Strategic Direction predicts that the utility Business Model is likely to adjust based on the following shifts:

- Utility revenues will in future be made up of a greater mix of regulated distribution service charges and new revenue streams that result from leveraging the utility's core competencies to provide value-added services
- The customers for these services may be within or outside of the distributor's traditional service territory, and in some cases, may be other utilities.
- The continued push to transition to renewable energy sources also represents a continued revenue opportunity for utilities that have a core strength in this area.

Strategy Workshop

Black & Veatch conducted a strategy workshop with members of the Hydro Ottawa leadership team including:

- Lance Jeffries - Chief Electricity and Distribution Officer
- Julie Lupinacci - Chief Customer Officer
- Mark Fernandes - Chief Information and Technology Officer
- Adnan Khokhar - Envari, Chief Energy & Infrastructure Services Officer
- Guillaume (Gee) Paradis - Operations Director
- Laurie Heuff – Project Metering Systems Manager

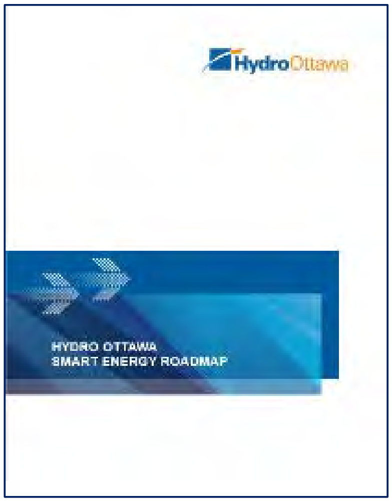
During this workshop, the group explored key directions and/or expectations from AMI. Some of the key takeaways of this session included the following key concepts and drivers:

- Customers should not need to inform us when there is an outage
- Customer flexibility
    - energy efficiency models
    - mine data and utilization of data
    - forecasting and predicting what customers' needs are - this needs to be baseline before any prepay or other programs,
    - home and commercial building automation - build and resell
- "Support" home automation rather than directly "own/control" home automation
- Real Time availability of data is the key utility differentiator from aggregators and retailers
- Enablement new business models over improvement of performance statistics

All these themes seem to reinforce those from the Strategic Direction in that they are strongly focused on customer capabilities enablement, customer services, and changing business models.

Smart Energy Strategy

Finally, Black & Veatch reviewed the Smart Energy Strategy as portrayed in the Smart Energy Roadmap. This yielded a more granular view of the intention for expanded Smart Grid programs and the specific expected timing of many programs that are either dependent on the AMI strategy or may be precursors to elements of the AMI Strategy.



Smart Energy Vision Statement

The Smart energy vision will be realized through a roadmap of projects and programs, which are aligned with Smart Energy strategic imperatives and desired strategic outcomes.

Smart Energy Strategic Outcomes

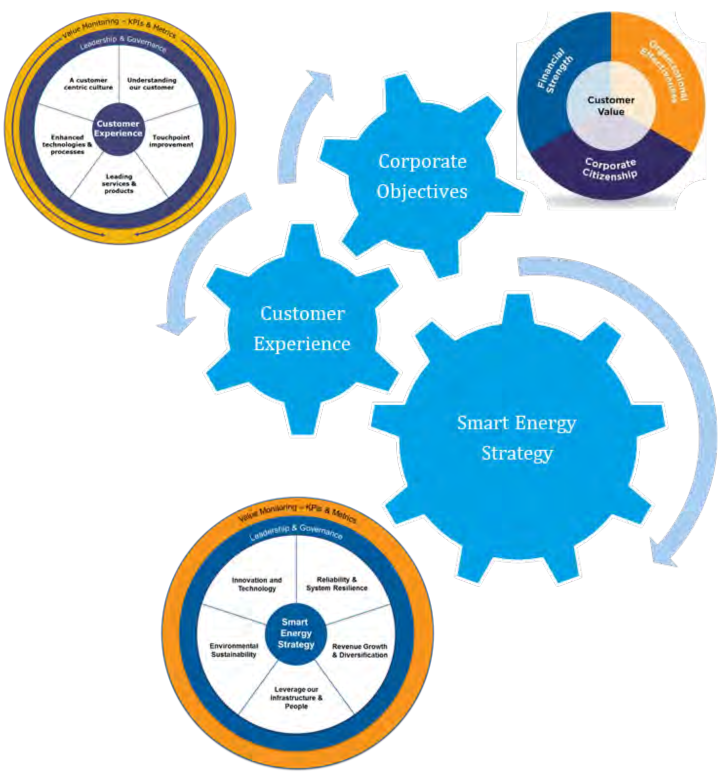
100% Reliable Service - Develop enhance grid reliability, and service offerings to enable provision of 100% reliability electrical service guarantee.

Customer Energy Solutions - Position Hydro Ottawa as the provider of proactive and innovative energy solutions which are driven by our customers' needs, preferences, and objectives.

Expanding Current Businesses - Expand current value and revenue streams building on our core areas of strength in the provision of electricity and related services.

As with the Strategic Direction and the executive workshop, common themes emerge of enabling customer solutions and exploring new business models (while maintaining reliable service).

Alignment with other Initiatives



The smart energy steering committee is one of the initiatives through which Hydro Ottawa will achieve its overall corporate strategic objectives. To deliver on the corporate objective of Customer Value, alignment between the Smart Energy Steering Committee, the Customer Experience Steering Committee and other Strategic initiatives is required.

The Smart Energy Roadmap describes a number of project specific initiatives which embody the execution of this roadmap, they include the following projects, many of which will be directly or indirectly enabled by the AMI Roadmap:

Smart Energy Initiatives

1. Telecommunication Master Plan
   A robust communication infrastructure to support, Hydro Ottawa and our customer smart energy applications.
2. Enabling Transactive Marketplace (GREAT-DR)
   Preparing for the shifted role of the utility moving to provide, integrated energy solutions, supporting customer transaction, in community and Across the grid.
3. Enhanced Mobile Workforce Management
   Extend workforce management for all HOL distribution field activities.
4. Self-Healing Grid
   Distribution system can automatically Isolate faults and restore power.
5. Outage Intelligence
   Automatically locate, and identify root cause distribution system faults
6. Outage Analytics and Leveraging Existing Data
   Deliver custom reporting, and analytics at our staffs finger tips.
7. Storage for Reliability
   Deploy Storage to enable a 100% reliability for our customers.
8. Outage Notification
   Automatic notification of customer power outage.
9. EV Enabling Charging Infrastructure
   Deployment of private charging infrastructure (Commercial & Residential)
10. District Thermal Business
    Provide integrated energy solutions to meet customer needs.
11. Smart Assessment and Repair
    Damage assess tools to support and streamline grid event response.
12. Analytic Field Assistant (KITT)
    Process assistant (AI) to help in triage and prioritization distribution system response.
13. Smart System Planning
    System information available at our finger tips, to support decisions that align to the real condition of our system.
14. Dynamic Grid
    Distribution system can dynamically respond to operating environment.
15. Electrification of transportation
    B2B enabling of Commercial vehicles and charging infrastructure.
16. Outage Prediction
    Machine learning and artificial intelligence to identify and prevent incipient faults.
17. Asset Lifecycle Information
    All information associated with Asset available in a single source.
18. Smarty Pants
    Wearable Technology to support field operations.

Additional Opportunities:

1. Microgrids - Campus
   Hydro Ottawa to provide integrated energy solution to campus and community partners that meet the customer(s) supply security and/or environmental criteria.
2. Biomass for District Thermal
   Hydro Ottawa able to offer bio-mass as part of heating and electricity solution to its customers.
3. Electrify HOL Fleet
   Build Reputation as a trusted advisor in the shift to electrified transportation by converting HOL fleet.
4. Storage for Capacity Management
   Hydro Ottawa to participate in the deployment of local storage, to manage solar generation, manage customer loads such as EV charging

All these initiatives are mapped against the identified AMI Roadmap stages in the Recommendations Section to portray any interdependencies that these Smart Energy initiatives may have with the planned AMI Roadmap phases.

State of the AMI Lifecycle

Advanced Metering Infrastructure (AMI) within the North American electric utility industry has become a regularly adopted solution for improving operational efficiencies and managing many common business challenges. These challenges include aging infrastructure, system operational management, integrity, customer service, and conservation objectives. In fact, many utilities are already facing the new challenge of addressing the opportunities for replacing a first-generation AMI system with the latest technology available.

Hydro Ottawa is in this more common situation of assessing the "Renewal Strategy" for addressing an aging "first-generation" AMI technology. The "Renewal Strategy" stage is one of the key steps in the Black & Veatch model for managing the AMI Lifecycle. This Black & Veatch approach to supporting the complete lifecycle of a successful AMI program is portrayed in the following graphic:

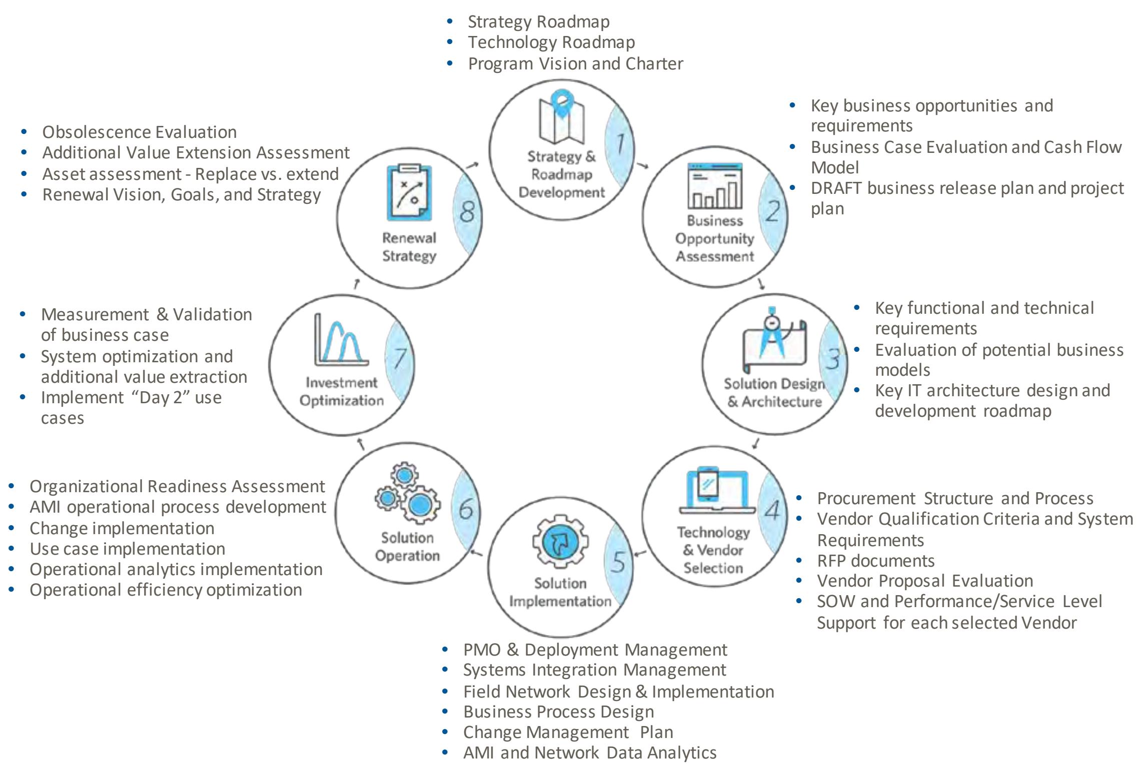


Figure 12 - AMI Lifecycle

HOL has extracted significant value from the 1st generation AMI system which has been operating for 12+ years. It is understood that this system was originally intended to enable the provincial requirements for universal TOU rates and interval data to be provided to the provincial MDMS system. The current system has successfully provided this required functionality and the information needed to address this initial requirement.

However, as HOL has sought to expand the usefulness of the AMI system and extract additional value from the system, it has experienced several technical and system integration hurdles. These hurdles can be characterized as falling into three key categories:

1. Obstacles in extracting available data via the current AMI network either due to bandwidth/latency limitations or backhaul connectivity limitations (dial up modems)

2. Obstacles in developing additional enhancements to downstream system to enhance their potential use of AMI data that may already be available

3. Obstacles borne from core metering and/or data capabilities of the sealed electric meters currently in the field.

Advanced Metering Current State

System Obsolescence

The HOL AMI system is over 12 years old and faces two significant technology obsolescence issues:

1. **Meters**: Approximately 61% of the metering endpoints consists of early generation Honeywell REX1 meters. The other 39% of the meter population consists of Honeywell REX2 generation meters, which HOL continues to purchase to maintain network compatibility. The following table represent the approximate population of meter types currently in the HOL system.

	# Meters Installed				
Seal Year	All Rex Meters	Rex 1	Rex 2	Fully Depreciated Year	% of Total
2006	89622	89622	0	2021	28%
2007	86020	86020	0	2022	27%
2008	51871	18476	33395	2023	16%
2009	21302	396	20906	2024	7%
2010	5090	0	5090	2025	2%
2011	5725	0	5725	2026	2%
2012	9320	0	9320	2027	3%
2013	8548	0	8548	2028	3%
2014	7236	0	7236	2029	2%
2015	9975	0	9975	2030	3%
2016	8453	0	8453	2031	3%
2017	7172	0	7172	2032	2%
2018	6157	0	6157	2033	2%
Total	316491	194514	121977		
		61%	39%		

Figure 13 - Meter Population Installation Age

The REX2 meter is likely to be discontinued by Honeywell soon in lieu of their newest metering product offering, the REXU and future Alpha 4 residential meter. Thus, HOL is likely to be forced to transition their supply from the REX2 product to the REXU product. The REXU product can be utilized in the current HOL AMI network in place of the REX2, provided that HOL upgrades the Headend software application to the Connexo NetSense

10.2 or higher. Specifically, the meter/network compatibility for the current and newer vintage of meters from Honeywell is understood to be as follows:

- REX1 meters limit mode of network operation to LAN1 only (currently the mode of operation for the HOL AMI network to accommodate the population of REX1 meters currently deployed)
- REX2 meters can operate on LAN1 or LAN2 (the REX2 meters deployed at HOL are operating in LAN1 mode to remain network compatible with the older REX1 meters still on the system)
- REXU meters can operate on LAN1 or LAN2 or the newer SynergyNet IPv6 network protocol that is the latest offering from Honeywell. However, REX1 and REX2 meters are not compatible with next generation Honeywell network (SynergyNet).
- The next generation Alpha 4 meter is only supported on the SynergyNet network.

2. **AMI Headend**: The AMI system is currently operating using the Honeywell EnergyAxis v9.x headend software application. This version of software is currently two major versions behind the currently offered production software (v11.2) which makes it an “N-2” version of software application. As can be seen from the following chart of support services offered by Honeywell, this current version has reached “end of life” status with Honeywell and carries a significantly escalated support cost structure in addition to increased exposure to the inability to correct software problems.

Version		Version @ 01/01/19	Fee Structure	Support Status
N		11.2	SMA	The release is fully supported
N-1		10.2	SMA	The release is fully supported
N-2	EOL	9.x	SMA + 30%	The release has reached end of life, and system support will be limited to Severity 1 issues defined in Appendix D-3 while allowing Licensee time to complete system upgrades.
N-3 & Less	EOS	All other releases	SMA + 30% plus $500 an hour	The release has reached end of life support (EOS). Support is limited to technical assistance and emergency recovery, this does not include any new software or firmware fixes. Recommended that the Licensee upgrade its release as soon as possible.

Current Releases:

- The current general availability major release is 11.2, launched in April 2018.
- The next EnergyAxis major release is 12.x, planned for the first quarter of 2019.

Figure 14 - Honeywell Head End Application Support Status

Furthermore, Honeywell has announced that it plans to release the next major version of AMI headend software in Q2 2019; version 12.x. With this release, the HOL version 9.x headend software will become an “N-3” version and will reach “end of life support” status with Honeywell whereby Honeywell will not commit to any further ongoing support. This will leave HOL severely exposed to technical risks if the current software were to become inoperable.

System Deficiencies

Beyond system obsolescence, the HOL AMI system performance is hindered by a key network communications deficiency which hampers several potential AMI opportunities. That is, the backhaul network which is used to communicate to the A3 based AMI collectors relies on dial up phone connections for retrieving data. In many cases, this phone connection is a shared line with the customer on whose premise the meter/collector resides. Thus, in its current configuration, it is not operating as a true two-way network and is unable to transmit real time, push alarms from the endpoints when received. These alarms and events can only be retrieved when the head end dials up the collectors on a schedule or on demand to retrieve data held at the collectors.

Because of this deficiency, no AMI benefits that are dependent on real time alarms or push notifications are possible.

Measurement Canada Requirements

Measurement Canada has issued new metering requirements under PS-E-18 that may impact future HOL metering strategies. For example, the following table describes two specific sections of PS-E-18 which may create future compliance issues for HOL:

Section 13-6.1.11 (Interval Data Memory)	The LR interval data shall not be overwritten before a period of time which is the longer of two identified below has occurred: - 35 days - The time required to fill memory to capacity.	REX1 has a maximum memory storage capacity to hold 60-minute interval data for 20 days.
Sections 6.5 - 6.6 (Reactive and Apparent Energy)	• Reactive energy used in calculating apparent energy shall be measured directly and not calculated from other legal units of measure. • Meters shall establish apparent energy based on continuous measurement of active and reactive energy flow in all directions.	REX1 does not record reactive and apparent energy

Figure 15 - Excerpt of Measurement Canada metering requirements

Note: The above table is not intended to be an all-inclusive list of all new requirements that current HOL REX1 meters will not meet. It is intended to provide examples of Measurement Canada requirements which may require HOL to change metering capabilities to avoid non-compliance.

Honeywell has indicated that the REX2 meter will also not meet the requirements of PS-E-18. The REXU does not currently meet the standards to calculate energy values (WH and VARH) from fundamental only signals but Honeywell indicates that a code set could be implemented to the metrology engine. The A4 meter is expected to meet the standard; however, facilities are not yet available in Canada to test these meters. The REXU, as it currently stands, does not calculate these energy values from fundamental only signals and changes would have to be made to the metrology engine.

This PS-E-18 specification will become a compliance requirement January 1, 2022. However, a grandfather provision has been included which allows for electricity meters that are currently in service (i.e. the legacy REX1 and REX2 meters that would not comply with PS-E-18) to may remain in service until the end of their current and subsequent reverification periods. The allowable re-verification periods are as follows:

Table 2

Electronic-type				
Column I	Column II		Column III	
Type	Initial Reverification Period		Subsequent Reverification Period	
5. Electrical Energy Functions– watt-hour, reactive-volt-ampere-hour, volt-ampere-hour, Q-hour, A^2hour, V^2hour including those with integrated pulse initiators and/or receivers, multi-tariff registers, remote-meter-reading or automatic-meter-reading (AMR) features.				
	Qualifying under clause 5.4	All Others	Qualifying under clause 5.4	All Others
a) single-phase types	10 years	6 years	8 years	4 years
b) polyphase types	10 years	6 years	8 years	4 years
6. Electrical Demand (Power) Functions– watt, reactive-volt-ampere or volt-ampere including those with integrated energy meters and associated functions				
a) single-phase types	10 years	6 years	8 years	4 years
b) polyphase types	10 years	6 years	8 years	4 years

Figure 16 - Measurement Canada Seal Periods

Thus, the Measurement Canada functional requirements may not be an immediate forcing trigger for HOL to replace the current REX1 and REX2 meters as HOL can continue to re-verify REX1 and REX2 meters until the end of 2038. However, ultimately HOL will need to upgrade the entire population of REX1 and REX2 meters to Measurement Canada compliant meters.

Meters and Meter Reading

HOL has a population of 1st generation AMI meters which already contain metrology and data capabilities that meet current requirements for TOU and enable additional HOL use cases to drive business value. However, newer vintage meters have added more capabilities which may enhance HOL Smart Meter use cases if/when they replace the existing Honeywell REX1 and REX2 meters. These enhanced capabilities include:

- Integrated service disconnect switches
- Voltage threshold alerts
- Meter temperature alarms
- Outage notifications (last-gasp)
- Additional recording channels
- Meter data encryption
- Bi-directional and net metering

Thus, none of the opportunities available from these features can be implemented without requiring a selective or complete change-out of the meter population.

Meter Depreciation and Potential Replacement

The current population of residential AMI meters is represented in the following table. It is VERY important to note that all the REX1 meters and approximately 80% of the entire residential meter population becomes fully depreciated in the next 5 years (by 2024).

While this may create an opportunity to embark on an upgrade of these older meters with newer, more capable meters without stranding these existing assets, this will only accommodate 80% of the existing population. In addition, this only considers the assets depreciation schedule and may or may not align with the retained book value of these assets. Finally, there will always be some part of the existing population which is not fully depreciated when a mass meter upgrade is planned.

	# Meters Installed			
Seal Year	All Rex Meters	Rex 1	Rex 2	Fully Depreciated Year
2006	89622	89622	0	2021
2007	86020	86020	0	2022
2008	51871	18476	33395	2023
2009	21302	396	20906	2024
2010	5090	0	5090	2025
2011	5725	0	5725	2026
2012	9320	0	9320	2027
2013	8548	0	8548	2028
2014	7236	0	7236	2029
2015	9975	0	9975	2030
2016	8453	0	8453	2031
2017	7172	0	7172	2032
2018	6157	0	6157	2033

Figure 17 - Meter Population Installation Age

Thus, the depreciation schedule for the existing population provides a significant opportunity to upgrade to a newer metering capability but it does not provide a 100% basis for a system-wide replacement exercise.

Plans for HOL Field Area Network (FAN)

HOL has been finalizing and implementing a Telecom Master Plan to address all layers of the enterprise communications requirements. As part of this plan, HOL has a specific element that is meant to address the Field Area Network (FAN) element of the required communications needs. This FAN has the potential to serve as the HOL owned backhaul network to carry data from the AMI local area network (LAN) back to the AMI headend OR, depending on regulatory enablement, may be able to serve as the FAN and LAN for AMI, DA, and DER endpoints. Thus, depending on the final determination of the capabilities and limitations of the FAN technology to be implemented, the AMI Roadmap could include a significant leverage of the FAN as the primary AMI/DA/DER communications network OR the AMI Roadmap could lead to a “network of networks” concept whereby a more traditional AMI solution, as offered by the existing AMI vendors, provides the LAN connection to AMI/DA/DER endpoints while the HOL FAN provides the traditional AMI backhaul role. This key driver of the AMI Roadmap results in a specific phase of the roadmap that is directly dependent on this outcome.

This FAN plan and implementation is currently dependent on regulatory and governmental bodies to enable HOL to own and manage their own private cellular networks. It is understood that this plan will be finalized and the regulatory constrictions fully understood by the end of 2020. Thus, the opportunities that might directly leverage this FAN, and the ultimate strategy for the long-term AMI solution for HOL are dependent on this final FAN strategy determination.

Current State of IT System elements

HOL has a robust system architecture consisting of a full portfolio of appropriate IT and OT systems. The following diagrams portrays a representation of the current state of HOL operational systems.

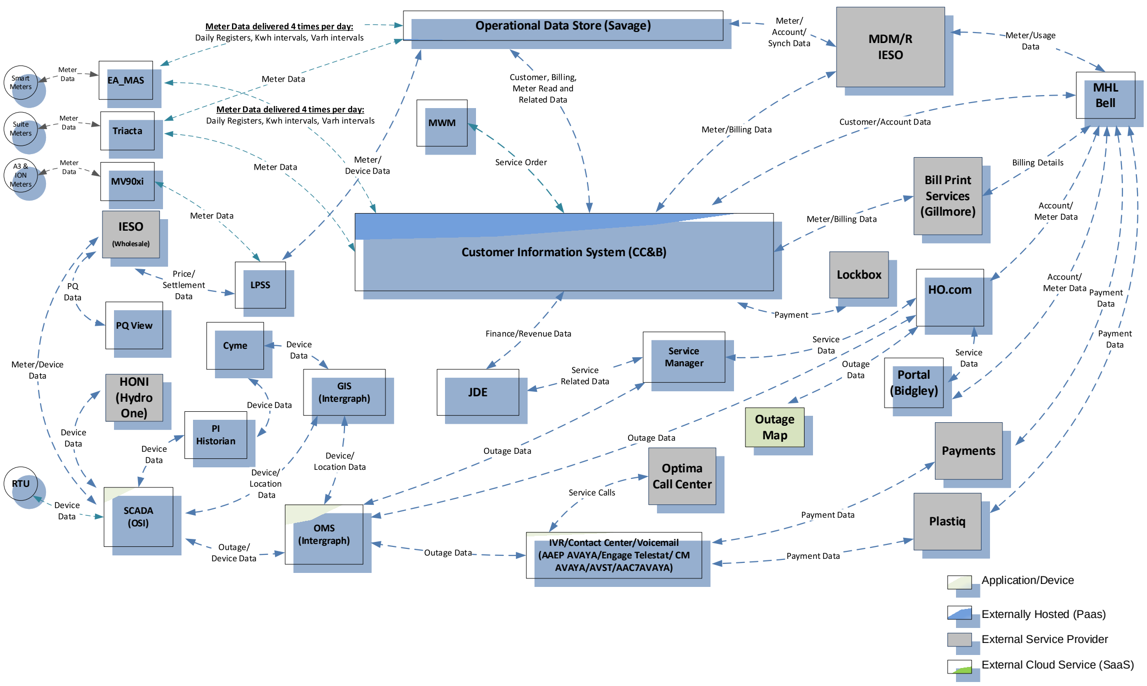


Figure 18 - Current State IT Systems diagram

Security

In today's digitally enabled world, it is critical to recognize and plan for the fact that AMI solutions measure, store, and transmit data associated with individual household activities and enable critical grid system controls. Thus, it is vitally important that all AMI technology implementations should not compromise on security. End-to-end security must be integrated into all considered and implemented AMI technology investments.

The minimum standard for communications security for AMI solutions is often identified as emulating the security profile of cellular encryption and authentication models. This minimum standard requires that all transmitted data is encrypted to protect the data stream.

If HOL implements a cellular AMI solution (by virtue of the HOL Telecom FAN plan), this standard should be incorporated into the cellular endpoint solutions. If HOL implements a private RF network, it should also require the network and endpoint devices to enable encryption strategies.

It is understood that the current Honeywell EnergyAxis solution does not support network and/or endpoint encryption. This significant deficit of the current AMI solution may form a primary driver for accelerated replacement of the current AMI architecture. However, this concern has not been raised by HOL stakeholders and, therefore, is not currently considered a primary driver for replacement of the existing Honeywell solution as part of the AMI Roadmap portrayed herein.

That said, given HOL's intent to leverage the planned Telecom FAN for elements of AMI communications, the security profile for cellular service should be considered as the minimum standard for AMI security connections between remote system elements. Cellular service providers typically use an authentication and encryption approach for moving data in a secure fashion. This profile (or an emulation of this profile) should be applied for all remote system connections; including meter to concentrator and concentrator to AMI Head End applications.

Privacy

Deployment of an AMI system creates a significant amount of consumer related consumption and activity data to be collected by the utility and potentially displayed on internet and mobile accessible sites. Ensuring the privacy of data is paramount to a good customer service interaction and being a trusted service provider.

Specific privacy policy choices should include:

- Encryption of stored data – to minimize unauthorized access to data stored at the vendor facility
- Authentication rules for access to on-line customer data through a portal – to protect access to customers data

Thus, Hydro Ottawa will need a definitive policy for customer data privacy to govern customer usage and billing information. Examples from other utility initiatives can provide a basis for developing this policy. Specifically, the California PUC developed a Smart Meter Data Privacy framework (based on the Fair Information Practice Principles from the U.S. Department of Homeland Security developed as its privacy framework). This framework addresses the following data privacy elements:

- Transparency
- Individual participation
- Purpose specification
- Data minimization
- Use limitation
- Data quality and integrity
- Security
- Accountability and auditing

AMI OPPORTUNITIES AND POTENTIAL BENEFITS

Black & Veatch conducted a series of Stakeholder workshops to explore the possibilities and prioritization of potential opportunities from AMI technologies. This provided a rich list of AMI use cases, some of which have already been achieved and some of which are purely future opportunities not available today.

A graduated ranking system was used to identify the importance of these opportunities according to the following scale:

5 = Must Have

4 = High Priority

3 = Needed but not priority

2 = Like to have but does not drive priority

1 = Not necessary

0 = Not applicable

The following is an example excerpt that portrays, the information gathered. The complete AMI Opportunities matrix is included in the Appendix:

Benefit Category	Hydro Ottawa Stakeholder Group	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Use Case Summary
Billing	Customer Care	Fully Achieved	**Billing Exceptions (Level 1) - Reduced number and resolution time of billing exceptions/issues**	X	X		5	Daily readings provides more readings available to derive accurate bill determinants. Thus, fewer billing exceptions are generated.
Billing	Customer Care	Future	**Summary / Consolidated Billing - Improve cash flow for existing Summary Billing customers**	X	X		4	Billing reads available for every day to enable summary aggregation for summary accounts on any given day. This will allow all summary billing accounts effective bill date to be accelerated to the bill cycle for the first read meter.
Billing	Customer Care	Fully Achieved	**Flexible Billing dates - Improved cash flow from accelerated billing date: improved working capital from flexible billing options**	X	X		3	Processing of meter readings daily; enablement of Billing System to bill based on first available meter reading in bill window potentially accelerating cash flow. Billing determinants available on any day enable any customer to be billed on any day. Requires flexible billing dates enabled by Billing System.
Billing	Customer Care	N/A	**Reduction in Manual Bill processing**		X		0	High percentage of automated daily readings provides more readings available to derive accurate bill determinants without manual intervention for complex bill processing
DER	Market Engagement	Future	**EV Charging Aggregation and Market participation (HOL separately metered)**	X	X		5	Enable consumption and aggregation of private charging infrastructure (Commercial & Residential) to provide for HOL or Third Party market participation.
DER	Market Engagement	Future	**Customer Portal information for EV Charging (HOL provided)**	X	X		3	Provide detailed charging consumption profiles of private charging infrastructure (Commercial & Residential)
DER	Market Engagement	Partially Achieved	**Disaggregation of Load / Appliance Monitoring (individually metered)**	X	X		2	Measure usage of individual devices behind the meter such as HVAC, water heater, and appliances by using individual metering devices. Metering does not need to be revenue grade.
Distribution Operations	Customer Care	Future	**Outage Management - Improved Customer Communication**	X	X		5	Proactive communication to customers caused by improved outage event situational awareness. Highly efficient restoration updates with system wide pinging/polling to confirm OMS outage information. Restoration tracking and confirmation: status of individual service restoration by enabling customer service representatives to ping meter.

Figure 19 - Excerpt from AMI Opportunities matrix

A view of the number of opportunities by priority rating indicates that the team sees a significant number of high priority opportunities remaining. All Opportunities prioritized as 3 or higher were deemed to be significant enough to specifically address within the Roadmap and Business Release plan.

