Exhibit 2:

Rate Base
Interrogatory Responses

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ATTACHMENTS

Exhibit 2 – Rate Base Interrogatory Responses

2-Staff/CCC/CCMBC/AMPCO-35

Ref. 1: Chapter 2 Appendices

Ref. 2: Distribution System Plan, p. 132

Question(s):

a) Please provide a revised version of Chapter 2 Appendix 2-AA. As part of this revised version, please provide an update to the 2025 (and 2026-2030 as necessary) capital expenditures using the most up-to-date information available (including that of the new Administrative Building). In addition, instead of including the capital contributions only at the major category level (e.g., system access, system renewal, etc.), please also provide the capital contributions at the program level (e.g., connections, expansions, etc.).

   a. As part of the revised Chapter 2 Appendix 2-AA, please add two additional columns that show the first six-month spending for 2024 by program and the last six-month spending for 2024.
   b. Please also include two additional columns showing the first six-month spending for 2025 by program and the forecasted last six-month spending for 2025.
   c. Please note how many months of actuals are included in the revised 2025 forecast if it is not six months.
   d. Please provide explanations for any material changes to the 2025 and 2026 forecasts compared to the original application.

b) Please provide a separate revised version of Chapter 2 Appendix 2-AA. Similar to the revisions requested above, please provide an update to the 2025 (and 2026-2030 as necessary) capital expenditures using the most up-to-date information available. In addition, instead of including the capital contributions only at the major category level (e.g., system access, system renewal, etc.), please also provide the capital contributions at the program level (e.g., connections, expansions, etc.). In this revised version, for any programs that have switched from one line item to another (as between the historic and forecast period), please restate with those programs shown as a continuation on one budget line across the entire 2021-2030 period.

c) (DSP, P. 132) Oshawa PUC Networks notes that “for capital projects spanning multiple years, costs remain in construction work-in-progress (WIP) until the project is completed and energized.” For forecasting purposes, please discuss how Oshawa PUC Networks converts capital expenditures to in-service additions. More specifically, does Oshawa PUC Networks assume that all capital expenditures forecast for the test year will go into service in that year? If not, please explain the methodology applied to forecast the timing of in-service additions.

d) With respect to the costs shown in Appendix 2-AA, 2-AB and the DSP, please advise whether Oshawa PUC Networks is showing capital expenditures or in-service additions for each year of the historical and forecast period.

e) Please provide an example calculation using Oshawa PUC Networks’ cost of debt, ROE, and a weighted-average depreciation rate that highlights the company’s conversion of each of: (i) Rate Base to Revenue Requirement and; (ii) capital expenditures to in-service additions to rate base to revenue requirement.

Oshawa Power Response

a) See revised Appendix 2-AA, as part of the Revised Chapter 2 Appendices - OPUCN_IRR_2026_Filing_Requirements_Chapter2_Appendices_1.0_20250730 , filed with these interrogatory responses. Changes to total in-service amounts for 2025 and 2026 are immaterial.

b) Please refer to excel file Supplemental IR35b Revised Appendix 2AA Breakdown filed with these interrogatory responses.

c) Oshawa Power assumes that all capital expenditures forecasts for the test year will go into service in that year.

d) Oshawa Power is showing in-service additions each year of the historical and forecast period.

e) Please see the following Table and assumptions in response to both i) and ii):

Assumptions:

- Long-Term Debt Rate: 3.41%
- Short-Term Debt Rate: 3.91%
- Return on Equity: 9.00%
- Capital Structure:
  - 56% Long-Term Debt
  - 4% Short-Term Debt
  - 40% Equity

Weighted Average Cost of Capital = (.56 x 3.41%) + (.04 x 3.91%)+(.40 x 9.00%)

= 5.666%

- Amount of Capital Expenditure Placed In-Service: $1,000 (Asset #1)
- Depreciation Expense on Asset #1 Added in Test Year: $20 (assumes a 50-year asset service life)
- Weighted Average Depreciation Rate: 2.0%
- No Income Tax or OM&A impact of asset addition

IRR Table 2-1: Illustrative Example Calculation

Illustrative Example			
	Bridge Year	**Test Year**	**Reference**
Closing Rate Base for Asset #1	0		(a)
Capital Expenditures *		1,000	(b)
Closing Rate Base for Asset #1		1,000	(c)
Average Rate Base in Test Year **		500	(d) = ((a)+(c))/2
Depreciation Expense - Annual		20	(e)
Depreciation Expense – Test Year **		10	(f) = (e)/2
** Assumes all Capital Expenditures are in-service additions in the Test Year*			
*** Half-year rule for calculation of Test Year Revenue Requirement Impact*			

Return on Capital = Test Year Average Rate Base x Weighted Average Cost of Capital = $500 (d) x 5.666% = $28.33

Test Year Revenue Requirement = Return on Capital + Test Year Depreciation Expense = $28.33 + $10.00 (f)

= $38.33

2-Staff/PP-36

Ref. 1: EB-2020-0048 Settlement Proposal, p.12

Question(s):

As part of its last settlement agreement, Oshawa PUC Networks committed to improving its ability to efficiently track the number of assets that it installs in a given year by major asset category. How has Oshawa PUC Networks improved its ability to efficiently track the number of assets it installs?

Oshawa Power Response

Oshawa Power has improved its ability to efficiently track with an update to its GIS system in 2023. This updated GIS system allows for better tracking and analysis of assets than the previous system by making installation dates mandatory for all new assets. Timely and accurate updates from as-constructed drawings into this system including in-service dates improves the ability to efficiently track the number of assets, not only by major asset category but also what was installed in any given year. The GIS system further allows field verification from office staff to improve installed asset tracking.

2-PP-37

Ref. 1: EB-2020-0048 Settlement Proposal, p. 12

Preamble:

As noted in the response to PP-1, Oshawa PUC Networks expects to achieve efficiencies and enhanced customer experience through coordination with the City of Oshawa (“Oshawa”) and the Regional Municipality of Durham (“Durham”) on their energy and emissions plans. Oshawa PUC Networks considers the goals, objectives, and targets of Oshawa and Durham energy and emissions plans and planning with a view to pursuing cost efficiencies and reduced emissions as outlined in Exhibit 2, Appendix 2-1 Distribution System Plan, Appendix K – Grid Modernization Plan, and

Oshawa PUC Networks will continue to do so. In addition, Oshawa PUC Networks will continue coordinating with regional and municipal governments as part of its broader distribution system planning process. The Parties agree that Oshawa PUC Networks will qualitatively report on areas of realized cost efficiencies and distribution system planning improvements associated with its coordination with Oshawa and Durham in its next cost of service application.

Question(s):

Please provide details for the results achieved during the 2021 – 2025 rate term in advancing results in support of the Oshawa and Durham energy and emission plan objectives.

Oshawa Power Response

During the 2021-2025 rate term, Oshawa Power took several actions to advance the results achieved in support of the Oshawa and Durham energy and emission plans, including:

- Designing and securing funding for a Region-wide EV outreach and educational program called E-Mission, which resulted in several years of community test drive events;
- Installing Durham's first eight on-street EV chargers throughout Oshawa's downtown core;
- Supporting the study and connections required for Durham Region Transit's E-Bus pilot by applying for a grant from The Atmospheric Fund, in partnership with DRT;
- Supporting the Region's application for a Federation for Canadian Municipalities grant to offer the Durham Greener Homes program;
- Promoting the Durham Greener Homes program to customers;
- Supporting Key Account engagement events such as the Durham Greener Buildings awards night and the Oshawa Chamber of Commerce's Sustainability Award; and,

- Assisting with the development of resilience communications with respect to energy security.

Oshawa Power is actively in talks with Durham and the City of Oshawa with respect to supporting these plans going forward and expects to find new areas of shared value with the implementation of the LDC eDSM, NWS and ESG strategies. In terms of efficiencies, one example would be sharing communications efforts for the Durham Greener Homes program, which offers individualized home energy coaching, including detailed information about the Save On Energy programs. Oshawa Power is currently proposing to leverage eDSM funding to augment these services in the City of Oshawa, to drive cost-efficient participation through a one-stop-shop for customers.

2-Staff-38

Ref. 1: Chapter 2 Appendices, 2-G SQI

Question(s):

a) Did Oshawa PUC Networks miss its targets for telephone accessibility and telephone call abandonment metrics in 2024 due to increased call volumes and a new outsourced call centre in 2024? If so, has increased investments in outsourced call centres in 2025 improved this metric thus far in the year? If not, what has caused these missed metrics?

b) What does Oshawa PUC Networks attribute to its improved 2024 SAIDI and SAIFI reliability figures (0.3 and 0.29 respectively), and is a similar trend occurring in 2025?

Oshawa Power Response

a) The low performance in 2024 was primarily due to increased call volumes that couldn't be quickly accommodated by the call centre. This metric has been greatly improved in 2025.

b) The improvements to 2024 SAIDI and SAIFI figures are a cumulative effect and as a result of Oshawa Power's commitment to continuously monitoring reliability and making system improvements as mentioned on pages 39 to 41 of Exhibit 2, DSP.

Key improvements include:

- Implementation of Fault Location, Isolation, and Service Restoration (FLISR) to improve fault location and service restoration capabilities
- Continued effort to remove porcelain insulators from the distribution system
- Installation of animal protection devices
- A solid approach to asset replacement focused on system planning and efficiency

For 2025 Oshawa Power is currently trending toward 0.39 SAIDI and 0.43 SAIFI reliability figures - slightly higher than 2024 but still well below target.

2-CCC/CCMBC-39

Ref. 1: Exhibit 2, p.55

Ref. 2: Chapter 2 Appendices, 2-D

Question(s):

Please discuss how Oshawa PUC Networks determines the appropriate capitalization of each of: (i) labour and benefits; (ii) material handling; and (iii) vehicle and related costs. As part of the response, please explain the decline in capitalization of OM&A between 2021 and 2026 (on a percentage basis).

Oshawa Power Response

Oshawa Power determines the appropriate capitalization treatment as follows:

I. **Labour and benefits –** Labour pertaining to engineering and construction work directly related to asset preparation is capitalized.

II. **Material handling –** The transport and handling and related costs of materials used in a capital project are capitalized.

III. **Vehicle (Fleet) Costs -** Usage of fleet vehicles directly associated with capital projects is tracked and capitalized in the same manner as labor costs.

IV. **Related costs (third-party costs)** - Costs from subcontractors and external vendors directly related to asset construction or enhancement are capitalized.

The decline in capitalization of OM&A on a percentage basis between 2021 and 2026 is primarily attributed to the increase in Administrative costs as discussed in detail throughout the Application. This increases the overall OM&A before capitalization costs, thereby reducing the percentage of capitalized OM&A.

2-CCC/CCMBC/AMPCO-40

Ref. 1: Distribution System Plan, p.14

Question(s):

a) (P.14) Please advise when the overhead and underground departments were combined.

b) (P. 14) Please provide an estimate of the savings ($) resulting from the combination of the overheard and underground departments and reference where those savings are reflected in the capital expenditure plans as well as the OM&A plans.

Oshawa Power Response

a) Oshawa Power combined the overhead and underground departments in 2021.

b) Oshawa Power's consolidation of the overhead and underground team into one group primarily delivers productivity and qualitative benefits such as cross-training/competence building, fewer separate crew mobilizations, and reduced disruption to planned work when crews are required to respond to trouble calls. This was an operational resourcing adjustment and Oshawa Power does not have an estimated cost savings resulting from this consolidation.

2-Staff/VECC/AMPCO-41

Ref. 1: Distribution System Plan, pp. 35-36, Table 8

Question(s):

a) If available, please provide an annual breakdown of outages by weather event type (i.e., wind, storms, etc.) and include 2024 data.
b) Please provide a breakdown of Defective Equipment Interruptions by equipment type for the years 2019 to 2024.
c) Please provide a breakdown of Defective Equipment Number of Customer Interruptions by equipment type for the years 2019 to 2024.
d) Please provide a breakdown of Defective Equipment Number of Customer Interruption Hours by equipment type for the years 2019 to 2024.
e) Please update Table 8 to include 2024 results.

Oshawa Power Response

a) Please see table below for a breakdown of weather events.

IRR Table 2-2: Weather Events 2019-2024

Adverse Weather Condition	2019	2020	2021	2022	2023	2024
Wind	2	19	5	1	2	6
Snow	0	0	0	2	3	0
Rain	0	0	0	0	0	0
Total	**2**	**19**	**5**	**3**	**5**	**6**

b) Please refer to the tables below.