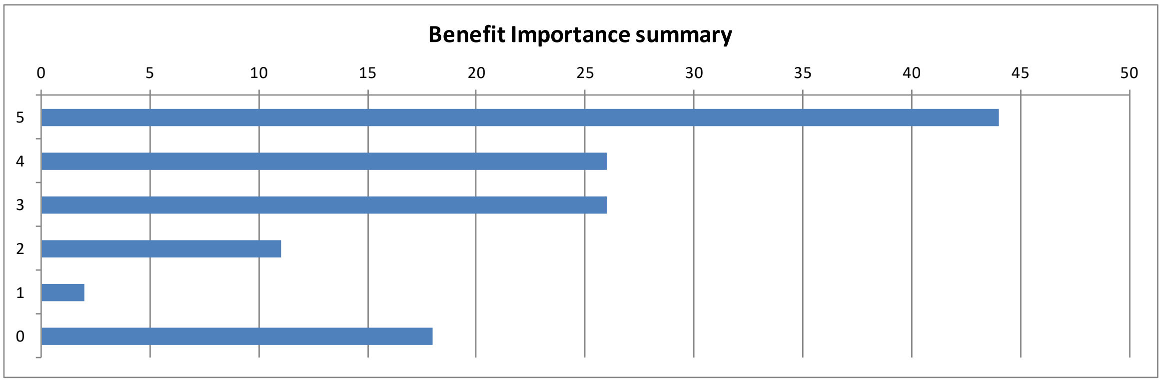


Figure 20 - Benefit Importance Bar Diagram summary

A further analysis of the raw count of the opportunities identified provides some insight into the focus areas:

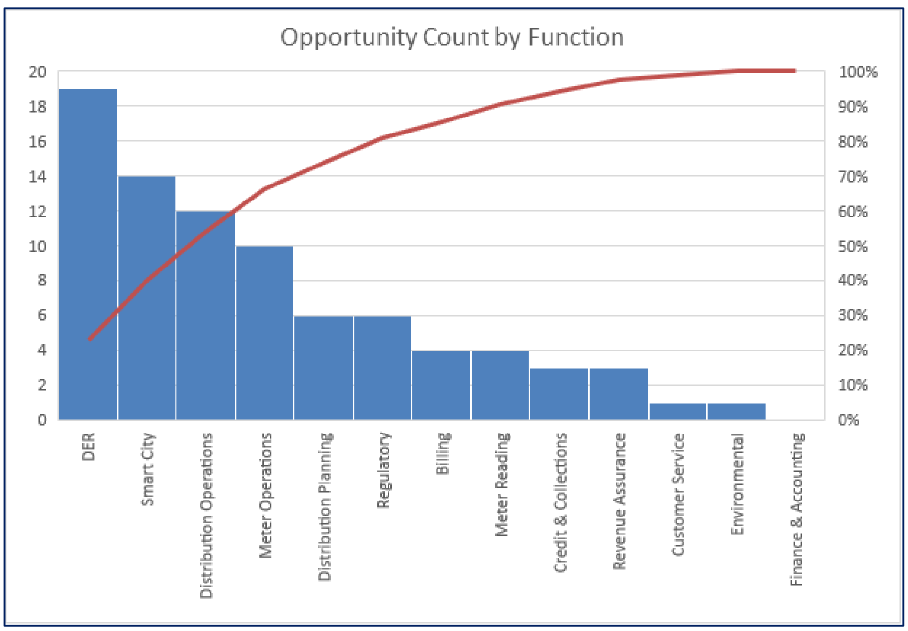


Figure 21 - Opportunity Counts by Function

This analysis of the opportunities clearly indicates that HOL has achieved many of the traditional meter-to cash opportunities and has a strong desire to extend AMI capabilities to support expanded use cases beyond traditional meter-to-cash operations. This is evident in the number of opportunities rated 3, 4, or 5 which are related to Distributed Energy Resources (DER), Smart City enablement, and Automated Distribution Operations. This distribution also supports the overall goals for the HOL Strategic Directions report.

Qualifying Opportunities by Cost and Level of Effort

Following the qualification of the identified opportunities by priority, a further qualification was developed to provide a hi-level, subjective assessment of the expected relative cost and level of effort to achieve the prioritized (3,4,5) opportunities. Each prioritized opportunity was assessed as to the expected Cost and Level of Effort as follows:

Cost:	5 - Hi Cost	4 - Med Cost	3 - Lo Cost
Level of Effort:	5 – Significant Effort	4 – Moderate Effort	3 – Low Effort

This assessment provided a subjective relative cost element to the opportunity assessment.

Combined with the priority ranking this provided a relative "net ranking" qualification to the opportunities such that a high-level analysis of the opportunities might provide further insights into the potential impacts of further AMI enhancements. Thus, re-examining the potential opportunities when including both priority and relative cost/effort yields the following:

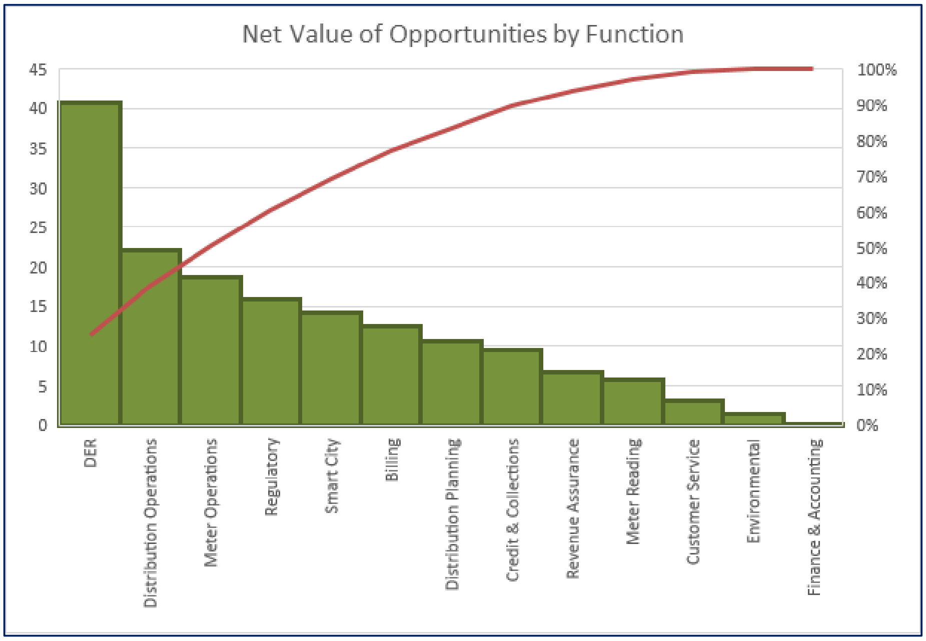


Figure 22 - Opportunities by Function; ranked by net value

This analysis infers that the opportunities for DER and Distribution Operations still provide the greatest net value to HOL but that more traditional operations and rate/regulatory opportunities may also carry interesting net value.

IT AND COMMON SYSTEM ELEMENTS

System Integration Architecture

HOL's current system architecture utilizes dedicated point to point integration of data streams between source and target systems. Given the expected amount of additional data potentially available from AMI systems and the expected leverage of that data across additional downstream systems, it may become important to consider new system integration architectures for improved and more efficient use of AMI data across multiple systems.

Consideration of new system integration architectures is not included in the Business Release plans portrayed in the Roadmap recommendations. The Business Release plans are focused on functional integration of new system capabilities and the consideration for alternative integration techniques is considered a distinct IT decision.

That said, some of the key integration approaches include:

- Point to Point integration - involves development of custom integration interfaces.
- Messaging-based integration using Message Oriented Middleware (MOM) such as MQ Series, TIBCO rendezvous, etc.
- SOA & ESB-based integration using integration middleware supporting SOA and ESB. BPM-based integration providing integration between data, applications and people together through a common business process.
- Pre-built integrations packages may provide a productized integration between two applications.

AMI System Head End applications as Common System Elements

As described previously, the existing version of the EnergyAxis Management System (EA_MS) is two versions behind the current Honeywell Connexo NetSense headend and is expected to be three versions behind when Honeywell introduces v12.x in Q1 2019. In addition to being unsupported, the existing EA_MS 9.x version does not support key functionality required for advanced use cases such as temperature readings, voltage monitoring, advanced metrology functionality, instrumentation data using on request reads for A3 meters, and REXU meters. A comparison of features for EA_MS and NetSense is provided in Appendix D.

The need to have a supported AMI headend with an advanced platform that enables functionality for future use cases and securely manages the data collection from multiple devices (with various communications platforms) to feed downstream systems is a key requirement to evolve to the next generation AMI.

Meter Data Management Capabilities

The current Savage ODS meets HOL's requirements along with IESO's MDMR. Meter data is stored in ODS and interval data (alarms/events) are sent to MDMR for calculating billing determinants which are then sent back to HOL for billing. HOL has access to the data and can utilize it to for their requirements.

In the future, ODS will require changes as new meter data (intervals less than 60 minutes, new events and alarms) will have to be stored and processed. The interface to MDMR will not change as IESO requirements are fixed and HOL cannot change them. HOL will need to evaluate changes to ODS interfaces as more systems are interconnected in conjunction with their data warehouse strategy. This evaluation is required to determine what interfaces can be supported by ODS. For example:

- Can it support web services and other interfaces to meet real time requirements?

- Does it have the capability to store water or other types of data such as smart city use cases?
- Can it provide data separation for electric and water as they will be different utilities and data privacy/security is required?

Additionally, the operational efficiency and capability to process the increased data must be evaluated for future interval data which is likely to be more granular than the current 60-minute intervals.

Technology Review

Black & Veatch provided an overview of AMI technology and the AMI vendor landscape as part of an on-site meeting and further arranged numerous meetings at DistribuTECH with key AMI and communication vendors in which HOL participated. The below sections highlight the AMI technologies and considerations in selecting an AMI technology. Nonproprietary sections of the presentation material is also provided in Appendix E.

ADVANCED METERING INFRASTRUCTURE TECHNOLOGIES

A smart metering/AMI system is traditionally characterized by its remote, fixed network communications infrastructure, its ability to collect data from various sensor and control devices located in fixed locations throughout the service territory, and its bi-directional communication capabilities. Typically, an AMI system operated as a full two-way system is capable of the following functionalities:

- Requesting and receiving "on-request" data retrieval to allow personnel to query the endpoints as needed.
- Realtime alarms or alerts that provide additional information on grid issues, customer use or device problems to allow more proactive resolution.
- Remote firmware updates for the network elements and endpoints that allows for focused or system-wide updates and reduces technology obsolescence risks (within allowable Measurement Canada sealing requirements).
- Time synchronization of the network, endpoints, and the Head End software application (HES) to allow for complete system data synchronism.

There are several common network structures in use today for AMI focused networks, including the following:

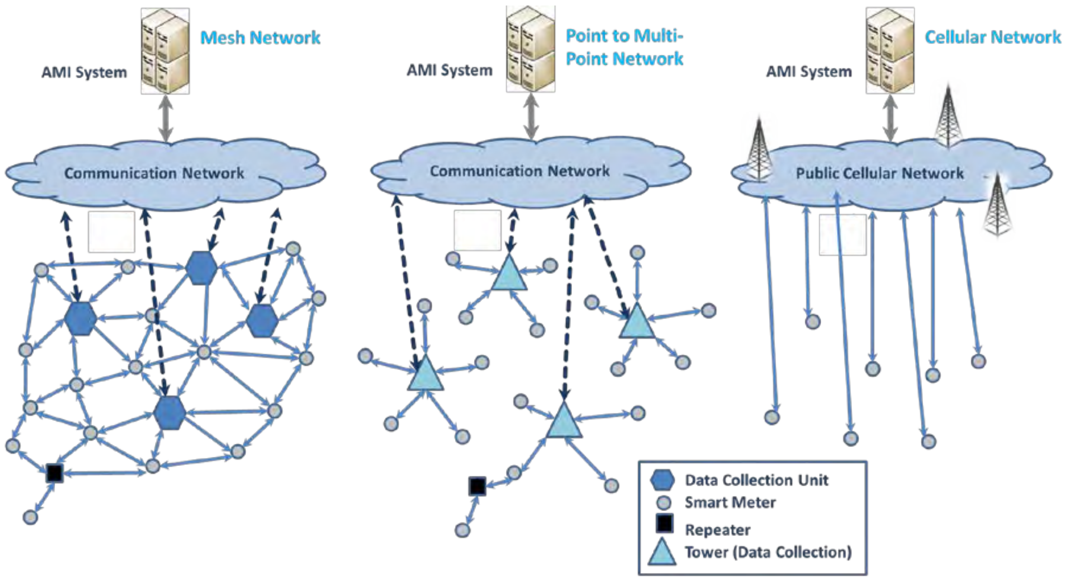


Figure 23 - Common AMI Network Structures

The selection of a network type is dependent upon several factors in the service area of the utility. The availability of public carrier (cellular) coverage, proximity of the meters to each other, the uniformity of the service territory, the physical location of meter assets (indoors, etc.,), availability of utility assets to mount network infrastructure, and the topography of the service area all contribute to the determination of the type and amount of network infrastructure required for a reliable network.

More recently, the availability and viability of private cellular networks has presented additional options for potential AMI networks.

There are several layers of technology choices implicit in the selection of a preferred AMI solution. These include:

1. Private network versus Public Network
2. If Private network; Private cellular versus Private/proprietary RF
3. If RF network; Mesh RF architecture versus STAR RF architecture and licensed frequency versus un-licensed frequency

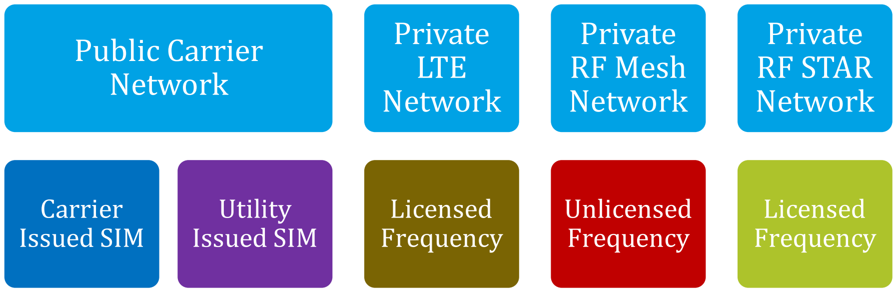


Figure 24 - Network technology options

Public (Cellular) Network

Public Network with Public Carrier provided SIM

This network configuration assumes that the cellular modem is either embedded in the meter MIU or a cellular device is attached to the endpoint for data access (i.e. DA devices or in-home devices). In this scenario a cellular provider is responsible for connectivity from the meter to the Head End System or to any other application that is reliant on the endpoint data.

The advantage of a public cellular solution is that it requires no network deployment by the utility. The public carrier (Telecom Company) cell towers are utilized to collect data from the meters and transmit to the AMI HES.

The major disadvantage of the cellular system is that the utility is fully reliant of the phone company for the availability of the communications to the endpoint. Whereas in private RF networks, the Telecom carrier is typically only providing backhaul communications and the RF network provides significant redundancy to overcome and reliability exposure to the Telecom service provides. Another disadvantage is that each endpoint (meter, DA device, in-home device, and sensor) will have a recurring monthly service charge for communications. This serves to add to the utilities O&M costs while private network options limit these O&M charges by investing in utility owned network capital.

Public Network with Utility issued SIM

As an alternative to the traditional Public Carrier provided service, whereby the Public Carrier issues the SIM cards required to provision the endpoint devices onto the Carriers network, HOL is exploring the possibility of garnering regulatory approval to issue their own SIM cards for provisioning HOL endpoint devices across Public Carrier networks, but utilizing the bulk carrier, wholesale roaming charge rates. This option, if enabled, may dramatically reduce the monthly O&M fees for communicating to endpoint devices while still utilizing the existing network infrastructures provided by the public carriers. Thus, this option reduces HOL’s required capital investment and manages the monthly O&M fees required for each endpoint device to a minimum level. However, this option still retains full dependency on the public carrier for maintaining availability and reliability of the network for maintaining communications to potentially critical endpoints (such as DA devices).

Private Network

There are three available architectures and two available choices in the private network option. These include Private RF, including Mesh Network or Star Network configurations, and Private Cellular.

In the private connectivity model, the AMI provider will provide connectivity from the meter to a gateway or collector. This is included as part of the cost of the overall solution.

Private Network Architecture Considerations

Star RF Network

A star network is a point-to-multi point architecture and is a common type of fixed network AMI system used for electric, gas, and water in North America. In this system the meter or MIU transmits its data to a centralized network hub known as a collector or DCU. In its simplest form, a star network consists of a number of collectors and an AMI headend software application (HES), which manages the networks configuration and acts as a conduit to transmit data. Once the data is received by a collector, the collector transmits the data back to the AMI HES via a "backhaul" data network link (public carrier network or private utility network).

The advantage of having a star network is that it sets up and expands easily and propagation studies provide reliable projection of coverage. Non-centralized failure has little impact to the entire network, end-point failure is easy to detect, and the data is easily sent directly to data collectors without being repeated through another device. A potential disadvantage of having a star network is that if a collector fails, there is a higher risk of lost communications from the end-points that are assigned to that collector That said, transmitter signals can communicate to all collectors within their transmission footprint. As a result, it is common practice to provide overlapping collector coverage in the network to create network redundancy in the event of a DCU failure. It should also be noted that migrating AMR to AMI units does not allow drive-by AMR to be conducted if the AMI system fails.

Mesh RF Network

Another common type of fixed network system is the mesh network. In a mesh network, smart endpoints act as repeaters, passing the data to other nearby devices before arriving at a main collector. Thus, a mesh network is more data and communications intensive on the MIUs. It allows for continuous connections and reconfiguration around broken or blocked paths by "hopping" from endpoint to endpoint until the destination is reached. Mesh networks differ from other networks in that the component parts can all connect to each other via multiple hops.

One major advantage of a mesh network is that it is self-healing. The network can still operate if an endpoint breaks down or a connection fails. As a result of the self-healing, a very reliable network is formed. One disadvantage with mesh networks is that any battery-operated endpoints may consume more power for the increased frequency of transmitting, thereby reducing battery life expectancy of the MIUs. In actual practice today, most mesh systems rely on electrically powered devices to perform the majority of the mesh management and data repetition. Thus, most mesh systems that have been deployed to support water or gas AMI or battery operated Smart City sensors often will utilize electrically powered devices such as electric meters or repeaters to provide the “hopping” mesh node operations thus allowing the battery-operated endpoints to reduce the number of required transmissions.

Radio Frequency Considerations

Current AMR and AMI offerings operate in either a licensed or unlicensed frequency spectrum. The primary benefit of a licensed system is that the spectrum band that the system utilizes permits a higher power signal (2 watts for licensed frequencies versus a maximum of 1 watt in unlicensed frequencies), which enables a greater distance between the transmitter and receiver units (i.e., fewer network components required compared to an unlicensed band system), and the system utilizes a specific frequency band that is closed to outside users so there is significantly less chance of interference by other electronic devices in the area. To minimize interference on an unlicensed network, the system typically uses specialized modulation and encryption techniques that allow the system to share the band with other users in a reliable and robust fashion. Hydro Ottawa has not reported any problems with their unlicensed frequency equipment.

Private Cellular

Private Network with Utility issued SIM

As an alternative to the traditional Public Carrier provided service, HOL is also exploring the possibility of garnering regulatory approval to deploy their own completely private cellular network using HOL procured and deployed cellular devices. As a private cellular carrier, HOL would privately procure LTE network spectrum and invest in Private cellular/LTE network devices to establish a private cellular network and issue private SIM cards for desired endpoint devices.

This option, if enabled, may enable HOL to mirror a more traditional AMI RF network while using cellular compatible devices. Thus, this option eliminates the recurring O&M fees associated with monthly cellular service charges while substituting capital investment for a privately owned network.

Summary

	PROS	CONS
Public Carrier (Cellular) – Carrier issued SIM	■ The cellular companies can deliver the data directly to the HES. There is no need for the utility to have any utility owned network components or facilities as part of the data delivery to the HES. Thus, all network management is done by the cellular vendor. ■ Cellular will provide security both in authentication and encryption from the meter to the delivery point of the HES. ■ Easiest to deploy assuming cellular network coverage exists at each endpoint. ■ Enables multi-vendor endpoint strategies as multiple MIU vendors can share the same public network (may require multiple head end systems)	■ Likely not all points will have cellular coverage so a second connectivity method may be required for hard to reach devices. ■ Monthly recurring O&M charges will be incurred on a per device basis (telecom companies may offer up front “setup” charges in lieu of some monthly fees which may be capitalized) ■ Endpoint modem obsolescence may occur more rapidly than under owned network architectures as cellular providers upgrade networks to meet consumer demand. This may leave earlier version modems obsolete (as occurred with 2G modems on previous vintage utility devices). ■ Redundancy may be an issue. Cellular

		coverage could be available only from one cell tower. If a failure occurs at that location the device could go offline. ■ Load is managed by the cellular company. High use areas could still see network congestion thus inhibiting connectivity. Utility endpoints will not have any priority for recovery efforts by cellular company in times of outages
Public Carrier (Cellular) – Private SIM	■ Same as Public Carrier (Cellular) – Carrier issued SIM ■ Reduced monthly service fees – roaming rates	■ Same as Public Carrier (Cellular) – Carrier issued SIM except reduced monthly service fees
Private Network (Cellular)	■ Recurring, per endpoint telecom fees are eliminated. Additional endpoint devices don't increase recurring costs under private network ■ System design can be tailored to maximize the coverage based on the location of actual endpoints ■ Network infrastructure investment provides recoverable capital asset	■ Utility must operate, optimize and maintain a communications network increasing O&M costs and requiring RF network expertise
Private Network - unlicensed Mesh	■ No Industry Canada licensing to maintain ■ Self-healing network to route around communications problems	■ Lower power, shorter range; thus, more network infrastructure to maintain, potential battery life limitations ■ Many devices share the same spectrum. Unlicensed frequencies can still be prone to interference in heavily equipment populated areas.
Private Network – licensed STAR	■ Spectrum protected from interference ■ Can utilize higher power to provide more range and less network infrastructure to maintain; thus, easier "umbrella" network to deploy, fewer network attachment issues	■ Industry Canada license to maintain; more spectrum requires more licensing

Figure 25 - Summary table of Network Technology options

Recommendations

AMI TECHNOLOGY ROADMAP

Overview

The AMI Technology Roadmap is influenced by business, financial and regulatory issues that have created timing or opportunity dependencies that have been considered. There are four key roadmap dependencies which force specific phases of the AMI Technology Roadmap as follows:

- Obsolescence of existing AMI Headend and pending obsolescence of current meter version
- Plans for HOL Field Area Network
- Depreciation schedule of current electric meter population

- Future Measurement Canada metrology requirements

The implications of these dependencies and drivers are described in more detail in previous sections of the report. The dependencies and drivers such as obsolescence, HOL reseal program, new Meter Canada standards, and depreciation schedules have specific dates and are shown in the below timeline.

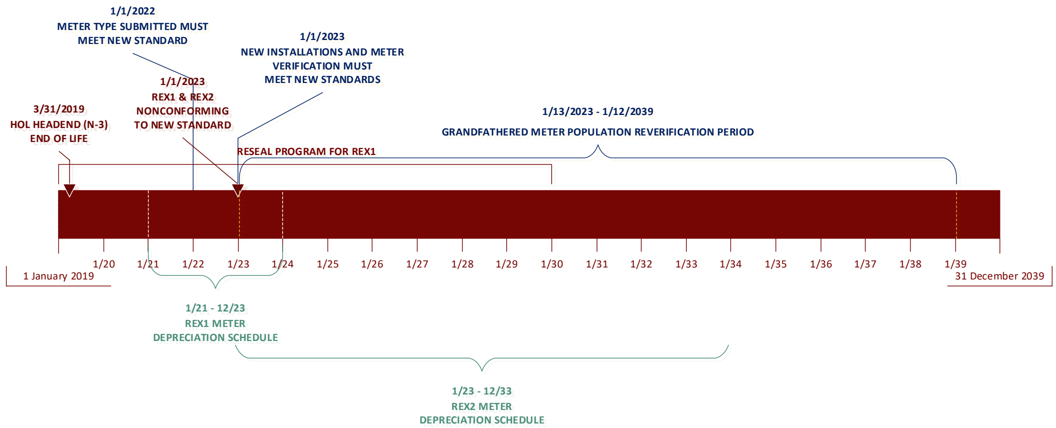


Figure 26 - AMI Strategy dependencies timeline

Based on the understanding of the current system, the desired and prioritized opportunities, and the influence of the HOL Telecom Plan and other dependencies, Black & Veatch recommends a sequence of strategic steps (or phases) that HOL might take to prudently address the remaining and new opportunities of AMI. The four strategic steps are illustrated in the diagram below.

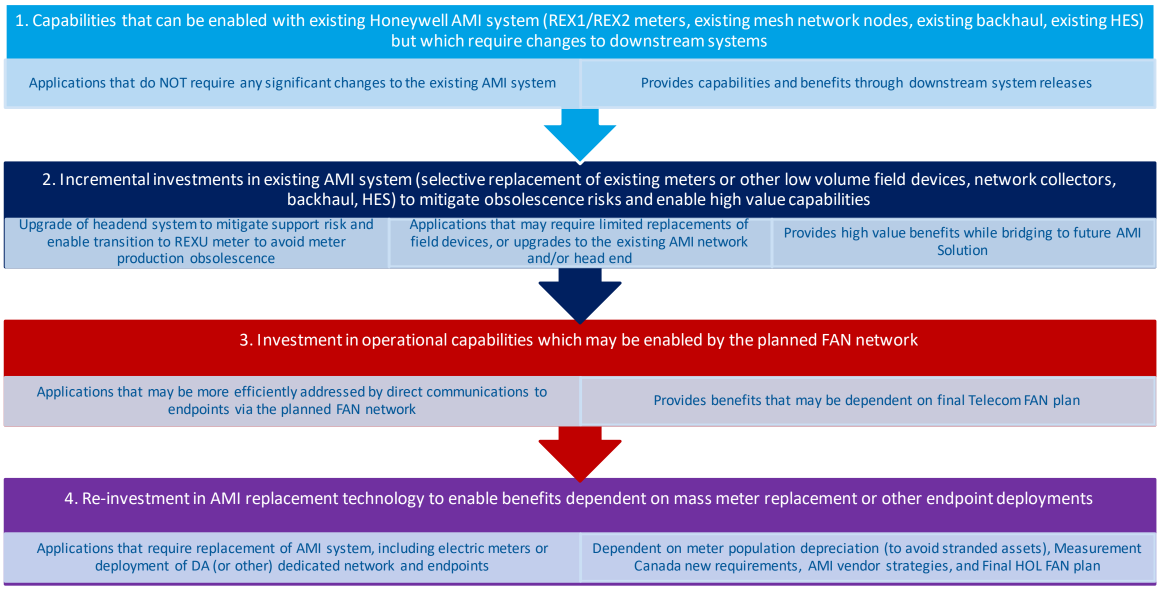


Figure 27 - AMI Strategy Phases

These phases then formed the basis of the Technology Roadmap which is shown in the below timeline.

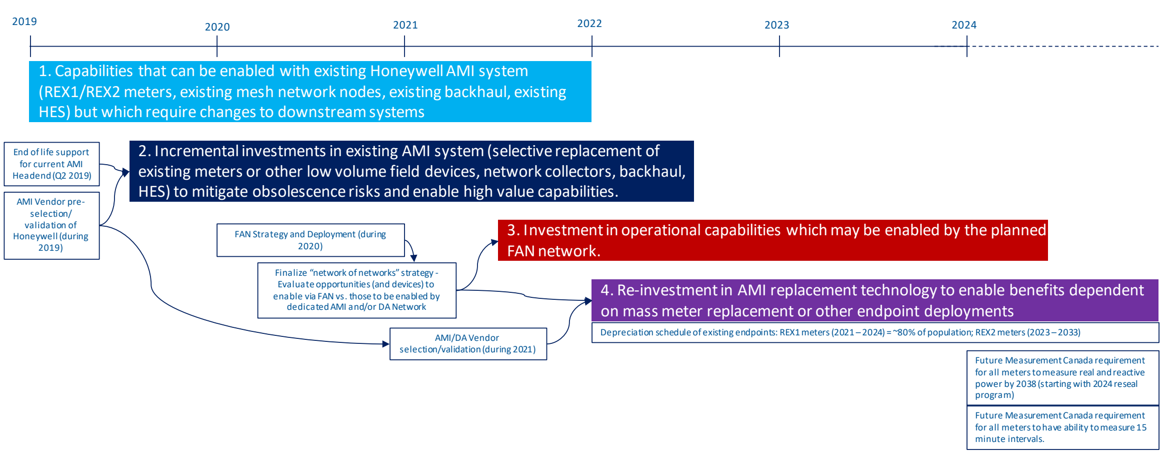


Figure 28 - AMI Strategy Phase sequence and timeline

Each of these phases is further defined below.

Phase 1 – Leverage existing AMI System

Phase 1 - Overview

- **Phase 1 implementation dependencies:**

- Validate selected opportunities included in the business releases. This would include a further prioritization and more detailed justification of the individual use cases, project implementation plans, project approvals and funding, and the assignment of appropriate project management resources
- Implementation of specific recommended capabilities contained in each business release may conflict with other planned upgrades to impacted systems (such as the Billing system upgrades)

■ **To Do during Phase 1:**

As HOL implements the opportunities offered in Phase 1, preparation for Phase 2 will begin. Thus, in preparation for Phase 2, the following activities should be undertaken during Phase 1:

- Develop and issue a Request for Information (RFI), or other suitable instrument, for AMI Technology. The RFI will serve three primary purposes as follows:
    1. To better understand the AMI vendor and technology landscape, the possible alternatives to the Honeywell solutions, and the likely future costs in order to better inform the choices to be made in Phases 2, 3, and 4.
    2. To qualify the likelihood that Honeywell remains the vendor of choice for incremental, near-term investments and, ultimately, for long-term replacement investments:
        - A deeper evaluation of the prudency in making the incremental investments in the existing system that are posed in Phase 2 is in order before embarking on Phase 2 investments. Each selective Phase 2 investment proposed in the existing Honeywell system may end up providing only short-term benefits, given the subsequent Phases 3 & 4 which may lead ultimately to a complete system replacement. Thus, it is prudent to evaluate whether each proposed incremental investment provides the benefits expected to warrant the size of the investment in the Honeywell system as well as the downstream systems.
        - The prudency of the proposed Phase 2 incremental investments may be influenced not only by the cost/benefit evaluation of each opportunity but also, more significantly, by the likelihood that Honeywell may remain the vendor of choice for the long-term Hydro Ottawa AMI solution and the investments contemplated in Phase 3 and 4.
    3. Analysis and Planning for the proposed AMI Head End system upgrade proposed to take place during Phase 2. While this head end upgrade is proposed as a business release during phase 2 (as it is considered an incremental investment in the Honeywell system), the planning activity to enable this upgrade to occur early during Phase 2 should be considered an action item to be completed during Phase 1.

Phase 1 - Business Releases

Phase 1 business releases are focused on expanding upon and enabling the opportunities that can be accomplished using the existing AMI system without incremental investments in the AMI system elements. That said, most of the opportunities will require enhancements or additional functional capabilities to downstream IT/OT systems to enable the further use of the AMI data that HOL already possesses or can retrieve from the existing AMI system.

During this phase, HOL may also want to begin reviewing organizational structures to sustain a multi-year, cross-functional, project oriented organization and governance structure. This could provide relief on operational resources as they will still need to be focused on operational issues and may do so at the detriment of progressing the projects. Additionally, the early development of this organization could transition to a full Program Management Office (PMO) in later Phases if HOL decides to replace or significantly upgrade their AMI system.

The following two graphics summarize the specific business releases recommended for Phase 1 of the AMI Roadmap as well as the IT systems expected to be impacted:

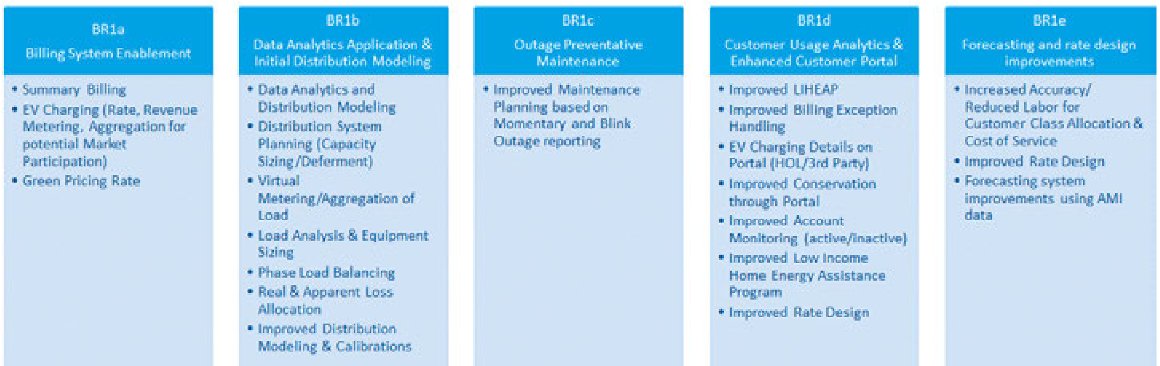


Figure 29 - Phase 1 Business Releases

Business Release 1 - Leverage Existing AMI System		
a. Billing System Enablement b. Data Analytics + Distribution Modeling c. Outage Reporting Metrics d. Customer Usage Analytics + Enhanced Customer Portal e. Forecasting + Rate Design	Analytics Billing System MDMS CSR and Customer Portal	Planning & Forecasting OMS Dispatch / MTU GIS

Figure 30 - Phase 1 Systems Impacted

Business Release BR1a – Billing System Enablement

The potential opportunities from AMI that were explored during the benefits discovery sessions described in the “AMI opportunities and potential benefits” section were examined to create the specific business releases. The opportunities that were ranked 3, 4, or 5 (i.e. desirable to HOL) and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
DER	Future	**EV Charging Aggregation and Market participation (HOL separately metered)**	X	X		5	Lo Cost	Targeted meter replacement	Low Effort		3	3.9	Enable consumption and aggregation of private charging infrastructure (Commercial & Residential) to provide for HOL or Third Party market participation.
DER	Partially Achieved	**EV Charging Rate and Revenue Metering for EV Charging Infrastructure**	X	X		5	Lo Cost	Meters installed by customer on EV Chargers	Low Effort	Customer manages charging but HOL monitors M&V impacts	3	3.9	Develop distinct TOU and Demand rates for Commercial & Residential EV Charging Separate revenue metering of private charging infrastructure (Commercial & Residential). Measuring consumption of the EV charger not consumption of individual vehicle.
Billing	Future	**Summary Billing - Increase number of Summary Billing customers**	X	X		4	Lo Cost		Low Effort		3	3.1	Billing reads available for every day to enable summary aggregation for summary accounts on any given day. This will allow more customers to aggregate sites together into summary billing accounts more easily.
Billing	Future	**Summary Billing - Reduction in labor costs associated with Summary Billing**		X		4	Lo Cost		Low Effort		3	3.1	Billing reads available for every day to enable summary aggregation for summary accounts on any given day. Summary bill aggregation from daily reads can be automated in MDMS on an automated report or billing determinant output.
Billing	Future	**Summary / Consolidated Billing - Improve cash flow for existing Summary Billing customers**	X	X		4	Lo Cost		Low Effort		3	3.1	Billing reads available for every day to enable summary aggregation for summary accounts on any given day. This will allow all summary billing accounts effective bill date to be accelerated to the bill cycle for the first read meter.
Regulatory	Future	**Green Pricing Rates**		X		3	Lo Cost	Use existing hourly interval data	Moderate Effort	Develop and implement Green Rate billing	3.5	1.9	Provide green energy rates associated with customers utilizing clean DER such as solar and wind.

Figure 31 – Business Release 1a Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network	MDMS	Billing	CSR & Customer Portals	Planning & Forecasting
Summary Billing			Aggregate timestamped interval data.	Aggregate multiple accounts into summary bill		
EV Charging	EV charger meter providing timestamped interval consumption data (discrete HOL metering device).	Timestamped interval data from total consumption and individually metered DER devices.	Separate DER generation sources from total consumption. Post daily consumption profile to customer portal. Post daily consumption profile to CSR portal	Create distinct DER generation source buckets. Request billing determinants from MDMS. Assign DER credits and total consumption and generate bill. Enable aggregated charged usage billing to third parties and/or market aggregators	Visibility to Customer bill. Visibility to total customer consumption and DER generation. Visibility to breakdown of bill into billing buckets and DER credits.	EV aggregation data to be used for Distribution planning & forecasting. PI Historian to store all data for CYME.
Green Pricing Rate	Total consumption interval data (timestamped) from revenue meters. Distinct HOL metering device on DER generation sources (solar,					

	wind, etc.) for Green Rate.					

Figure 32 – Business Release 1a Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

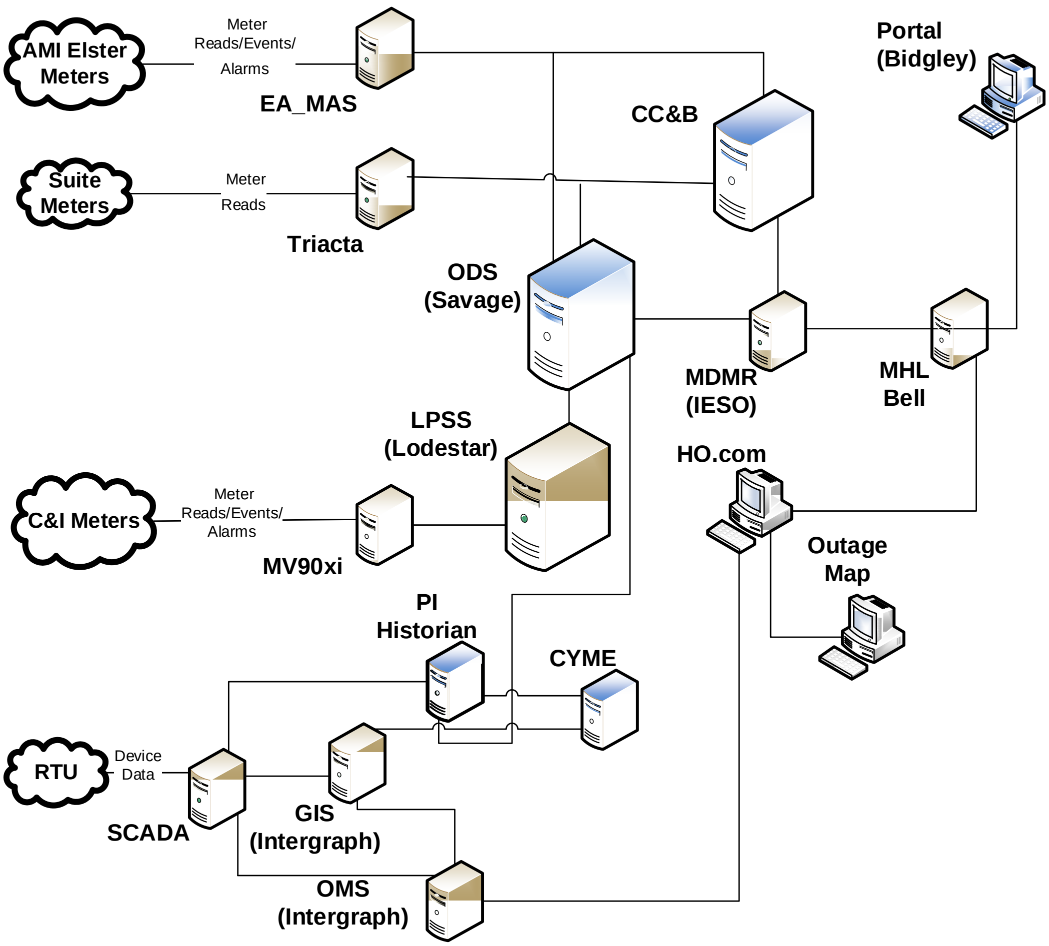


Figure 33 - Business Release 1a System Diagram

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Business Release BR1b – Data Analytics Application & Initial Distribution Modeling

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Planning	Future	**Defer Distribution system capacity requirements**		X		4	Lo Cost	Use existing hourly interval data	Moderate Effort	Enable distribution modeling using interval data	3.5	2.5	Processing of hourly metering data, provision of hourly data to Distribution Modeling for improved ability to model for max day and max hour demands near real-time. Improved Max Day/Hour Demand models; Drives down system design costs and saves capital.
Distribution Planning	Partially Achieved	**Aggregation of Load at Virtual Nodes for Distribution System Analysis, Transformer / Device Load Analysis and Equipment Sizing**		X		4	Lo Cost	Use existing hourly interval data	Moderate Effort	Enable distribution load aggregation using interval data + Data Analytics	3.5	2.5	Provide interval data and ability to aggregate interval data to distribution device nodes such as transformers to determine if equipment is properly sized.
Distribution Operations	Future	**Improved real and apparent loss allocation**		X		3	Lo Cost	Bellwether meter	Moderate Effort	Virtual metering aggregation + Data Analytics	3.5	1.9	Interval data processing on revenue and district meters; Virtual metering aggregation. Analytics for district and virtual metering losses
Distribution Operations	Future	**Phase Load Balancing**		X		3	Lo Cost		Moderate Effort		3.5	1.9	Interval meter data can be used to determine loads on each phase of the transformer.
Distribution Planning	Partially Achieved	**Improved Distribution Modeling and Calibration**		X		3	Lo Cost	Use existing hourly interval data	Moderate Effort	Enable distribution modeling using interval data	3.5	1.9	Processing of interval data; Improve system modeling for loss and correlation for seasonal loss detection

Figure 34 - Business Release 1b Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	MDMS	Data Analytics	GIS	Planning & Forecasting (CYME)
Defer Distribution system capacity requirements	Timestamped consumption interval data. Time stamp to be accurately aligned to system time to enable time synchronization.	Retrieve and process timestamped interval data daily. Export to MDMS	VEE. Export interval data sets to Planning & Forecast			Aggregate distribution load flows to discrete distribution devices and capacities. Determine system capacity margins based on rolled up endpoint load flows.
Aggregation of Load at Virtual Nodes for Distribution System Analysis, Transformer /			Process timestamped Aggregate interval data associated with	Aggregation of timestamped interval data to a virtual node. Analysis of load and distribution equipment	Provide distribution device connectivity model and device load	

Device Load Analysis and Equipment Sizing			identified grid nodes.	specifications to determine if equipment is sized properly.	capacities to analytics tools.	
Improved real and apparent loss allocation			VEE. Provide real and apparent power flows to data analytics.	Analyze consumption data, connectivity model, SCADA data, etc. for loss calculations		
Phase Load Balancing				Analyze totalized interval data of endpoints assigned to each phase to determine out of balance loads	Phase assignment of each endpoint.	
Improved Distribution Modeling and Calibration			VEE. Export interval data sets to Planning & Forecast			Consume and analyze interval data. Provide interval data to planning and forecasting models to improve accuracy and calibration.

Figure 35 - Business Release 1b Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

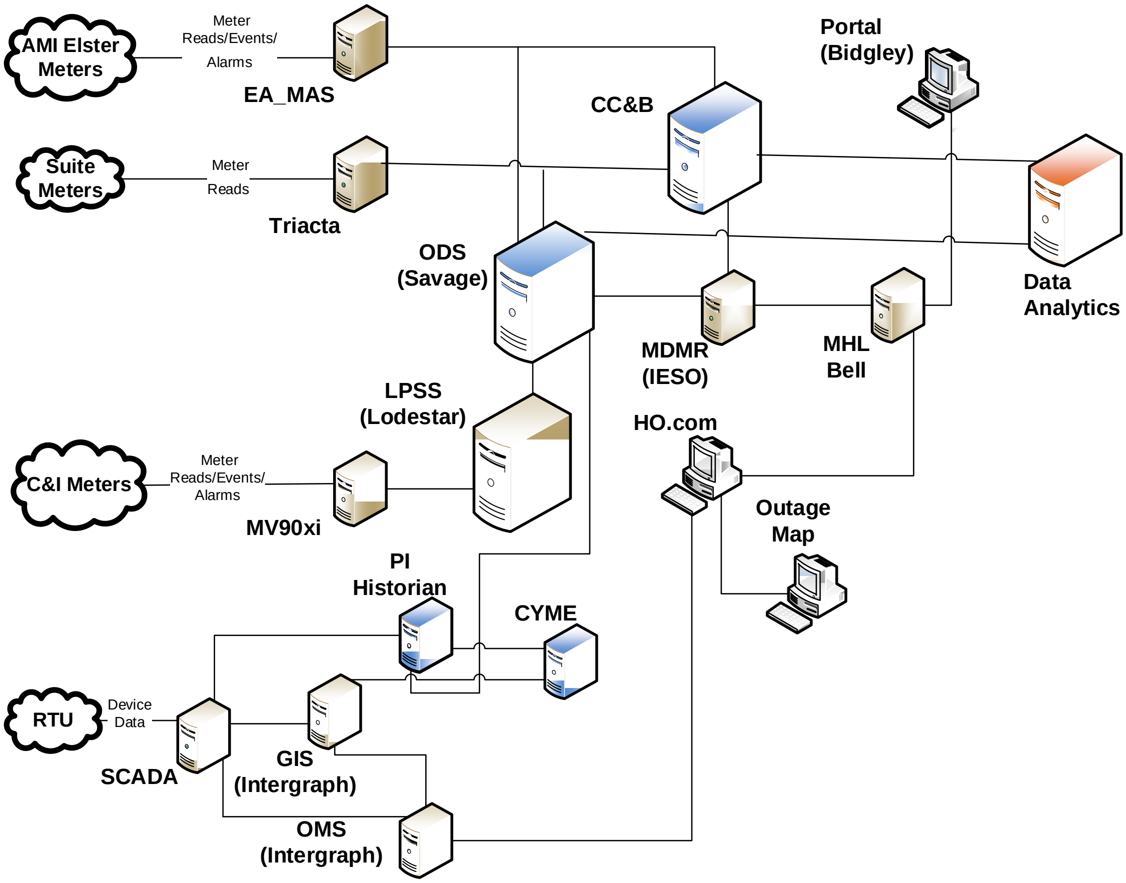
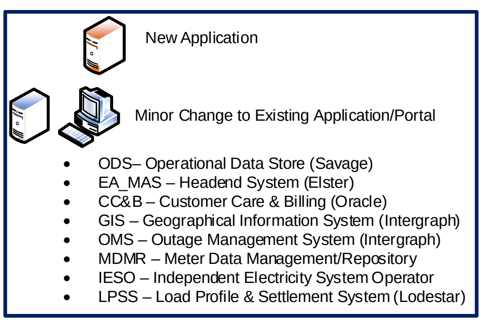


Figure 36 - Business Release 1b System Diagram



Business Release BR1c – Outage Preventative Maintenance

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Operations	Future	**Outage Management - Improved Momentary and Blink outages**	X	X		5	Lo Cost		Moderate Effort	Analytics + OMS	3.5	3.1	Proactive maintenance to address potential circuit performance problems. An ideal preventative indicator of conditions, which may evolve into a sustained SAIDI outage event - vegetation management secondary, weather head/service drop issues, loose meter socket connections, and recloser/breaker operations. Ability to validate repair after job completion. Can support use of MAIFI indicator.

Figure 37 - Business Release 1c Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	MDMS	Data Analytics	DMS/OMS
Outage Management - Improved Momentary and Blink outages	Power Status Event Log (timestamped) - Blink count	Retrieve and process momentary outage event logs daily.	Process outage event log and pass to Data Analytics	Analyze and correlate momentary outage events to circuit connectivity model to identify "trouble" areas for preventative maintenance.	Analyze and correlate momentary outage events to circuit connectivity model to identify "trouble" areas for preventative maintenance.

Figure 38 - Business Release 1c Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

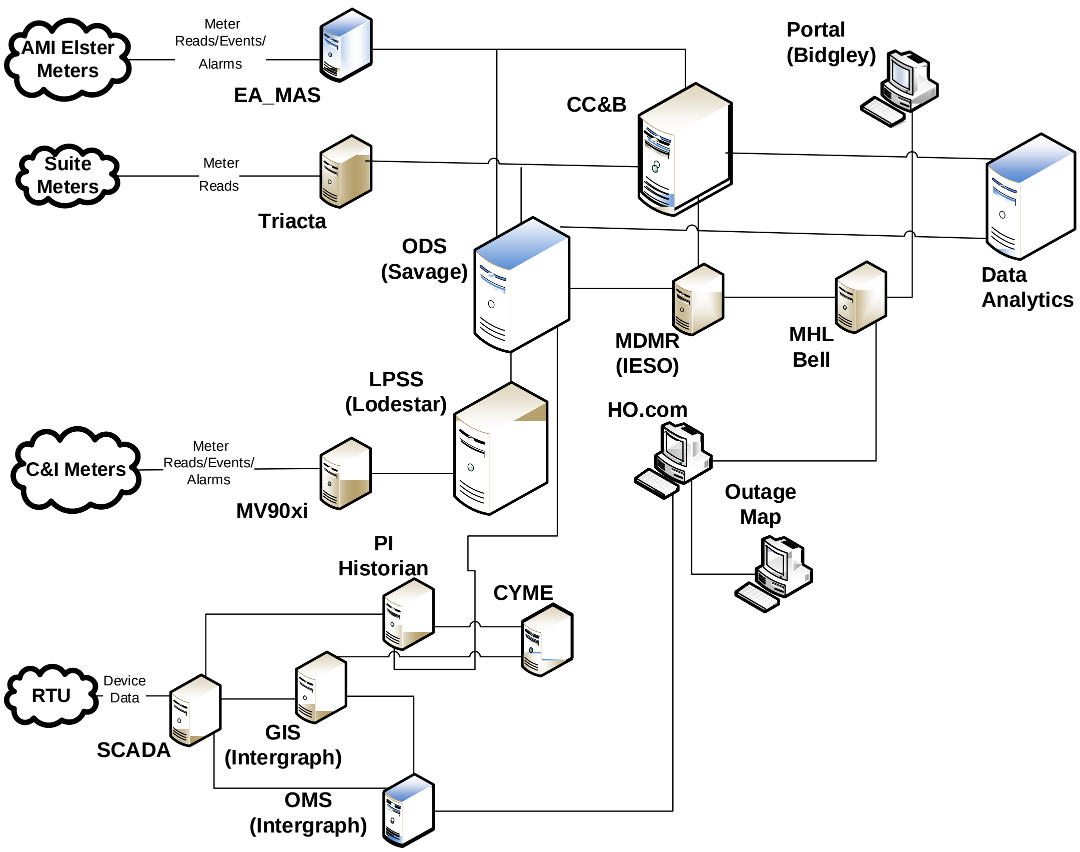


Figure 39 - Business Release 1c System Diagram

Minor Change to Existing Application/Portal

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Business Release BR1d – Customer Usage Analytics & Enhanced Customer Portal

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Hydro Ottawa Stakeholder Group	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Credit & Collections	Customer Care	Partially Achieved	**More rapid resolution of accounts in arrears (using field service dispatched service disconnect)** Reduction in labor to manage collections process; Reduction in uncollectables charge offs and short-term interest charges due to aggressive cut-off for non-pay		X	X	5	Lo Cost		Low Effort		3	3.9	Threshold monitoring of consumption; rapid dispatch of cut off field service reduces amount and number of collections issues.
Credit & Collections	Customer Care	Partially Achieved	**Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)**	X	X		4	Lo Cost		Low Effort		3	3.1	Reduced uncollectable charges due to improved customer understanding of usage and control over spending; Forecasted future usage based on historical usage; Threshold monitoring of forecasted consumption against customer identified usage; Customer Portal access/presentation/alerts
Billing	Customer Care	Partially Achieved	**Billing Exceptions (Level 2) - Reduced number and resolution time of billing exceptions/issues**	X	X		5	Lo Cost		Moderate Effort		3.5	3.1	Customer usage profile enablement on customer accessible portal improves customers ability to better understand bill and reduces need to inquire with utility to explain discrepancies. Availability of detailed customer usage profiles for CSR's enables faster and first call resolution of billing questions by CSR's.
Revenue Assurance	Market Engagement	Partially Achieved	**Reduced consumption on inactive accounts (using field disconnect visit)**		X	X	5	Lo Cost	Use existing hourly interval data	Moderate Effort	Analytics + Auto Dispatch	3.5	3.1	Daily monitoring of inactive accounts for "consumption on inactive accounts", data analytics to determine thresholds, field dispatch
DER	Market Engagement	Future	**Customer Portal information for EV Charging (HOL provided)**	X	X		3	Lo Cost	Meters installed by customer on EV Chargers	Low Effort		3	2.3	Provide detailed charging consumption profiles of private charging infrastructure (Commercial & Residential)
DER	Market Engagement	Future	**Enable / Improve Customer Conservation Programs**	X	X		3	Lo Cost		Moderate Effort	Enable bill forecasting engine	3.5	1.9	Customer portal providing consumption pattern, ability to use tools to forecast or check bills based on usage etc. Apps, emails, texts or other communications can be used to set up alerts or provide scheduled reports to customers.
DER	Market Engagement	Future	**Improved Effectiveness of Low Income Home Energy Assistance Program**	X	X		3	Lo Cost		Moderate Effort		3.5	1.9	Processing of meter data to develop hourly usage profile; Forecasting of usage (and bill) against LIHEAP usage caps; Customer profile enablement on customer accessible portal; CSR usage enablement of customer usage profiles

Figure 40 - Business Release 1d Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	MDMS	Data Analytics	Work Management	Billing	CSR & Customer Portal
More rapid resolution of accounts in arrears and reduced consumption on inactive accounts (using field disconnect visit)			Monitor usage and establish thresholds for disconnect of service. Identify accounts exceeding collections limits. Issue report for disconnect.	Dispatch field order to disconnect service. Provide disconnect service order information.	Issue virtual work orders for disconnect - reconnect of service based on exceeding allowable consumption in arrears.	
Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)		Forecast expected daily consumption for remainder of billing period based on historical profile of individual premise usage.				Enable forecasting of total bill (usage + charges) and provide access to CSR and customer
Reduced number and resolution time of billing exceptions/ issues		VEE. Process outage events to validate zero usage intervals as outages and not estimate across them.				Visibility to Customer bill. Visibility to customer consumption profile.

Customer Portal information for EV Charging (HOL provided)	EV charger interval consumption measurement (discrete HOL device).					Visibility to EV consumption profile.
Enable / Improve Customer Conservation Programs. **Improved Effectiveness of Low Income Home Energy Assistance Program**		VEE. Post daily consumption profile to customer portal. Post daily consumption profile to CSR portal				Enable advanced features such as energy load profiling and neighborhood energy comparisons. Enable forecasting of total bill (usage + charges) and present to customer. Forecast likely timing of reaching LIHEAP limits.

Figure 41 - Business Release 1d Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

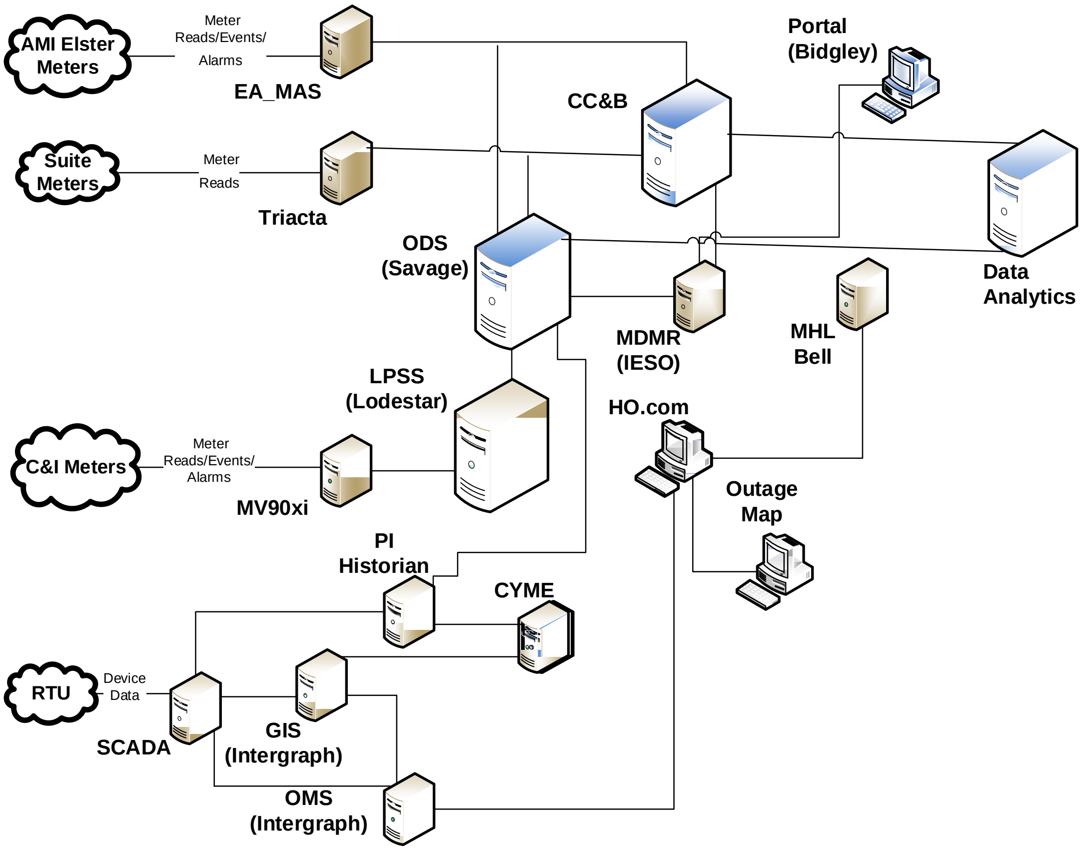
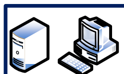


Figure 42 - Business Release 1d System Diagram



- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Business Release BR1e – Forecasting and rate design improvements using AMI data

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Hydro Ottawa Stakeholder Group	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Regulatory	Market Engagement	Partially Achieved	**Improved accuracy in rate design**			X	5	**Lo Cost**		**Low Effort**		3	**3.9**	Processing and storage of hourly consumption data support advanced tariff bill rate design
Regulatory	Market Engagement	Partially Achieved	**Increase accuracy of customer class allocations of cost of service**			X	5	**Lo Cost**		**Low Effort**		3	**3.9**	Processing of Daily/hourly usage profiling; Aggregation into customer class aggregations
Regulatory	Market Engagement	Partially Achieved	**Reduced labor to develop customer class allocations of cost of service**			X	5	**Lo Cost**		**Moderate Effort**	Aggregation using Data Analytics	3.5	**3.1**	Processing of Daily/hourly usage profiling; Aggregation into customer class aggregations
Distribution Planning	Distribution Automation	Future	**Improved Forecasting Capability**		X		5	**Med Cost**	15 minute interval data (assumes Forecasting is performed at 15 minute granularity)	**Significant Effort**	Enable nodal pricing and forecasting	4.5	**1.9**	Future direction from ISO is to move to nodal pricing which will require ability to forecast at a more granular level such as feeder level.

Figure 43 - Business Release 1e Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	MDMS	Data Analytics	Planning & Forecasting
Improved accuracy and reduced labor in rate design, customer class allocations, and cost of service			VEE. Post daily consumption profile to Data Analytics	Analyze usage information for rate design opportunities and impacts; customer class and cost of service allocations.	
Improved Forecasting Capability	Timestamped consumption interval data. Time stamp to be accurately aligned to system time to enable time sync.	Retrieve and Process timestamped interval data daily. Export to MDMS	VEE. Export interval data sets to Planning & Forecast		Consume and analyze interval data. Develop forecasting model which applies load flow at nodal level.

Figure 44 - Business Release 1e Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

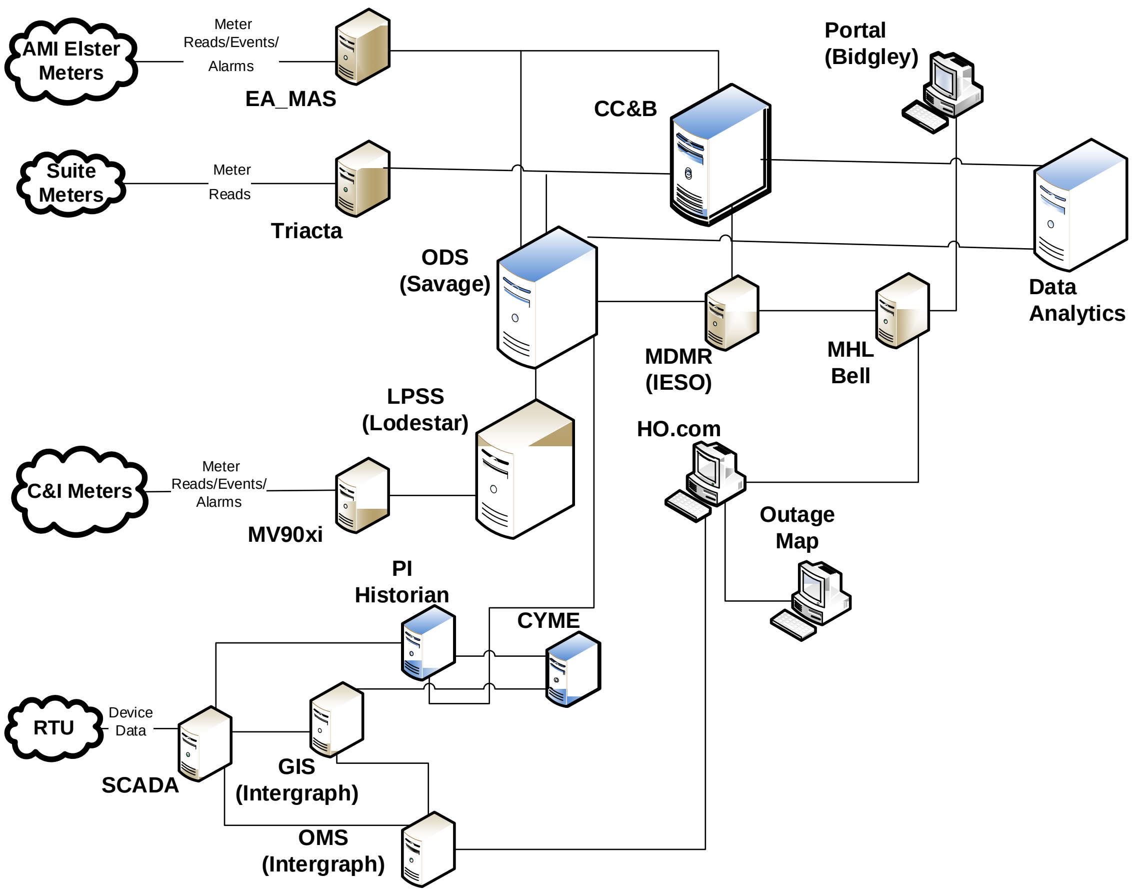
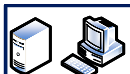


Figure 45 - Business Release 1e System Diagram



- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Phase 2 – Incremental investments in Existing AMI

The following AMI Roadmap diagram is replicated here for convenience and to provide context for the activities of Phase 2:

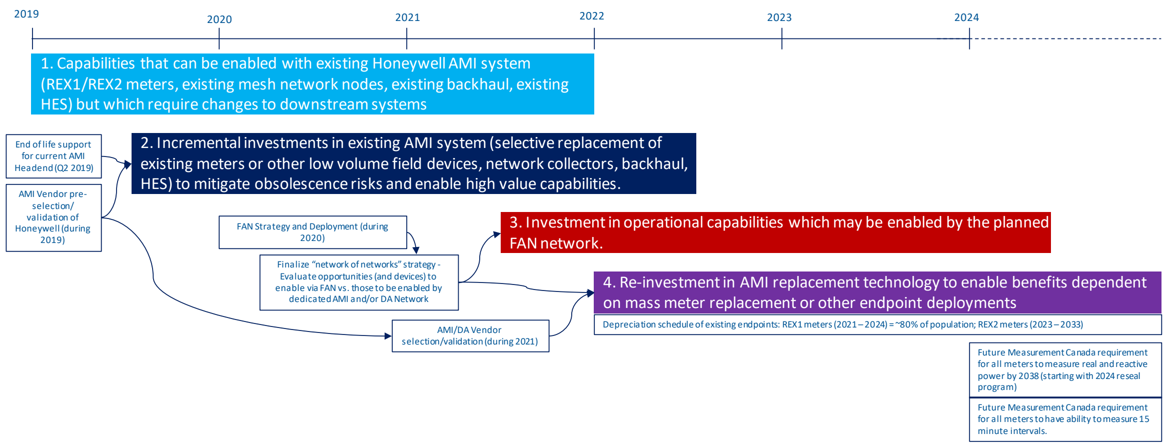


Figure 46 - AMI Roadmap Sequence and Timeline

Phase 2 – Overview

■ **Dependencies:**

- Finalize the strategy for enabling "always on, real-time" backhaul communications as the planned Phase 2 replacement of the shared POTs lines currently used in "one-way" dialup mode for AMI collectors. Specifically, will HOL want to utilize the planned Telecom FAN for this segment of the existing Honeywell AMI solution or simply utilize public carrier services as a bridge to a future HOL owned backhaul network?
  - This is considered a "soft" dependency as HOL can certainly upgrade the existing backhaul, shared service "dial-up" phone lines with dedicated phone lines from traditional telecom service providers.
  - If/when HOL replaces the POTs line then they will need to consider implications to commercial/industrial customers whose lines they currently share (especially those whose shared lines are currently used not just for connection to the AMI collector meter but are also used to connect to MV-90). Upgrading these to cellular nodes may impact:
    - o The ability of customers to access their data
    - o The ability for HOL to read the A3 meter as it converts from dialup to cellular due to coverage, and the reprogramming of modems in MV-90
- Completion of AMI RFI and/or validation of the risk of further investments in the Honeywell AMI solution for short-term opportunities. As the recommended opportunities of Phase 2 all involve selective investments in or supporting the Honeywell AMI solution, many of them will be dependent on HOL's determination of the business value of incrementally investing more into this current solution.