IRR Table 2-3: Interruptions by Asset Type 2019-2021

Equipment Type	2019			2020			2021		
	Equipment interruptions	Number of customer interruptions	Number of customer interruption Hours	Equipment interruptions	Number of customer interruptions	Number of customer interruption Hours	Equipment interruptions	Number of customer interruptions	Number of customer interruption Hours
Transformers	7	2463	297	8	139	591	9	160	792
Cutouts & switches	15	2338	2778	10	2595	2862	4	204	296
Cable faults	15	395	1079	27	5569	6315	18	1976	1907
Lightning arrestor	6	315	646	5	76	93	2	20	40
cable splices	1	2	18	2	3	6	2	52	145
Insulators	2	12516	9827	2	1533	3515	2	770	1560
crossarms	1	369	66	0	0	0	0	0	0
Elbows	1	15	4	0	0	0	0	0	0
OH connections	7	142	434	15	5590	7623	4	80	260
Quick Sleeves	0	0	0	1	1028	1765	0	0	0
Relays	1	3498	2624	0	0	0	0	0	0
Poles	0	0	0	1	747	1112	0	0	0
Ducts	0	0	0	0	0	0	1	1	11
Customer Equipment	0	0	0	0	0	0	0	0	0
Total	56	22053	17773	71	17280	23882	42	3263	5011

IRR Table 2-4: Interruptions by Asset Type 2022-2024

Equipment Type	2022			2023			2024		
	Equipment interruptions	Number of customer interruptions	Number of customer interruption Hours	Equipment interruptions	Number of customer interruptions	Number of customer interruption Hours	Equipment interruptions	Number of customer interruptions	Number of customer interruption Hours
Transformers	6	48	232	11	290	811	7	153	443
Cutouts & switches	4	36	82	4	2036	318	11	1243	290
Cable faults	33	1209	3479	25	1976	2714	16	2745	2316
Lightning arrestor	3	2511	2712	1	66	186	1	51	111
cable splices	1	19	110	1	6	39	1	1	12
Insulators	2	20688	2822	2	50	195	2	125	225
crossarms	0	0	0	0	0	0	0	0	0
Elbows	1	39	9	0	0	0	0	0	0
OH connections	3	220	303	4	1688	3085	2	13	14
Quick Sleeves	1	3	8	1	53	99	0	0	0
Relays	1	1746	407	1	1701	1332	0	0	0
Poles	0	0	0	2	853	446	0	0	0
Ducts	0	0	0	0	0	0	0	0	0
Customer Equipment	2	22	2	6	74	44	0	0	0
Total	57	26541	10166	58	8793	9269	40	4331	3411

c) See tables in b).

d) See tables in b).

e) Please see updated Table 8 from the DSP below.

IRR Table 2-5: Updated Table 8 from DSP – Historical Interruptions 2019-2024

Interruptions	2019	2020	2021	2022	2023	2024	Total of Row	% of Tot
Number of Interruptions								
0 - Unknown/Other	17	9	11	7	11	0	55	1.72%
1 - Scheduled Outage	485	427	731	378	470	313	2491	78.06%
2 - Loss of Supply	0	0	1	1	1	0	3	0.09%
3 - Tree Contacts	9	7	11	6	15	9	48	1.50%
4 - Lightning	1	5	1	2	6	0	15	0.47%
5 - Defective Equipmen	56	71	42	57	58	40	284	8.90%
6 - Adverse Weather	2	19	5	3	5	6	34	1.07%
7 - Adverse Environmen	6	0	0	0	0	0	6	0.19%
8 - Human Element	4	9	2	0	2	3	17	0.53%
9 - Foreign Interference	59	58	47	33	41	24	238	7.46%
							3191	100%
Number of Customer Interruptions								
0 - Unknown/Other	1316	8492	6523	2044	3066	0	21441	6.49%
1 - Scheduled Outage	4586	8187	7603	3338	5452	2432	29166	8.83%
2 - Loss of Supply	0	0	10554	5	13514	0	24073	7.29%
3 - Tree Contacts	3365	670	1146	1895	8439	5210	15515	4.70%
4 - Lightning	172	5232	8	2409	12121	0	19942	6.04%
5 - Defective Equipmen	22052	17280	3263	26541	8793	4331	77929	23.58%
6 - Adverse Weather	99	2500	922	17530	671	123	21722	6.57%
7 - Adverse Environmen	2314	0	0	0	0	0	2314	0.70%
8 - Human Element	14695	14559	6887	0	26	62	36167	10.95%
9 - Foreign Interference	15906	32597	13213	9425	11028	23868	82169	24.87%
							330438	100%
Number of Customer Hours of Interruptions								
0 - Unknown/Other	568	3317	4982	1562	2354	0	12784	3.91%
1 - Scheduled Outage	5212	8784	5494	3433	6391	1992	29315	8.97%
2 - Loss of Supply	0	0	9079	0	968	0	10047	3.08%
3 - Tree Contacts	7174	473	1449	2543	8589	10160	20227	6.19%
4 - Lightning	487	1975	9	1325	11914	0	15711	4.81%
5 - Defective Equipmen	17773	23882	5010	10167	9269	3410	66102	20.24%
6 - Adverse Weather	225	11741	1774	62908	130	306	76778	23.50%
7 - Adverse Environmen	3079	0	0	0	0	0	3079	0.94%
8 - Human Element	4682	10688	793	0	12	16	16175	4.95%
9 - Foreign Interference	19046	26001	14564	6835	9987	24084	76433	23.40%
							326649	100%

2-AMPCO-42

Ref. 1: Distribution System Plan, p.44 Table 9

Question(s):

Please provide the critical assets prone to unplanned downtime and explain how this is considered as an Asset Management objective target.

Oshawa Power Response

One of Oshawa Power's Asset Management Objectives has an Asset Management Target to target critical assets prone to unplanned downtime. In this context, Oshawa Power does not identify individual assets, or asset classes, as being critical and prone to unplanned downtime, but considers all assets as being critical in the overall functioning of its distribution system and so takes an overarching approach in trying to mitigate any unplanned downtime as all assets are prone to unplanned downtime due to failure and would negatively impact the reliability of the distribution system.

Oshawa Power categorizes every individual asset into risk bands via condition and impact assessments as described in detail in the Asset Condition Assessment (ACA) in Exhibit 2, DSP, Appendix C.

Assets recommended for replacement in the ACA are further subject to risk prioritization at a project/program level through Oshawa Power's Asset Management planning process as outlined in section 5.3.1.1. Table 16 provides an overview of assets prone to unplanned downtime that are planned for replacement in the 2026-2030 period through strategic proactive replacement programs, as an outcome of this exercise.

Table 9 in the DSP sets targets to:

- Maintain SAIDI / SAIFI at or below a fixed five-year historical average updated every 5 years; and
- Target critical assets prone to unplanned downtime; through
- Inspection / Proactive maintenance

These targets are designed to be achieved via prudent inspection and maintenance activities as highlighted under section 5.3.3 of the DSP and executing proactive replacement programs as scheduled in the DSP filed in this Application.

The target is quantified and measured through metrics such as system reliability (SAIDI & SAIFI) and asset management (Distribution System Plan Implementation Progress) reported on the OEB scorecard.

2-AMPCO/VECC-43

Ref. 1: Distribution System Plan, pp. 57

Question(s):

a) (p. 57) Please provide a copy of the 2018 Asset Condition Assessment on the record in this proceeding.

b) (p. 57) Please explain how the updated Maintenance Manual impacts costs since 2023.

c) (p. 74) Please provide the same data in Table 16 for each of the years 2021 to 2025 and the total for the historical period, on a planned and actual basis.

d) (p. 74) Please provide a sub-set of the data in part (c) to reflect the planned and actual replacement of assets in poor and very poor condition.

e) (p.81-82) Please explain any changes to proactive compared to reactive asset replacement strategies since the last COS application.

f) (p. 83) Please provide the total number of assets replaced due to reactive maintenance for each of the years 2021 to 2025 by asset type. Please confirm reactive maintenance has the same meaning as reactive replacement and that the budget is reflected in SR-12.

g) For each asset category (System Access, System Renewal, System Service, General Plant) please provide the percentage of costs allocated to a Third-Party for the years 2021 to 2024 and the forecast for 2025 to 2030 and provide the calculation.

Oshawa Power Response

a) Please refer to Attachment 2-1 for a copy of the 2018 Asset Condition Assessment (2018 ACA).

b) The maintenance manual updates were an improvement to record keeping by documenting maintenance practices and aligning with ANSI/NETA MTS 2023. It did not involve significant changes to maintenance activities themselves. Costs associated with improved inspection & maintenance are already built into actuals starting 2021.

c) Please refer to table below for Table 16 with planned and actual asset replacements by asset type for the 2021-2025 period.

IRR Table 2-6: Updated Table 16 from DSP – Distribution Asset Replacement Plan (2021 to 2030)

Asset Class	2021		2022		2023		2024		2025		Totals		Unit	2026	2027	2028	2029	2030
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Plan	Actual						
Poles	208	220	220	150	185	209	221	55	127	87	961	721	#	69	55	86	84	79
Overhead Conductors	5100	5600	7400	5000	6400	6700	7500	1650	4100	4700	30500	23650	m	2600	1050	2900	2800	2550
Underground Cables	1560	1334	8210	5371	6000	3722	5840	2280	8250	1049	29860	13756	m	724	1350	2631	1542	4061
Pole-Mount Transformers	59	42	48	25	58	62	66	10	15	7	246	146	#	11	9	40	31	46
Padmount Transformers	0	0	0	0	0	0	0	0	0	0	0	0	#	9	2	25	23	33
Firon Overhead Switches	0	0	0	0	0	0	0	0	0	0	0	0	#	0	99	99	99	99
Porcelain Switches and Insulators	285	732	285	701	285	683	285	293	285	193	1425	2602	#	0	233	233	233	233
Quick Sleeves	33	67	33	58	0	0	0	0	0	0	66	125	#	0	141	141	141	141
Distribution Switchgear	0	0	0	0	0	0	0	0	0	0	0	0	#	0	2	0	1	2
Meters	0	0	0	0	0	0	0	0	0	0	0	0	#	2800	2800	2800	2800	2800
Locks	0	0	0	0	0	0	0	0	0	0	0	0	#	1555	1555	1555	1555	1555

d) Oshawa Power does not have the exact sub-set of the data in part (c) to reflect the planned and actual replacement of assets in poor and very poor condition. However, Oshawa Power used the recommendation (i.e. assets categorized as poor and very poor) from the 2018 ACA as a key input into formulating proactive capital projects / programs in the 2021 rate application. Though renewal efforts were deferred in some cases, Oshawa Power did not introduce new proactive system renewal projects, with one notable exception discussed below. The municipal switchgear replacement project required expanded scope to include riser pole and egress cable replacements to address broader future system planning capacity requirements. Therefore, it is reasonable to say that the vast majority of the replacements in the 2021-2025 rate period are assets that were categorized as poor or very poor per the previous ACA.

e) There has been minimal shift in proactive vs. reactive asset replacement strategies. Proactive renewal programs may defer from historical program based on factors such as regulatory considerations (e.g. proactive meter replacement program), asset groups that are recommended for replacements as per the ACA (e.g. Pole replacement Program), and corrective measures to mitigate operational inefficiencies (e.g. Firon switch replacement program).

Cumulative benefits of historical proactive replacements are taken into consideration, and hence approximately 8% lower reactive expenditures compared to 2021-2025 are forecasted in the 2026-2030 period.

f) Please find best available information below on reactive replacements in 2021-2025 by major asset category type.

IRR Table 2-7: Reactive Replacements 2021-2025

YEAR	Poles (#)	Underground Cable (m)	Overhead conductor (m)	Padmount TX (#)	Polemount TX (#)
2021	1	4552	5614	46	18
2022	6	3923	837	55	23
2023	14	5161	1542	69	6
2024	2	6982	2823	58	18
2025	-	2054	1341	3	8
Grand Total	**23**	**22672**	**12157**	**231**	**73**

Reactive maintenance is not the same as reactive replacement. The budget in project SR-12 is for reactive replacement. The Reactive Maintenance section on Page 83 incorrectly includes the word “replace” when the intention was to only use the word “repair”. The sentence should have read “The asset is repaired to restore service immediately and, in some cases, permanent repair or replacement is completed in subsequent days.

g) This information has been filed in the revised Appendix 2-AA in the Revised Chapter 2 Appendices. The contribution amounts are the costs allocated to third parties.

2-CCC/VECC/AMPCO-44

Ref. 1: Distribution System Plan, pp. 53, 72-74, 151

Question(s):

a) (P. 53) Please provide additional details with respect to the “stewardship operational theme.” As part of the response, please provide specific examples that highlight how a “financial” and “regulatory” impact would be measured.

b) (P. 53) Please explain how innovation is considered as part of the risk matrix (including how the scoring is applied).

c) (P. 72) Please explain what the “DAI” percentage is in Table 15.

d) (P. 72) Using wood poles as an example, please explain how Oshawa PUC Networks interprets the asset condition for assets with an invalid HI and explain how that interpretation is used as part of the capital planning process.

e) (PP. 73-74) For each asset class in Table 16, please provide a table showing the number of planned replacements (in each year between 2026 and 2030 and in total for the forecast period) relative to the number of assets/meters of assets that are in poor or very poor condition (as shown in Table 15). For example, it appears that Oshawa PUC Networks plans to replace 10,308 meters of underground cables and the ACA shows that the company has 5,640 meters of underground cable in poor or very poor condition. If the asset classes shown in the ACA and the planned replacement tables are not on the same basis (i.e., not showing the same assets), please explain and, to the extent possible, provide Tables 15 and 16 on the same basis.

f) (PP. 73-74) Similar to the above question, please provide a table that provides a comparison between the number of assets planned for replacement and the number of assets that are considered to be in fair, poor or very poor condition. To the extent that Oshawa PUC Networks plans to replace assets in fair condition, please provide the number of assets (by class) that are in fair condition and are targeted for replacement.

g) (PP. 53, 74) Please explain the difference between the impact matrix shown in Table 10 and the discussion of the impact analysis at P. 74, which states that risk is evaluated on three factors (safety, reliability and environment).

h) (P. 151) Please provide the detailed TRS calculation for each program included in Table 30.

i) (P. 151) Based on the discussion at pages 53-54, it appears that there was one more step in Oshawa PUC Networks' prioritization strategy – the calculation of the CRRF. Please explain whether that was done and why it is not shown in Table 30. If the CRRF prioritization was done, please provide the relevant information.

j) (P. 151) Please confirm our understanding that a small change in the TRS means that a project does not meaningfully reduce risk.

Oshawa Power Response

a) Table 3.1 in the DSP provides AM objectives associated with stewardship:
    - Ensure all regulatory & environmental risks are either met, or mitigated
    - Minimize revenue losses by strategic investments & maintain high level of reliability

   Please also refer to the Strategic Asset management plan in Appendix H of the DSP.

   Some noteworthy references are:

i. Table 2 - risk factors and potential mitigation strategies.

ii. Table 3 ‑ Performance monitoring and Reporting.

iii. Appendix A ‑ operational themes and impact matrix

Financial stewardship – Energization of large capital investments as per scheduled plan to prevent losses on shareholder return, ensuring capital investments are balanced against Oshawa power's lending capacity (cash flow) through prudent monitoring of CAPEX, and reduction of asset maintenance costs through well informed condition assessments and implementation of proactive replacements are considered examples of financial stewardship.

Regulatory stewardship – An example would be avoidance of penalties from environmental non-compliance such as elimination of lead cables, PCB elimination, and SF6 monitoring and regulation.

b) **Innovation** is evaluated on its potential benefits rather than the risks it may bring.

- In the "before" scenario (without the innovation), the risk is seen as the missed opportunity to gain those benefits (what is lost by not implementing the proposed innovative solution).
- In the "after" scenario (with the innovation), the risk is lower because those benefits of the innovative solution have now been achieved (previously unrealized benefits are now gained through the innovative solution).

Oshawa Power quantifies the benefit of innovation via evaluating how much impact it has on other operational themes such as safety, reliability, customer focus, and stewardship. The larger the impact an innovative solution is expected to have on the other operational themes, the higher the risk it alleviates. Please refer to the Strategic Asset Management Plan in Exhibit 2, DSP, Appendix H for more details.

c) DAI (Data Availability Index) is the weighted percentage of condition parameters with valid data. Please refer to section 3.1.3 of the Asset condition assessment in Exhibit 2, DSP, Appendix C.

d) Oshawa Power interprets assets with an invalid HI as follows: "If an asset has an invalid HI then a ratio of age over TUL is used to determine the probability" (Exhibit 2, DSP, Appendix C, Page 9). This ratio alone does not constitute a recommendation for replacement. Oshawa Power uses the ratio combined with the risk associated with the asset to determine if it should be replaced. Specifically for wood poles, as described in Section 7.1.1.1 - Wood poles (Exhibit 2, DSP, Appendix C, Page 154), 308 wood poles have invalid HI AND have also been identified as being either high or extreme risk based on impact of their failure. None of these poles are currently included under Oshawa power's pole replacement program. These poles will undergo inspection early in the 2026-2030 planning period to gather condition data to determine when they should be planned for consideration for replacement.

e) Adding asset condition numbers to Table 16 would detract from Oshawa Power's approach to asset replacement focused on overall system planning and efficiency. Table 16, is the product of a multiple layer risk prioritization approach as described in section 5.3.1.1 of the DSP.
   - **Individual asset risk analysis**: METSCO recommended asset replacement based off three factors: asset condition, asset risk, and asset economic life cycle. Comparing the asset Replacement Plan against a single factor such as the asset condition would fail to provide a full picture as to Oshawa powers replacement needs. Table E-4 of the ACA shows Distribution Assets Recommended for Replacement looking at assets on an individual level.
   - **Project/Program risk analysis**: Many assets are interconnected and replacement of one asset in very poor condition can have a cascading effect causing the replacement of multiple additional assets that are in other states of condition. As an example, when replacing very poor condition legacy overhead conductors, the poles may need to need to be replaced, regardless of their condition, to support the incremental

load/tension to adhere to safety requirements as set by Ontario Reg 22/04.

Individual asset replacement recommendations from the ACA, therefore, have been further evaluated for operational feasibility and effectiveness to formulate strategic proactive renewal projects/programs. These projects/ programs are further subject to risk prioritization as described in section 4.4 of Oshawa Power's SAMP in Exhibit 2, DSP, Appendix H.

f) Please refer to response e).
g) As described in response e) above, the impact analysis in page 74 is the individual asset specific impact analysis within the ACA. The impact matrix in Table 10 applies to project/program level impact analysis that comes later in Oshawa Power's planning process.
h) Please refer to Attachment 2-2 for individual TRS calculations.
i) The Cost of Risk Reduction Factor (CRRF) is limited to comparison of projects with similar costs. The formula is CRRF = Project Cost / difference between step 1 and 2 TRS (page 54, DSP). When it comes to ranking all projects / programs against each other, the cost aspect will need to be ignored as projects of higher costs (where costs are not comparable) will always rank lower due to the numerator being high. Oshawa Power applies the CRRF calculation on a case-by-case basis when project reprioritization becomes necessary, such as when there is a need to accommodate an unplanned system access project. In such cases, where Oshawa Power needs to make a decision on proceeding between two projects of comparable costs, the CRRF plays a role. TRS is a better metric for overall project/program ranking as it places emphasis on risk reduction, without limiting it to projects of similar costs.
j) Confirmed.

2-AMPCO-45

Ref. 1: Distribution System Plan pp. 54-55

Question(s):

a) Please provide the value of the preliminary investment portfolio and compare and explain the test against Oshawa PUC Networks' total capital and operating funds.

b) Please quantify and explain the changes in the preliminary investment portfolio following customer engagement mechanisms.

c) Please provide the value of the capital investment plan sent to the Finance and Audit Committee for review and approval.

d) Please confirm the final approval of the budget and capital investment plan by the Executive and Board of Directors reflects the version approved by the Finance and Audit Committee.

e) Please confirm the plan approved by the Board of Directors is reflected in the current application.

Oshawa Power Response

a) The preliminary investment portfolio was approximately $109.9M over the 2026-2030 planning period. The test against Oshawa Power's capital and operating funds involved analyzing the total preliminary portfolio envelope of $109.9M against Oshawa Power's lending capacity and also minimizing bill increases without compromising the integrity of the distribution system. The test resulted in a reduction of the total budget envelope to $77.6M following strategic revisions. With the release of the OEB's amendments to the DSC to extend the revenue horizon to 40 years, the total envelope needed to be increased to the current proposal of $80.8M.

a) After reasonable revisions, the $77.6 million investment portfolio was presented to customers for engagement. Feedback confirmed strong support for Oshawa Power's 2026-2030 plans, so no changes were necessary as a result of engagement. Key highlights below (page 55 of the DSP):

- 88% agreed with Oshawa Power's proposed investments in equipment and fleet vehicles for operational needs

- 88% agreed with Oshawa Power's plan to invest in automation and remote monitoring and control for the distribution system in order to improve reliability and decrease response time for outages
- 87% agreed with the Oshawa Power's proposed NWS strategy to modernize its system and ensure it can effectively meet increasing electricity demand

More details can be found in Exhibit 1, Attachment 1-10 and section 5.2.2 of the DSP.

However, as mentioned in the response to question a) above, the December 23, 2024 amendment to the OEB's Distribution System Code, extending the revenue horizon for residential connections to 40 years, shifted the cost responsibility for certain projects from the customer to the LDC, resulting in an increase of the total envelope to the currently proposed $80.8M.

c) $80.8M for the DSP.
d) Confirmed.
e) Confirmed.

2-CCC/CCMBC-46

Ref. 1: Distribution System Plan, p. 61

Preamble:

Oshawa PUC Networks' peak 2024 summer demand was 231MW. At present time, Oshawa PUC Networks remains a summer peaking LDC.

Question(s):

a) If available, please provide a forecast of peak demand for 2025 and 2026 (including the underlying calculation).
b) Please explain how the peak demand forecast influences Oshawa PUC Networks' capital plan if at all.

Oshawa Power Response

a) Peak demand forecast was provided as part of the IRRP stage of the GTA East regional planning. Please tables below.

IRR Table 2-8: Peak Demand Forecast

Combined Forecast	
Summer	
Year	Load Impact (MW)
2025	247.48
2026	254.05
Winter	
Year	Load Impact (MW)
2025	210.01
2026	217.50

Connected loads (Yet to Ramp up)	
Summer	
Year	Load Impact (MW)
2025	5
2026	5
Winter	
Year	Load Impact (MW)
2025	5
2026	5

Customer Growth			
Summer			
Residential (A)		Commercial (B)	
Year	Load Impact (MW)	Year	Load Impact (MW)
2025	2.38	2025	1.03
2026	4.75	2026	2.07
Winter			
Residential		Commercial	
Year	Load Impact (MW)	Year	Load Impact (MW)
2025	1.87	2025	0.8
2026	3.74	2026	1.6

Electric Vehicles			
Summer			
LDEV		MHDEV	
Year	Load Impact (MW)	Year	Load Impact (MW)
2025	2.12	2025	0.30
2026	4.48	2026	0.60
Winter			
LDEV		MHDEV	
Year	Load Impact (MW)	Year	Load Impact (MW)
2025	2.12	2025	0.30
2026	4.48	2026	0.60

Building Electrification			
Summer			
Residential		Commercial	
Year	Load Impact (MW)	Year	Load Impact (MW)
2025	0.54	2025	0.22
2026	0.88	2026	0.37
Winter			
Residential		Commercial	
Year	Load Impact (MW)	Year	Load Impact (MW)
2025	1.5	2025	1.7
2026	2.5	2026	2.9

Base Load	
Summer	
Year	Load Impact (MW)
2025	235.89
2026	235.89
Winter	
Year	Load Impact (MW)
2025	196.68
2026	196.68

b) In the 2026-2030 planning period peak demand forecast and customer growth is addressed in the following ways:

- Building infrastructure to the location of customer connection needs – Through the expansions program under system access. Please refer to Exhibit 2, DSP, Appendix B, pages 11-16.
- Alleviating capacity constraints at the 13.8kV feeder and station level by introducing better interconnectivity to the distribution system – Through

the "3 New Feeders from MS9" project. Please refer to Exhibit 2, DSP, Appendix B, pages 71-75.

- Non-Wires Solutions – Aimed to enhance the system's flexibility and capacity, positioning it to keep future capital investments in traditional wires solutions deferred to beyond 2030 while mitigating impacts of a high scenario in electrification growth. Please refer to Exhibit 2, DSP, Appendix A, and Appendix B pages 85-89.

2-CCC/VECC-47

Ref. 1: Distribution System Plan, pp. 103, 107, 109, 110-112, 114, 117-118

Question(s):

a) Please provide an update to the 2025 variance analysis for all capital categories (i.e., system access, system renewal, system service and general plant) using the most up-to-date information available.

b) (PP. 107, 110) Based on the 2023 (actual) and 2025 (forecast) costs incurred, it appears that the Municipal Substation Switchgear Replacement Program experienced an approximate $2.4M cost overrun. Please provide a detailed variance analysis with respect to the Municipal Substation Switchgear Replacement Program for each of 2023 and 2025 (and in total) between actual costs and forecast costs. As part of the response, please provide any internal documentation (e.g. change requests, project status updates, etc.) with respect to this program. Please also provide the evidence from Oshawa PUC Networks' 2021 Rates application that discussed this project.

c) (P. 111) Please provide additional information with respect to the 2021 reliability improvement project (reconfiguration in the Simcoe-Winchester area). As part of the response, please confirm that evidence with respect to this project was not provided in Oshawa PUC Networks' 2021 Rates application (or if evidence was provided, please file excerpts of that evidence). In addition, please provide any internal documentation that launched the project (and documentation with respect to the project as it was underway).

d) (P. 112) With respect to the 2022 overhead automated self-healing switches and smart grid program, please provide a detailed variance analysis between actual costs and forecast costs. As part of the response, please provide any internal documentation (e.g. change requests, project status updates, etc.) with respect to this program. Please also provide the evidence from Oshawa PUC Networks' 2021 Rates application that discussed this project.

e) (P. 114) With respect to the 2024 44kV Line Extension program, please provide a detailed variance analysis between actual costs and forecast costs. As part of the response, please provide any internal documentation (e.g. change requests, project status updates, etc.) with respect to this program. Please also provide the evidence from Oshawa PUC Networks' 2021 Rates application that discussed this project.

f) (P. 117) With respect to the 2022 Information Technology General program, please provide a detailed variance analysis between actual costs and forecast costs. As part of the response, please provide any internal documentation (e.g. change requests, project status updates, etc.) with respect to this program. Please also provide the evidence from Oshawa PUC Networks' 2021 Rates application that discussed this project. In addition, please discuss the alternatives that Oshawa PUC Networks considered relative to a server upgrade in the context of rising server costs.

Oshawa Power Response

a) Please find variance analysis based on the revised Appendix 2-AA.

System Access

- Expansions resulting from residential development have significantly ramped up in 2025. YTD in-service amounts are already $134K over the full year forecast. New year-end forecast is expected to be 900K higher than the initial forecast. Higher contributions help offset the overall impact.