■ **To Do during Phase 2:**

As HOL implements the chosen opportunities offered in Phase 2, preparation for Phase 3 will begin. Thus, in preparation for Phase 3, the following activities should be undertaken during Phase 2:

1. Finalize and begin implementation of the definitive HOL Telecom FAN Plan. Based on this FAN plan, develop the long-term AMI Technology Plan that is best supported by the finalized FAN Plan is finalized. The AMI Technology plan is dependent on the ability of the FAN to provide supporting AMI functions versus direct AMI functions. The strategies and choices to be reconciled include:
    a. The extent to which the FAN is able to support a full portfolio of commercially available endpoint devices (i.e. meters, DA devices, in-home devices, Smart City devices, etc.). The extent to which the FAN has proven mitigation techniques to reach "hard to reach" endpoints.
    b. The extent to which a "network of networks" strategy provides greater coverage, reachability mitigation options, commercially available endpoints or financial benefits
2. Develop a meter replacement strategy to mitigate the likely production obsolescence of the current REX2 meters. It is expected that meters will start to become fully depreciated and information will become clearer on the planned AMI alternatives and Measurement Canada regulations. Specifically, the following Honeywell operational characteristics will need to be accommodated in an obsolescence mitigation strategy that will need to be determined during Phase 2.
    a. REX1 limits the mode of operation to LAN1 mode. There is no path to migrate REX1 to LAN2 mode or the newer SynergyNet network.
    b. To move to LAN2 mode, all REX1 meters must be replaced on that node (geographic area).
    c. Replacement of A3 Collectors (gatekeepers) with Pole Mounted Collectors will NOT (significantly) improve coverage area, speed, or enable less devices due to operating those collectors in LAN1 mode because of REX1 meters.
    d. Migration to the SynergyNet IPv6 network would require the REXU meter (or A4) and new collector/router as an overlay to the existing network. SynergyNet is not backward compatible for REX1 or REX2 meters.

    Thus, the outcome of the RFI process described in the Phase 2 dependencies will influence the meter replacement strategy and the extent to which HOL wants to progress down the path to ultimately migrate to the full Honeywell SynergyNet solution or simply mitigate the REX2 obsolescence with the REXU meter (but utilized in the LAN2 mode).

Phase 2 - Business Releases

Phase 2 business releases are focused on enabling the opportunities that can be accomplished with incremental investments in the AMI infrastructure. These investments include the following potential selective investments:

- Upgrading the AMI headend
- Replacing the backhaul communications on all collectors to cellular, fiber, or other communication
- Selectively replacing meters with service disconnect equipped meters

The opportunities identified in Phase 2 have the potential to improve field meter operations, enhance outage management processes, provide more analytics to better assess customer and operational issues, and enable additional customer programs.

Organizational considerations during this phase will include evaluation of AMI Operations and how to best support multiple departmental needs for information. Those departments are likely to include Engineering, Distribution Operations, Emergency Response, Dispatch and Marketing / Customer Programs. Each of these departments will be reliant on AMI data and staffing, roles and responsibilities, and service levels may need to be evaluated to balance the needs of the core AMI functionality and the new requirements.

The following two graphics summarize the specific business releases recommended for Phase 2 of the AMI Roadmap as well as the IT systems expected to be impacted:

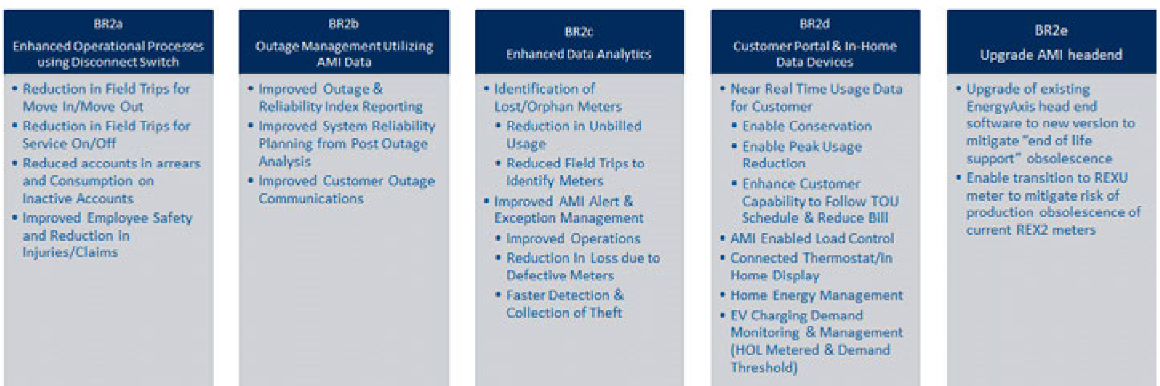


Figure 47 - Phase 2 Business Releases

Business Release 2 - Incremental Investment in Existing AMI System		
a. Enhanced Operational Processes b. Outage Management using AMI Data c. Enhanced Data Analytics d. Customer Portal + In-Home Data Device e. Upgrade AMI Headend	Analytics Billing System CSR and Customer Portal IVR	AMI Headend OMS Dispatch / MTU GIS

Figure 48 - Phase 2 Systems Impacted

Business Release BR2a – Enhanced Operational Processes using Disconnect Switch

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Meter Operations	Partially Achieved	**Field Employee Safety - reduced technician field trips for shut off for non-pay.**		X		5	Med Cost		Moderate Effort		4	2.5	Remote Connect/Disconnect functionality almost eliminates the need for field visits for disconnection of service or reconnection.
Credit & Collections	Partially Achieved	**More rapid resolution of accounts in arrears (using meter enabled disconnect switch)** Reduction in labor to manage collections process; Reduction in uncollectables charge offs and short-term interest charges due to aggressive cut-off for non-pay		X	X	5	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort		4	2.5	Threshold monitoring of consumption; remote disconnect reduces amount and number of collections issues.
Meter Operations	Partially Achieved	**Reduction in Meter Operations field orders for "disconnects / reconnects for non pay" by using remote disconnects / reconnect functionality.**		X		5	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort		4	2.5	Remote Connect/Disconnect switch included in meter eliminates the need for field visits for disconnection and reconnection of service due to unpaid balance. If customer notices must be left at premise during disconnect a lower skilled resource could be utilized or process modified to eliminate need.
Revenue Assurance	Partially Achieved	**Reduced consumption on inactive accounts (using service disconnect switch)**		X	X	5	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort	Analytics + Auto Dispatch	4	2.5	Daily monitoring of inactive accounts for "consumption on inactive accounts", data analytics to determine thresholds, remote service disconnect
Meter Operations	Future	**Reduction in Meter Operations field orders for "move-in / move-out" by using remote disconnects / reconnect functionality.**	X	X		4	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort		4	2.0	Remote Connect/Disconnect switch eliminates the need for field visits for disconnection and reconnection of service due to move ins/ move outs. If customer notices must be left at premise during disconnect a lower skilled resource could be utilized or process modified to eliminate need.
Meter Operations	Partially Achieved	**Reduced injuries & claims**		X		3	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort	Analytics	4	1.5	Reduction in meter reading and operations field visits leads to reduction in hazardous exposure.
Environmental	Partially Achieved	**Carbon Offset Value - reduction in vehicle emissions due to reduced field trips**			X	3	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort	Data Analytics + Auto Dispatch	4	1.5	Provide remote disconnect / reconnect switches and improved field maintenance analytics to eliminate un-necessary field visits; thereby reducing the carbon footprint and fuel costs.

Figure 49 - Business Release 2a Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

<table>
<tr><th></th><th>Meters</th><th>Network & HES</th><th>Data Analytics</th><th>Work Management</th><th>Billing</th></tr>
<tr><td>Reduction in Meter Operations field orders for "disconnects / reconnects for non-pay" and for "move-in / move-out".</td><td rowspan="2">Service disconnect switch.
Hourly consumption interval data.
Alarms and alerts.</td><td rowspan="2">Process inputs from billing/work order systems prompting disconnect and reconnect commands.
Send commands to meter to disconnect and reconnect service.
Receive and process switch state change verification and provide to billing / work order system.
Maintain switch status information.</td><td rowspan="2">Monitor usage and establish thresholds to indicate un-acceptable consumption on an expected inactive account or accounts which exceed collections limits.
Send report to billing system to issue disconnect command.
.</td><td></td><td rowspan="2">Identify inactive accounts and/or accounts exceeding allowable consumption in arrears to MDMS and data analytics.
Issue disconnect command based on data analytics identifying un-acceptable consumption on expected inactive accounts.</td></tr>
<tr><td>Reduced consumption on inactive accounts.

Rapid resolution of accounts in arrears.
Reduction in labor to manage collections;
Reduction in uncollectables and short-term interest.</td><td></td></tr>
<tr><td>Reduced Field Trips due to improved operational analytics.

Improved Field Employee Safety, Reduced injuries & claims. Reduced Carbon footprint.</td><td></td><td>Issue disconnect and reconnect.
Provide switch status.
Process register data daily.</td><td>Develop meter maintenance algorithms to correlate interval, register, and alarm data with work management systems to improve diagnostics and triage of field work.
Capture avoided field trips</td><td>Automate field work dispatch based on data analytics outputs.
Align correct resource skills to triaged and filtered</td><td></td></tr>
</table>

			and mileage to calculate carbon reduction.	field maintenance work.	

Figure 50 - Business Release 2a Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

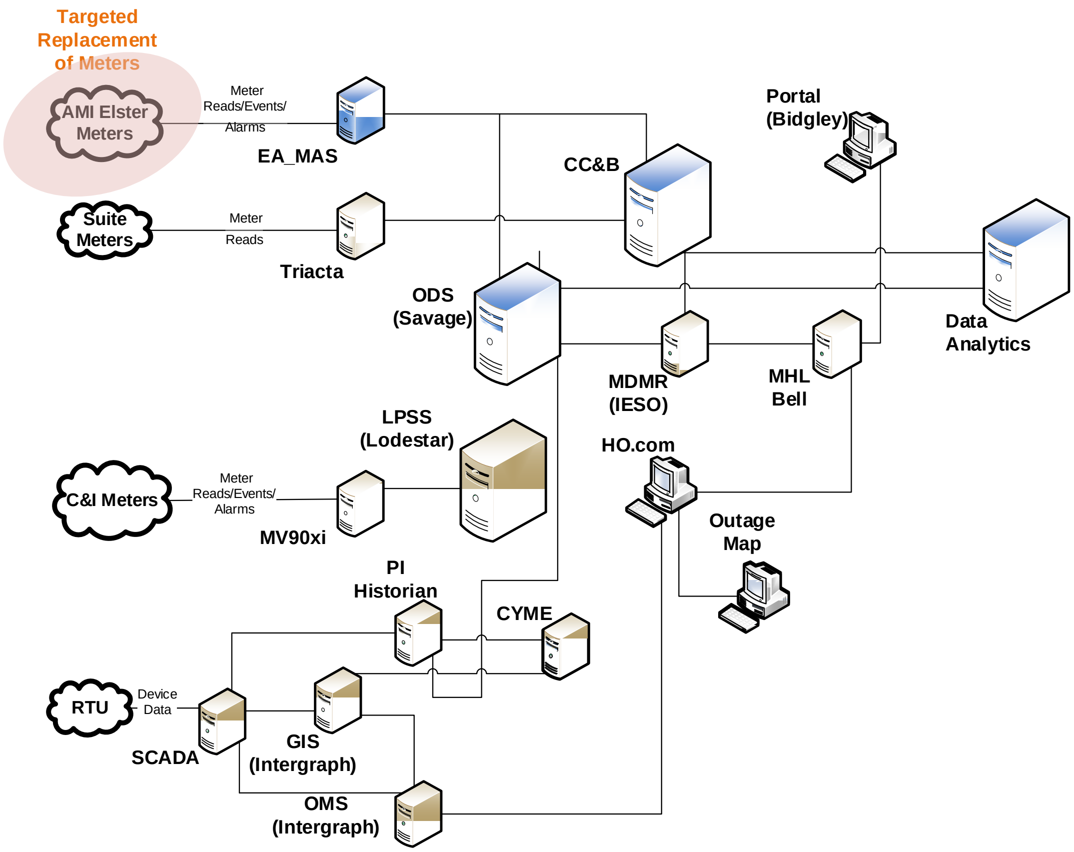


Figure 51 - Business Release 2a System Diagram

- Minor Change to Existing Application/Portal
- Targeted Meter Replacement
- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Business Release BR2b – Outage Management Utilizing AMI Data

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Operations	Future	**Outage Management - Reduced Trouble Calls (single lights out)**	X	X		5	Med Cost	Replacement of POTs backhaul	Moderate Effort	OMS system enablement +IVR	4	2.5	Leverage AMI ping power verification capabilities to reduce O&M costs associated with field investigations for these types of outage calls. Provide ability to ping the meter and determine whether there is utility side power to the service prior to dispatch. The customer service tool is to perform the preliminary assessment before opening an outage ticket.
Distribution Operations	Future	**Outage Management - Improved Outage and Reliability Index Reporting and System Reliability Planning through post event analysis.**		X		5	Med Cost	Replacement of POTs backhaul	Moderate Effort	OMS enablement	4	2.5	Improved knowledge of system performance and validation of exact outage durations. Post-event reliability analysis to identify improvements for long range reliability/capacity planning (outage and voltage events). Post-event restoration analysis to identify potential improvements and efficiencies to the restoration plan. Verification of SAIDI/CAIDI calculations. Post-event system reliability analysis data to identify areas in which system reliability can be improved based on actual outage information, and analysis of pre-event conditions.
Distribution Operations	Future	**Outage Management - Improved Customer Communication**	X	X		5	Med Cost	Replacement of POTs backhaul	Significant Effort	OMS system enablement + Customer Portal enablement	4.5	1.9	Proactive communication to customers caused by improved outage event situational awareness. Highly efficient restoration updates with system wide pinging/polling to confirm OMS outage information. Restoration tracking and confirmation: status of individual service restoration by enabling customer service representatives to ping meter.

Figure 52 - Business Release 2b Opportunities

Business Release 2b will require HOL to replace the current dial-up, shared phone lines that are used to connect to the network collectors with dedicated, always on, two-way communications to enable outage alarms and events to be passed to HOL in real time.

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	Data Analytics	CSR & Customer Portal	IVR	DMS/ OMS
Reduced Trouble Calls (single lights out)	Power status ping response provided in real-time.	Retrieve power status on-demand in real-time.		Enable pinging power status	Enable "call-back" to customer for reported outage.	Disconnected meters need to be put in exclusion list to remove them from outage list.
Improved Outage and Reliability Index Reporting and System Reliability Planning through post event analysis.	Power Status Alerts (Last Gasp outage alert + Power restoration) timestamped and transmitted in real-time. Power status ping response provided in real-time.	Retrieve and Process power status event logs and provide to OMS.	Use timestamped restoration and power out events to perform post storm analysis to ensure accurate CAIDI / SAIFI and to identify target areas for reliability improvement strategies			OMS - Modify event times based on power status events. Use power status events as inputs into outage modeling.

Improved Customer Communication	Power Status Alerts (Last Gasp outage alert + Power restoration) timestamped and transmitted in real-time. Power status ping response provided in real-time.	Communicate power outage alerts and ping responses in real-time with high reliability. Process outage alerts and ping responses in real-time and send to OMS.		Outage information, status, and ETR updated on customer portal or custom outage portal	Ability to push outage status and ETR messages to customers for outages	Import outage event alerts to improve outage dispatch. Predictive analytics to improve estimated restoration time. Automated ping process to validate power restoration. Disconnected meters need to be put in exclusion list to remove them from outage list.

Figure 53 - Business Release 2b Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

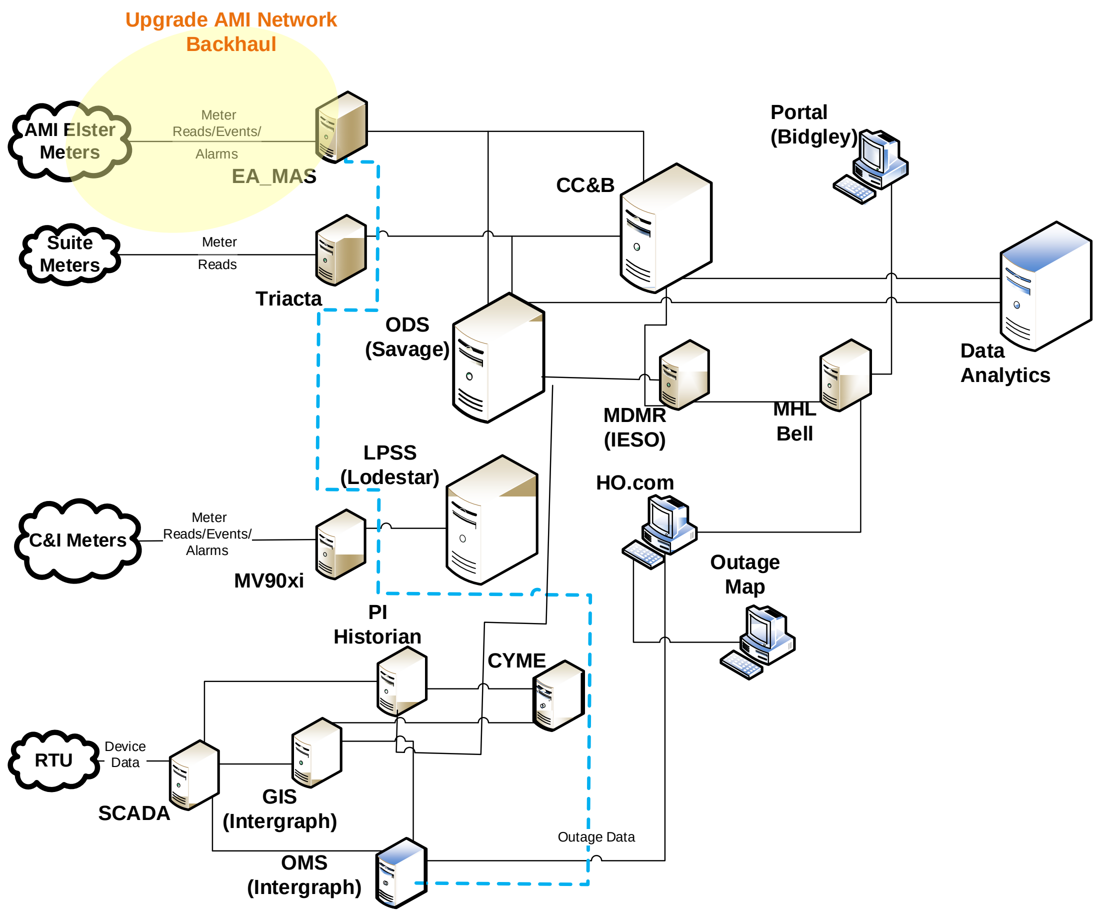


Figure 54 - Business Release 2b System Diagram

Minor Change to Existing Application

- New Interface to Utilize AMI Outage Data
- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Business Release BR2c – Enhanced Data Analytics

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Meter Operations	Partially Achieved	**Reduced unaccounted for usage and field labor due to improved identification of lost or orphan (a.k.a. data nodes) meters**	X	X	X	5	Lo Cost		Moderate Effort		3.5	3.1	Identification of orphan accounts through correlation of Billing System and AMI Head end to find active meters with no assigned account. Locate orphans through GPS assignments, RF triangulation, or field searches.
Meter Operations	Partially Achieved	**Improve AMI Alert and Exception Management by back end systems.**		X		4	Med Cost	Replacement of POTs backhaul + Time Stamped data + real time alerts	Significant Effort	Deploy network upgrades + Analytics + Auto Dispatch	4.5	1.5	Provide robust system to perform filtering, data management and analytics to filter, aggregate, analyze and provide advanced alert and exception processing.
Revenue Assurance	Partially Achieved	**Faster detection of and collection of theft**		X	X	3	Med Cost	Replacement of POTs backhaul + Time Stamped data + real time alerts	Significant Effort	Deploy backhaul upgrades + Analytics + Auto Dispatch	4.5	1.1	Processing of tamper alarms plus analytics and correlation of usage profile analysis to identify high probability theft

Figure 55 - Business Release 2c Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	MDMS	Data Analytics	GIS	Work Mgnt.
Reduced unaccounted for usage and field labor due to improved identification of lost or orphan meters		Identify all network devices which "hear" the lost or orphaned meter. Network diagnostics to determine mesh communication pathways.		Identify all meters that are transmitting data from the field but which are not assigned to a registered account. Triangulate RF signals to identify location of meters with no accounts assigned	Capture GPS location of endpoint upon field installation and store in GIS.	
Improve Alert and Exception Management by back end systems.	Timestamped consumption interval data. Timestamped meter data (alerts, events, etc.) Time stamp to be accurately aligned to system time to enable time synchronization.	Retrieve timestamped interval data daily. Retrieve timestamped meter data daily and real-time for certain events/alarms. Process timestamped interval data daily. Process timestamped	Process timestamped interval data. Process timestamped meter data	Analyze and correlate usage profiles, alarms and events to determine abnormal meters.		Issue work dispatch for critical events based on indicated priority from Data Analytics. Provide Data Analytics information to support expectation

Faster detection of and collection of theft		meter data daily and real-time for certain events/alarms		Analyze and correlate usage profiles, alarms and events to determine likely tamper events meters. Issue tamper target lists based on likelihood probabilities to work dispatch system.		Issue work dispatch for theft/tamper based on indicated priority from Data Analytics. Provide Data Analytics information to support expectation of tamper/theft.

Figure 56 - Business Release 2c Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

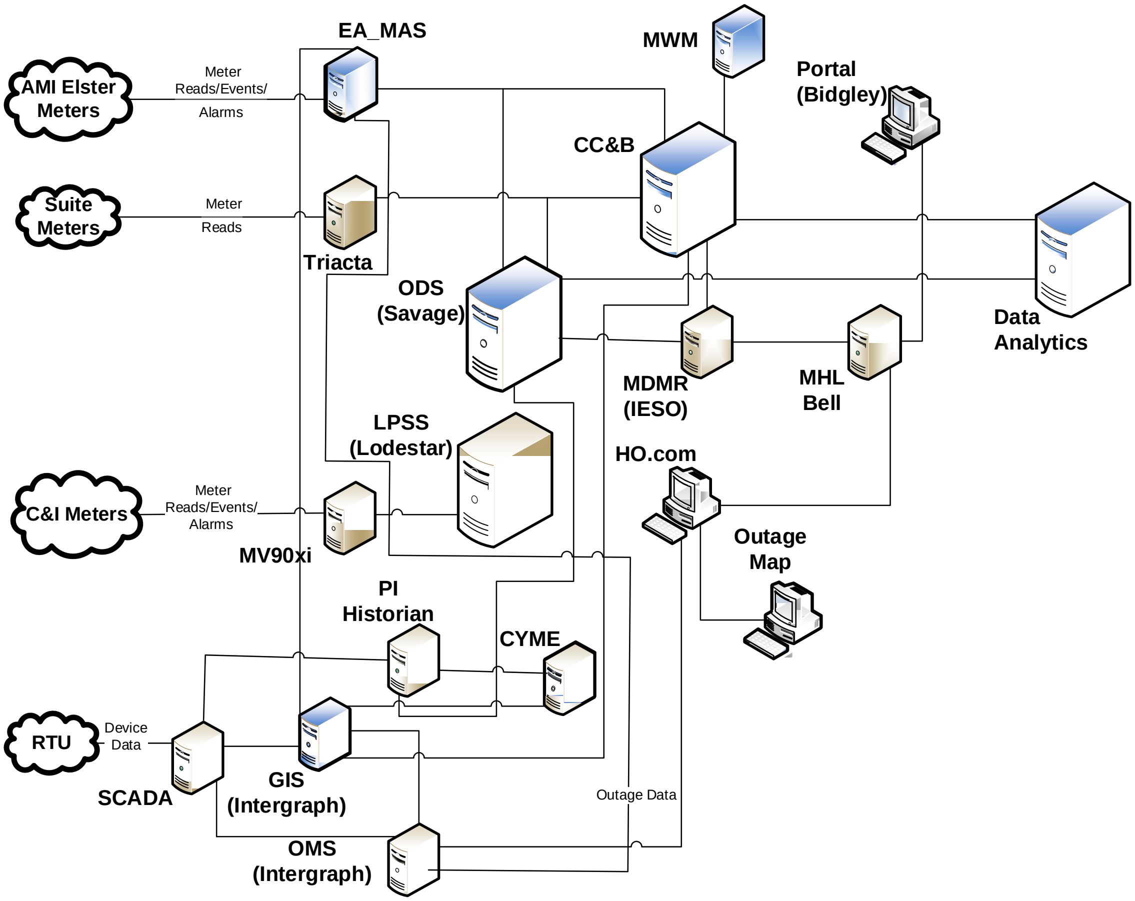


Figure 57 - Business Release 2c System Diagram

Minor Change to Existing Application

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- MWM – Mobile Workforce Management

Business Release BR2d – Customer Portal & In-Home Data Device

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Customer Service	Future	**Enable Residential Customer Direct Access to Meter Usage (near real-time)**	X			5	Med Cost	Targeted meter replacement	Low Effort		3.5	3.1	Provide near real-time consumption data to residential customers to enable enhanced home energy management
DER	Partially Achieved	**Home Energy Management**	X			5	Lo Cost	Customer provided Home Energy Management System + Targeted meter changeout	Significant Effort	Upgrade HES	4	2.3	Home Energy Management system to provide customer managed, in-home energy management. HOL to provide real-time energy consumption to customer owned home energy management system.
DER	Partially Achieved	**Load Control - Utility Enabled (AMI system compatible)**	X	X		5	Med Cost	Load control switches on loads required. Available Q4	Significant Effort	Upgrade HES	4.5	1.9	Utility controlled Demand Response events using AMI enabled load control devices, measurement and verification of load control events.
DER	Partially Achieved	**Connected Thermostat/In-Home Display**	X			5	Med Cost	HOL provided thermostats + Targeted meter changeout (ZigBee)	Significant Effort	Upgrade HES	4.5	1.9	Provide real-time data to display on connected thermostat; Provide setting signals to setback thermostat during DR events.
DER	Future	**EV Charging Demand Monitoring and Management (HOL metered with Demand Thresholds)**	X			5	Hi Cost	Smart Inverter + FAN + Software	Significant Effort	IT intensive	5	1.4	Direct monitoring and management of EV charging infrastructure (Commercial & Residential) to enable individual demand management

Figure 58 - Business Release 2d Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	In Home Devices	Network & HES	HES	Customer Portal
Enable Residential Customer Direct Access to Meter Usage (near real-time) using Smart Thermostat, in home display, or Home Energy Management System	Energy consumption data transmitted via: ZigBee Wi-Fi Other TBD real-time communication channel	Smart Thermostat, In home display, or Home Energy Management System to view real-time energy usage and other information pushed by utility	Retrieve interval data. Push messages and/or event alerts to In-Home device	Process real-time commands, events, and alarms.	Reconcile differences between VEE data and real-time data customer views on portal
Load Control - Utility Enabled (AMI system compatible)	Hourly consumption interval data	Load Control Switches compatible with AMI communications	Retrieve interval data daily. Provide on/off control signals to LCS devices. Retrieve switch status alerts from load control devices.	Process DR commands, events, and alarms. Process interval data to validate DR impacts.	
EV Charging Demand Monitoring and Management (HOL metered with Demand Thresholds)	EV charger real-time KW demand measurement (discrete HOL device) with demand thresholds and real-time threshold alert communications.	Load Control Switches compatible with AMI communications	Retrieve demand threshold alerts in real-time	Process demand threshold alerts in near real-time. Pass demand threshold alert to EV Control System. Enable re-programming of demand threshold alert settings.	

Figure 59 - Business Release 2d Functional Requirements

Note: Identify How Secure Pairing with Meter and Provisioning will be done, it is also Important for In-Home Device Information to be Stored in CC&B and ODS to tie it to the Meter/Account. Security and Provisioning are Important and can be done through EA_MAS or ODS/MDMS

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

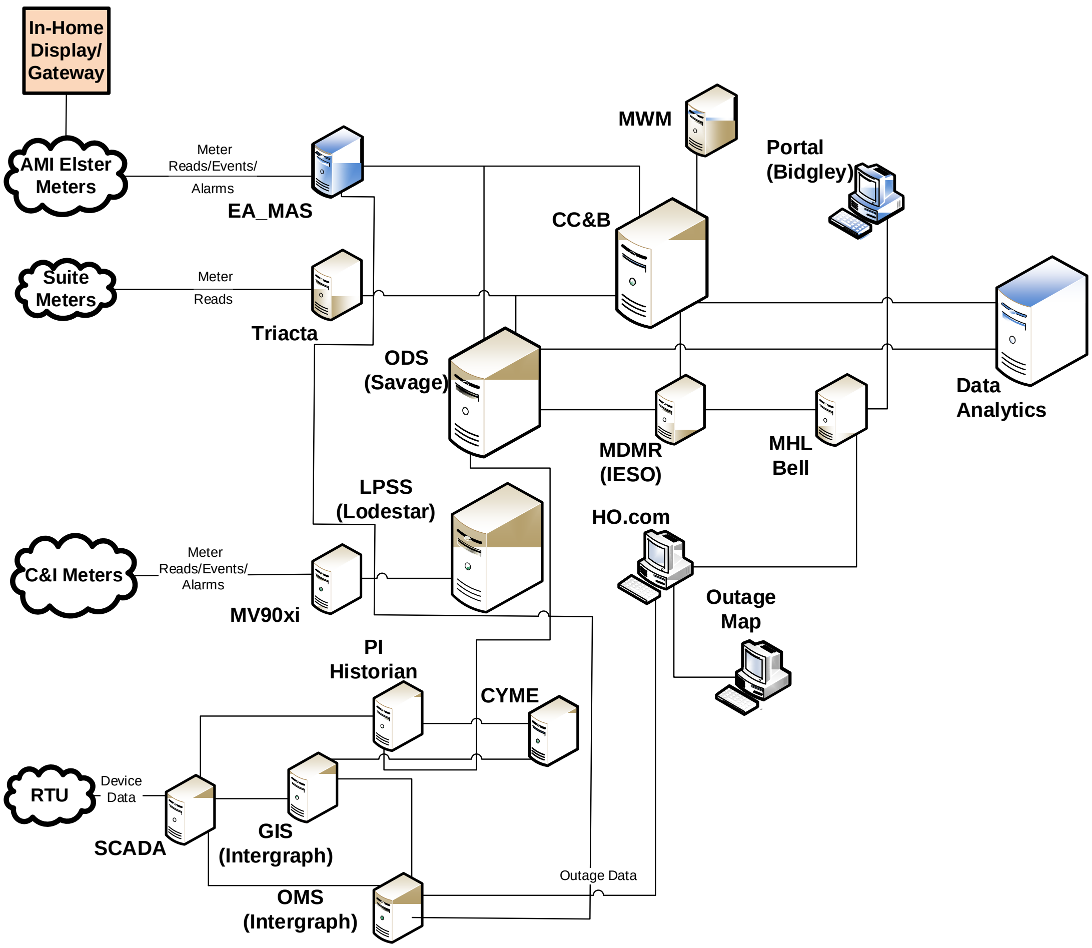


Figure 60 - Business Release 2d System Diagram

New Device/Application

Minor Change to Existing Application

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- MWM – Mobile Workforce Management

Business Release BR2e – Upgrade AMI Head End

As this business release is primarily focused on mitigation of obsolescence and the loss of application support there were no specific opportunities identified as tied to this upgrade.