- Third party relocation is expected to be $350K lower than initial forecast due to deferral of a region driven road widening project.
- Overall variance under system access from initial forecast is immaterial.

System Renewal

- No significant variances anticipated from initial forecast.

System Service

- No significant variances anticipated from initial forecast.

General Plant

- Automation Platform – capitalized in 2025 vs 2024.
- CIS over budget by $100k.
- CRM removed – duplicate.
- MWFM reduced to $150k.

b) Please find variance explanations in the tables below.

IRR Table 2-9: 2023 Municipal Substation Switchgear Replacement Program Variance Analysis

		MS2 (2023)			
Items	Description	Amount (per Switchgear)	Revised Amount	Difference	Explanation
1	As filed	$ 1,800,000.00			
2	Post settlement	$ 1,800,000.00	$ 2,125,000.00	$ 325,000.00	Acknowledging that the amount set was preliminary and additional scope changes were necessary prior to RFP, Oshawa Power revised the value of each switchgear revised to $2.125M. This is the amount that the variance analysis is based on.
3	RFP Finalization / Base Bid	$ 2,125,000.00	$ 2,230,750.00	$ 105,750.00	Final Base bid was more expensive than the initially anticipated amount of $2.125M
4	Change orders	$ 2,230,750.00	$ 2,658,053.00	$ 427,303.00	The approved additional costs along with descriptions can be seen in final MS2 invoice 42-1624293 that released holdback
5	Internal costs	$ 2,658,053.00	$ 3,111,322.00	$ 453,269.00	Since the egress cables were being upgraded in order to prepare for future demand growth from 500MCM to 1000MCM cable, pole calculations needed to remodelled in order to meet Ontario Reg 22/04 and the decision was made to replace riser poles as per industry best practice and prudent system planning. This work was performed internally. Internal costs also included supply of material such as insulation boots, station transformer, base, duct, and cable along with inspection of work performed by the third-party contractor.

IRR Table 2-10: 2025 Municipal Substation Switchgear Replacement Program Variance Analysis

MS7 (2025)					
Items	Description	Amount (per Switchgear)	Revised Amount	Difference	Explanation
1	All costs associated with items 1-5 above	$ 3,111,322.00			
2	Cable	$ 3,111,322.00	$ 3,328,197.00	$ 216,875.00	Additional cable requirements
3	Location complexities	$ 3,328,197.00	$ 3,500,950.00	$ 172,753.00	Estimated costs to account for location specific complexities. Expected to incur additional costs for traffic control and removal/replacement of the substation fencing for the crane.

Please refer to Attachment 2-3 for Final Invoice that includes description of work with associated costs, including those resulting from change orders, as well as material justification sheet filed in the 2021 rate application discussing this project.

c) Oshawa Power was receiving complaints from customers situated in subdivisions on Simcoe Street North between Conlin Road East and Winchester Road East. As a result, this project that was a continuation of the strategy adopted in a 2013 intersection rebuild job (Winchester and Simcoe Intersection) was proposed, with the following objectives in mind:
   - Improve reliability: Via introduction of better switching capabilities
   - Alleviate loading at MS7 via load transfers to MS9
   - Reduce number of customers on Feeder 7F4 and create an express feeder to serv rural Oshawa.

   Please refer to Attachment 2-4 for change order notice with relevant info. Confirmed that evidence for this project was not provided in the 2021 rate application.

d) The Expansion of Overhead Automated Switching, SCADA operated 44kV OH switches, and SCADA Integration and Deployment of Automation Controllers and Network Connected Devices (projects SS-02, SS-03, and SS-04) were delivered in close coordination with each other and are noted in Oshawa Power's 2021 rate applications. Their combined approved budget was $400K, while actual spending totaled $769K. See variance details below:

Please find a detailed variance analysis between actual costs and forecast costs in the following table.

IRR Table 2-11: Expansion of Overhead Automated Switching and SCADA Variance Analysis

Description	Anticipated costs	Actual Costs	Overspend	Explanation
Installation of Smart Switches	$ 300,000.00	$ 440,395.00	$ 140,395.00	$440K - The forecast assumed installation of 13.8 kV switches. In 2022, Oshawa Power instead installed 44 kV switches, to better align with concurrent distribution automation upgrades.
Centralized automation controller integration and deployment of network devices	$ 100,000.00	$ 328,318.00	$ 228,318.00	$159K - Contractor services (G&W / Survalent) and internal costs to configure the centralized FLISR platform and establish communication between field IEDs and the control system. 169K - Contractor and internal costs associated with station network upgrades, including replacement of GE relays and SEL RTACs, to integrate with the centralized FLISR system.
TOTAL	$ 400,000.00	$ 768,713.00	$ 368,713.00	

Change orders are not available for this project. Please refer to Attachment 2-5 for Material Justification Sheets filed as part of Oshawa Power's 2021 rate application. Please refer to Attachment 2-6 for works instructions to install 44kV switches.

e) The 2024 44kV Line Extension Project is not the same as the planned 44kV line extension project included in Oshawa Power's 2021 rate application. As mentioned in page 113 of the DSP, the 44KV Line extension (Ritson Road – Winchester Road East and Conlin Road East) project that was part of the 2021 rate application was deferred to align with a regional road widening project that affects the poles within the same project scope area. As of 2025, this work is still in the design phase.

The 44KV line Extension project in 2024 extended the 165M7 feeder (fed from Enfield TS) west along Conlin Road West to its intersection with Thornton Road North, enabling timely connections of multiple large industrial and commercial loads in the rapidly developing Northwood Business Park area.

Therefore, a variance analysis between the planned 2023 44kV line extension to the 2024 unplanned 44kV line extension would not be beneficial as the project scope and location are entirely different.

There was no evidence filed in the 2021 rate application regarding the 2024 44kV line extension project.

f) The 2022 Technology program details are as shown below:

IRR Table 2-12: 2022 Technology Program Forecast and Actual Spend

Project	**Spend**	**Budget**
End User Hardware	$139,492.04	$120,000
Mobile Hardware Replacements	$17,837.32	$20,000
Server Refresh	$259,886.34	-
Cyber Security	$37,313.31	
Total	$454,529.03	$140,000

As outlined on page 117 of the DSP, the majority of the $314k overage is due to a server refresh that was purchased in 2022 though it was scheduled in 2023. This was due to very favourable pricing provided by a vendor at a time of considerable pricing uncertainty in the market. This server upgrade was part of

Project number GP-06 on page 201 in Exhibit 2 of the 2021 rate application as described in the project summary:

> "Upgrade and planned refresh of retired hardware including laptops, desktops, networking gears, storage capacity, UPS and battery systems, phone systems, data back-up and the server infrastructure"

Please refer to Attachment 2-7 for evidence filed in the 2021 rate application, discussing this project.

An alternative to the server upgrades would have been to transfer to cloud-hosted infrastructure, however Oshawa Power was not ready at the time to entertain this possibility due to the following reasons:

1) Cyber Security: Oshawa Power was in the process of implementing various cyber security controls in alignment with the OEB Cyber Security Framework (OEB CSF). Moving to Infrastructure as a Service would have required a fresh start on many of the controls and would have delayed the effort significantly. This delay would present an unacceptable risk to the organization.

2) Cost: Given that Oshawa Power must maintain a minimum amount of physical infrastructure (to support applications that cannot be cloud-hosted, such as SCADA, the Outage Management System and, at the time, the meter data management software, the incremental cost of adding physical server infrastructure for hosting, as opposed to using Infrastructure As A Service (IaaS) is relatively much lower.

3) Operational ability to transition: Many of Oshawa Power's applications are somewhat legacy applications, such as the Great Plains financial system, and would require extensive testing and likely vendor support to function in an IaaS environment. Given

the current infrastructure and the risks of maintaining those past their end of support, it would not have been prudent to engage in such an effort, that likely would have costed much more than the server infrastructure.

As Oshawa Power enacts its business transformation plan and modernizes much of its software (ERP, GIS, CIS, etc.), cloud-first may become a more viable strategy. Oshawa Power will continue to assess its options and select the most prudent path moving forward.

2-CCC/VECC-48

Ref. 1: Distribution System Plan, pp. 121, 138

Question(s):

a) Please provide a table the same as Table 24 (P. 121) which shows the same information (i.e. contributions & gross/net for the four categories of system access) for the historical and bridge (2025) years.
b) (P. 121) Please confirm that the total actual/forecast gross capital cost for the 2021-2025 period was $82.3 million and confirm that this figure is comparable to the $97.1 million shown in Table 23.
c) (P. 121) Please confirm that the total actual/forecast net capital cost for the 2021-2025 period was $69.8 million and confirm that this figure is comparable to the $80.8 million shown in Table 23.
d) (P. 138) Please explain why a replaced asset (i.e., a new asset that replaces a more deteriorated asset) would not lead to operation cost savings.

Oshawa Power Response

a) Please refer to the revised Appendix 2-AA for this information.
b) Confirmed.
c) Confirmed.
d) In the majority of cases, a new asset will still operate under the same conditions and in the same function as a more deteriorated asset, therefore Oshawa Power

will still need to continue inspection and maintenance on new assets as per Appendix C of the DSC; hence its operational costs are not expected to change materially.

2-CCC/VECC-49

Ref. 1: Distribution System Plan, Appendix A – ERP Business Case, pp. 7-8, 13-14

Question(s):

a) (P. 7) Please advise whether Oshawa PUC Networks has support (e.g., quotes, etc,) for its statement that third-party support for Dynamics GPA is becoming more costly. If so, please provide analysis showing this increasing cost.
b) (P. 8) Option 1 discusses the imprudence of continuing Dynamics GP beyond 2029. Please explain why Oshawa PUC Networks is seeking to replace the ERP system in 2027.
c) (PP. 8-9) To the extent possible, please provide the cost difference between the three options (including both capital and operational costs) for the lifecycle of the ERP.
d) (PP. 13-14) Please advise whether the following is correct (or correct our understanding):
    i) There are no costs associated with the new ERP solution included in the 2026 test year revenue requirement.
    ii) If Oshawa PUC Networks elects to move forward with a cloud-based solution, it will record non-capitalized costs in the proposed Cloud Computing Deferral Account and will not seek ICM recovery of the capitalized portion of the costs. As part of this response, please confirm that Oshawa PUC Networks is seeking approval to record the ERP-related operational costs in the noted deferral account.
    iii) If Oshawa PUC Networks elects to move forward with an on-site solution, it will seek ICM recovery for the capital costs associated with the project. As part of the response, please advise whether Oshawa PUC Networks

will seek ICM recovery before, or after, it has began investing in the new ERP solution.

Oshawa Power Response

a) It is generally true that unsupported, or soon-to-be unsupported software, will become more expensive to maintain due to the declining availability of resources resulting from a reduction in the customer base. Oshawa Power did not perform a formal analysis to confirm this assertion. Oshawa Power has to replace the ERP software, as detailed in the ERP Business Case (DSP, Appendix A). Anecdotal supports include Oshawa Power experiencing increased difficulty in securing resources in recent projects to enhance purchase order automation in Great Plains and has been informed by the preferred vendor that this is because of declining availability of knowledgeable resources as the supply naturally declines as fewer customers exist to create a demand for them.

b) As stated in the business case, Oshawa Power is seeking to replace the ERP because the software is being deprecated by its vendor, meaning that it will be no longer supported. Though technical support is not due to end until 2029, it is prudent to not wait until the last minute for such a significant organizational change. Furthermore, as the end of support nears, third party tools and support will likely continue to decrease in quality and availability. Lastly, as Oshawa Power invests in automation, streamlining, integrations, and digitization, money spent on the existing system will potentially have to be re-spent once the organization switches to the new ERP, and so switching earlier will minimize sunk costs into the existing systems and interfaces.

c) For cost differences, Oshawa Power estimates an order of magnitude difference between options 2 and 3, however more detailed estimates cannot be provided without RFP processes for each.

d) Please see below.

   i) Correct.

ii) Correct. The capitalized portion of the costs associated with a cloud-based solution have been included in the 2026-2030 DSP.

iii) Correct.

2-Staff/CCMBC/AMPCO-50

Ref 1: Distribution System Plan, Appendix C - Asset Condition Assessment, pp.160-163

Question(s):

a) In its Asset Condition Assessment, METSCO recommended a number of data collection improvements. Please describe how Oshawa PUC Networks will consider METSCO's recommendations during the forecast period.
b) How recent was the inspection data used in the Asset Condition Assessment?

Oshawa Power Response

a) METSCO's 2023 Asset Condition Assessment (ACA) Report proposed 17 recommendations that would strengthen Oshawa Power's ACA framework. These include broad initiatives like standardized record-keeping and digitization, as well as targeted initiatives that apply only to specific assets, such as ongoing wood pole testing to improve data accuracy. Oshawa Power will assess and adopt feasible recommendations that will improve data availability on its assets in order to support Oshawa Power's decision-making abilities.
b) Oshawa Power's 2023 ACA used inspection data going back up to three years as its distribution system is required to be inspected based on the frequency highlighted in Appendix C of the DSC.

2-Staff/CCC/CCMBC/VECC/AMPCO-51

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.1-3

Question(s):

a) Have all third-party relocation projects been confirmed for 2025 and 2026? If not, at what stage are the listed third-party relocation projects?
b) What cost estimation class has been used for third-party relocation projects in 2025 and 2026?
c) (P. 1) Please explain how the capital contributions for the 2025 bridge year and forecast period (2026-2030) were estimated. As part of the response, please explain how historical actual contributions (which were approx. 50% of gross capital over the 2021-2024 period) were considered in the forecasting methodology.
d) (P. 3) Please provide the in-service dates for the projects shown in the table at page 3.
e) (P. 3) Please provide the km of line relocation for the projects shown in the table at page 3.
f) (P. 1) Please provide the forecast/planned capital (gross) and capital (net) amounts for each of the years 2021 to 2024.
g) (P. 1) Please provide the total planned and actual km of line relocated in each of the years 2021 to 2024.

Oshawa Power Response

a) Oshawa Power has two third party driven relocation projects confirmed for 2025 (i) Conlin Rd. E from Harmony to Grandview, and ii) and the intersection of Wilson Rd and the 401, of which both are currently under construction. Oshawa Power has no third party driven relocation projects confirmed for 2026. Projects for 2026 and onwards are only in the conceptual / coordination stage.
b) Estimates for third-party relocation assumes all poles in the identified area will be affected. Projected costs and expected contributions are derived from historical

data. In AACE terms, the estimate can be considered Class 5 (Conceptual estimate).

c) For third-party relocations, capital contributions for the forecast years were calculated based on the cost sharing precedent between Oshawa Power and regional / municipal governing bodies (third party), where the third party pays for 50% of the labor- and labor-saving devices. A sample of historical projects were chosen to find the average contribution received which was approximately 24.5%.

Historical contributions – In 2024, the Hydro One Wilson TS feeder relocation project should be considered an outlier where the full cost was recovered from Hydro One (as mentioned in Exhibit 2, DSP, page 103). When this number is removed from the calculation, the contribution percentage is 22.6% which aligns closer to the forecast assumption of 24.5%.

d) Please see Attachment 2-8 for additional Third-Party Relocation Details.

e) See d).

f) Excerpt from Oshawa Power's 2021 rate application (EB-2020-0048, Exhibit 2, DSP, Appendix A, page 1) showing forecast/planned capital (gross) and capital (net) amounts:

IRR Table 2-13: Third-Party Relocation Forecast Gros and Net Amounts (2021-2024)

	2021	2022	2023	2024
Capital Cost	$1,820,000	$900,000	$520,000	$600,000
Capital Contribution	$455,000	$225,000	$130,000	$150,000
Net Cost	$1,365,000	$675,000	$390,000	$450,000

g) As noted in response a), scope of work for third-party relocations are not known in advance. Third-party relocations typically see large variances in scope during the design stages making the preliminary km assumptions unreliable. Oshawa Power did not have a planned km assumption for third-party driven line relocations in each of the years 2021 to 2024. Actual km of lines relocated for the years 2021 to 2024 do not provide a clear picture of the work performed. The projects completed varied in scope, with several resulting in zero kms of line relocation. For example, a relocation in 2021 involved adjusting multiple anchors around a new multi-use path. Although there was significant work, it is not reflected in km of line.

2-Staff-52

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.6-7

Question(s):

a) In reference 1, Oshawa PUC Networks provided a graph outlining the cost per connection per year. Why were costs per connection in 2021 and 2024 lower than in other historical years, and why were contributions for connections lower in 2023?

b) Please provide an updated forecast for the number of connections and net cost in 2025 and 2026.

Oshawa Power Response

a) As referenced in Exhibit 2, DSP, Appendix B ‑ Material Justification sheets, page 6, the cost per service can vary widely due to the nature of work involved in connecting or upgrading the customer.
The nature of the connection / upgrade also dictates the cost allocation between the customer and Oshawa Power. For example, a customer upgrade from a 100A to a 200A service could involve no additional work from the distributor other than providing a disconnect / reconnect or could involve upgrading the overhead / underground service conductors, service bus, and the supply transformer. As clarified by the OEB staff bulletin RE: Residential Customer Connections & Service Upgrades dated August 24, 2023, such upgrades are to be treated as enhancements and as such the cost is to be borne by the distributor.
The connections program is made up of several of these individual instances. As a result, the cumulative effect in 2021 and 2024 was that majority of the projects

involved minimal distributor related costs and as such yielded lower per connection costs. In contrast, 2023 projects involved projects where the distributor borne portion of the costs were higher and consequently experienced lower customer contributions.

b) Oshawa Power is expecting the forecast number of connections / service upgrades and net cost to remain unchanged.

2-Staff/CCC/AMPCO-53

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.11-14

Question(s):

a) With respect to the Expansions budget, why did Oshawa PUC Networks select the subdivision projects that it did in its sample in determining the cost per lot?
b) Please provide an updated estimate of new residential customers and cost for the Expansions budget for 2025 and 2026.
c) Has Oshawa PUC Networks confirmed the number of new developments with third parties for 2025 and 2026? If not, how accurate are the estimates of new residential customers?
d) Please provide a description of new developments in 2025 and 2026.
e) Please provide the cost per lot estimate calculation for the Expansions program for both 2025 and 2026 and explain how the cost per lot was used to determine the gross and net budget for the program in 2025 and 2026.
f) (P. 11) Please confirm that the 1.6% growth rate is applied starting in 2024 to forecast 2025-2030 new residential customers. Also, please further discuss how the 1.6% growth rate was determined.
g) (P. 11) Please confirm that the “number of new residential customers” is equivalent to the number of new lots.
h) (P. 11) Please confirm, or correct, that the net cost per lot, on average, between 2021-2024 was $758.

i) (P. 12) Is Oshawa PUC Networks able to perform a calculation of the average cost per lot across all subdivisions in a manner that aligns the costs with the number of customers (to avoid the timing issue noted on page 12)? If so, please provide that calculation.
j) (P.12) Please provide the underlying calculations supporting the $2,526 net cost per lot.
k) (P. 13) Please provide the underlying calculations supporting the $3,120 net cost per lot.
l) (P. 14) Please explain how alternative bids are reflected in Oshawa PUC Networks' forecast expansion costs for 2026-2030.

Oshawa Power Response

a) Oshawa Power selected 10 subdivision projects from the most recent historical three-year period for the cost per lot analysis so that it reflects - current construction realities, estimates based on current labor and material costs, and the nature of work currently experienced within Oshawa's service territory. Individual projects needed to be chosen as opposed to generic historical averages so that the projects could be remodeled under the revised EEM with 40-year revenue horizon to show shift towards higher distributor borne costs.
b) Oshawa Power is expecting the residential customer forecasts to remain the same. Please refer to the revised Appendix 2AA provided as a response to 2-Staff/CCC/CCMBC/AMPCO-35 a) for revised 2025 expansions budget. The 2026 budget forecast remains unchanged.
c) Oshawa Power is in regular communication with developers during the design process of subdivisions. As of June 2025, there were 725 remaining residential lots yet to be connected in subdivisions where distribution assets on the right of way are already installed and energized. There are several other subdivisions that are approaching energization of distribution assets (constructed by the developer – Alternative bid option). Additionally, there are subdivisions in design / construction stages where definitive energization dates have not been provided by the developers. Oshawa power finds the estimated residential customer

growth in its rate application to be reasonable and accurate based on best info available at this time.

d) Please refer to Attachment 2-9 for a map showing areas of developments in 2025 and 2026.

e) Please refer to responses j) and k) below for details on cost per lot estimate calculation. For the 2025 Bridge year and 2026 Test Year, the projected residential growth of 932 and 947 lots respectively were multiplied by the net cost per lot of $3,121 to arrive at the net capital annual budget of $2.95M.

f) Confirmed that the 1.6% growth rate is applied starting in 2024 to forecast 2025-2030 new residential customers. Oshawa Power considers the residential customer growth percentage of 1.6% to be reasonable based on historical trends. Though 2024 increase was lower compared to the rest of the historical period, this was expected with the DSC amendment to increase of revenue horizon to 40 years to come into effect in December 2024. Hence Oshawa Power anticipates that growth will continue to follow the 1.6% with the policy currently in effect.

g) This is correct for the planning period but not for the historical period due to timing issue mentioned in the material justification sheet.

h) $758 cannot be considered the average cost per lot due to the timing issue as mentioned in Exhibit 2, DSP, Appendix B – Material Justification Sheets, page 12. The average net cost per lot would be approximately $2,526.90 as per outputs of the EEM. The EEM methodology is set by the OEB and is elaborated in Appendix B of the DSC.

i) The table below uses lot counts to subdivision projects placed in service in each historical year, rather than using total annual customer connections, to give a better picture of net cost per lot.

IRR Table 2-14: Subdivision Projects In-Service (2021 to June 2025)

Item	2021	2022	2023	2024	2025 Jan to June	TOTAL
Expansions (Net $)	$ 407,246.00	$ 404,463.00	$ 3,396,749.00	$ 154,117.00	$ 4,105,988.00	$ 8,468,563.00
Lots (#)	199	198	1497	0	1330	3224
Net Cost per Lot ($)	$ 2,046.46	$ 2,042.74	$ 2,269.04	$ -	$ 3,087.21	$ 2,626.73

As can be seen in 2025 actuals, number of subdivisions being energized has rapidly increased due to reasons stated in response f). This trend is expected to continue in the forecast period.

j) Please refer to response a) in conjunction with details on the EEM model in Appendix B of the DSC. The inputs into the EEM model were based on detailed designs. For example:

The estimated expansion costs for connecting 241 lots in one of the projects included in the average calculation are as follows:

IRR Table 2-15: Estimated Expansion Costs Calculation

Category	Item Description	Quantity	Amount ($)
Material	Cable - Primary + Secondary (m)	$ 23,763.00	$ 572,826.38
	Duct (m)	$ 11,515.50	$ 69,059.15
	concrete encased feeder (m)	$ 970.00	$ 170,100.00
	transformers (#)	$ 24.00	$ 145,847.60
	Switchgear (#)	$ 3.00	$ 50,120.00
	Civil work	$ 973.00	$ 18,493.90
	Miscellanous hardware (#)	$ 28,806.50	$ 74,510.78
Labor			$ 441,430.23
Vehicles			$ 166,473.50
TOTAL			$ 1,708,861.54

The inputs above, when modelled using the EEM (prior to revenue horizon increase to 40 years), guided by Appendix B of the DSC, outputs $2,991.00 net cost per lot to Oshawa Power. The average of all 10 projects run through the EEM yields an average net cost per lot of $2,526.

k) The inputs from response j) above, when modelled using the EEM (with the revised model post revenue horizon increase to 40 years), guided by Appendix B of the DSC, provides $3,183.00 net cost per lot to Oshawa Power. The average of all 10 projects run through the model yields an average net cost per lot of $3,120.

l) Oshawa Power treats alternative bid the same as distributor constructed subdivisions in terms of in-service and impact on net amounts as costs are reported in in-service amounts and all costs are realized when the subdivision is placed in-service in either case.

2-Staff/CCC/VECC-54

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.17-20

Question(s):

a) With respect to the Revenue Metering budget, why are costs per meter expected to decrease in 2025 compared to 2023 and 2024?

b) Please provide an updated estimate of meter connections and cost for the Revenue Metering budget for 2025.

c) Why does Oshawa PUC Networks believe there will be a 9% increase in the number of new meters from 2025 to 2026?

d) Oshawa PUC Networks noted that the average cost per meter is higher in the forecast period partially due to the adoption of the next generation of Elster meters. When did Oshawa PUC Networks adopt the next-generation Elster meters? What is the unit cost for material only when comparing the two meter options?

e) (P. 18) Please provide the growth rate applied for the new connections metering program for 2026-2030.

f) (P. 19) Please explain the high variability of metering costs per unit between 2021-2025.

g) (P. 19) Please advise which type of meter is being installed in 2025 with a unit cost of $309 (i.e., the old series of meter or the new series of meter).

h) (P. 20) Please explain why a new metering connection would have a significantly higher cost than a replacement meter (i.e., $462/meter for new metering connection vs. proposed $393 for a replacement meter).

Oshawa Power Response

a) 2024 saw an additional installation of an AMI communication device and a larger than average number of three-phase installations. 2025 numbers returned closer to the mean value. Higher costs are per meter are expected in the forecast years due to higher allocation costs for the units themselves with the next generation

Elster A4 meters.

b) Estimated meter connections for 2025 is 1237 connections with a budget of $550,000. This corresponds to a per meter cost of $445.

c) Oshawa Power experienced low expansions in 2024 (see Appendix 2-AA, Chapter 2 Appendices), hence meter connections that follow subdivision energizations were assumed to be low in 2025. However, subdivision activity has picked up significantly in 2025 as can be seen in 2025 YTD in-service actuals (see revised Appendix 2-AA in Revised Chapter 2 Appendices). Hence a higher number of meters are expected 2026 onwards.

d) The next generation of Elster meters will complete their testing phase in 2025 and installation will occur as needed in late 2025. Unit cost increase varies on type of install when comparing meter for meter with each generation of Elster meters. Elster no longer manufactures the old generation of meters.

e) A growth rate of 2.44% for commercial customers and 1.6% for residential areas was applied starting 2026 Test Year.

f) High variability is due to number of each type of meter installed in a particular year. Commercial and industrial connections are significantly more costly than residential.

g) In 2025, the old series of meter is being installed.

h) Total metering cost can include current transformer (CT) and potential transformer (PT) costs, Meter replacement cost does not include these additional materials.