However, the specific goals of this upgrade to the EnergyAxis Headend application are intended to avoid the risk of obsolescence of the current Honeywell EnergyAxis system elements, including:

- EnergyAxis headend system v9.x – scheduled to be at end of support life in Q2 2019
- REX2 meters – near end of production (no date confirmed yet from Honeywell); replaced by REXU (requires upgraded headend system to enable)

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

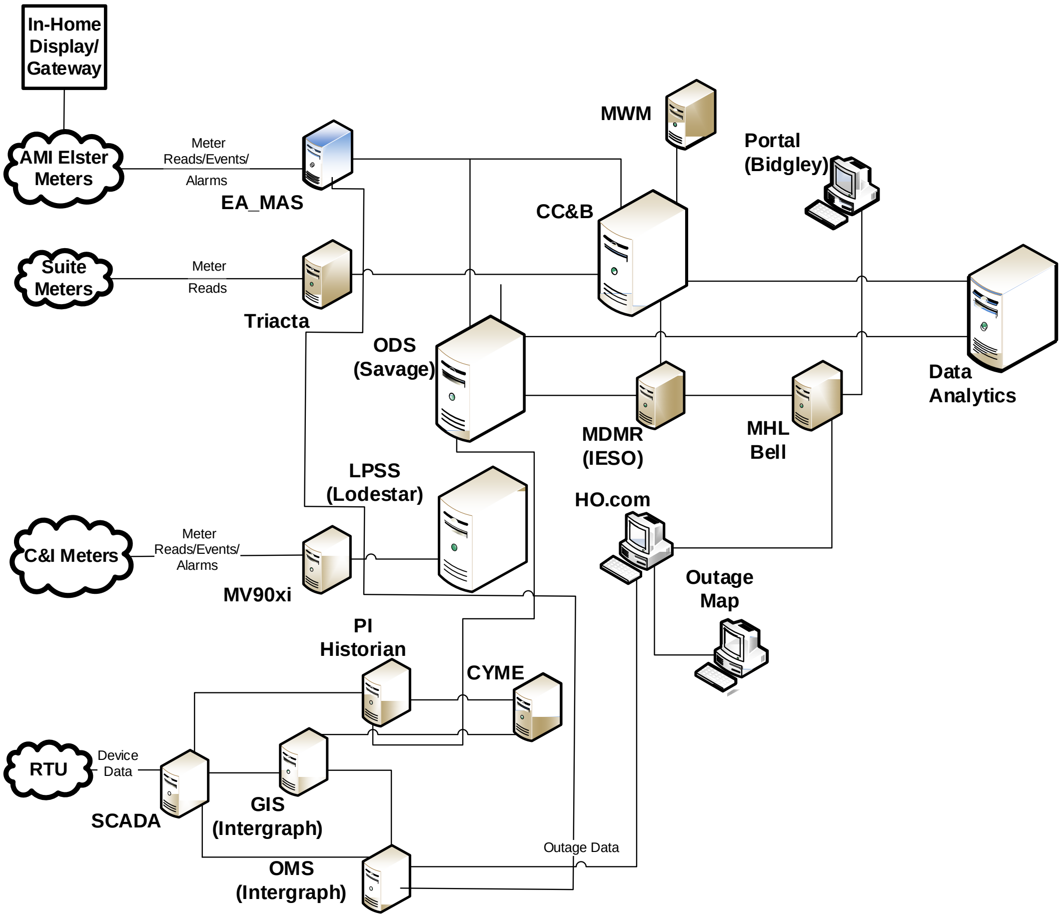
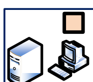


Figure 61 - Business Release 2e System Diagram



- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- MWM – Mobile Workforce Management

Phase 3 – Alternative FAN / Communications Technologies

The following AMI Roadmap diagram is replicated here for convenience and to provide context for the activities of Phase 3:

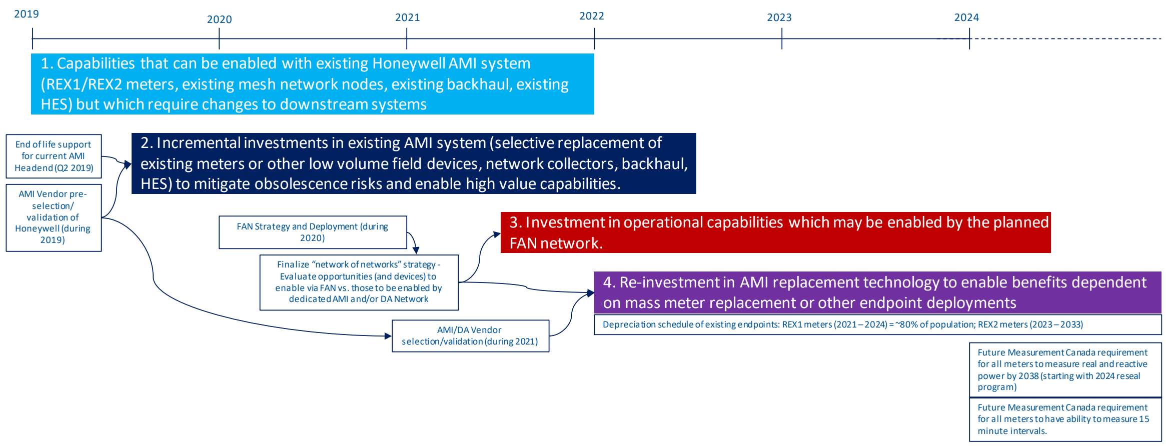


Figure 62 - AMI Strategy Phase Sequence and Timing

Phase 3 - Overview

- **Dependencies:**
  - HOL Telecom FAN plan finalization and implementation
  - AMI RFI results
- **To Do during Phase 3:**

As HOL implements the chosen opportunities offered in Phase 3, preparation for Phase 4 will begin. Thus, in preparation for Phase 4, the following activities should be undertaken during Phase 3:

- Develop and launch AMI RFP to finalize selection of potential AMI replacement solution. This selection will be dependent on the outcome of the RFI process executed during Phase 1 as this will determine whether HOL has already committed to the Honeywell solution as the long term vendor of choice (in which case Phase 4 will focus on migration to the latest Honeywell AMI platform) or whether another solution is contemplated (either another AMI vendor or a private Telecom FAN based solution).

Phase 3 - Business Releases

Phase 3 business releases are focused on enabling smart grid applications such as smart city sensors, distribution automation, volt/var control, EV charging control, distributed energy resource management, demand response and load control. All of these solutions will be dependent on the determination of the network solution. That is, direct leverage of the HOL Telecom FAN as the communications path directly to the endpoint device OR a "network of networks" strategy whereby the HOL Telecom FAN provides the backhaul for a dedicated AMI and/or DA network to connect to endpoints.

The following two graphics summarize the specific business releases recommended for Phase 3 of the AMI Roadmap as well as the IT systems expected to be impacted:

BR3a Initial DERMS System Implementation	BR3b Initial DA/DMS	BR3c Smart City Sensor Integration	BR3d DERMS and DA integration
• EV Charging Capacity Management • On Premise Storage Monitoring and Individual Demand Management (HOL metered with Demand Thresholds) • On premise Storage Monitoring and Individual Demand Management (HOL metered with Processed interval data) *Note: DERMS can be Standalone Application or a Module in DMS*	• Automated Reclosers and/or Switches • Faulted Circuit Indicators (FCI) • FLISR (Fault Location, Isolation and Service Restoration) • Reduction in O&M Costs for Distribution Monitoring Communication Infrastructure • Volt/VAR Management	• Streetlight Automation • Snow Level Monitoring • Traffic Congestion Monitoring • Waste Collection & Bin Level Monitoring • Indoor Air Quality Monitoring (Commercial/Industrial/Municipal) • Noise Level Monitoring • Surface Monitoring for Walkways and Roadways • Surface Temperature • Vibration Monitoring • Wind Speed • Fire / Smoke detection • Outdoor Air Quality Monitoring • Parking Monitoring	• EV Charging Demand Monitoring and Management (HOL Metered with Interval Consumption Thresholds) • On Premise Storage Monitoring and System Capacity Management • Conservation Voltage Reduction (CVR) • Community Based Energy Storage

Figure 63 - Phase 3 Business Releases

Business Release 3 - Alternative FAN / System Communication Technologies		
a. DERMS Implementation b. DA/DMS c. Smart City Sensor Integration d. DERMS and DA Integration	Analytics	DMS DERMS Dispatch / MTU GIS

Figure 64 - Phase 3 Systems Impacted

Business Release BR3a – Initial DERMS System Implementation

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
DER	Future	**On premise Storage Monitoring and individual Demand Management (HOL metered with Demand Thresholds)**	X			5	Hi Cost	Replacement of POTs backhaul + Software	Significant Effort	DERMS implementation and management	5	1.4	Enable dispatch of privately owned energy storage for individual demand management
DER	Future	**On premise Storage Monitoring and individual Demand Management (HOL metered with processed interval data)**	X			5	Hi Cost	Replacement of POTs backhaul + Software	Significant Effort	DERMS implementation and management	5	1.4	Enable dispatch of privately owned energy storage for individual demand management
DER	Future	**EV Charging Capacity Management**		X		5	Hi Cost	Smart Inverter + FAN + Software	Significant Effort	IT intensive	5	1.4	Direct management of EV charging infrastructure (Commercial & Residential) to enable system capacity management. Future requirements will require measuring output of all customer DER rated at 10 kW and greater. Metering does not need to be revenue grade. DER > 50 kW is

Figure 65 - Business Release 3a Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	Alternative FAN Network	HES	MDMS	DERMS	DMS/ OMS

On premise Storage Monitoring and individual Demand Management (HOL metered with Demand Thresholds)	Premise metering with real-time KW demand measurement with demand thresholds and real-time threshold alert communications.	Retrieve demand threshold alerts in real-time	Storage Control system to enable dispatch of storage energy based on Demand Threshold alert and HOL signal.	Process demand threshold alerts in near real-time. Enable re-programming of demand threshold alert settings.		Dispatch DM signals to storage devices. Verify reduced demand based on demand threshold.	
On premise Storage Monitoring and individual Demand Management (HOL metered with processed interval data)	Premise metering with interval consumption measurement and real-time interval data communications.	Retrieve interval data near real-time	Storage Control system to enable dispatch of storage energy based on Calculated Demand Threshold alert and HOL signal.	Process interval data near real-time. Pass to MDMS in real time.	Process interval data near real-time. Calculate demand in near real-time. Calculate demand threshold alerts in near real-time. Pass demand threshold alerts to Energy Storage Control System.	Dispatch DM signals to storage devices. Verify reduced demand based on calculated demand.	
EV Charging Capacity Management			EV Control system to enable discontinuance of charging based on HOL capacity situation and DM signal.			Dispatch nodal DM signals to EV chargers. Verify reduced Nodal demand.	Identify HOL system capacity event and dispatch nodal DM signals to DERMS.

Figure 66 - Business Release 3a Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

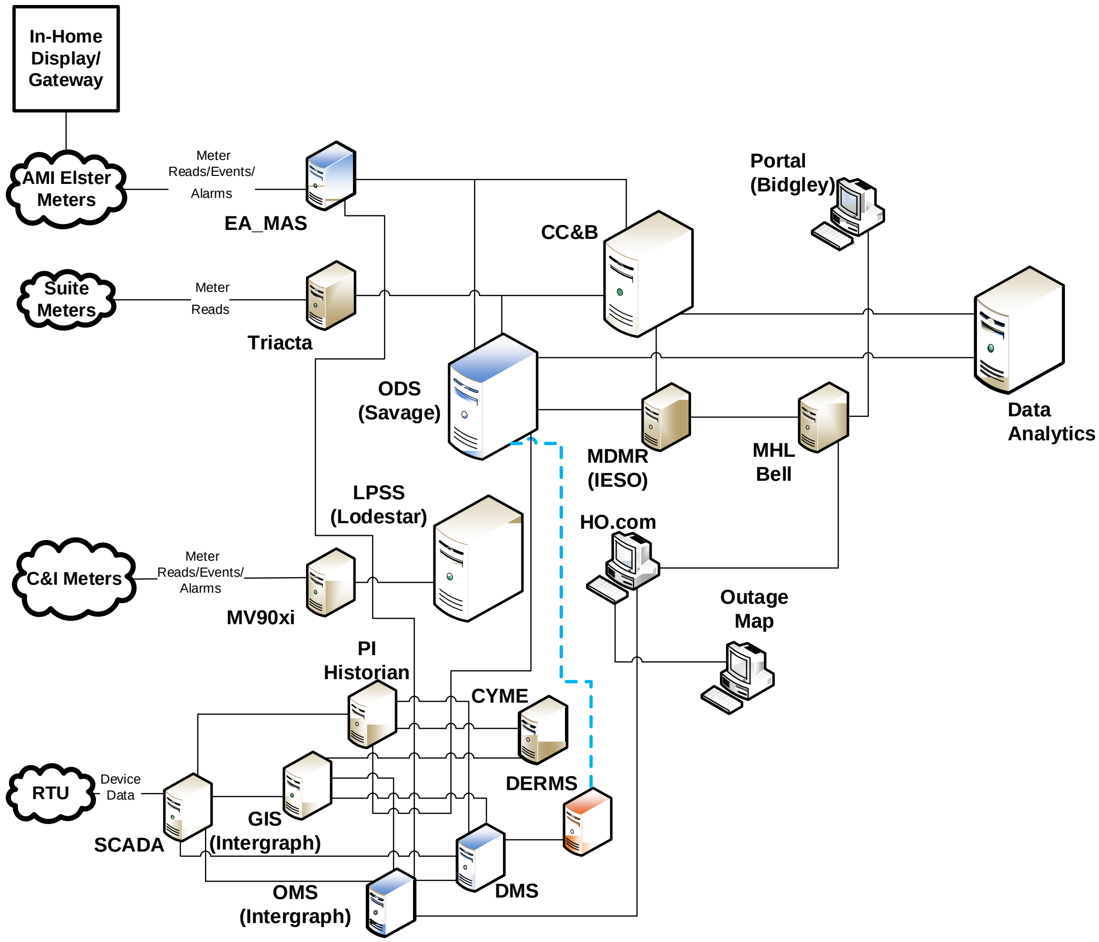


Figure 67 - Business Release 3a System Diagram

New System/Application
New Interface for DERMS - Tentative

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation

Business Release BR3b – Initial DA/DMS

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Operations	Partially Achieved	**FLISR**		X		4	Hi Cost	DA Comms module + DA FAN	Significant Effort	DA FAN deployment + DA HES + DMS	5	1.1	Enable Fault Isolation and Restoration with and without operator intervention. Distribution system can automatically Isolate faults and restore power. Deployment of Auto Restore and Auto-Generated switching order, on key portions of the distribution system.
Distribution Operations	Partially Achieved	**Automated Reclosers and/or switches**		X		4	Hi Cost	DA Comms module + DA FAN	Significant Effort	DA FAN deployment + DA HES + DMS	5	1.1	Deploy AMI/DA communications to automated reclosers to improve grid understanding and improve switch controls.
Distribution Operations	Partially Achieved	**Faulted Circuit Indicators**		X		4	Hi Cost	DA Comms module + DA FAN	Significant Effort	DA FAN deployment + DA HES + DMS	5	1.1	Fault circuit indicators with communication capability to interface with AMI network
Distribution Planning	Future	**Volt/VAR Management**		X		4	Hi Cost	Replacement of POTs backhaul + Bellwether meter + DA Network + Voltage Regulator and/or Cap Bank controller modules	Significant Effort	DA Network deployment + Enable proactive VVO in DMS	5	1.1	Monitor voltages at bellwether and "end of line" meters to provide real-time feedback as inputs to VVO management.

Figure 68 - Business Release 3b Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	DA Devices	AMI Network	DA Network	AMI HES	DA HES	Work Mgnt.	DMS/ OMS
FLISR **Automated Reclosers and/or switches** **Faulted Circuit Indicators**		DA devices (FCI's, reclosers, switches) compatible with DA communications		Communicate real-time with DA devices		Process real-time commands, events, and alarms. Monitor/Assure continuous comms. connectivity	Dispatch crews with information on executed FLISR scheme and required work. Dispatch crews with information on executed FLISR scheme and required work.	Consume real-time DA device information from DA headend. Process for identification of Fault Location. Identify isolation strategy. Send commands to DA Headend to execute isolation switch scheme. Identify optimized restoration strategy. Send commands to DA Headend to execute restoration switching scheme. Identify required field work required &

								send to dispatch.
Volt/VAR Mgnt.	Voltage data - instantaneous and historical profile. Voltage threshold alerts.	Voltage regulators and/or Capacitor Control devices compatible with DA communications	Retrieve timestamped voltage profiles daily and real-time voltage at set intervals and on-demand.		Process timestamped voltage profiles daily and real-time voltage at set intervals and on-demand. Send voltage data to DMS.	Send commands to voltage regulators and/or Capacitor controls to adjust voltage or VAR levels.		Consume real-time voltage data from AMI headend. Provide Volt and/or VAR correction commands to DA Head End to adjust voltage or Cap settings on specific feeders.

Figure 69 - Business Release 3b Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

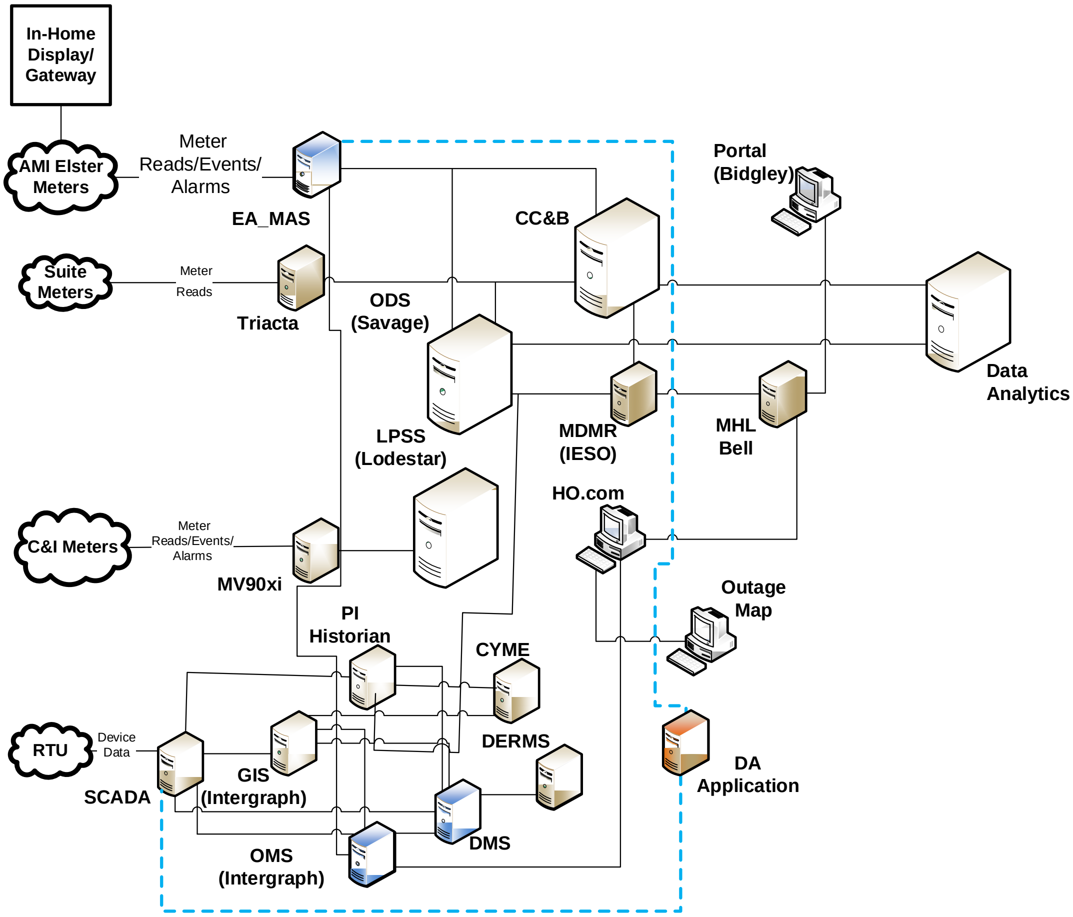


Figure 70 - Business Release 3b System Diagram

New System/Application
New Interface for DA - Tentative

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- CVR – Conservation Voltage Reduction

Business Release BR3c – Smart City Sensor Integration

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Smart City	Partially Achieved	**Streetlight Automation**		X	X	5	**Med Cost**	Streetlight sensors/ controllers + Network upgrade	**Significant Effort**	Field deployment of devices + Streetlight controls software module	4.5	**1.9**	Communication modules on streetlight controls compatible with AMI system are used for streetlight control. Vendors may offer advanced capability which can be used for security/warning or conservation purposes.
Smart City	Future	**Snow Level Monitoring**			X	4	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**1.1**	Snow level detection of specific locations to enable optimized snow removal planning and dispatch.
Smart City	Future	**Traffic Congestion Monitoring**			X	4	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**1.1**	Traffic monitoring for congestion relief and for long term traffic planning.
Smart City	Future	**Waste Collection & Bin Level Monitoring**			X	4	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**1.1**	Monitoring of waste container levels to optimize waste collection cycles and routes.
Smart City	Partially Achieved	**Indoor Air Quality Monitoring (Commercial/Industrial/Municipal)**			X	4	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**1.1**	Monitoring Air Quality Sensors for specific customers to alert air quality issues and/or provide long term air quality trends as service to customers.
Smart City	Future	**Noise Level Monitoring**			X	4	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**1.1**	Neighborhood disturbance monitoring.
Smart City	Future	**Wind Speed**			X	3	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**0.8**	Wind speed to determine potential hazardous conditions
Smart City	Future	**Fire / Smoke detection**			X	3	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**0.8**	Community fire/smoke detection to provide rapid response.
Smart City	Future	**Outdoor Air Quality Monitoring**			X	3	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**0.8**	Monitoring Air Quality Sensors to alert air quality issues and/or provide long term air quality trends without cost of field visits.
Smart City	Future	**Parking monitoring**			X	3	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**0.8**	Monitor Parking lot flows to identify full/empty lots
Smart City	Future	**Surface Monitoring for Walkways and Roadways**			X	3	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**0.8**	Monitoring road conditions for hazardous conditions (snow, ice, flooding) and congestion using a combination of various sensor devices.
Smart City	Future	**Surface Temperature**			X	3	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**0.8**	Measurement of surface temperature for various applications.
Smart City	Future	**Vibration Monitoring**			X	3	**Hi Cost**	Sensors + Network upgrade	**Significant Effort**	Field deployment of devices + Software integration	5	**0.8**	Monitor street, building, earthquake vibrations and alert via AMI network

Figure 71 - Business Release 3c Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Smart City Sensors	AMI Network & HES	AMI HES
Streetlight Automation	Streetlight sensors compatible with AMI communications	Communicate streetlights controls and consumption / timing metrics.	Streetlight monitoring / control system integrated with AMI communications
Smart City Sensors • Wind Speed • Fire / Smoke detection • Outdoor Air Quality Monitoring • Snow Level Monitoring • Traffic Congestion Monitoring	Sensor directly compatible with AMI network OR Gateway device compatible with sensor providing event or analog data near real-time or event based	Sensors integrated with AMI network	Receive and process analog or event data from Sensors or gateway module in real-time. Pass to Smart City system or other designated system of action.

• Waste Collection & Bin Level Monitoring • Indoor Air Quality Monitoring (Commercial/Industrial/Municipal) • Noise Level Monitoring • Surface Monitoring for Walkways and Roadways • Surface Temperature • Vibration Monitoring			
Parking monitoring	Parking slot or entry/exit Sensor data near real-time.	Pass count data from Sensors or gateway module in real-time.	Receive and process count data from Sensors or gateway module in real-time. Pass to Smart City system or other designated system of action.

Figure 72 - Business Release 3c Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

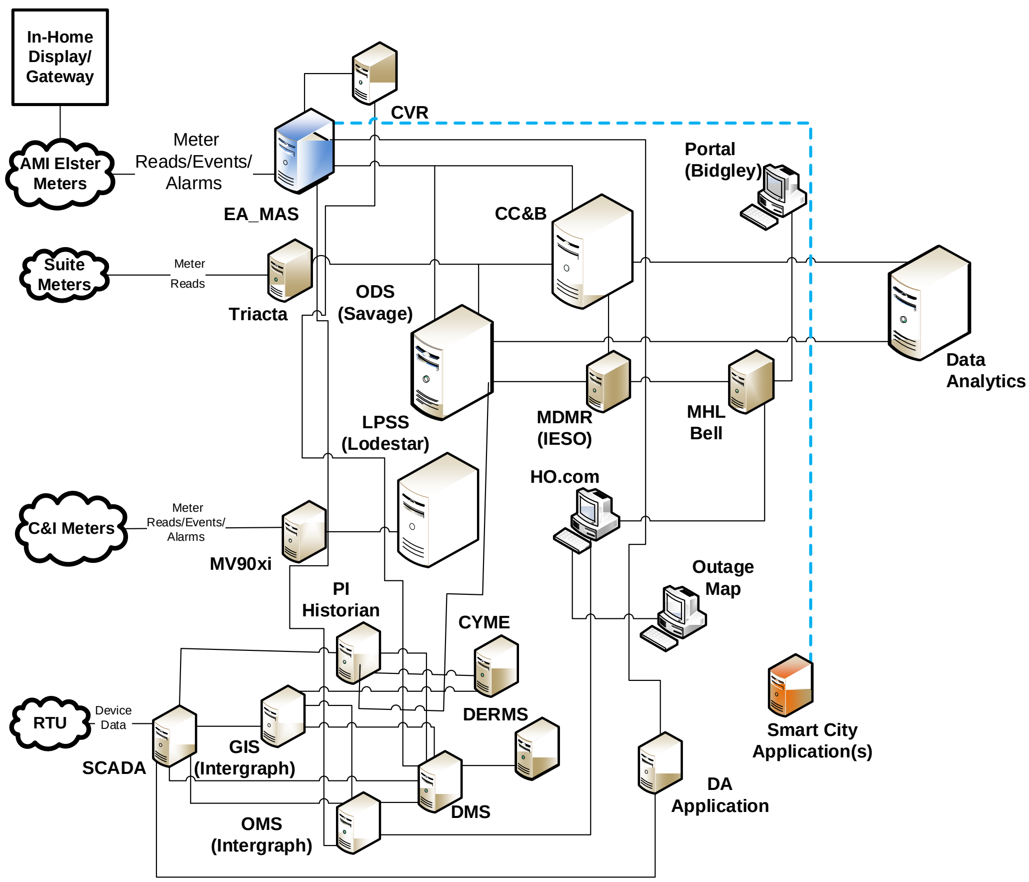


Figure 73 - Business Release 3c System Diagram

- New System/Application
- New Interface for Smart City Applications - Tentative
- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- CVR – Conservation Voltage Reduction

Business Release BR3d – DERMS and DA integration

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
DER	Future	**On premise Storage Monitoring and System Capacity Management**		X		5	Hi Cost	Smart Inverter + FAN + Software	Significant Effort	IT intensive	5	1.4	Enable dispatch of privately owned energy storage for system capacity management. Future requirements will require measuring output of all customer DER rated at 10 kW and greater. Metering does not need to be revenue grade. DER > 50 kW is expected to be monitored with SCADA in the future. Additionally system planning requires greater knowledge of DER and Energy Storage devices on system to properly size equipment. Dependencies on having a DMS.
DER	Future	**Conservation Voltage Reduction (CVR)**		X		4	Hi Cost	Replacement of POTs backhaul + Bellwether meters + Software	Significant Effort	DERMS implementation and management	5	1.1	Monitor voltages at meters to provide feedback loop for management of CVR. Use of interval consumption data can validate energy conservation. Benefit is reduced energy consumption. Proactively adjust voltage through controls to cap banks, voltage regulator, or voltage control devices.
DER	Future	**EV Charging Demand Monitoring and Management (HOL metered with Interval Consumption Thresholds)**	X			5	Hi Cost		Significant Effort		5	1.4	Direct monitoring and management of EV charging infrastructure (Commercial & Residential) to enable individual demand management
DER	Future	**Community based energy storage**		X		4	Hi Cost		Significant Effort		5	1.1	Deploy storage to enable improved reliability in capacity constrained locations

Figure 74 - Business Release 3d Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	DA Devices	AMI Network	Alternate FAN Network	AMI HES	DA HES	DERMS	DMS/ OMS
On premise and/or Community based energy storage **Monitoring and System Capacity Mgnt.**	Bi-directional energy storage measurement (discrete HOL device).		Retrieve interval data near real-time	Storage Control system to enable charging and dispatch of storage energy based on HOL capacity situation and DM signal.	Process interval data near real-time.		Dispatch nodal DM signals to storage devices. Verify reduced Nodal demand based on processed interval data.	Identify HOL system capacity event and dispatch nodal DM signals to DERMS.
EV Charging Demand Monitoring and Mgnt. (HOL metered)	EV charger interval consumption measurement (discrete HOL device) and real-time interval data communications.		Retrieve interval data near real-time	EV Control system to enable discontinuance of charging based on Demand Threshold alert / HOL signal.	Process interval data near real-time. Calculate demand in near real-time. Calculate demand threshold alerts in near real-time. Pass demand threshold alerts to EV Control System. Enable re-programming of demand			

					threshold alert settings.			
Conservation Voltage Reduction (CVR)	Voltage data - instantaneous and historical profile. Voltage threshold alerts.	Voltage regulators and/or Capacitor Control devices compatible with DA communications	Retrieve timestamped voltage profiles daily and real-time voltage at set intervals and on-demand.		Process timestamped voltage profiles daily and real-time voltage at set intervals and on-demand. Send voltage data to DMS.	Send commands to voltage regulators and/or Capacitor controls to adjust voltage levels.	Consume real-time voltage data from AMI headend. Provide voltage reduction commands to DA Head End to adjust voltage levels on specific feeders.	Consume real-time voltage data from AMI headend. Provide voltage reduction commands to DA Head End to adjust voltage levels on specific feeders.

Figure 75 - Business Release 3d Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

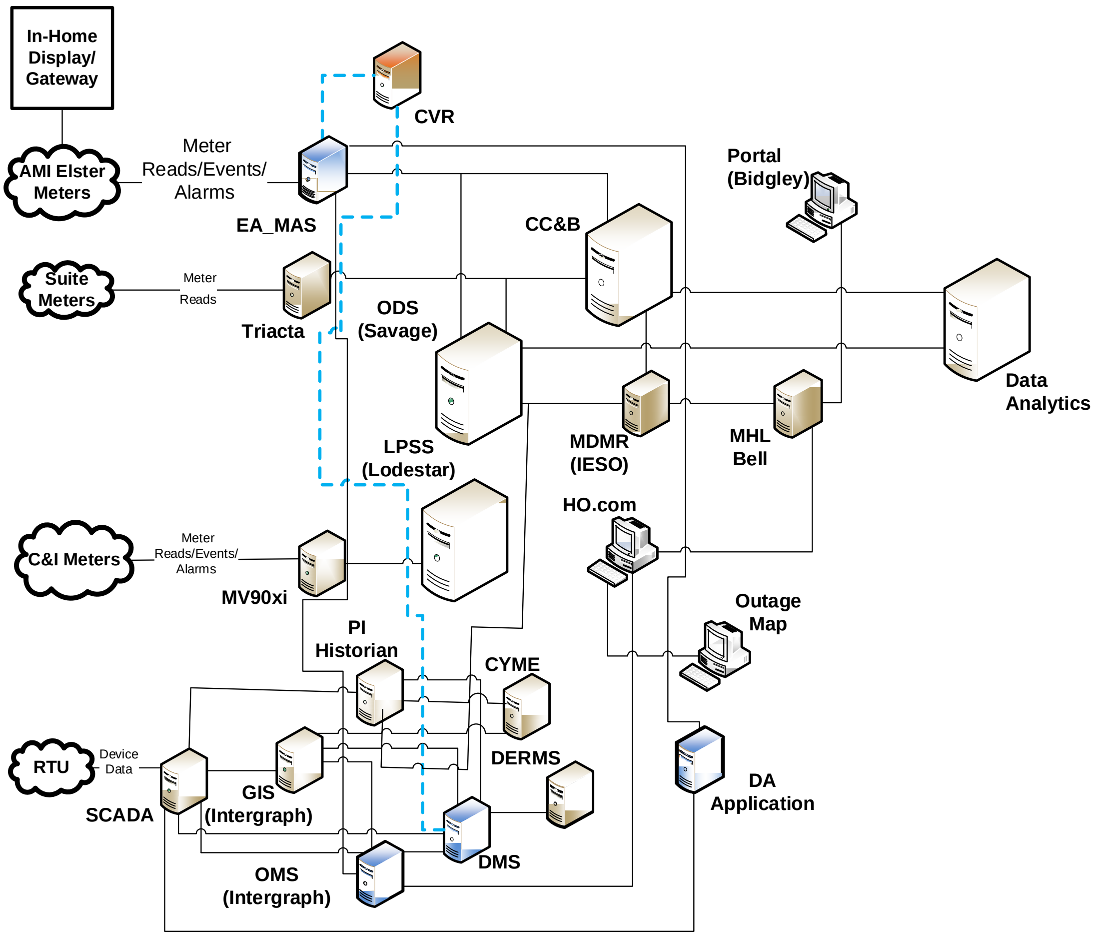


Figure 76 - Business Release 3d System Diagram

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- CVR – Conservation Voltage Reduction

Phase 4 – Replacement AMI Solution

The following AMI Roadmap diagram is replicated here for convenience and to provide context for the activities of Phase 3:

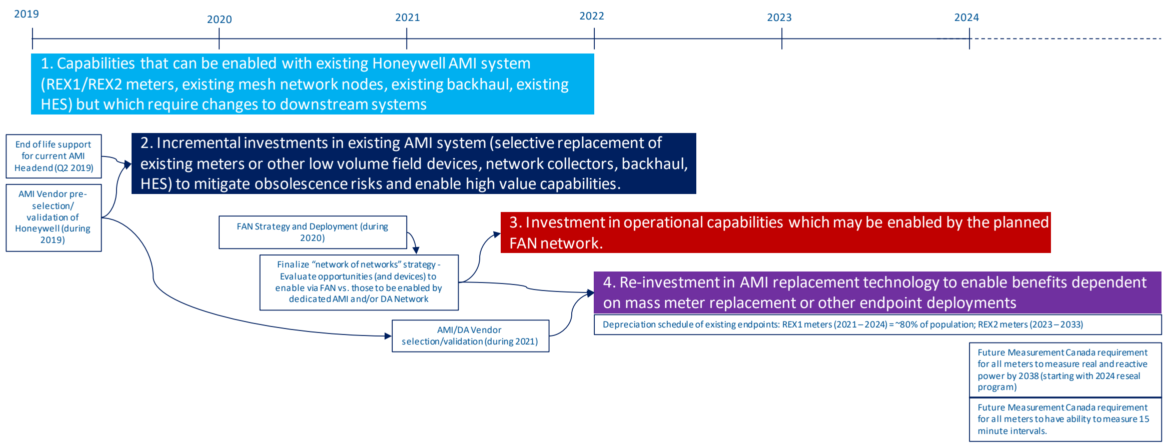


Figure 77 - AMI Strategy Phase Sequence and Timing

Phase 4 - Overview

- **Dependencies:**
  - Telecom FAN Plan final strategy and implementation
  - RFP for AMI technology vendors and validation of next generation AMI system to be employed
  - Outcome of Measurement Canada new meter regulations
  - Depreciation schedule of endpoints vs. book value of endpoints vs. seal period of endpoints
- **To Do during Phase 4:**

As HOL implements the chosen opportunities offered in Phase 4, the following activities are recommended to support the completion of the final phase of the AMI Roadmap:

- Establish Program Management Office (PMO) and governance structure for potential large scale AMI system and endpoint rollout
- Determine system and endpoint rollout strategy. This will be dependent on the following choices:
  - Whether the Telecom FAN will serve as the AMI network, all the way to the endpoints
  - If HOL chooses to follow a “network of networks” approach, the selection of the AMI solution to be employed (i.e. migration to the Honeywell SynergyNet solution or replacement of the existing network with a different AMI vendor provided solution)
  - Endpoint deployment strategy and duration to optimize benefit achievement and meter depreciation versus program deployment costs and potential stranded asset write-off

Phase 4 - Business Releases

Phase 4 business releases are focused on replacing the existing AMI system or transitioning to the next generation Honeywell AMI system to enable smart meter functionality that exists in next generation AMI systems.