2-CCC/AMPCO-55

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.21-25

Question(s):

a) (P. 21) Please reconcile the 518 poles referenced as being considered to be in fair, poor or very poor condition to the information provided in Table 15 (DSP p. 74) that shows 101 poles in those conditions.
b) (P. 22) Please confirm that Oshawa PUC Networks is forecasting a 46% increase in the cost per pole relative to the 2021-2026 period. Please provide additional details regarding Oshawa PUC Networks' forecasting methodology to determine the cost per pole for the 2026-2030 period.
c) (P. 22) Please discuss whether Oshawa PUC Networks considered pole reinforcement solutions instead of pole replacement. If yes, please provide any analysis carried out with respect to this potential alternative.
d) (P. 24) Please provide the number of pole failures, customer interruptions and customer interruption hours for each of the years 2021 to 2025.

Oshawa Power Response

a) As stated in Exhibit 2, DSP, Appendix C (Asset Condition Assessment), page 9, "METSCO recommends asset replacements over the next five years for assets in Poor or Very Poor condition, assets classified as high or extreme risk, and assets that are past their economic end of life.' Please also note that the 518 poles includes concrete poles. Table 15 is a summary of the asset condition only. The 518 poles come from Table E-4 of the ACA, (Exhibit 2, DSP, Appendix C, page 10) which is the final output of the ACA.
b) Confirmed. The 2026-2030 pole replacement program focuses on structures that carry critical infrastructure such as three-phase 44 kV and 13.8 kV feeders (or both) rather than the broader mix addressed historically. Ranking poles by condition and risk as per the ACA methodology, pushes the most complex, high-impact structures to the top of the list which are more expensive to replace.

Oshawa Power reviewed each candidate pole's attributes (circuit count, phase configuration, voltage class, and attached equipment such as transformers and single-/three-phase risers). These details were matched to current unit-cost data to generate the budget for the program.

c) Oshawa Power did not consider reinforcements for poles targeted under this program.

d) Please refer to tables provided in response to 2-Staff/VECC/AMPCO-41 b). Typically pole failure occur due to either MVAs or structurally compromised poles failing in adverse weather. A singular pole failing due to condition will not cause an outage as the tensioned conductors on the poles hold the pole up. This does, however, introduce significant safety hazards**.** Poles are thus typically replaced on a proactive basis and not reactive. Reactive replacement could also involve significantly more time and effort to replace.

2-AMPCO-56

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, p. 30

Question(s):

Please estimate the lower corrective maintenance cost savings expected from the improved distribution system.

Oshawa Power Response

The Customer Value Evaluation Criteria and Information Requirements needs to be read in its entirety as "Customers within the project area will benefit from this project through the reduction of the risk of outages and will also indirectly benefit from the lower corrective maintenance costs that the improved distribution system will provide." The main rationale behind these capital expenditures is detailed under the Project Description found on Page 26, namely safety and reliability. The lower corrective maintenance costs have been identified as an indirect benefit, in that it would be reasonable to consider that a rebuilt section of overhead line would naturally be expected to require less maintenance as the installation consists of new assets, built to the latest construction standards. Lower corrective maintenance cost savings, being identified as only an indirect benefit, were not estimated.

2-CCC/AMPCO-57

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.31-37

Question(s):

a) (P.31) Please reconcile the statement regarding 12km of planned underground cable replacement with the:
   i. approx. 8.4km set out in the table at page 33 of the material justification sheet
   ii. approx. 10.3km set out in Table 16 (DSP, p. 74)
   iii. approx. 5.6 km of underground cable in poor or very poor condition set out in Table 15 (DSP, p. 72).

b) (P. 32) Please confirm that the 2026 test year cost per meter is $543, which compares to the 2021-2025 average cost per meter of $367.50 per meter, which reflects a 48% increase. Please provide additional details regarding the 2026 test year unit cost forecast (including a discussion of the high unit cost for the Cricklewood Drive project).

c) Please provide the number of underground asset failures, customer interruptions and customer interruption hours for each of the years 2021 to 2025.

d) (P. 35) Please estimate the lower maintenance cost savings that a new system will provide.

Oshawa Power Response

a) The reference to 12 km of cable in the material sheet is inaccurate. The correct total, based on individual projects under the Underground System Rebuild program, is 8.4 km. See clarification below.
   i. 8.4 km of cable to be replaced is in Underground System Rebuild Program (Page 33).

ii. 10.3km of cable to be replaced (Table 16, page 74) = 8.4km under the Underground System Rebuild Program (ii above) + 1.96km under the Distribution Switchgear Replacement Program (Appendix B – Material Justification sheets, page 54, Table 1).

iii. Please refer to response to 2-CCC/AMPCO-55 a).

b) Confirmed that the 2026 Test Year cost per meter is $543.

For the Cricklewood Drive project, the scope comprises 724 m of primary-cable replacement and nine pad-mount transformer replacements. Estimated unit costs are $322 per metre for cable and $17,767 per pad-mount transformer.

The 2026-2030 underground system rebuild program includes the proactive replacement of pad-mount transformers which was not covered in the historical program. When underground primary cable is replaced, each pad-mount transformer is also isolated. Replacing the transformer at the same time minimizes outage duration, lowers total lifecycle cost, and eliminates duplicate efforts. As noted in Exhibit 2, DSP, Appendix C - Asset Condition Assessment, page 52 – "Utilities generally replace pad-mount transformers during underground rebuild projects." Oshawa Power is following accepted industry practice by bundling these related scopes where it provides the greatest customer benefit.

c) Please refer to the tables provided in response to 2-Staff/VECC/AMPCO-41 b). Line items "cable faults", "cable splices, "elbows", and "ducts "are underground assets.

d) The entire sentence under the Customer Value, Evaluation Criteria and Information Requirements needs to be read in its entirety as "Customers within the project area will benefit from this project through the reduction of the risk of outages and will also indirectly benefit from the lower corrective maintenance costs that the improved distribution system will provide." The main rationale behind these capital expenditures is detailed under the Project Description found on page 32, namely reliability. The lower corrective maintenance costs have been identified as an indirect benefit, in that it would be reasonable to consider that a rebuilt section of underground line would naturally be expected to require less maintenance as the installation consists of new assets, built to the latest construction standards. Lower corrective maintenance cost savings, being identified as only an indirect benefit, were not estimated.

2-CCC/VECC-58

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.38-42

Question(s):

a) (P. 39) Please discuss how Oshawa PUC Networks determines where to target TDR testing (e.g., does it test all of its cable on a schedule, does it do targeted testing, etc.).

b) (P. 40) Please discuss the $280/meter underground cable replacement unit cost cited on page 40.

Oshawa Power Response

a) This will be Oshawa Power's first cable injection program and as such, the intent is to evolve the program and incorporate activities that make the program efficient. At this time, Oshawa Power does not perform TDR testing on a routine basis. For the locations identified in Exhibit 2, DSP, Appendix B – Material Justification Sheets, page 39, Table 1, the intent is to conduct TDR tests before injection to identify the condition of the cable before making a decision whether to leave the cable segment as is, to inject the cable segment, or to replace the cable segment so the most prudent capital investment can be made on test results evidence. The insights gained will help us evaluate the merits of adopting regular, system-wide TDR testing in future maintenance cycles and to evolve the cable injection program.

b) The replacement cost of $280/m reflects an ideal, though reasonable, installation scenario where there is easy access and ample right-of-way space for installing new duct and cable. This unit rate comes from a budgetary quote for replacing direct buried cable (not in duct), with new cable in direct buried ducts. It was deemed reasonable to adopt the lower bound of industry pricing so as not to overstate the financial advantage of the cable injection program. Since this is Oshawa Power's first experience with cable injection, an evaluation of actual versus budget costs will be completed on an ongoing basis in order to develop the unit cost based on actual installations.

2-AMPCO-59

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets

pp. 46, 49

Question(s):

a) (P. 46) Please provide the number of quick sleeve failures, customer interruptions and customer interruption hours for each of the years 2021 to 2025.
b) (P. 49) Please estimate the lower corrective maintenance cost savings from this program.

Oshawa Power Response

a) Please refer to line item - "quick sleeves" in the tables provided as a response to IR 2-Staff/VECC/AMPCO-41 b).
b) The entire sentence under the Cost Benefit Analysis, Investment Justification to be read in its entirety as "Replacement of the quick sleeves on 44kV and 13.8kV primary overhead conductor lines in a proactive way will reduce the cost of unplanned failures. This program will help reduce system O&M costs over time through reductions in corrective maintenance spending." The main rationale behind these capital expenditures is detailed under the Project Description found on Page 46, namely safety and reliability. The "reductions in corrective maintenance spending" should have read "reductions in reactive trouble call

response spending as there is no maintenance associated with conductors on their own but would be the avoided costs associated with trouble call response, the repair of the conductor, and the restoration time by eliminating the quick sleeve. Neither reductions in corrective maintenance spending, nor reductions in reactive trouble call response spending were estimated.

2-AMPCO-60

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets pp. 54-57

Question(s):

a) (P. 54) Please provide the number reactive switchgear replacements for the years 2021 to 2024 and the corresponding costs per year.
b) (P. 57) Please estimate the lower corrective maintenance savings from this program.

Oshawa Power Response

a) There were no reactive switchgear replacements from 2021 to 2024.
b) The entire sentence under the Cost Benefit Analysis, Investment Justification to be read in its entirety as "Replacement of switchgear in a proactive way will reduce the cost of unplanned failures and the associated corrective maintenance costs. This program will help reduce system O&M costs over time through reductions in corrective maintenance spending." The main rationale behind these capital expenditures is detailed under the Project Description found on page 54, namely reliability. The reduction in corrective maintenance spending would be reasonable to assume given that a new switchgear would naturally be expected to require less maintenance. Reductions in corrective maintenance spending were not estimated.

2-CCC/AMPCO/Staff-61

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.58-62

Ref. 2: Distribution System Plan, Appendix C – Asset Condition Assessment, p. 158

Ref. 3: Distribution System Plan, Appendix C – Asset Condition Assessment, Substation Power Transformers and Switch Gear Lifecycle Risks & Options Analysis Report 2023, p. 17

Question(s):

a) (Material Investment Justification, P.58) Please provide the reference within the Asset Condition Assessment that shows the condition of the switch gears that are planned for replacement (as opposed to only the age).

b) (Material Investment Justification, P. 59) Please advise which municipal substations are comparable to each other in terms of scope of work (MS2 & MS5 and MS7 & MS11 or a different combination).

   a. If MS7 and MS11 are similar in scope, please explain the variance in cost between MS7 and MS11.

c) Please provide a breakdown of costs for the municipal substation switchgear program in 2025 and 2026.

d) What is the status of work completed for this project in 2025 for MS7?

e) (Material Investment Justification, P.59) Based on the discussion at pages 107 and 110 of the DSP, it appears that the MS2 and MS7 projects experienced cost overruns. Please explain what lessons learned are planned to be applied to the MS5 and MS11 projects.

f) (Asset Condition Assessment, p. 158) Metsco states that it "recommends the replacement or refurbishment of switchgears that have exceeded their economic EOL or will exceed their economic EOL during the planning period as found in Appendix B."

   Please confirm that the replacement/refurbishment of switchgears is based on asset age not condition. If so, please explain why this is appropriate and whether Oshawa PUC Networks or Metsco have any information about the condition of the assets that are planned for replacement in the planning period (i.e., MS5 and MS11) and the assets that were already replaced in 2023 and 2025 (i.e., MS2 and MS7).

g) (Transformer & Switch Gear Report, P. 17) Please confirm that the CICs shown in Table 2-1 are premised on underlying survey responses from customers in the United States.
h) (Transformer & Switch Gear Report, P. 20) Please provide the basis for the findings shown in Table 3-2.
i) (Transformer & Switch Gear Report, P. 22) Please explain what Metsco means by the statement "in cases where OPUCN's switchgear contract would be broken by not replacing the asset and instead refurbishing or letting the asset RTF the cost of breaking the contract was also considered as cash outflow in the initial year." As part of the response, please explain what contract is being referred to.
j) (Transformer & Switch Gear Report, P. 22) Please provide support for the discount rate of 5.9% used in the analysis. If this discount rate is outdated, please revise the analysis.
k) (Transformer & Switch Gear Report, P. 22) Please provide the detailed calculations (and assumptions) underpinning Table 4-1.
l) (P. 62) Please quantify and explain how the expected lower preventative maintenance costs are considered in the OM&A budget.

Oshawa Power Response

a) Section 4.2.3 of the Asset Condition Assessment (ACA) outlines the health index condition parameters to use to calculate the asset condition of the Station Switchgears. The condition results for the station switchgears can be seen in Figure 4-43. Please also refer to the methodology in the "Substation transformer and switchgear lifecycle risk and options analysis report 2023" in Exhibit 2, DSP, Appendix C – Asset Condition Assessment and Options Analysis Report for the methodology backing the options analysis recommendations that the planned switchgear replacements were based on.

b) MS2, MS5 and MS7 are reasonably comparable in scopes of work.
   a. MS7 and MS 11 are not similar in scope.
c) Please refer to the response to 2-CCC/VECC-47 b) for the scope of work involved in 2025 - MS7 and 2026 MS5 (equivalent to MS2 breakdown in the response).
d) The current status of the MS7 project is as follows:
   a. All major equipment and material has been procured including the E-house unit, switchgear with circuit breakers, and egress cable.
   b. Ensuring communication equipment expected to be impacted by the planned outage are currently being rerouted to the control room.
   c. The station isolation is planned for the first week of September 2025 to hand off the site to the contractor for switchgear installation.
   d. Majority of the work is to be performed starting September with an anticipated in-service date early December.
e) The majority of the cost overruns were due to changes in scope of work. These will also apply to subsequent stations (with exceptions such as additional cable) as the initial RFP did not incorporate these changes in the scopes of work. The main lesson learnt was around the need to capture as much detail as possible when the project is tendered which will be carried forward to future station related projects such as switchgear replacements.
f) The recommendation for replacement is based on a number of factors, including asset condition, risk analysis including failure mode and cost impacts. It is not based on age alone. EOL refers to end of life which incorporates multiple factors, including condition and risk. Please refer to the methodology in the “Substation transformer and switchgear lifecycle risk and options analysis report 2023” in Exhibit 2, DSP, Appendix C – Asset Condition Assessment and Options Analysis Report for the methodology supporting the options analysis recommendations.
g) Yes. The CICs shown in Table 2-1 are premised on the underlying survey responses from customers in the United States.

h) Please refer to the methodology in section 3 of the “Substation transformer and switchgear lifecycle risk and options analysis report 2023” in Exhibit 2, DSP, Appendix C – Asset Condition Assessment and Options Analysis Report.
i) Oshawa Power already had a contract with a third-party for the replacement of the switchgears MS2, MS5, MS7, and MS11. This contract was legally binding, and if Oshawa Power decided not to replace these assets, financial penalties would be incurred. Therefore, the cost of these penalties was taken into account when METSCO was carrying out its analysis.
j) The current regulated return on rate base is 5.67% (refer to Exhibit 6, page 7). The difference in rates used is 0.02%, and immaterial to the calculation.
k) The methodology and calculation are explained in beginning of section 4 of the “Substation transformer and switchgear lifecycle risk and options analysis report 2023” in Exhibit 2, DSP, Appendix C – Asset Condition Assessment and Options Analysis Report.
l) Lower preventative maintenance costs have not been considered in the OM&A budget because this project is not complete as only 1 of 4 MS switchgear have been replaced at this time.

2-Staff-62

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, p.63

Question(s):

To what does Oshawa PUC Networks attribute its lowered reactive system renewal budgets in 2024 ($1.6 million) and 2025 ($1.3 million), and why is a similar expenditure not expected for 2026?

Oshawa Power Response

Collective impacts of targeted proactive renewal programs, and introduction of distribution automation since 2021 removed a portion of the reactive work that occurred in historical high-cost years like 2021. 2024 actuals had low reactive costs (was the best case - anomaly) reflected in strong 2024 SAIDI SAIFI scores of 0.3 and 0.29 respectively.

Oshawa Power anticipated the same trend may continue for some or all of 2025 based on its set reliability targets and unusually favourable weather, and set the 2025 reactive system renewal budget on this basis. The 2026 Test Year budget was increased to $1.8M to reflect a more typical, sustainable mid-range that recognizes year-to-year weather volatility. The proposed 2026-2030 budget reflects an 8% reduction from the 2021-2025 historical average.

2-CCC-63

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.63-66

Question(s):

a) (P. 64) Please confirm that the proposed 2026-2030 reactive replacement budget reflects an 8% reduction relative to the 2021-2025 budget.
b) (P. 64) Please provide the basis for the 20% reduction for the 2026-2030 reactive replacement budget relative to the 2021-2023 historical period (instead of the entire period). Please confirm that the same logic regarding increased proactive replacement would support a reduction to reactive replacement relative to the entire 2021-2025 historical period.
c) (P. 64) Please further discuss the historical capital contributions paid on reactive capital (i.e., what types of work attract capital contributions).

Oshawa Power Response

a) Confirmed.
b) The 2026-2030 reactive program budget was developed before 2024 actuals were available and so the comparison in the application measures the 2026-2030 total budget against the 2021-2023 historical average. However, Oshawa Power did qualitatively factor in expectations of lower reactive costs in 2024 and 2025

attributable to targeted proactive renewal programs and the introduction of distribution automation. See response 2-Staff-62 a).

Incorporating these considerations results in a 20% reduction compared to the 2021-2023 average during which impacts from proactive initiatives were not seen, and an 8% reduction compared to the full 2021-2025 historical average, during which were expected to have seen early program effects. Oshawa Power did not apply the full 20% reduction to the 2021-2025 average because 2024 and 2025 reflect unusually favourable weather and strong reliability. These years are seen more as atypical that could not be confidently relied on to continue.

Confirmed that the same logic regarding increased proactive replacement would support a reduction to reactive replacement relative to the entire 2021-2025 historical period.

c) Contributions received due to reactive work resulting from third party intervention such as motor vehicle accidents, and damages from contractor dig-ins or underground infrastructure, account for the historical reactive capital contributions.

2-CCC-64

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.67-70

Question(s):

a) (P. 67) Please provide the average age of Oshawa PUC Networks' meters.
b) (P. 67) Please provide the number of meters that will reach their seal expiry date in each year 2026-2030.
c) (P. 67) Please provide the average number of years prior to seal expiry meters will be replaced based on Oshawa PUC Networks' proposal.
d) (P. 68) Please confirm that the historical actual (2021-2024) cost per meter replaced was $305 and the full historical period (2021-2025) the cost per meter

was $314. Please explain the basis for using a simple average for unit cost analysis in Figure 1 on page 68.

e) (P. 69) With respect to Option 1 (Table 1 – Options Analysis), please provide the number of meters that expect to be replaced with an annual budget of $0.3 million.

Oshawa Power Response

a) The average age of Oshawa PUC Networks' meters is 12 years, with a median age of 15 years.

b) See table below.

IRR Table 2-16: Number of Meters Reaching Seal Expiry (2026-2030)

Year	Reaching seal expiry
2026	4,342
2027	2,036
2028	41,953
2029	4,253
2030	1,491

c) The meter replacement program as outlined will be proactive in nature as replacements are planned prior to failure. However, as all meters which will be replaced will have passed at least their 10-year seal expiry. No meter replacements prior to initial seal expiry are planned.

d) The average cost per meter for the full periods of 2021-2024 and 2021-2025 are $305 and $314, respectively. However, the average cost per year is as indicated on Figure 1, page 68, Appendix B and more effectively illustrates the year-over-year changes. A simple average was used on page 68 for comparison purposes but was not the basis for the projected per-unit cost.

e) Following the same calculation method used for Option 2 (Table 1 Options Analysis), $827 per year or $4,135 for the 2026-2030 period are expected to be replaced with an annual budget of $0.3M.

2-Staff/CCMBC-65

Ref 1: EB-2025-0014, Exhibit 4 – Operating Expenses, Section 4.9 Funding Options for Future Non-Wires Solutions, Page 114

Ref 2: EB-2025-0014, Exhibit 2 – Rate Base, Distribution System Plan, Appendix A – "NWS-Business Case", Pages 11–15

Ref 3: IAS 16, Property, Plant and Equipment

Question(s):

a) Please clarify the different types of costs under each of the four NWS projects, including whether one-time investments are payments for services to third-party providers. Provide a description of the cost, the associated amount, the ownership arrangement and the nature of the cost (e.g. capital or operations, maintenance and administration).

b) Please provide the rationale for why costs for each of the four NWS projects are considered Capital Expenditures, instead of Operations, Maintenance and Administration costs. Please explain in detail any deviations from IFRS on capital expenditure and accounting.

c) Please explain how Oshawa PUC Networks distinguishes between NWS investments that are distribution funded versus those that are funded externally. Please explain how the distinction influences the accounting treatment of those costs.

Oshawa Power Response

a) As noted in the NWS business case, the project costs presented are for budgetary purposes and are expected to be finalized using the approved benefit cost analysis (BCA) format. The costs are representative of a foreseeably meaningful level of investment that will need to be appropriately scaled and categorized as O&M or Capital when agreements with potential suppliers are developed. At this time, this would not be possible as a result of not knowing the unique attributes of the DER designs. Oshawa Power will apply approved accounting practices to any financial agreements and transactions associated with the NWS budget.

b) The costs associated with the NWS projects are currently categorized as Capital because of their relevance to the DSP, in the context of this Application. NWS projects are intended to replace DSP investments in the future, and have therefore been included as capital expenditures. As noted above, with further development of the programs and with the use of the proper BCA format, Oshawa Power will be able to appropriately categorize the costs in alignment with IFRS. For example, if the Managed Residential EV Charging project moves forward and is a cloud-computing solution, those costs would need to be managed as O&M.

c) NWS investments will require a full BCAs and application to the OEB to be funded. In turn, the financials for these projects will be captured with the same accounting methodologies as any other capital project in the DSP (capitalization policy adherence, job codes, journals; etc.). NWS investments that are externally funded via grants may be accounted for under IFRS using the IAS 20 rule, which states that:

Government grants are not automatically considered capital. Their treatment depends on whether they relate to assets or income. Grants related to assets may be recognized as deferred income and released to profit or loss over the useful life of the asset. Grants related to income may be recognized as other income or deducted from the related expense.

2-Staff-66

Ref. 1: Distribution System Plan, p.111
Question(s):

Please explain what projects are being completed in 2025 as part of the Operational Technology program ($376k) and their respective need.

Oshawa Power Response

Please see the below table for the Operational Technology Program details.

IRR Table 2-17: Operational Technology Program (2025)

Project	Projected Budget	Need
GIS Upgrades and Enhancements	$ 220,000.00	This project is to implement an engineering analysis interface with the GIS. Oshawa Power currently does not have an up-to-date engineering model other than one that is being kept up manually, effectively duplicating the work of maintaining the GIS. Implementing the interface will allow engineers to download the GIS data into the analysis software and create much needed capacity in that department.
OMS Upgrade	$ 50,000.00	The project is to enhance the OMS to help fix issues with the meter last-gasp reporting. Currently the OMS cannot report on single-transformer outages without having the AMI network become flooded and paralyzed. Oshawa Power is working to add a message filtering layer in between using its automation platform to alleviate this issue. In addition, labour for upgrading to the latest version of Survalent will be captured under this project. Resolution of these issues will reduce misreporting of outages, frustrations by customers due to lack of communication of outages, and unneeded truck rolls.
Meter Data Management System Related Upgrades	$ 56,000.00	This project is to cover upgrades of ODS-related systems including the metering head-end, which is at end of life and requires an upgrade before being able to add new gatekeepers, and the MV90 system which needs to be upgraded to bring back inhouse from an outsourced vendor and realize the budgeted OpEx savings.

Planned SCADA Upgrade	$ 50,000.00	This project is required to upgrade the SCADA hardware from out-of-support hardware and hypervisor to supported systems.

2-Staff-67

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.71-72

Question(s):

a) Please provide a breakdown of the costs for the Three New Feeders MS9 project ($1 million in 2026) and the basis for the estimates. As part of the response, please provide a comparison to any similar projects that Oshawa PUC Networks has completed previously.

b) How did Oshawa PUC Networks appropriately size the new feeders to take into account future developments and the adoption of electric vehicles/heat pumps?

c) Besides not proceeding with the project, what other alternatives were considered? Did Oshawa PUC Networks consider non-wire solutions or increasing capacity at MS7? If so, why were these alternatives not chosen over the requested solution?

d) In addition to the $1 million expenditure attributed to this project, how has this project affected third-party relocation costs at Conlins Road in 2026?

Oshawa Power Response

a) Conceptual estimate shown in the table below.

IRR Table 2-18: Three New Feeders MS9 Project Cost Breakdown Estimate

Item Description	Quantity	Unit Cost		Total Cost	
Riser Pole Cost with labour	3	$	30,000.00	$	90,000.00
Cable (Material + Labor)	1158 m	$	582.00	$	673,956.00
Road Crossing work (Civil + ducts)	29m	$	4,800.00	$	139,200.00
Boulevard work (Civil + ducts)	80	$	1,920.00	$	153,600.00
Total				$	1,056,756.00

Oshawa Power does not have a comparable project that is limited to the scope of work mentioned above.

b) The new feeders were sized using higher ampacity 1000MCM copper cable as opposed to the lower ampacity 500MCM which are found in some of Oshawa Power's older municipal substations to account for the expected increased demand of future developments and the adoption of electric vehicles / heat pumps on its distribution system.

c) Yes. Alternatives were considered including high level preliminary considerations of NWS, and capacity additions elsewhere in the distribution system (including MS7). However, all other alternatives did not address all of the key multiple needs found in the Project Description Exhibit 2, DSP, Appendix B – Material Justification Sheets, page 71.

d) This project does not have a direct impact on third-party relocation work on Conlin Road.

2-CCC-68

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.76-78

Question(s):

(P. 78) Please provide the self-healing switch unit costs for the 2021-2025 historic period and 2026-2030 forecast period broken down between 44kV and 13.8kV units.

Oshawa Power Response

Please see revised table below.