During this phase, HOL will need to implement a PMO and governance structure to oversee the implementation of the AMI technology selected.

The following two graphics summarize the specific business releases recommended for Phase 3 of the AMI Roadmap as well as the IT systems expected to be impacted:

Figure 78 - Phase 4 Business Releases

Business Release 4 - Replacement AMI Solution		
a. AMI Replacement b. Data Analytics + DMS/OMS Enhancements c. Planning & Forecasting d. Enhancements to Billing + MDMS + Customer Portal	Analytics Billing System MDMS CSR and Customer Portal	Planning & Forecasting OMS Dispatch / MTU

Figure 79 - Phase 4 Systems Impacted

Business Release BR4a – Meter, Network & HES Replacement

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Meter Reading	Future	**Measurement of 15 minute consumption profiles for Residential Customers**	X	X		5	**Hi Cost**	Replace all meters + Upgrade Ntework to handle bandwidth	**Significant Effort**	Replace all meters	5	1.4	Enable 15 minute consumption data at all endpoints to provide increased granularity and visibility to usage impacts. Future requirement for all residential customers - currently at 1 hour.
Meter Reading	Future	**Measurement of Real and Reactive Power**		X	X	5	**Hi Cost**	Replace all REX1 meters + upgrade network to handle bandwidth	**Significant Effort**		5	1.4	Provide real and reactive power profiles to all endpoints to provide increased visibility to power demands. Future Measurement Canada requirement is for all meters to have ability to measure real and reactive power beginning in 2038 with implementation starting during the 2024 reseal program.
Meter Operations	Future	**Improve safety associated with poor meter installations by monitoring Temperature within Meter**		X		3	**Hi Cost**	Replacement of POTs backhaul + Replace all meters	**Significant Effort**	Replace AMI System + Data Analytics + Auto Dispatch	5	0.8	Utilize temperature monitoring and temperature threshold alarms to provide rapid dispatch for correction of "hot sockets".
Smart City	Future	**Metering for Other Municipal Services (Water)**			X	3	**Hi Cost**	Existing electric meters do not support comms to water meter	**Significant Effort**	Field deployment of devices + HES Software integration	5	0.8	The AMI system should have be able to support additional metering for other municipal services such as water. Hydro Ottawa to provide services to deliver meter reads to other utility (no asset management or billing)

Figure 80 - Business Release 4a Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Smart City Sensors	AMI Network & HES	MDMS	Work Mgnt.	CSR and Customer Portals
15 minute consumption profiles for Residential Customers	15 minute consumption interval data (timestamped) Timestamp to be accurately aligned to system time to enable time synchronization.		Retrieve and process timestamped interval data daily. Export to MDMS	VEE. Post daily consumption profile to customer and CSR portal.		Visibility to customer consumption profile.
Real and Reactive Power	Timestamped consumption interval data. Timestamped reactive interval data. Time stamp to be accurately aligned to system time to enable time synchronization.		Retrieve and process real and reactive power profile data daily. Export to MDMS.	Process and retain timestamped real and reactive power interval data.		
Improve safety associated with poor meter installations by monitoring Temperature within Meter	Temperature sensors within meter with temperature threshold alarm settings.		Retrieve and process temperature readings on demand and temperature threshold events in real-time.		Dispatch field investigations due to high meter temperature alarms. Provide high meter temperature alarm information.	

			Send to work dispatch.			
Metering for Other Municipal Services (Water)		Water meter, Gas Meter, Sewage meter modules (typically battery powered discrete retrofitted modules)	Provision and support water metering and other module types. Retrieve water and other meter/module data including consumption registers, consumption interval data, events, and alarms. Ability to parse data and track by company.	VEE and other functionality for water and other services being measured. Parse data by jurisdiction/ company. Provide segregated data to each Municipal service provided for individual billing.		

Figure 81 - Business Release 4a Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

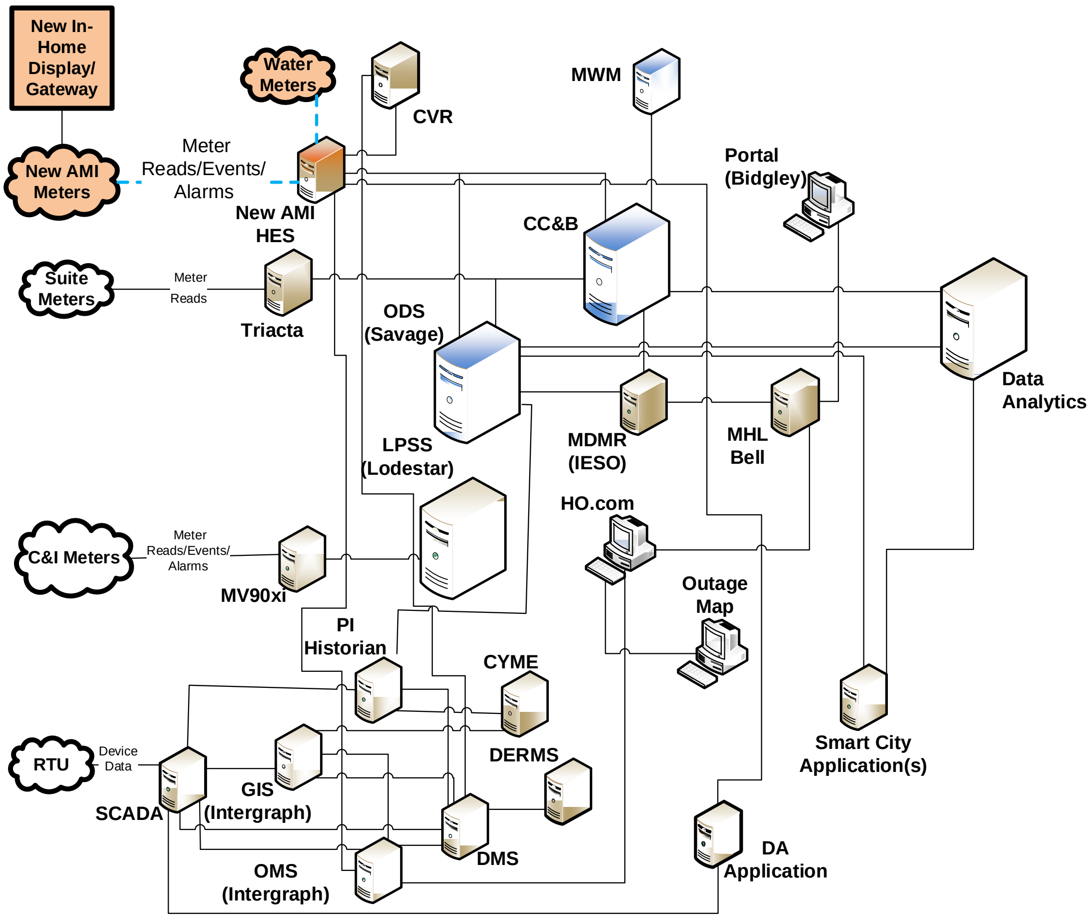


Figure 82 - Business Release 4a System Diagram

- New AMI Network
- New AMI HES
- New AMI Meters/Water Meters
- New In-Home Displays/Gateway
- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- HES – Headend System
- CVR – Conservation Voltage Regulation

Business Release BR4b – Data Analytics and/or DMS/OMS Enhancements

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Operations	Future	**<u>Outage Management</u> - Improved System Reliability Through Reduced Outage Times.**	X	X		5	**Hi Cost**	Replacement of POTs backhaul + REX1 meters	**Significant Effort**	Field deployment of REX1 + replacement of POTS backhaul + OMS system enablement	5	**1.4**	Reduced outage assessment and restoration times improves SAIDI and CAIDI. Reduced storm restoration time and crew costs. In major events, OMS algorithms can incorrectly "roll up" an outage to an upstream device. AMI provides a real measure of outage/restoration status to confirm OMS outage logic and remaining outages. OMS uses the meter power status alerts to determine whether an outage should be upgraded to the transformer, fuse, recloser, etc. Use of AMI alarms and pinging improves storm restoration efficiency and aids in the identification of nested outage conditions. Similarly, operators can confirm restoration in a similar manner. Reduce dependency on customer outage reporting - particularly in major events.
Distribution Operations	Future	**Value of Service (VOS) / Revenue Improvement Through Improved Reliability**	X	X		4	**Hi Cost**	Replacement of POTs backhaul + REX1 meters	**Significant Effort**	Field deployment of REX1 + replacement of POTS backhaul + OMS system enablement	5	**1.1**	Increase in value of service (and/or revenues) because of lower SAIFI, CAIDI and MAIFI.
Meter Operations	Future	**Edge based intelligence to improve AMI Alert and Exception Management**		X		4	**Hi Cost**	Replacement of Collectors + POTs backhaul + REX1 meters	**Significant Effort**	Edge computing + automated self healing network	5	**1.1**	Provide Smart collectors to filter, aggregate, analyze and perform distributed field processing (edge computing) to enable automated self healing exception management.
Meter Operations	Future	**Voltage Diagnostics**	X	X		4	**Hi Cost**		**Significant Effort**		5	**1.1**	AMI systems can deliver voltage information and voltage threshold alarms to improve customer service and detect system issues.

Figure 83 - Business Release 4b Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	AMI Network & HES	Data Analytics	Work Mgnt.	DMS/ OMS	Planning & Forecasting
Outage Management - Improved System Reliability Through Reduced Outage Times.	Power Status Alerts (Last Gasp outage alert + Power restoration) timestamped and transmitted in real-time. Power status ping response provided in real-time.	Retrieve and process power status alerts and ping request and response in real-time.	Use power outage, power restoration, and status pinging to identify nested outages. Use timestamped power out events to perform post storm analysis to ensure accurate CAIDI / SAIFI. Analyze, filter and validate power status event to minimize false alarms.		OMS - Use power status events as inputs into outage modeling. Enable pinging power status for single meter and groups of meters based on connectivity model.	
Value of Service (VOS) / Revenue Improvement Through Improved Reliability	Power Status Alerts (Last Gasp outage alert + Power restoration) timestamped and transmitted in real-time. Momentary outage event logs.	Capture, transmit, and process high percentage of last gasp and power restoration alerts and send to OMS/DMS. Transmit and process Momentary outage event log daily.	Measure reduction in CAIDI minutes to calculate revenue		Process outage alerts to improve outage responsiveness and dispatch of crews.	Process momentary outage event logs to target low reliability circuits.

		Send to reliability/ planning.				
Edge based intelligence to improve AMI Alert and Exception Management	Timestamped register data. Real-time voltage data. Timestamped meter data (alerts, events, etc.) provided in real-time.	Process voltage and alarm/alert data to identify correlated changes to voltage and/or outage events. Submit triaged exception analytics to AMI Head End. Process submitted network triaged exceptions.	Process submitted network triaged exceptions to add historical data for further analytics. Analyze and correlate usage profiles, alarms and events to determine abnormal meter or network conditions.			
Voltage Diagnostics	Voltage data - instantaneous and historical profile. Voltage threshold alerts.	Retrieve and process timestamped voltage profiles daily and real-time voltage at set intervals and on-demand. Receive and transmit voltage threshold alarms in real-time.	Analyze voltage profiles, and thresholds. Process voltage threshold alarms to determine work order requirements. Issue work order reports to address low/high voltage conditions.	Dispatch work orders to address Lo/High voltage conditions. Provide data analytics information to support work orders to address Lo/High voltage conditions.		

Figure 84 - Business Release 4b Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

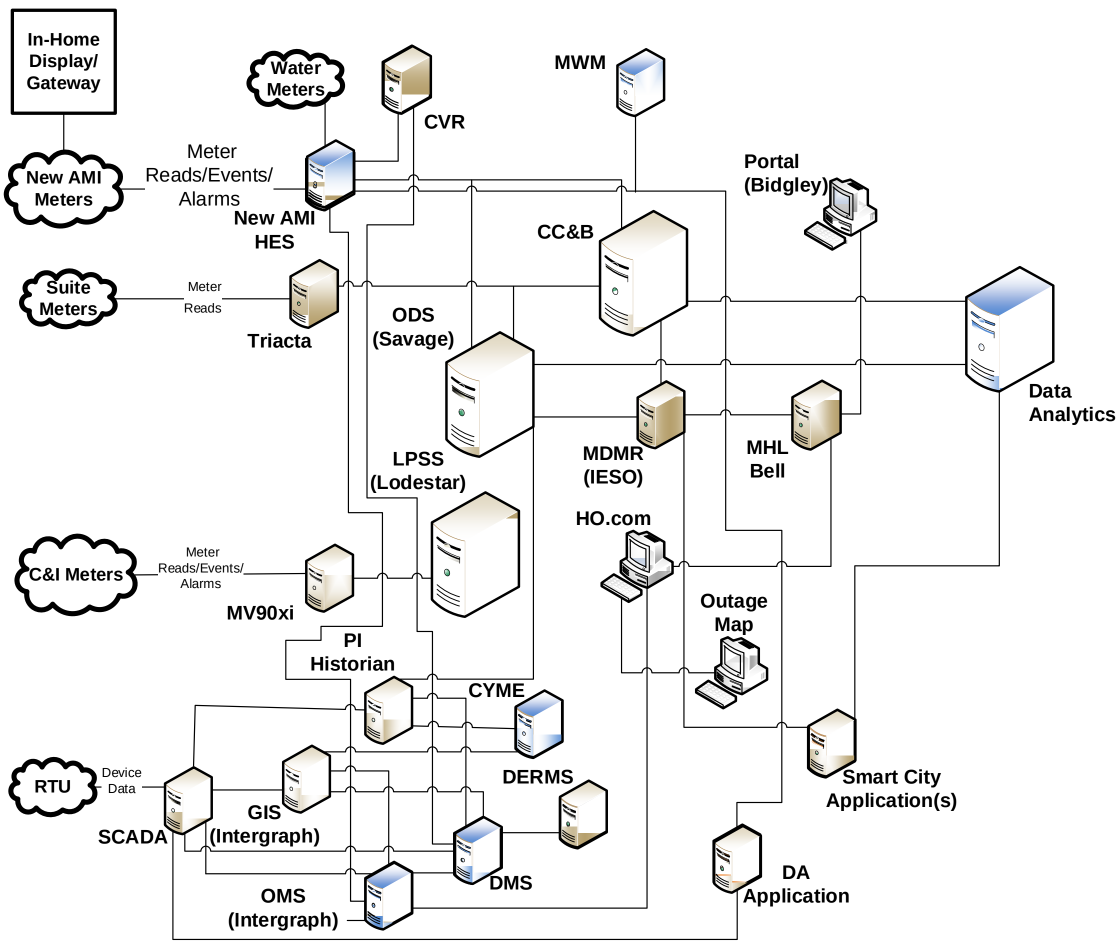


Figure 85 - Business Release 4b System Diagram

Minor Change to Existing Application/Portal

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- HES – Headend System
- CVR – Conservation Voltage Regulation

Business Release BR4c – Planning and Forecasting

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Planning	Future	**Improved forecast accuracy**		X		3	Hi Cost	Replace all meters + Upgrade Ntework to handle bandwidth	Significant Effort	Replace all meters + Enable improved forecasting using individual and aggregated profiles	5	0.8	Processing of 15 minute interval data; provision of data to forecasting system (Assumes forecasting is performed at 15 minute intervals)

Figure 86 - Business Release 4c Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	AMI Network & HES	MDMS	Planning & Forecasting
Improved forecast accuracy	15 minute consumption interval data (timestamped) Timestamp to be accurately aligned to system time to enable time synchronization.	Receive and process timestamped interval data daily. Export to MDMS.	VEE. Export interval data sets to Planning & Forecast.	Consume and analyze interval data. Apply improved endpoint load analysis into forecasting models for improved accuracy.

Figure 87 - Business Release 4c Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

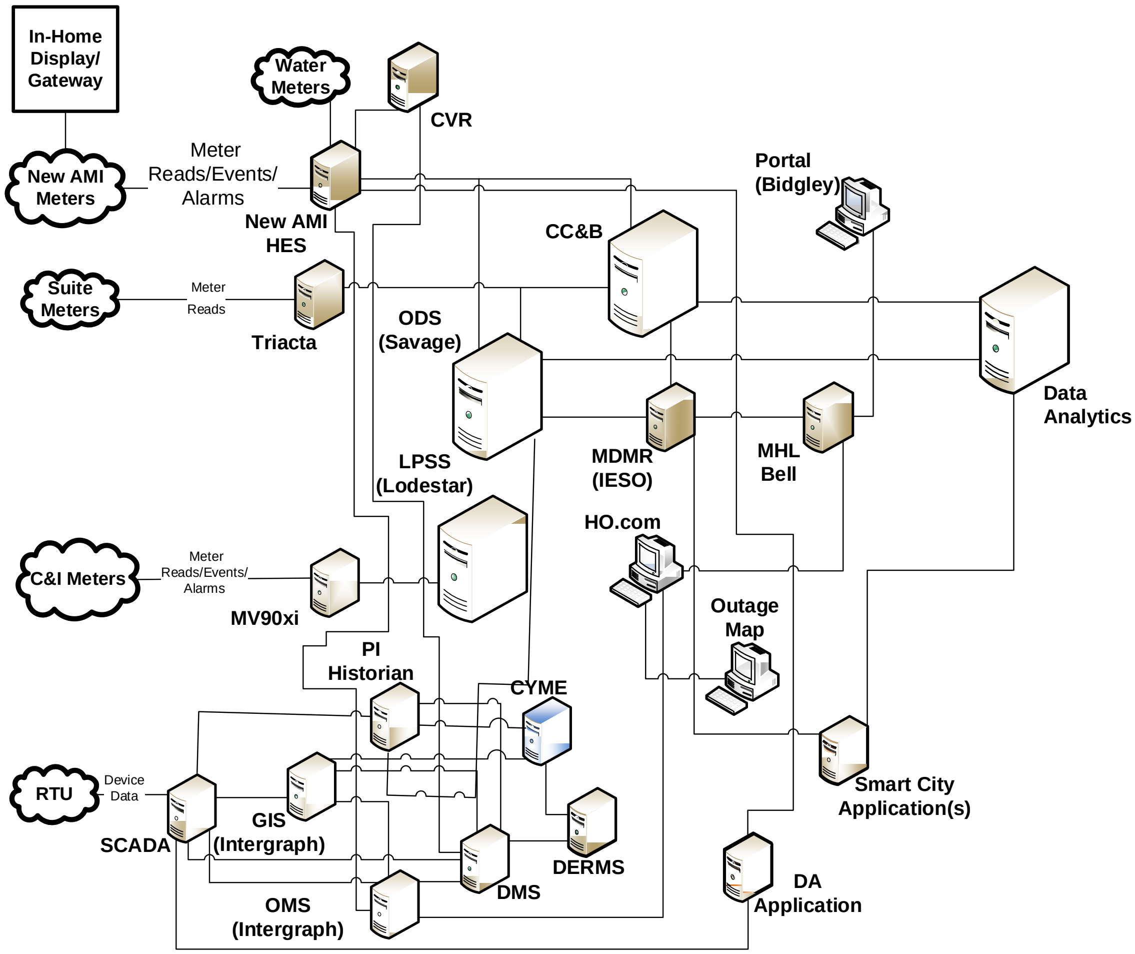


Figure 88 - Business Release 4c System Diagram

Minor Change to Existing Application/Portal
- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- HES – Headend System
- CVR – Conservation Voltage Regulation

Business Release BR4d – Billing, MDMS and/or Customer Portal Enhancement

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Regulatory	Future	**Prepayment Programs / Rates**		X		5	Med Cost	Targeted RCD meter replacement for Prepaid customers	Significant Effort	Implement Prepay system	4.5	1.9	Threshold monitoring of daily consumption, Prepay debiting and payment mechanism, rapid dispatch of remote disconnect. Benefits include improved accounts receivable balances, reduced working capital, reduced deposit requirements, fewer cuts for nonpay, increased customer satisfaction, and energy conservation.
Regulatory	Future	**Critical Peak Pricing or Peak Time Rewards**		X		4	Hi Cost	Replace all meters + Upgrade Ntework to handle bandwidth + Realtime alerts	Significant Effort	Replace all meters + Customer alerts, billing enablement, rate design	5	1.1	Notification of Peak Pricing hours to customer; Processing of hourly data into Peak hours rate buckets; Billing System billing based on Peak Pricing time rates

Figure 89 - Business Release 4d Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	AMI Network & HES	Prepay Solution	MDMS	Billing	CSR and/or Customer Portal
Prepayment Programs / Rates	Service disconnect switch. Hourly consumption interval data.	Enable disconnect and reconnect. Provide switch status. Retrieve register data daily. Issue disconnect and reconnect. Provide switch status. Process interval data daily.	Prepayment Solutions offered by various vendors to manage credits/debits and communications to customer (via web, mobile, text, etc.)	VEE. Post cumulative consumption to Prepayment application.	Calculate "to-date" monthly bill (including all charges); provide to Prepayment Solution to compare against available credit and post to customer portal. Receive input from Prepayment application when current charges exceed available credit. Send disconnect command to AMI head end upon exhaustion of credit. Receive input from Prepayment application when credit had been applied to exceed current charges. Send reconnect command to AMI head end upon posting of credits.	Prepayment application: Post "to-date" monthly bill (including all charges); compare against available credit; post to customer portal or send to in-home display.
Critical Peak Pricing or Peak Time Rewards	15 minute consumption interval data (timestamped)	Retrieve timestamped interval data daily.		VEE. Separate usage into Peak and Off Peak periods for	Identify Peak Time periods to MDMS for usage disaggregation.	Visibility to Customer bill. Visibility to customer

	Timestamp to be accurately aligned to system time to enable time synchronization.	Process timestamped interval data daily. Export to MDMS		bill determinant processing. Post billing route files to Billing System.	Request billing determinants from MDMS and generate bill.	consumption profile. Identification of Peak Time periods, consumption per period, and billing amounts.

Figure 90 - Business Release 4d Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

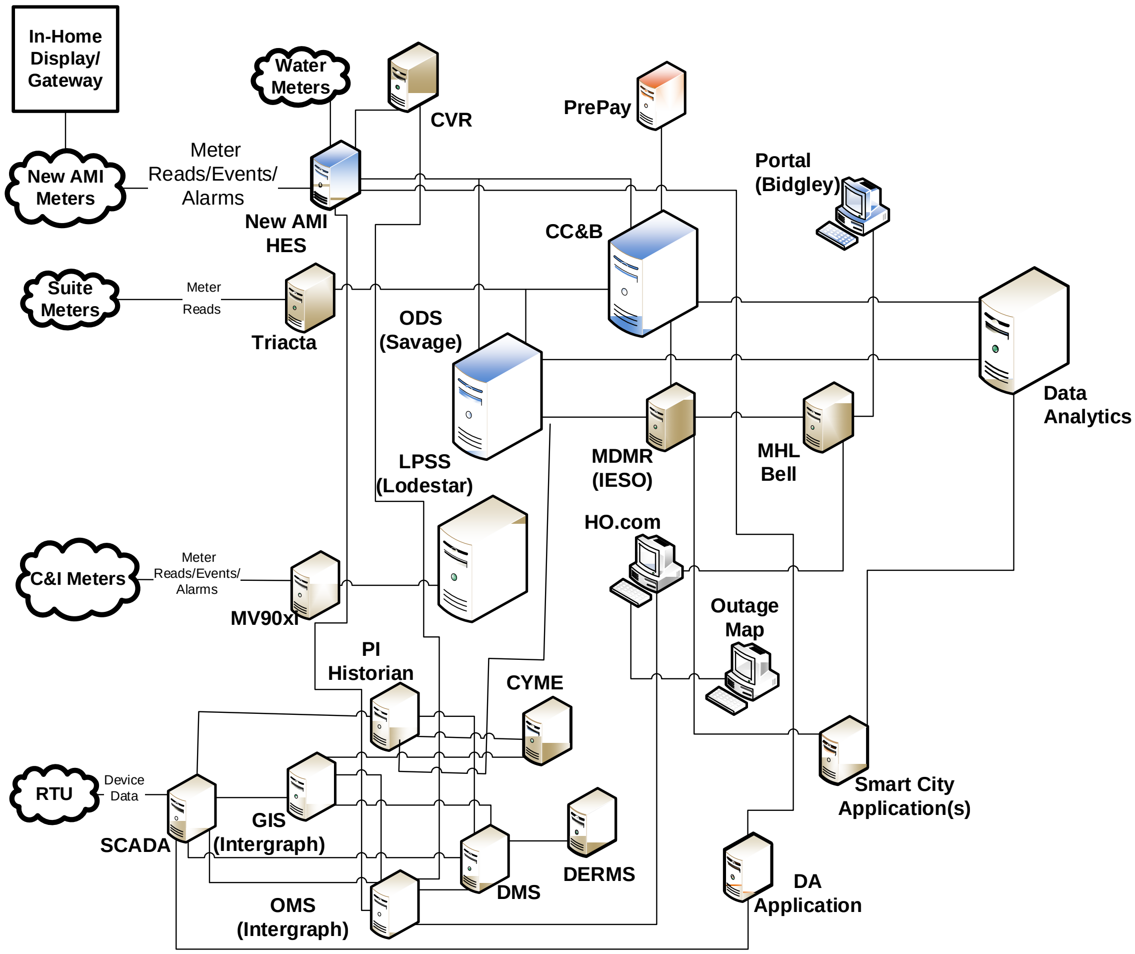


Figure 91 - Business Release 4d System Diagram

Minor Change to Existing Application/Portal

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- HES – Headend System
- CVR – Conservation Voltage Regulation

Smart Energy Strategy alignment

As previously described, HOL has developed a well-defined Strategic Plan (reference: Strategic Direction 2016-2020) and a detailed strategy for the programs anticipated in a longer-term transition to a Smart Energy provider (reference: Smart Energy Strategy). The strategic directions serve to ensure that both the Smart Energy Strategy and the AMI Roadmap maintain adherence to overall HOL goals. However, the AMI Roadmap and the defined projects of the Smart Energy Strategy have a much closer potential inter-dependency. As such, the following diagram serves to portray which programs of the Smart Energy Strategy are dependent on which phases of the AMI Strategy, and vice versa.

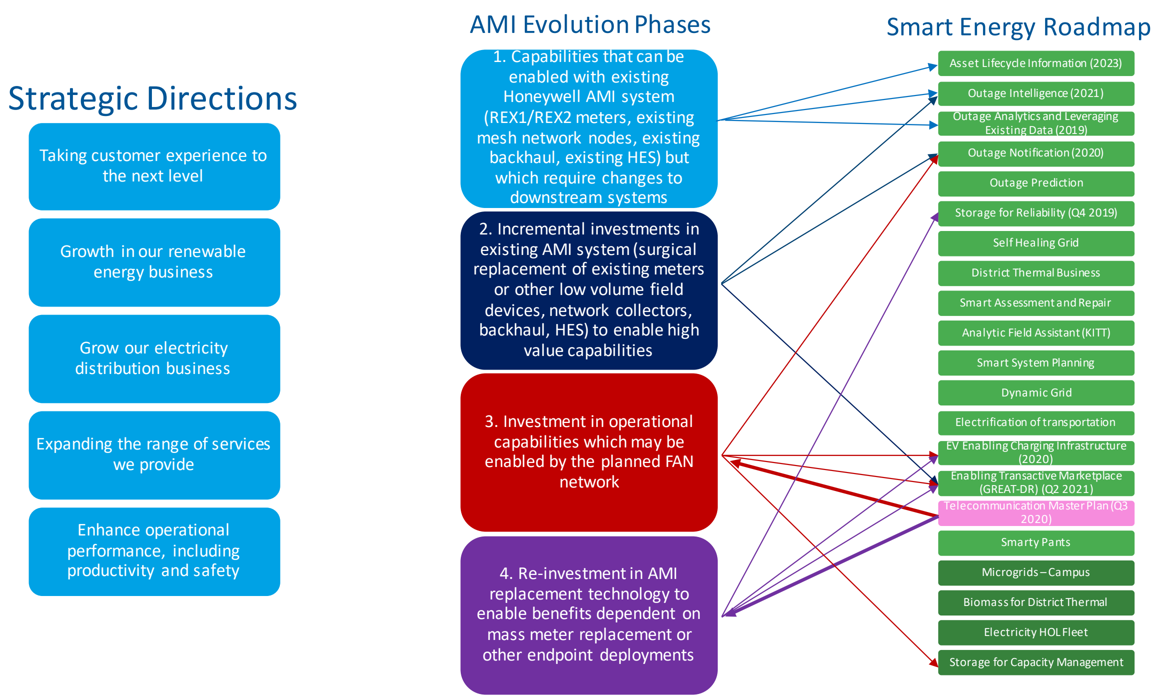


Figure 92 - AMI Roadmap Strategy Alignment

KEY IT SYSTEMS IMPACTED

While the business releases recommended in this Roadmap are organized around business opportunities, they are implemented through a sequence of functional capability enhancements for several key IT systems. Thus, to support IT planning activities, the following sections alternatively describe the various business releases from the perspective of several of the key HOL IT systems.

Billing System

Enhancements to the Billing system, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Billing System Requirements
BR1a	Enable / Expand Summary Billing	Create single bill from aggregated consumption into single, multi-site bill
	Green Pricing Rates	Create distinct DER generation source buckets. Request billing determinants from MDMS. Assign DER credits and total consumption and generate bill.
	EV Charging Aggregation and Market participation (HOL separately metered)	Enable aggregated charged usage billing to third parties and/or market aggregators.
	EV Charging Rate and Revenue Metering for EV Charging Infrastructure	Request billing determinants from MDMS and generate EV Charger bill.
BR1d	Reduced consumption on inactive accounts (using field disconnect visit)	Identify inactive accounts to MDMS and data analytics. Issue disconnect work order based on data analytics identifying un-acceptable consumption on expected inactive accounts.
BR2a	Improve Operations Safety & Carbon Footprint through Increased Utilization of Remote Connect Disconnect: - Reduced field trips for move-in / move-out and non-pay customers - Reduced injuries, claims and environmental impact - Rapid resolution of accounts in arrears - Reduce consumption on inactive accounts	Identify account status (active/inactive) to MDMS and data analytics. Issue virtual work orders for disconnect - reconnect of service and commands based on specific data analytics for the business process. Synch meter switch status with AMI head end.
BR4d	Prepayment Programs / Rates	Calculate "to-date" monthly bill (including all charges); provide to Prepayment application to compare against available credit and post to customer portal or send to in-home display. Receive input from Prepayment application when current charges exceed available credit. Send disconnect command to AMI head end upon exhaustion of credit. Receive input from Prepayment application when credit had been applied to exceed current charges. Send reconnect command to AMI head end upon posting of credits.
	Critical Peak Pricing or Peak Time Rewards	Identify Peak Time periods to MDMS for usage disaggregation. Request billing determinants from MDMS and generate bill.

Figure 93 - Billing System Functional Requirements

Note: An Upgrade to the AMI Headend is recommended due to end of life support and should be done as part of Release 2 (BR2e).

MDMS

Enhancements to the MDMS, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Meter Data Management System Requirements
BR1a	Enable / Expand Summary Billing	Aggregate multiple accounts into summary bill
	EV Charging Aggregation and Market participation (HOL separately metered)	Aggregate timestamped interval data from metered EV charger(s)
	EV Charging Rate and Revenue Metering for EV Charging Infrastructure	Process billing determinants for separately metered EV charger(s)
	Green Pricing Rates	Separate DER generation sources from total consumption. Post daily consumption profile to customer portal and CSR portal.
BR1b	Improve Distribution Modeling and Defer Distribution System Capacity Requirements	Export interval data sets to Planning & Forecast
	Aggregation of Load at Virtual Nodes for Distribution System Analysis, Transformer / Device Load Analysis and Equipment Sizing	Aggregate interval data associated with identified grid nodes.
	Improve real and apparent loss allocation	Process real and apparent power from AMI meters and provide flows to Data Analytics.
BR1c	Outage Management - Improve Momentary and Blink outages	Process outage event logs from AMI meters and pass to Data Analytics
BR1d	Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)	Forecast expected daily consumption for remainder of billing period based on historical profile of individual premise usage.
	Billing Exceptions (Level 2) - Reduced number and resolution time of billing exceptions/issues	Process outage events to correctly validate zero usage intervals as outages and not estimate across them. Post daily consumption profile to customer portal and CSR portal.
	Enable / Improve Customer Conservation Programs and LIHEAP	Post daily consumption profile to customer portal and CSR portal.
BR1e	Improved Rate Design and Customer Class Cost Allocations	Post daily consumption profile to Data Analytics
	Improve Forecasting Capability	Export interval data sets to Planning & Forecasting system.
BR4a	Measurement of 15 minute consumption profiles for Residential Customers	Process, store, aggregate 15 minute interval data; Post daily consumption profile to customer portal and CSR portal.D3
BR4a	Measurement of Real and Reactive Power	Process and retain timestamped real and reactive power interval data.
BR4a	Metering for Other Municipal Services (Water)	VEE and other functionality for water and other services being measured. Parse data by jurisdiction/company. Provide segregated data to each Municipal service provided for individual billing.
BR4b	Edge based intelligence to improve AMI Alert and Exception Management	Process submitted network triaged exceptions to add historical data for further analytics.
BR4c	Improve Forecast Accuracy	Export interval data sets to Planning & Forecast
BR4d	Prepayment Programs / Rates	Post cumulative consumption to Prepayment application.
	Critical Peak Pricing or Peak Time Rewards	Separate usage into Peak and Off Peak periods for bill determinant processing. Post billing route files to Billing System.

Figure 94 - MDMS Functional Requirements

CSR & Customer Portal

Enhancements to the Customer and Customer Service Representative Portals, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Customer Service Representative Portal Requirements
BR1a	Green Pricing Rates	Visibility to total customer consumption and DER generation. Visibility to breakdown of bill to billing buckets and DER credits.
BR1d	Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)	Enable forecasting of total bill (usage + charges) and provide access to CSR
BR1d	Improved Effectiveness of Low Income Home Energy Assistance Program	Forecast of consumption and likely timing of reaching LIHEAP limits.
BR2b	Outage Management - Reduced Trouble Calls (single lights out)	Enable pinging power status
BR4d	Critical Peak Pricing or Peak Time Rewards	Identification of Peak Time periods, consumption per period, and billing amounts.

Figure 95 - CSR Portal Functional Requirements

Business Release #	Potential Opportunity	Customer Web Portal Requirements
BR1a	**Green Pricing Rates**	Visibility to total customer consumption and DER generation. Visibility to breakdown of bill to billing buckets and DER credits.
BR1d	**Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)**	Enable forecasting of total bill (usage + charges) and present to customer
	Customer Portal information for EV Charging (HOL provided)	Visibility to EV consumption profile.
	Enable / Improve Customer Conservation Programs	Enable advanced features such as energy load profiling and neighborhood energy comparisons. Enable forecasting of total bill (usage + charges) and present to customer
	Improved Effectiveness of Low Income Home Energy Assistance Program	Forecast of consumption and likely timing of reaching LIHEAP limits.
BR2b	**Outage Management - Improved Customer Communication**	Outage information, status, and ETR updated on customer portal or custom outage portal
BR2d	**Enable Residential Customer Direct Access to Meter Usage (near real-time)**	Reconcile differences between VEE data and real-time data customer views on portal
BR4d	**Prepayment Programs / Rates**	Prepayment application: Post "to-date" monthly bill (including all charges); compare against available credit; post to customer portal or send to in-home display.
	Critical Peak Pricing or Peak Time Rewards	Identification of Peak Time periods, consumption per period, and billing amounts.

Figure 96 - Customer Portal Functional Requirements

Dispatch/MTU

Enhancements to the Dispatch and Mobile Terminal systems, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Field Work Dispatch / Mobile Terminal System Requirements
BR1d	More rapid resolution of accounts in arrears (using field service dispatched service disconnect)	Dispatch virtual field order to disconnect service. Provide disconnect service order information to MTU.
	Reduced consumption on inactive accounts (using field disconnect visit)	Dispatch physical field order to disconnect service. Provide disconnect service order information to MTU.
BR2a	Carbon Offset Value - reduction in vehicle emissions due to reduced field trips	Automate field work dispatch based on data analytics outputs. Align correct resource skills to triaged and filtered field maintenance work.
BR2c	Improve AMI Alert and Exception Management by back end systems.	Issue work dispatch for critical events based on indicated priority from Data Analytics. Provide Data Analytics information to support expectation to MTU.
	Faster detection of and collection of theft	Issue work dispatch for theft/tamper based on indicated priority from Data Analytics. Provide Data Analytics information to support expectation of tamper/theft to MTU.
BR3b	FLISR	Dispatch crews with information on executed FLISR scheme and required work.
BR3c	Enable Smart Cities Functionality	Ability to support multiple non-traditional work types for dispatch. - Streetlight Automation - Parking Monitoring - Other Smart Cities Sensors and Devices as applicable
BR4a	Improve safety associated with poor meter installations by monitoring Temperature within Meter	Dispatch field investigations due to high meter temperature alarms. Provide high meter temperature alarm information to MTU.
BR4b	Voltage Diagnostics	Dispatch work orders to address Lo/High voltage conditions. Provide data analytics information to support work orders to address Lo/High voltage conditions to MTU.

Figure 97 - Dispatch System Functional Requirements

DMS/OMS

Enhancements to the Outage Management and DMS systems, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Distribution Management and Outage Management Systems Requirements
BR1c	Outage Management - Improved Momentary and Blink outages	OMS - Analyze and correlate momentary outage events to circuit connectivity model to identify "trouble" areas for preventative maintenance.
BR2b	Outage Management - Reduced Trouble Calls (single lights out)	OMS - Disconnected meters need to be put in exclusion list to remove them from outage list.
	Outage Management - Improved Outage and Reliability Index Reporting and System Reliability Planning through post event analysis.	OMS - Modify event times based on power status events. Use power status events as inputs into outage modeling.
	Outage Management - Improved Customer Communication	OMS - Import outage event alerts to improve outage dispatch. Predictive analytics to improve estimated restoration time. Automated ping process to validate power restoration. Disconnected meters need to be put in exclusion list to remove them from outage list.
BR3a	EV Charging Capacity Management	DMS - Identify HOL system capacity event and dispatch nodal DM signals to DERMS.
BR3b	FLISR	DMS - Consume real-time DA device information from DA headend. Process for identification of Fault Location. Identify isolation strategy. Send commands to DA Headend to execute isolation switch scheme. Identify optimized restoration strategy. Send commands to DA Headend to execute restoration switching scheme. Identify required field work required & send to dispatch.
	Automated Reclosers and/or switches	DMS - Consume real-time recloser information from DA headend. Issue recloser commands as needed.
	Faulted Circuit Indicators	DMS - Consume real-time FCI information from DA headend.
	Volt/VAR Management	DMS - Consume real-time voltage data from AMI headend. Provide Volt and/or VAR correction commands to DA Head End to adjust voltage or Cap settings on specific feeders.
BR3d	On premise Storage Monitoring and System Capacity Management	DMS - Identify HOL system capacity event and dispatch nodal DM signals to DERMS.
	Conservation Voltage Reduction (CVR)	DMS - Consume real-time voltage data from AMI headend. Provide voltage reduction commands to DA Head End to adjust voltage levels on specific feeders.
	Community based energy storage	DMS - Identify HOL system capacity event and dispatch nodal DM signals to DERMS.
BR4b	Outage Management - Improved System Reliability Through Reduced Outage Times.	OMS - Use power status events as inputs into outage modeling. Enable pinging power status for single meter and groups of meters based on connectivity model.
	Value of Service (VOS) / Revenue Improvement Through Improved Reliability	OMS - Process outage alerts to improve outage responsiveness and dispatch of crews.

Figure 98 - DMS/OMS Functional Requirements

GIS

Enhancements to the GIS system, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Geographic Information System Requirements
BR1b	Aggregation of Load at Virtual Nodes for Distribution System Analysis, Transformer / Device Load Analysis and Equipment Sizing	Provide distribution device connectivity model and device load capacities to analytics tools.
	Phase Load Balancing	Phase assignment of each endpoint.
BR2b	Outage Management - Improved Outage and Reliability Index Reporting and System Reliability Planning through post event analysis.	Use timestamped restoration and power out events to perform post storm analysis to identify target areas for reliability improvement strategies.
BR2c	Reduced unaccounted for usage and field labor due to improved identification of lost or orphan (a.k.a. data nodes) meters	Capture GPS location of endpoint upon field installation and store in GIS.
BR3c	Enable Smart Cities Functionality	Ability to map various sensors including analog data and/or events for the following: - Streetlights - Wind Speed data - Fire/Smoke sensor data - Air Quality sensor data - Parking data - Snow level sensor - Traffic monitoring data - Waste collection levels - Noise level data - Road surface conditions - Surface temperatures - Vibration sensor data

Figure 99 - GIS Functional Requirements

Planning & Forecasting

Enhancements to the Planning and Forecasting systems, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Planning / Forecasting Requirements
BR1a	Enable EV Charging Rates, Revenue Metering, Load Aggregation & Market Participation	Aggregation of EV charger data to be used for Distribution planning & forecasting. PI Historian to store all data for CYME.
BR1b	Defer Distribution system capacity requirements	Aggregate distribution load flows to discrete distribution devices and capacities. Determine system capacity margins based on rolled up endpoint load flows..
	Improved Distribution Modeling and Calibration	Consume and analyze interval data. Provide interval data to planning and forecasting models to improve accuracy and calibration.
BR1e	Improved Forecasting Capability	Consume and analyze interval data. Develop forecasting model which applies load flow at nodal level.
BR4b	Value of Service (VOS) / Revenue Improvement Through Improved Reliability	Process momentary outage event logs to target low reliability circuits.
BR4c	Improved forecast accuracy	Consume and analyze interval data. Apply improved endpoint load analysis into forecasting models for improved accuracy.

Figure 100 - Planning & Forecasting Functional Requirements

KEY NEW SYSTEMS

Some of the business releases recommended in this Roadmap include the likelihood of new systems capabilities that do not currently exist within the HOL IT architecture. Thus, the following section describes these key systems and their required hi-level functionality.

Data Analytics

Analytics is a key enabler to extracting value from AMI data. Specifically, many of the opportunities identified by HOL as having high priority will be dependent on leveraging existing and additional AMI data to improve operational processes and customer insights.

The functional capabilities of the Data Analytics system, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Data Analytics Requirements
BR1b	Aggregation of Load at Virtual Nodes for Distribution Planning and Operations.	Aggregation of timestamped interval data to a virtual node. Analysis of load and distribution equipment specifications to determine if equipment is sized properly.
	Improved real and apparent loss allocation	Analyze consumption data, connectivity model, SCADA data, etc. for loss calculations
	Phase Load Balancing	Analyze totalized interval data of endpoints assigned to each phase to determine out of balance loads
BR1c	Outage Management - Improved Momentary and Blink outages	Analyze and correlate momentary outage events to circuit connectivity model to identify "trouble" areas for preventative maintenance.
BR1d	More rapid resolution of accounts in arrears and reduced consumption on inactive accounts	Monitor usage and establish thresholds to indicate un-acceptable consumption on an inactive account or which exceed collections limits. Issue report to work management system upon exceeding consumption threshold.
BR1e	Improved accuracy in rate design	Analyze usage information for rate design opportunities and impacts, customer class and cost of service allocations.
BR2a	Improved AMI Alert and Exception Management. Faster detection of and collection of theft.	Develop meter maintenance algorithms to correlate interval, register, and alarm data with work management systems to improve diagnostics and triage of field work. Analyze and correlate usage profiles, alarms and events to determine likely tamper events meters. Issue tamper target lists based on likelihood probabilities to work dispatch system.
BR2b	Improved Outage and Reliability Index Reporting and System Reliability Planning.	Use timestamped restoration and power out events to perform post storm analysis to ensure accurate CAIDI / SAIFI and to identify target areas for reliability improvement strategies.
BR2c	Reduced unaccounted for usage and field labor due to improved identification of lost or orphan meters	Identify all meters that are transmitting data from the field but which are not assigned to a registered account. Triangulate RF signals to identify location of meters with no accounts assigned.
BR3c	Smart Cities Sensor Analytics	Perform real-time analysis and trending of: - Streetlight data - Wind Speed data - Fire/Smoke sensor data - Air Quality sensor data - Parking data - Snow level sensor - Traffic monitoring data - Waste collection levels - Noise level data - Road surface conditions - Surface temperatures - Vibration sensor data Send alert to City to respond to Sensor threshold based alarms.
BR4b	Improved System Reliability Through Reduced Outage Times.	Use power outage, power restoration, and status pinging to determine nested outages prior to crews leaving area. Analyze, filter and validate power status event to minimize false alarms. Measure reduction in CAIDI minutes to calculate revenue
	Voltage Diagnostics	Analyze voltage profiles, and thresholds. Process voltage threshold alarms to determine work order requirements. Issue work order reports to Work Order Management to address low/high voltage conditions.

Figure 101 - Data Analytics Functional Requirements

Unfortunately, HOL's current IT architecture does NOT include any specific platform to provide the detailed analytics that will be required. While there are several options for accomplishing data analytics; including MDMS modules, hosted services from Data Analytics vendors (such as Oracle), or dedicated applications, a significant element in the IT Business Release plan will be to enable data analytics capabilities. Specifically, the three approaches that HOL may consider include:

- Platform or use case enabled application
  - The analytics "platform" approach is a build-it-yourself strategy. In this approach, Hydro Ottawa would architect the databases, the dashboards, the extracts, and the algorithms to analyze the data based on their own use case definitions and process automation descriptions. This approach should only be undertaken by organizations that are very adept at complex data base architecture designs, with strong in-house data science and analytical capabilities, and expert data presentment skills.
  - This approach is based on sourcing an analytics solution from a vendor who can provide not only their own underlying "platform" but also the rules engines, configuration and

programming tools, and (most importantly) implemented use cases from other utilities. This would be the preferred approach for utilities with well-defined use case targets which should be the case at HOL based on the opportunities assessments.

- MDMS or Head End System module alternative
  - Many of the top tier MDMS vendors offer data analytics modules as add-on applications to their MDMS solutions. Based on whether the current MDMS vendor (Savage) can provide data analytics applications, leveraging their data analytics solution may provide an opportunity for more efficient access to data analytics and reduced implementation risk.
  - Several of the top tier AMI vendors offer data analytics modules as options for their AMI system head end application. Based on the long-term AMI solution vendor of choice, this may become a viable option for HOL to consider.
- Full service/SaaS or DBRT
  - Full Service and Software as a Service (SaaS) vendors provide not only the platform, the application, the use cases, but also the data scientist and professional services to develop new use cases and data tests as Hydro Ottawa's needs evolve. Specifically, Oracle provides this capability via their prior acquisition of DataRaker, which is offered as a hosted service.
  - Design, Build, Run, Transfer (DBRT) strategies leverage application suppliers and consultants to develop and configure the platform and application, develop and implement the initial use cases, integrate the use cases into automated business processes, help run the new automated processes with Hydro Ottawa, and finally transfer the platform, application, and the developed use cases over to Hydro Ottawa for long term operation and support.

Hence, the first step in preparing for the data analytics release and the solution selection process for Hydro Ottawa will be a diligent identification and prioritization of the desired use cases that Hydro Ottawa believes will drive value from expanded AMI data availability. Many of these are readily identifiable from the AMI Opportunities Matrix.

Distributed Energy Resource Management (DERMs)

Based on the strong proponent for expanding HOL's Distributed Energy Resources and Market Participation, it is anticipated that HOL may need to explore and implement some advanced Distributed Energy Resource management capabilities to help gather information from distributed resources as well as manage and control generation, storage, and loads using an integrated system.

The functional capabilities of the Distributed Energy Resource Management system, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Distributed Energy Resource Management System Requirements
BR3a	Energy Storage and Demand Management	Dispatch DM signals to storage devices. Verify reduced demand based on demand threshold or calculated demand.
	EV Charging Capacity Management	Dispatch nodal DM signals to EV chargers. Verify reduced Nodal demand.
BR3d	Energy Storage and System Capacity Management	Dispatch nodal DM signals to storage devices. Verify reduced Nodal demand based on processed interval data.
	Conservation Voltage Reduction (CVR)	Consume real-time voltage data from AMI headend. Provide voltage reduction commands to DA Head End to adjust voltage levels on specific feeders.

Figure 102 - DERMS Functional Requirements

Enterprise DERMS can be defined as:

> "***a utility enterprise system that enables the monitoring, management, coordination and optimization of numerous DERs owned and operated by the utility, its customers or third-party aggregators.***"

The types of DERs supported by a true "Enterprise DERMS" include:

- Distributed Generation
  - PV (grid-scale, rooftop)
  - Wind
  - Backup generators/spinning mass
  - Fuel cells
- Energy Storage (generation and consumption)
  - Batteries
  - Electric Vehicles
- Demand Response/Curtailment
  - Heating/cooling/thermostats
  - Lighting
  - Pumps and appliances

This includes utility-owned, third-party, customer, "in front of" and "behind" the meter DER assets. No commercially available DERMS systems are known to be able to provide all of these capabilities.

DERMS systems are integrated with DMS/OMS systems supporting situational awareness and grid operations management. DERMS may also support market participation operations for both wholesale and (future) distribution markets.

Figure 103 - DERMS Vendors

The DERMS vendor landscape has become a very crowded space. Each DERMS solution requires significant investment and system integration to work with the DMS/OMS systems and with the DER assets on the grid. At some point, it should be anticipated that vendors may combine DERMS with ADMS systems, making integration with operational systems easier.

Appendices (separate attachments)

APPENDIX A – STRATEGY WORKSHOP PRESENTATION

18 Hydro Ottawa AMI Strategy.pdf

APPENDIX B – AMI REQUIREMENTS MATRIX

AMI Opportunities 20190318 v14.xlsx

APPENDIX C – BUSINESS RELEASE PLAN

AMI Roadmap & Business Release Stra

AMI Roadmap IT Requirements 20190:

APPENDIX D – NETSENSE FEATURE MATRIX COMPARISON TO EA_MS

NetSense Feature Matrix.pdf

APPENDIX E – AMI TECHNOLOGY OVERVIEW

AMI Technology Overview - 20190117.

METSCO
MAKING IT POSSIBLE

Mark Wojdan, P.Eng,
Supervisor, Maintenance & Reliability
Hydro Ottawa Limited

Dear Mark:

Re: Review of Hydro Ottawa's Asset Condition Assessment Framework

METSCO was requested by Hydro Ottawa Ltd. ("Hydro Ottawa") to review their asset condition assessment (ACA) framework. This framework represents an integral component as part of Hydro Ottawa's broader asset management (AM) framework, leveraging information captured from maintenance programs, including visual inspection, testing and monitoring data, in order to produce health index (HI) results that allow the utility to proactively manage its fleet of distribution assets and ensure that the right actions are undertaken to the right assets at the right time.

METSCO decided to undertake this assignment as per the following three stages: (a) review of the overarching processes, systems and associated input data that are supporting the ACA framework, (b) review of the asset-class HI formulations, including the produced results and sample sizes, and (c) review of the end-state applications produced by the ACA framework, including how the HI results are ultimately integrated into broader AM deliverables.

METSCO's review of Hydro Ottawa's ACA framework produced the following conclusions:

(a) Review of the Overarching Processes, Systems & Associated Input Data

METSCO's review has found that Hydro Ottawa's ACA framework is well integrated within AM-related processes, procedures and outcomes. Hydro Ottawa has developed detailed and robust documentation for both the ACA framework, which includes the underlying health index formulations, as well as the underlying maintenance programs that supply inputs into the ACA framework.

Hydro Ottawa is constantly striving for continuous improvements, and in this regard, they continue to enhance and evolve their ACA framework and associated business processes. This includes efforts to transition from manual to automated procedures with respect to ingesting input data, including inspection, testing and monitoring data, in order to process health index results in a turn-key manner, and with an eventual goal to store this data into enterprise systems, such that the results can be better integrated into other planning procedures. Hydro Ottawa has also developed detailed and robust documentation both for the ACA framework itself, including the underlying health index formulations, as well as for the underlying maintenance programs that supply inputs to the ACA framework.

Maintenance work procedure documentation continues to be enhanced and evolved within the organization. Currently, Hydro Ottawa's procedures for overhead lines have been found to be the most detailed, providing field crew workers with a clear understanding of how to differentiate between the different condition grades for each degradation factor. Hydro Ottawa continues to expand this level of detail to their other asset groups, including underground lines, substation and manhole assets.

(b) Review of the HI Formulations, including Results & Sample Sizes

Hydro Ottawa currently uses Microsoft Excel to store the associated input data and perform the necessary calculations to produce the desired HI results. Microsoft Excel provides a flexible and open architecture, thereby allowing asset managers to quickly learn the mechanics of the HI calculations, as well as identifying the potential gaps regarding the underlying maintenance data, such that continuous improvements can be quickly introduced. The Excel environment also permits Hydro Ottawa to quickly introduce necessary improvements and enhancements to the framework should any gaps or anomalies be identified.

In this regard, Hydro Ottawa has implemented a number of enhancements to the ACA framework since METSCO's initial assessment was performed. The current configuration of the ACA framework allows for HI results to be calculated in a consistent manner, leveraging as much available input data (i.e. inspection, testing and monitoring data) as possible, such that the sample size of HI results can be maximized as effectively as possible. As noted in part (a), Hydro Ottawa is also continuing to transition away from the Excel environment and transition their ACA framework and HI calculations into enterprise system environments, which will introduce more automation, and also allow for expanded applications and use cases, such as the storage of historical health index results, which can be used further validate the formulas and also develop utility-specific condition-based failure probability functions.

On an overall whole, Hydro Ottawa's ACA framework can be described as utilizing robust formulations that are aligned with best practices.

(c) Review of the End-State Applications produced by the ACA Framework

Hydro Ottawa is applying continuous improvements to their ACA framework, which includes the development of automated connections to end-state products, such that these products can be delivered and deployed in a turn-key manner. Currently, HI results, once computed within the Excel environment, are loaded into enterprise systems for further assessment. This includes loading ACA data into Hydro Ottawa's asset investment planning (AIP) software, which is designed to manage key elements within the capital expenditure process, including risk assessment, project prioritization and optimization. As first explained in part (a), Hydro Ottawa continues to transition away from the Excel environment as part of continuous improvements, such that all calculations will be managed within enterprise system environments. This will not only allow greater efficiencies to be realized, but also for more end-state applications to be produced.

Hydro Ottawa is also leveraging an industry-derived function that allows for the conversion of the health index into an effective probability of failure value. This function is applied as part of a broader risk modelling approach for substation assets in order to perform a reliability risk assessment on a station level for major substation assets. This analysis considers not only the probability of failure but also the impacts of failure based upon customer impacts and derives a risk cost to quantify the total effects of asset failure. In METSCO's view, Hydro Ottawa is well-positioned to continuously improve upon and evolve this framework into an economically-driven risk-based AM approach, in which the costs of risk are balanced against the capital costs of offsetting these risks in order to determine an economic end-of-life result for the evaluated assets in question. This form of analysis allows for Hydro Ottawa to establish risk-based business cases for each investment within their system, which aligns closely with their ongoing initiative of certifying the organization to the ISO 55000 asset management standard.

Hydro Ottawa has established an implementation roadmap in order to achieve a desired end-state such that ACA results are available in a common, auditable, accessible and convertible format. One of the key features of this future state is having input data accessible from a central electronic repository, and being able to upload results from the ACA framework into their enterprise systems for further analysis and evaluation. It is recommended that Hydro Ottawa continue to execute upon this roadmap as they continuously improve upon and evolve their ACA and broader AM frameworks respectively.

Overall Conclusions

METSCO has found Hydro Ottawa's ACA framework as utilizing robust formulations that are in alignment with best practices, and to be tightly integrated with Hydro Ottawa's broader AM-related processes, procedures and outcomes. With the framework now established, and with asset managers fully understanding the underlying methodologies and concepts, Hydro Ottawa continues to strive forward with improvements and enhancements, including the integration of their framework into enterprise systems. As Hydro Ottawa continues to apply their framework to their asset base, they will also be able to execute improvements in a targeted, cost-effective and prudent manner, thereby proportionally enhancing their ACA outputs and applications. This will further elevate the maturity levels of the framework, and ensure that the right actions are being undertaken to the right assets at the right time.

Yours Truly,

Robert Otal
Director of Asset Management & Analytics

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MAKING IT POSSIBLE

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CAPITALIZATION POLICY

In accordance with section 2.2.2.5 of the *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications,* as updated on July 12, 2018 and addended on July 15, 2019, Hydro Ottawa's Capitalization Policy is provided in this Schedule. Hydro Ottawa converted to International Financial Reporting Standards ("IFRS") effective January 1, 2015. No changes have been made to Hydro Ottawa's capitalization policy since its last rebasing application.[1]

International Accounting Standard 16 - *Property, Plant and Equipment* ("IAS 16") requires that the useful life of an asset be reviewed at least at each financial year-end. After undertaking a review, Hydro Ottawa is proposing to change its depreciation expense policy with respect to the useful life of laptop computers. Notwithstanding the fact that laptops have an operational or functional lifespan, the primary reason for the replacement of laptops is obsolescence due to advances in software and hardware technology. With the ongoing adoption of data analytics and automated tools, Hydro Ottawa is processing more information and running heavier applications, which requires newer and faster technology. The need to keep computer software and hardware technology current is essential to maintaining and improving user productivity. Moreover, planned obsolescence is a key consideration in Hydro Ottawa's Information Technology replacement strategy.

While there are many studies and opinions in the public domain regarding how often to replace a laptop, the general consensus is between two to four years.[2] Bearing this in mind, Hydro Ottawa is requesting to reduce the useful life of its laptops from five to four years. (For more information, please refer to Attachment 4-3-1(A): OEB Appendix 2-BB - Service Life Comparison). Hydro Ottawa is also requesting to make changes to the useful life of its transportation equipment. (See Attachment 2-4-3(F): Fleet Replacement Program for further details).

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

[2] For example: VBS iT Services, "How Often Should Your Company Replace Computers?" (February 13, 2016); BiTs, "How Often Should Your Company Replace Its Computers" (April 4, 2017).

The requested years of useful life of laptops and transportation equipment are within the ranges contained in the Asset Depreciation Study for the OEB prepared by Kinectrics Inc. dated July 8, 2010.[3]

[3] Kinetrics Inc., *Asset Depreciation Study for the Ontario Energy Board,* Report No. K-418033-FA-001-R000 (July 8, 2010).

HYDRO OTTAWA CORPORATE POLICY

Subject: Capitalization		
Category: Finance		**Policy Number**: POL-Fi-013.01
Administrator: Director, Finance	**Owner:** Chief Financial Officer	**Approver:** President and Chief Executive Officer

1. PURPOSE

The purpose of this policy is to define the criteria for acquisition, capitalization, transfer and retirement of Hydro Ottawa capital assets.

2. SCOPE

This policy applies to Hydro Ottawa.

3. DEFINITIONS

Capital assets include tangible and intangible assets, exclusive of goodwill

Commissioned or energized, in the context of this policy, is when a capital asset is placed into service or when the enhancement or betterment to an existing capital asset is complete

Directly Attributable Costs are costs that bring the asset to the location and condition intended for use, and include direct labour, inventory, outside services, non-stock materials and specific burdens

Enhancement or Betterment is an expenditure that contributes towards improving an asset's productivity or output or useful life

Goodwill, as defined by IAS 38, is the difference between the purchase price of an asset and the net amount of the acquired asset and assumed liability

Grouped Assets are asset purchases that are pooled into a single capital asset category as, by their nature, it would be impractical to identify individual units. These grouped assets are managed as a single asset for the purposes of depreciation

Hydro Ottawa refers to Hydro Ottawa Holding Inc. and its affiliates

IAS refers to International Accounting Standards

IAS 16 refers to the International Accounting Standard titled Property, Plant and Equipment

IAS 23 refers to the International Accounting Standard titled Borrowing Costs

IAS 38 refers to the International Accounting Standard titled Intangible Assets

IASB refers to the International Accounting Standards Board

IFRS refers to International Financial Reporting Standards

Intangible Assets, as defined by IAS 38, are identifiable non-monetary assets without physical substance

OM&A refers to operating, maintenance and administrative expenses

PP&E refers to Property, Plant and Equipment or Tangible Assets

Readily Identifiable Assets are discrete capital assets that are easily identifiable, so the asset can be individually recorded and depreciated

Residual Value is the estimated amount that an entity would currently obtain from disposal of the asset, after deducting the estimated costs of disposal, if the asset were already of the age and in the condition expected at the end of its useful life

Tangible Assets, as defined by IAS 16, include PP&E that are used on a continuing basis in the production or supply of goods and services and are not intended for sale in the ordinary course of business

4. POLICY DIRECTIVES

a) Hydro Ottawa will capitalize assets based on the standards established by the IASB under IAS 16 and IAS 38 whereby qualifying expenditures have to meet the following criteria:
   i. It is probable that further economic benefits associated with the item, for more than one year, will flow to the entity; and
   ii. the cost of the item can be measured reliably.

b) Capital asset are recorded using the cost method, whereby the cost of a capital asset comprises:
   i. its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.

ii. any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. This shall include borrowing costs, in accordance with IAS 23, to finance capital projects with a duration greater than six months and accumulated cost is in excess of $100,000.

iii. the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

c) Contributed plant that meets the definition of a capital asset is measured at fair value.

d) The following cost allocation rates included in directly attributable costs are based on management's best estimates of the applicable cost allocation determinants:

i. Direct Labour - The hourly rate recovers direct labour and benefits costs. It will be applied to all direct labour hours through timesheet reporting.

ii. Vehicle and Equipment - Vehicle and equipment hourly rates capture the directly attributable costs associated with fleet usage. Individual rates are developed for major vehicle classifications based on expected utilization. Charges will be accomplished through vehicles timesheet reporting.

iii. Supervision Burden - The supervision burden rate recovers the directly attributable costs associated with the supervision of internal labour and outside services.

iv. Engineering Burden - The engineering burden rate recovers the directly attributable engineering costs. It will be applied to Distribution Capital projects where applicable.

v. Supply Chain Burden - The supply chain burden rate recovers the directly attributable procurement and warehouse costs.

vi. These rates are reviewed and monitored on an annual basis. Material adjustments for over or under recoveries will also be recorded at the end of the fiscal year.

e) Subsequent enhancement or betterment costs which are incurred after the original asset is available for use will be capitalized based on the same criteria as the initial capital investment.

f) The materiality value for capitalizing newly acquired readily identifiable assets or additions to existing assets will be $500.

g) The materiality value for capitalizing grouped assets will be $1,000.

h) Equipment such as switchgear, transformers and meters that are reserved for emergency (capital spares) should be accounted as capital assets otherwise these items will be accounted for as inventory.

i) Depreciation of capital assets is based on the straight-line method in accordance with IAS 16 and 38. The useful lives of assets are reviewed annually.

j) Costs that are incurred to maintain the existing service potential of capital assets should be considered repairs and will be recognized in the profit or loss in the period in which they occur.

k) Hydro Ottawa may incur expenditures for amounts paid to other distributors or transmitters for capital projects. These expenditures, once available for use, should be recorded as Intangible Assets – Capital Contributions Paid.

l) Customer contributions associated with capital projects will be treated as deferred revenue and amortized to income over the life of the assets to which they relate.

m) When assets are retired from service, the capital cost and accumulated depreciation will be removed from Hydro Ottawa's financial statements with any gain or loss (after salvage proceeds, if applicable) charged to OM&A in the period in which the decommissioning occurs.

5. RELATED POLICIES, PROCEDURES AND REFERENCE DOCUMENTS

Hydro Ottawa Code of Business Conduct

6. EXCLUSIONS

There are no exclusions from this policy

7. ADDITIONAL POLICY ELEMENTS

There are no additional policy elements

8. COMPLIANCE

Employees must report incidents of non-compliance relating to this policy in a timely manner to the Policy Owner.

All instances of non-compliance shall be addressed immediately and may result in progressive disciplinary action. All members of the work group who had prior knowledge of the non-compliance may also be subject to progressive discipline. Repeat instances of non-compliance, or those that appear to be of a serious nature, must be immediately reported directly to the Director, Finance.

9. APPROVAL HISTORY

Revision	Effective Date	Description of Changes	Policy Owner:	Approved by:
.00	January 2015	Supersedes Policy FIN5-001-02 published on January 1, 2009	G. Simpson, Chief Financial Officer	B. Conrad, President and CEO
.01	October 2019	Minor updates to wording to match IFRS Standards and clause added regarding CCRA payments	DocuSigned by: Geoff Simpson 43DC885CF33E43E... G. Simpson, Chief Financial Officer	DocuSigned by: Bryce Conrad 8EDB4595749C4E3... B. Conrad, President and CEO
Scheduled Re-affirmation Date: **October 2022**			Responsibility: **Chief Financial Officer**	
Signatures on original only; original retained by Chief Financial Officer Division				

10. POLICY EXCEPTIONS

Exceptions to the above directives and/or changes to this policy must receive written pre-authorization from the President and CEO. For clarification on any aspect of this policy, contact the Director of Finance.

CAPITALIZATION OF OVERHEAD

Effective January 1, 2012, Hydro Ottawa revised its capitalization methodology used to apply overhead costs to property, plant, and equipment and intangible assets to be in accordance with International Financial Reporting Standards ("IFRS"). Under IFRS, International Accounting Standard 16 – *Property, Plant and Equipment* ("IAS 16") and International Accounting Standard 38 – *Intangible Assets* ("IAS 38") prohibit the capitalization of administration and other general overhead costs. As a result, the amount of capitalized overhead was significantly reduced as many of the costs that were capitalized prior to the revision of the policy were considered administrative or other general overhead. There have been no changes to Hydro Ottawa's capitalization of overhead since January 1, 2012 (and thus there have likewise been no changes since the utility's last rebasing application).

Hydro Ottawa applies overhead costs to capital through three separate burden rates: Supervision burden, Engineering burden, and Supply Chain burden. The use of multiple burden rates allows overhead costs to be applied more precisely to the particular projects that are associated with the various types of overhead costs. Please refer to Attachment 2-4-4(A): Capitalization Policy for Hydro Ottawa's capitalization policy.

As shown in Attachment 2-4-5(A): OEB Appendix 2-D - Overhead Expenses, the overhead costs capitalized (including labour and fleet) from 2017-2021 are in the range of 26% to 29%.

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	**2017 Historical Year**	**2018 Historical Year**	**2019 Bridge Year**	**2020 Bridge Year**	**2021 Test Year**
Distribution Operations	$ 42,072,595	$ 42,985,534	$ 43,175,751	$ 44,455,558	$ 45,958,946
Engineering & Design	$ 12,437,569	$ 13,398,062	$ 13,294,088	$ 13,977,990	$ 14,167,879
Customer Billing	$ 8,936,703	$ 8,912,271	$ 8,447,649	$ 9,274,258	$ 9,619,556
Customer & Community Relations	$ 7,300,361	$ 7,010,829	$ 6,912,228	$ 8,003,925	$ 8,617,580
Collections, Acct & Activities	$ 3,781,614	$ 2,948,863	$ 2,587,010	$ 3,278,626	$ 3,377,588
Facilities	$ 6,443,441	$ 7,127,723	$ 9,548,152	$ 7,338,521	$ 7,475,608
Finance	$ 3,847,245	$ 3,963,955	$ 3,046,156	$ 3,340,269	$ 3,441,938
Human Resources & Training	$ 3,889,418	$ 4,056,098	$ 3,558,965	$ 3,853,861	$ 3,939,877
Information Mgt & Technology	$ 10,722,068	$ 10,884,225	$ 10,870,402	$ 11,952,687	$ 10,310,302
Metering	$ 2,856,917	$ 2,621,587	$ 2,633,373	$ 2,967,981	$ 3,074,131
Regulatory Affairs	$ 2,037,050	$ 2,157,111	$ 2,012,013	$ 2,248,403	$ 2,998,222
Safety, Environment & Bus Cont	$ 2,261,796	$ 3,434,261	$ 4,429,373	$ 3,662,418	$ 3,719,278
Supply Chain	$ 2,632,039	$ 2,465,807	$ 2,428,264	$ 2,267,583	$ 2,321,330
Corporate Costs	$ 5,854,631	$ 6,385,206	$ 6,826,780	$ 7,070,979	$ 7,625,461
Total OM&A Before Capitalization (B)	$ 115,073,447	$ 118,351,532	$ 119,770,204	$ 123,693,059	$ 126,647,696

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	**2017 Historical Year**	**2018 Historical Year**	**2019 Bridge Year**	**2020 Bridge Year**	**2021 Test Year**	**Directly Attributable? (Yes/No)**	**Explanation for Change in Overhead Capitalized**
Supply Chain	$ 1,160,695	$ 1,213,508	$ 1,230,652	$ 1,205,476	$ 1,231,474	Yes	
Supervision	$ 2,365,426	$ 2,539,391	$ 2,179,994	$ 2,287,211	$ 2,530,939	Yes	
Engineering	$ 3,020,405	$ 3,235,342	$ 3,179,981	$ 2,910,979	$ 3,184,311	Yes	
Fleet	$ 2,954,501	$ 3,101,160	$ 3,266,875	$ 3,333,470	$ 3,317,225	Yes	
Labour	$ 23,327,587	$ 21,398,793	$ 22,367,493	$ 21,965,502	$ 22,461,088	Yes	
Total Capitalized OM&A (A)	$ 32,828,614	$ 31,488,194	$ 32,224,995	$ 31,702,638	$ 32,725,037		
% of Capitalized OM&A (=A/B)	29%	27%	27%	26%	26%		

SERVICE QUALITY AND RELIABILITY PERFORMANCE

1. INTRODUCTION

Hydro Ottawa reports service quality indicators, which consist of Service Quality Requirements ("SQRs") and service reliability metrics, to the OEB on an annual basis. As per section 2.2.2.8 of the *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications*, as updated on July 12, 2018 and addended on July 15, 2019, this Schedule provides the reported SQR and service reliability metrics reported to the OEB for the last five Historical Years. As required, a summary of the Major Event Days ("MEDs") experienced by Hydro Ottawa since 2016 is presented in section 3 below, along with a comprehensive cause code analysis for the 2014-2018 period. In addition, the OEB's Appendix 2-G is included as Attachment 2-4-6(A). Hydro Ottawa confirms that the information presented in this Schedule and in Appendix 2-G is consistent with the Electricity Utility Scorecard.

2. SERVICE QUALITY PERFORMANCE

Section 7 of the *Distribution System Code* outlines the OEB's expectations regarding SQRs for electricity distributors. As shown in Table 1 below, Hydro Ottawa's SQR results have remained steadily above the OEB minimum standard for the last five Historical Years (2014-2018). On average, Hydro Ottawa's SQR performance exceeded the OEB minimum standard by 9% for the 2014-2018 period. In some cases, the utility exceeded the minimum standard by over 20%. (For example, Hydro Ottawa's 2018 Telephone Accessibility SQR result is 23.7% above the OEB's minimum standard). At no time over the 2014-2018 period did Hydro Ottawa fail to meet the OEB's minimum standard for any service quality indicator.

Table 1 – Five-Year Historical Summary of Service Quality Requirements

Indicator	OEB Minimum Standard	2014	2015	2016	2017	2018
Low Voltage Connections*	**90%**	100%	100%	100%	100%	100%
High Voltage Connections	**90%**	100%	100%	100%	100%	100%
Telephone Accessibility*	**65%**	80.3%	82.5%	83.8%	85.1%	88.7%
Appointments Met*	**90%**	98.3%	97.1%	99.6%	99.4%	99.7%
Written Responses	**80%**	100%	100%	100%	100%	100%
Emergency Urban Response	**80%**	98.8%	98.0%	97.8%	99.5%	96.6%
Emergency Rural Response[1]	**80%**	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	**10%**	2.3%	1.7%	1.8%	1.7%	0.4%
Appointment Scheduling	**90%**	100%	100%	100%	100%	100%
Rescheduling a Missed Appointment	**100%**	100%	100%	100%	100%	100%
Reconnection Performance Standard	**85%**	100%	100%	100%	100%	100%
Billing Accuracy*	**98%**	99.6%	99.8%	99.9%	99.9%	99.9%

* indicates measure appears on the Electricity Utility Scorecard

Hydro Ottawa aims to maintain all SQRs above the OEB's minimum standard. For detailed discussion on Hydro Ottawa's performance with respect to key SQRs that appear on the Electricity Utility Scorecard, please see Attachment 1-1-12(C).

3. RELIABILITY PERFORMANCE

Hydro Ottawa continually assesses the distribution system's service reliability. Where issues are found, the appropriate analysis and action is undertaken to address weaknesses and improve performance. Hydro Ottawa's Reliability Council is one example of how continued focus is maintained and actioned with regards to system and customer reliability. Comprised of stakeholders from across the utility, the purpose of this council is to further foster a robust

[1] Hydro Ottawa's service territory is a mix of urban and rural areas, with approximately 60% of the territory considered rural. The administrative complexity of capturing urban and rural response rates relative to Hydro Ottawa's emergency response rate overall is not cost-effective or insightful for the utility. Rather, Hydro Ottawa strives to adhere to the urban emergency response rate (60 minutes as opposed to 120 minutes) for both rural and urban customers.

culture of reliability and drive change from a diverse set of perspectives to deliver solutions. The council meets monthly to review system performance and operational issues.

Consistent with OEB requirements and best industry practices, two principal metrics employed by Hydro Ottawa to measure the utility's reliability performance are the following: System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"). In the Electricity Utility Scorecard, the OEB utilizes plain language metrics as substitutes for these terms: "Average Number of Hours that Power to a Customer is Interrupted" is synonymous with SAIDI, while "Average Number of Times that Power to a Customer is Interrupted" is synonymous with SAIFI. For the purpose of this Schedule, Hydro Ottawa will use the terms SAIDI and SAIFI.

Hydro Ottawa's reliability performance in 2018 was significantly impacted by three severe weather events: freezing rain and windy conditions on April 16th, heavy winds on May 4th, and tornadoes on September 21st. These major events experienced during 2018 included significant outage impacts resulting from Loss of Supply ("LoS") from the Ontario grid. Out of an overall SAIDI score of 22.08 in 2018, 19.29 is attributable to these events.

Table 2, Table 3, and Table 4 below present information on Hydro Ottawa's five-year reliability performance under the different parameters which Hydro Ottawa reports to the OEB through the Reporting and Record Keeping Requirements ("RRRs") – namely, with either one or both of LoS and MEDs excluded or included.

Table 2 – Five-Year Historical Summary of SAIDI and SAIFI (including LoS and MEDs)

Index	Including outages caused by Loss of Supply and including Major Event Days					5-Year Historical Average
	2014	2015	2016	2017	2018	
SAIDI	1.66	1.62	1.21	1.58	22.83	*5.780*
SAIFI	1.08	1.42	0.95	1.03	2.03	*1.302*

Table 3 – Five-Year Historical Summary of SAIDI and SAIFI (excluding LoS and including MEDs)

Index	Excluding outages caused by Loss of Supply and including Major Event Days					5-Year Historical Average
	2014	2015	2016	2017	2018	
SAIDI	1.59	1.15	1.13	1.51	3.54	*1.784*
SAIFI	0.86	0.75	0.78	0.83	1.19	*0.882*

Table 4 – Five-Year Historical Summary of SAIDI and SAIFI (excluding LoS and MEDs)

Index	Excluding outages caused by Loss of Supply and excluding Major Event Days					5-Year Historical Average
	2014	2015	2016	2017	2018	
SAIDI	1.08	1.08	1.00	1.11	0.85	*1.024*
SAIFI	0.73	0.71	0.74	0.73	0.78	*0.734*

In order to facilitate an understanding of how the utility's 2014-2018 reliability performance compared against utility-specific reliability targets established by the OEB, Hydro Ottawa has included Table 5 below.

Table 5 – Five-Year Historical Summary of SAIDI and SAIFI (excluding LoS and MEDs) vs. OEB-Assigned Reliability Targets

Index	Excluding outages caused by Loss of Supply and excluding Major Event Days				
	2014	2015	2016	2017	2018
SAIDI	1.08	1.08	1.00	1.11	0.85
SAIFI	0.73	0.71	0.74	0.73	0.78
Index	5-Year Average Targets[2]				
	2014	2015	2016	2017	2018
SAIDI	1.04	1.09	1.15	1.12	1.13
SAIFI	1.02	0.99	0.98	0.90	0.83

Over the course of 2014-2018, Hydro Ottawa successfully achieved its SAIDI and SAIFI targets, which were based on historical five-year averages. The lone exception was in 2014, when the SAIDI value excluding LoS and MEDs exceeded the five-year average by 0.04. The 2014 SAIDI value excluding LoS and MEDs was an improvement over the SAIDI results in the three preceding years (2011-2013). In those years, Hydro Ottawa had experienced lower than historic service reliability marked by significant impacts of adverse weather and defective equipment interruptions. The utility's improving trend leading to 2014 and continued maintenance of target results in subsequent years can be attributed to a review and update of its vegetation management program, aimed at storm-hardening its system by removing all tree overhang in 2014 and 2015, as well as to continued targeted renewal of distribution assets.

The average number of hours of customer power interruption (i.e. SAIDI) in 2018 was 0.85 (excluding LoS and MEDs), which represents an improvement over historical performance. With LoS and MEDs excluded, Hydro Ottawa's SAIFI results were generally consistent over the 2014-2018 period.

[2] Targets are determined by the OEB such that they represent reliability performance that is equivalent or superior to the previous five-year average.

3.1. MAJOR EVENT DAYS

Since Hydro Ottawa's last rebasing in 2016,[3] and through the end of the 2018 calendar year, Hydro Ottawa has experienced six MEDs. The utility determines MEDs based on the IEEE Standard 1366 method. In 2018, there was a noted increase in the severity of MEDs with regards to the number of customer interruptions and number of customer hours of interruption experienced during each event. For further information on this increase, please see section 4.3.2 of Exhibit 2-4-3: Distribution System Plan.

Table 6 below provides key details on each of the MEDs experienced by Hydro Ottawa during the 2016-2018 timeframe.

Table 6 – Summary of Major Event Days (2016-2018)

Date of Major Event	Primary Cause of Interruption	Description	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
September 21, 2018	Loss of Supply	Tornadoes	39	216,001	6,808,300
May 4, 2018	Adverse Weather	High Winds	41	63,869	244,733
April 16, 2018	Adverse Weather	Freezing Rain	63	55,101	257,931
September 27, 2017	Tree Contact	High Winds	40	11,391	94,006
January 4, 2017	Tree Contact	Freezing Rain and Heavy Snow	38	19,130	38,115
July 1, 2016	Adverse Weather	Thunderstorm, Lightning and Tree Contact	16	12,297	41,791

[3] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

3.2. CAUSE CODE ANALYSIS

Hydro Ottawa records all outage causes and monitors the primary causes for trends. Where trends are identified, the utility performs detailed analysis into the root causes to assess risk and identify investment needs. Table 7 below provides a breakdown of each primary cause set out in section 2.1.4.2.5 of the RRRs for the last five years.

From 2014-2018, the four primary contributors to SAIFI and SAIDI were the following: Loss of Supply, Defective Equipment, Scheduled Outages, and Adverse Weather. These four cause codes account for 64% of the SAIFI and 89% of the SAIDI, as shown below in Tables 8 and 9, and in Figures 1 and 2.

Table 7 – Reliability Performance by Cause Code (2014-2018)

Primary Cause		2014	2015	2016	2017	2018
Unknown/Other	Number of Interruptions	34	52	37	39	49
	Customer Interruptions	11,751	18,802	32,593	17,961	43,021
	Customer-Hours	18,575	10,639	16,156	10,625	19,463
Scheduled Outage	Number of Interruptions	1,068	1,200	1,031	863	762
	Customer Interruptions	24,851	34,162	31,446	20,436	20,103
	Customer-Hours	76,844	101,699	97,984	62,770	40,273
Loss of Supply	Number of Interruptions	28	24	11	17	52
	Customer Interruptions	71,072	214,891	58,466	66,181	278,727
	Customer-Hours	23,371	148,471	26,002	23,557	6,436,022
Tree Contacts	Number of Interruptions	73	99	88	191	157
	Customer Interruptions	15,652	16,253	26,006	39,675	54,923
	Customer-Hours	24,950	25,578	58,121	115,929	183,236
Lightning	Number of Interruptions	37	17	32	33	27
	Customer Interruptions	29,279	11,957	24,130	15,711	21,822
	Customer-Hours	77,122	23,319	18,739	6,919	22,298
Defective Equipment	Number of Interruptions	276	210	200	364	369
	Customer Interruptions	88,483	82,008	58,747	62,993	89,393
	Customer-Hours	120,603	113,818	94,802	109,659	133,733
Adverse Weather	Number of Interruptions	72	29	40	67	101
	Customer Interruptions	43,110	6,715	17,467	27,839	113,916
	Customer-Hours	117,892	8,693	35,612	93,957	727,176
Adverse Environment	Number of Interruptions	12	18	5	10	2
	Customer Interruptions	287	19,935	1,960	13,338	167
	Customer-Hours	870	26,612	5,389	17,794	378
Human Element	Number of Interruptions	24	19	20	33	31
	Customer Interruptions	32,295	34,456	27,288	38,459	21,144
	Customer-Hours	38,396	36,966	5,624	42,095	14,676
Foreign Interference	Number of Interruptions	146	124	155	163	186
	Customer Interruptions	27,097	16,547	32,989	36,021	33,803
	Customer-Hours	28,608	23,829	35,659	36,999	38,512

Table 8 – Annual Contribution to SAIFI by Cause Code (2014-2018)

	Cause Code	2014	2015	2016	2017	2018	5-Year Average
0	Unknown/Other	3.42%	4.13%	10.48%	5.30%	6.35%	*5.94%*
1	Scheduled Outage	7.23%	7.50%	10.11%	6.04%	2.97%	*6.77%*
2	Loss of Supply	20.67%	47.15%	18.79%	19.54%	41.17%	*29.46%*
3	Tree Contacts	4.55%	3.57%	8.36%	11.72%	8.11%	*7.26%*
4	Lightning	8.51%	2.62%	7.76%	4.64%	3.22%	*5.35%*
5	Defective Equipment	25.73%	18.00%	18.88%	18.60%	13.20%	*18.88%*
6	Adverse Weather	12.54%	1.47%	5.61%	8.22%	16.83%	*8.93%*
7	Adverse Environment	0.08%	4.37%	0.63%	3.94%	0.02%	*1.81%*
8	Human Element	9.39%	7.56%	8.77%	11.36%	3.12%	*8.04%*
9	Foreign Interference	7.88%	3.63%	10.60%	10.64%	4.99%	*7.55%*

Figure 1 – SAIFI by Cause Code: Five-Year Average (2014-2018)

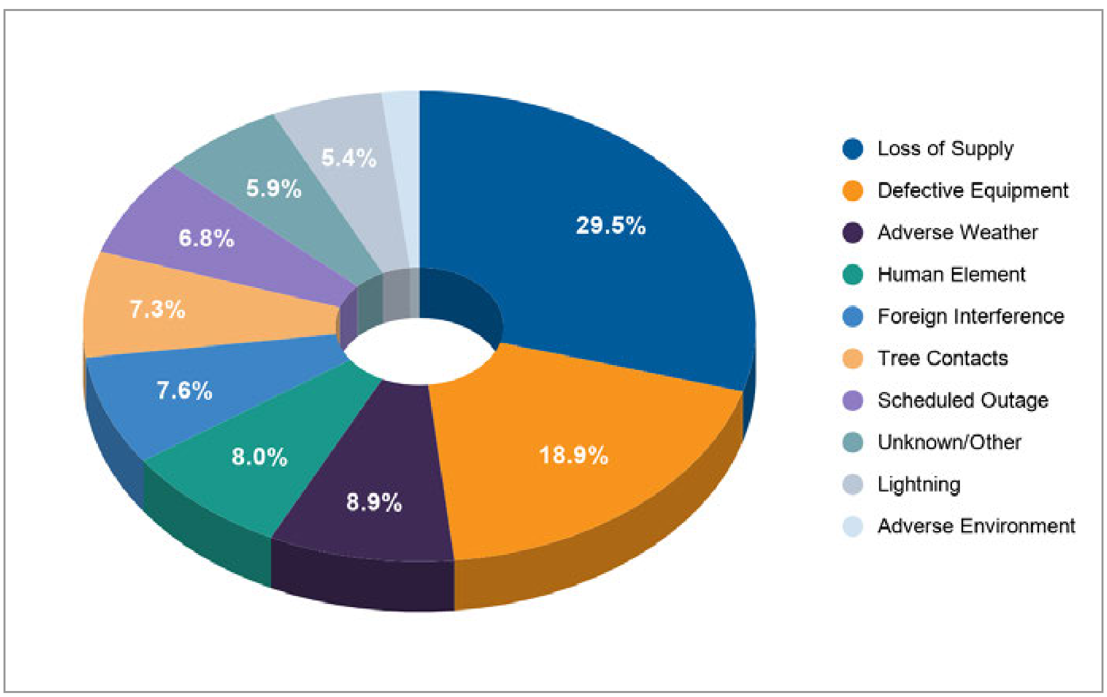
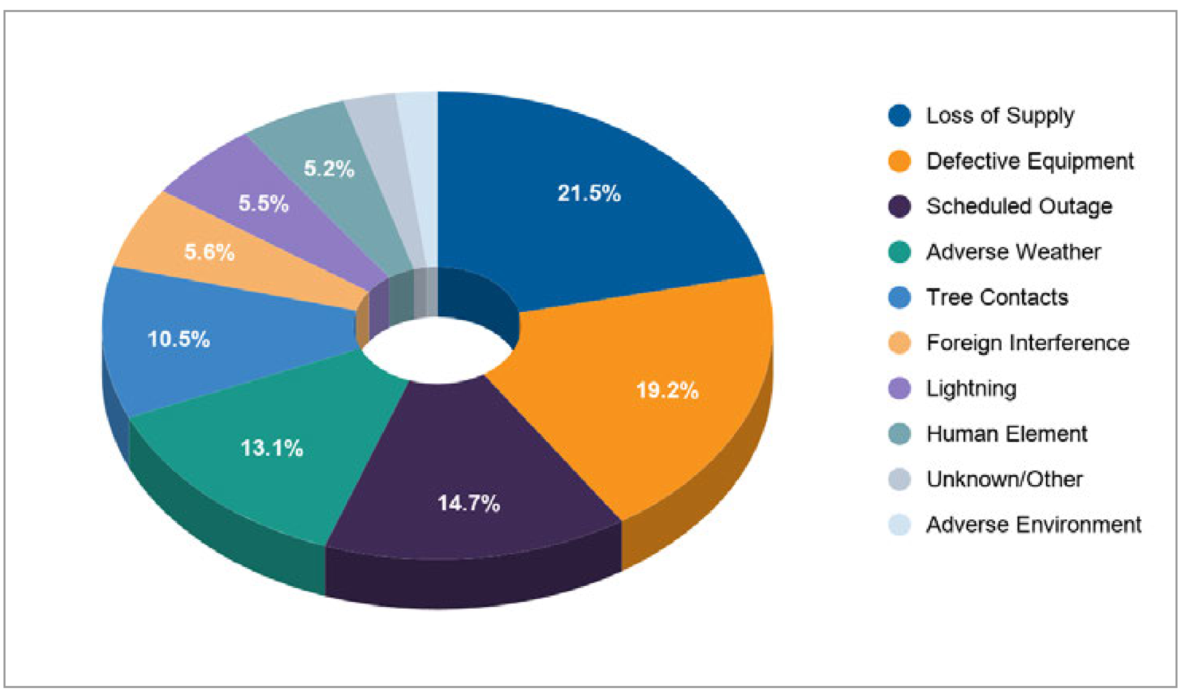


Table 9 – Annual Contribution to SAIDI by Cause Code (2014-2018)

Cause Code		2014	2015	2016	2017	2018	5-Year Average
0	Unknown/Other	5.40%	2.33%	5.19%	3.14%	0.26%	*3.26%*
1	Scheduled Outage	22.35%	22.32%	31.50%	18.54%	0.53%	*19.05%*
2	Loss of Supply	6.80%	32.58%	8.36%	6.96%	84.51%	*27.84%*
3	Tree Contacts	7.26%	5.61%	18.68%	34.24%	2.41%	*13.64%*
4	Lightning	22.43%	5.12%	6.02%	2.04%	0.29%	*7.18%*
5	Defective Equipment	35.07%	24.98%	30.47%	32.38%	1.76%	*24.93%*
6	Adverse Weather	34.28%	1.91%	11.45%	27.75%	9.55%	*16.99%*
7	Adverse Environment	0.25%	5.84%	1.73%	5.25%	0.00%	*2.61%*
8	Human Element	11.17%	8.11%	1.81%	12.43%	0.19%	*6.74%*
9	Foreign Interference	8.32%	5.23%	11.46%	10.93%	0.51%	*7.29%*

Figure 2 – SAIDI by Cause Code: Five-Year Average (2014-2018)



3.2.1. Unknown/Other

Outages due to Unknown/Other are on a slightly increasing trend over the last five years, as shown in Table 7 above. Hydro Ottawa strives to identify the root causes of outages through line patrols and fault point analysis.

3.2.2. Scheduled Outage

Scheduled Outages were a significant contributor to the annual customer reliability results, representing 19% of the SAIDI result and 7% of the SAIFI result. While scheduled interruptions are essential to completing distribution work safely and efficiently, Hydro Ottawa has made the effort to reduce the impact on customers when planning outages. These efforts can be seen in a decreasing trend in both Scheduled Outage SAIDI and SAIFI over the last five years, as indicated in Table 7 above. Hydro Ottawa has made the effort to reduce the impact on customers when planning outages. This includes installing temporary switches and using live-line techniques to minimize the number of customers affected.

3.2.3. Loss of Supply

The reliability and redundancy of the system supply is continuously evaluated as part of system planning exercises. The overall reliability result was significantly impacted by the unprecedented LoS impacts associated with major events in 2018. Excluding the 2018 result, LoS has tracked to 14% of SAIDI and 27% of SAIFI. From 2014-2017, LoS had a relatively constant frequency and customer impact, as shown in Table 7. Hydro Ottawa works proactively to identify and address supply reliability issues, whether working with the transmitter (Hydro One Networks Inc.), addressing supply issues, or mitigating their impact through distribution interties.

3.2.4. Tree Contacts

As per the information displayed in Table 7, outages due to Tree Contacts are on an upward trend over the last five years. The increasing trend is attributed largely to an increase in large tree limbs and full trees falling onto wires from outside the powerline corridor, typically as a result of extreme weather events. Hydro Ottawa has reviewed and continues to evaluate the performance of its vegetation management program and is increasingly working with customers to address risk trees outside the trim zones wherever possible.

3.2.5. Lightning

The impact associated with Lightning outages is on a declining trend, as shown in Table 7 above. Hydro Ottawa mitigates sustained outages through its system design and application of lighting protection and shielding.

3.2.6. Defective Equipment

Defective Equipment was the second largest contributor to annual customer reliability, representing 25% of the SAIDI result and 19% of the SAIFI result. Outages due to Defective Equipment are on an increasing trend over the last five years. However, despite its increasing trend, the impact of these outages on the number of customers interrupted and customer-hours is relatively constant, as indicated above in Table 7. Hydro Ottawa has been mitigating risk due to asset failures by prioritizing renewal investments and targeting asset classes with higher reliability impact. Analysis of contributions to the overall results of different asset groups can be found in section 4.1.3.1 of Exhibit 2-4-3: Distribution System Plan.

3.2.7. Adverse Weather

Adverse Weather was another major contributor to the annual customer reliability results, contributing to 17% of SAIDI and 9% of SAIFI. Outages due to Adverse Weather are on an increasing trend over the last five years, as per Table 7 above. Historical outages have been largely due to high winds and freezing rain weather. Many of the extreme weather events have resulted in the classification of MEDs, as described above in section 3.2 above. The impact of these extreme weather events on Hydro Ottawa's assets and operations has increased over the past decade. In response to these events, Hydro Ottawa has undertaken the preparation of a Climate Vulnerability Risk Assessment and subsequent development of an adaptation plan as part of its distribution planning activities. For more information, please see section 8.1.6.3 of Exhibit 2-4-3: Distribution System Plan, Attachment 2-4-3(H): Distribution System Climate Risk and Vulnerability Assessment, and Attachment 2-4-3(I): Hydro Ottawa Climate Change Adaptation Plan.

3.2.8. Adverse Environment

As shown in Table 7 above, outages due to Adverse Environment are on a declining trend over the last five years. Historical outages have been largely due to pole fires occurring as a result of salt contamination on insulators, caused by the City of Ottawa's winter de-icing efforts. Hydro Ottawa has mitigated these risks by performing a bi-annual insulator wash program to clean insulators of salt and other contamination. In addition, renewal and replacement of insulators with polymer insulators which are less susceptible to this failure mode continues to reduce the overall risk profile.

3.2.9. Human Element

Outages due to Human Element have occurred on a relatively steady basis over the last five years; however, the impact of these outages are on a declining trend, as indicated in Table 7 above. Historical outages have been largely due to incorrect records and switching errors. Each incident is reviewed and appropriate actions such as records updates, procedural changes, or employee training are undertaken to prevent reoccurrence.

3.2.10. Foreign Interference

Outages due to Foreign Interference have shown an increasing trend over the last five years, as captured above in Table 7. However, the number of Foreign Interference interruptions in 2013 were nearly equivalent to the 2018 outcome, suggesting a long-term level trend. Historical outages have been largely due to animals and foreign objects contacting the lines. Hydro Ottawa's standard for new construction requires the incorporation of animal guards. In addition, legacy construction is being retrofitted in a targeted and prioritized manner.

Appendix 2-G
Service Quality and Reliability Indicators

Service Reliability

Index	Including outages caused by loss of supply and including Major Event Days					Excluding outages caused by loss of supply and including Major Event Days					Excluding outages caused by loss of supply and excluding Major Event Days				
	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018
SAIDI	1.66	1.62	1.21	1.58	22.83	1.59	1.15	1.13	1.51	3.54	1.08	1.08	1.00	1.11	0.85
SAIFI	1.08	1.42	0.95	1.03	2.03	0.86	0.75	0.78	0.83	1.19	0.73	0.71	0.74	0.73	0.78

5 Year Historical Average

SAIDI		5.780		1.784		1.024
SAIFI		1.302		0.882		0.738

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2014	2015	2016	2017	2018
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Accessibility	65.0%	80.3%	82.5%	83.8%	85.1%	88.7%
Appointments Met	90.0%	98.3%	97.1%	99.6%	99.4%	99.7%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	98.8%	98.0%	97.8%	99.5%	96.6%
Emergency Rural Response	80.0%	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	10.0%	2.3%	1.7%	1.8%	1.7%	0.4%
Appointment Scheduling	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%