IRR Table 2-19: Self-Healing Switch Unit Costs and Forecast (2021-2030)

Category	Historical Period				Bridge Year	Test Year	Forecast Period			
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital (Gross)	302	338	181	203	200	0	0	565	565	565
44kV Units	~~2~~ 0	2	~~1~~ 2	2	3	0	0	4	4	4
13.8kV units	3	0	0	~~1~~ 0	0	0	0	5	5	5
average unit cost - 44KV	$106,835					$81,250				
average unit cost -13.8kV	$100,800					$48,000				

2-CCC/AMPCO-69

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.91-95

Ref. 2: Exhibit 4, p. 57

Question(s):

a) (P.92) With respect to the server infrastructure refresh, please provide further details regarding the work that will be undertaken and the need for the work. As part of the response, please discuss how cloud computing investments and other subscription services (as discussed at Exhibit 4, p. 57) are expected to influence Oshawa PUC Networks need for its own server capabilities.
b) (p.92) Please provide the date of the previous Server Infrastructure Refresh, the cost and a comparison to the forecast cost of $450,000 in 2028.
c) (P. 91) Please estimate the decreased maintenance requirements as a result of GP-04 and explain how this is reflected in the OM&A budget.

Oshawa Power Response

a) Oshawa Power's existing servers are reaching end of support in 2027 and will need to be refreshed. This project involves replacing host server hardware and correspondingly upgrading the hypervisor environment and migrating existing servers to the new infrastructure.
   Oshawa Power does not anticipate switching to cloud computing for the majority of its processes, however new technology and pricing is continually reassessed.

   Generally, Oshawa Power's software fall into one of four categories:

   1. Software that must remain on-premise,
   2. Software that is more cost effective to keep on-premise,
   3. Software that is more cost-effective to host in cloud or purchase as SaaS, and
   4. Software that must be cloud-hosted or purchased as SaaS.

Much of the software required over the next cost of service period falls into the first two categories. Examples include SCADA software, the ADMS, the Meter Data Repository, the current financial software and others. Consequently, because we must maintain on-premises infrastructure to support those, the third category becomes much smaller due to the incremental costs of additional on-premises infrastructure being often lower than cloud infrastructure costs. Exhibit 4, p.57 is largely referring to items that fall into categories 3 and 4, which includes off-the-shelf applications such as Office suites and HRIS SaaS. Oshawa Power does not have a cloud-first nor on-prem-first policy but chooses the more prudent and fitting solution for each scenario, taking all factors into account.

b) Oshawa Power's most recent server infrastructure upgrade took place in early 2022. At that time, four new servers were purchased for approximately $210,000. Subsequent incremental upgrades (2023-2025) were required due to increasing workload totalling approximately $150,000. These investments were required to replace aged hardware that hosts all in-house Oshawa Power IT infrastructure.

   The planned 2028 refresh follows a typical 6-year server refresh cycle and is forecasted to be $450,000. This is approximately the cost of the previous cumulative purchases, six years of inflation and a small amount of growth to account for growing data storage requirements and any new compute loads such as local Large Language Models that may arise.

   Finally, it is probable that current economic instabilities and tariffs will inflate the real-world price leading to even higher than forecast costs, however that is difficult to predict at this time and was therefore not factored in.

c) Oshawa Power will evaluate the options at that point and make a business case for the most prudent decision. If Oshawa Power changed from an on-premise to a SaaS solution, it is estimated that OM&A costs will increase as a result of GP-04. This increase is not included in the 2026 OM&A budget.

2-Staff/CCMBC-70

Ref. 1: Distribution System Plan, p.119

Question(s):

a) Oshawa PUC Networks noted that the CIS software and enhancements ($1.4 million) will advance business transformation efforts by facilitating a greater degree of automation, improved business processes, and integration with other systems. Please expand further upon the need for this project and how the software and enhancements will advance business transformation efforts. Please provide specific examples of how processes will be affected by this software and how systems will be integrated.
b) What quantitative effect will the CIS software have on administrative expenses in the 2026 test year? If quantitative effects cannot be assumed, please provide a qualitative assessment.
c) Please provide a breakdown of the costs for this project and the basis for the estimates. Please also note what part of the work was deferred from 2021.
d) Please provide the spend amount to date for this project and the status of the project.
e) What are the risks of not proceeding with this expenditure in 2025 and deferring the project to future years?

Oshawa Power Response

a) As part of Oshawa Power's CIS upgrade, Oshawa Power has documented and optimized over seventy meter to cash business processes in conjunction with the incoming vendor. A selection of examples of processes that have been automated with the new software include:

- Full automation and application of incoming payments from Paymentus and Banks
- Automation of the billing cycles for 'one click' billing absent any errors.

- Automation of the entire delinquency process, managing and sending notices without any user intervention.
- Automation of the Move-in/Move-out processes utilizing a new customer-facing move hub to minimize CSR intervention
- An upcoming proof of concept for an Agent-assist AI integration using the software's native interfacing capabilities.

b) Qualitatively, the new system, in alignment with the business transformation initiative, will increase internal staff capacity, allowing us to offset the need for more staff via streamlined workflows and automations as exemplified in part a. For example, Oshawa Power has had to invest significant resources into managing the day-to-day collections tasks which have been nearly fully automated by the new CIS, freeing up the existing resources to provide deeper analysis into arrears and to focus on executing collections tasks rather than administrative work.

c) All work was deferred from 2021. See below a breakdown of the estimated project costs.

IRR Table 2-20: CIS Project Approximate Costs

Item	Approximate Cost
Software License Purchase	[redacted]
Vendor implementation Costs	[redacted]
Labour	[redacted]

d) As of June 30th total spend was $1,471,926.
We are in final testing and expect to go live in Q3.

e) Oshawa Power has already completed the majority of the work required and would lose the entire investment if the project was cancelled. Had we not proceeded with the project and deferred it to future years, we would have not realized the benefits listed in part a).

2-Staff/CCMBC-71

Ref. 1: Distribution System Plan, p.119

Question(s):

a) Please expand upon the need and benefits of the Mobile Workforce Management Software expenditure ($235k in 2025). What processes will this expenditure digitize? How will this expense affect Oshawa PUC Networks 2026 administrative budget?

b) Please provide the spend amount to date for this project and the status of the project.

c) What are the risks of not proceeding with this expenditure in 2025 and deferring the project to future years?

Oshawa Power Response

a) The Mobile Workforce Management software will enable Oshawa Power to move paper-based field operations to digital, improving efficiency, reducing errors, increasing the quality and granularity of data that can be collected and reducing administrative burdens.

The processes that will be digitized include, not exhaustively, equipment change out forms, asset inspection forms, metering workflows, new equipment data sheets and trouble call forms. These are all paper-based workflows to date.

This will result in a minor increase in the administrative budget due to software maintenance costs, but will increase capacity and improve efficiency by reducing overheads and errors.

b) There has been no spend to date on this project.

c) Deferring this project to 2026 has minimal risks, however continuing to defer further will lead to continued inefficiencies due to the paper-heavy field workflows. It would also fundamentally affect Oshawa Power's ability to improve the quality of its GIS, Asset Management, outage management, and engineering analysis due to lack of good data, and would likely result in having to hire more staff to keep up with the increasing workloads from connection impact assessments, engineering analyses, tree trimming and other such requirements of the aforementioned systems. However, based on recent quotes from vendors, the estimated cost has been revised to $150,000 in the revised Appendix 2-AA.

2-Staff-72

Ref. 1: Distribution System Plan, p.119

Question(s):

a) Oshawa PUC Networks noted that its Information Technology General budget is $531k and will exceed its original planned amount by $208k in 2025. Please break down the budget for this expenditure in 2025 and the benefits of each item.
b) Please provide the spend amount to date for this expenditure and the status of each item.
c) What are the alternatives of each item, including the risk of not proceeding with each item and deferring the items to future years?

Oshawa Power Response

a) Oshawa PUC Networks noted that its Information Technology General budget is $531k and will exceed its original planned amount by $208k in 2025.

b) Budget for this expenditure in 2025 and the benefits of each item.

IRR Table 2-21: 2025 Technology General Budget and Expenditure

Project	Description	Approved Budget ($)	Revised Budget ($)	YTD Spend* ($)	Risks of not proceeding/completing
New IT Equipment Upgrades	This project covers end-user equipment requirements, mostly for the 'evergreen' program.	130,000	110,000	109,421	Neglecting this project would have left us with devices running windows 10, on which windows 11 was not supported. Windows 10 will be end of life at the end of 2025.
Switches, Router & Firewall Upgrades	This project covers the crucial upgrade of network and security hardware. The majority of the 2025 spend has been to replace end-of-life switches.	140,000	100,000	95,133	Using out of support hardware is a major cyber security risk, as well as an operational risk.
Mobile Phone Refresh	This project covers the planned replacement of mobile devices for staff, especially field crews. These devices are essential tools that enable teams to receive work orders, report on outage restoration progress in real-time, and communicate effectively while servicing customer	16,000	4,000	2,908	Neglecting this project would hinder field crews' ability to respond quickly and efficiently. Outdated devices can fail or lack compatibility with modern apps, leading to slower outage restoration times and delays in responding to on-site customer service requests.

	needs in the community.				
Customer Data Interface	This project is for interfacing our customer information system with our IVR in order to expand self-serve options and is intended to attempt to reduce incoming calls to agents. In 2025, we have added functionality to have customers check balances, check payments and check recent transactions without need to speak to an agent.	20,000	10,000	0	Given that we some of the call centre-related OEB targets have been missed, this project is important to help reduce the volume of calls coming into the call centre and keeping costs from continuing to rise.
OMS Licensing Increase	Because the number of SCADA points has increased beyond our previous licensing threshold we had to purchase a new block of licenses.	100,000	100,000	100,000	The software could not have legally continued to be used without this purchase.
Automation Platform	The Automation platform project covers work involving automation of processes using the automation platform	105,000	120,000	116,045	As Oshawa Power currently lacks capacity, the automation projects are a key part of its strategy to increase capacity while minimizing staffing increases. Without this project

	software. In calendar year 2025 we have used this to automate various processes including automating metering processes between systems that were formerly manual and automating customer signups for PAP. We have also included IVR updates in this project.				finding opportunities for automation, further increases to staffing would be required.
Cyber Security Upgrades	This project covers targeted investments in advanced security tools designed to proactively protect our systems and customer data. It strengthens our defenses against an evolving landscape of cyber threats, ensuring the security and integrity of our customers' private information.	20,000	87,000	72,837	Neglecting this project would expose our customers' sensitive data to an unacceptable level of risk. A security breach could lead to a loss of customer privacy and trust, while a successful cyber-attack could disrupt our operations and our ability to deliver reliable power.

*Note that YTD spend is not the same as ‘In Service’ dollars and therefore this table will not match the figures given in the revised Appendix 2-AA. Not all YTD spend is considered ‘In Service’.

c) See b).

d) See b).

2-Staff/VECC/AMPCO-73

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.101-102

Question(s):

a) Oshawa PUC Networks has budgeted $150k in 2025 for fleet and $500k in 2026. Please provide the fleet condition parameters that are underscoring the need for replacement of each vehicle being replaced in 2025 and 2026.
b) What is the status of the vehicle acquisition in 2025?
c) Have 2026 vehicles already been pre-ordered?
d) How did Oshawa PUC Networks ensure prudent selection when acquiring vehicles for purchase? Did Oshawa PUC Networks compare pricing of various vendors?
e) Please explain why in 2021, 2024 and 2025 fleet expenditures were significantly lower than in other years and lower than what is forecast for 2026 onward.
f) (P. 102) for each of the fleet in the table to be replaced over the 2026 to 2030 period, please provide the following: annual operational costs for the period 2020 to 2024, accumulated mileage, utilization rates (show the calculation) and environmental impact (CO2 emissions).

Oshawa Power Response

a) Please see the fleet condition parameters below.
   a. 2025 – New Forklift (Outdoor Use) - this is an additional unit, not a replacement. Oshawa PUC Networks Inc did not possess an outdoor forklift.
   b. 2026 – Panel Van (Replaces Tr.# 44) - Currently above the age threshold required for replacement and rapidly nearing the engine hours threshold.
   c. 2026 – Aerial Device (Replaces Tr.# 19) – Age, engine hours and repair costs are the thresholds that this vehicle has met for the replacement.

   d. 2026 – Pole Trailer (Replaces Tr.# 531) - Current pole trailer no longer able to handle the weights of the poles and the springs have been replaced a few times due to this.

b) New Forklift (Outdoor Use) has been purchased and received in June 2025.

c) The 50' Aerial Device (Replaces Tr.# 19) has been ordered as the lead times for this purchase is typically lengthy. The Panel Van (Replaces Tr.# 44) and the Pole Trailer (Replaces Tr.# 531) have not been ordered to date.

d) For Large vehicles such as Aerial Devices and Radial Boom Derricks, alternative suppliers were considered, but the decision was made to continue with the same supplier and manufacturer as all other Large vehicles to aide in the ease of use, training and maintenance schedules.

e) During the years 2021 through 2025, only two large fleet vehicles were acquired, causing the spend to be higher in the years 2022 & 2023 the years the vehicles were manufactured and delivered.

f) See each aspect detailed below.

   a. Annual Operational Data:

      - Includes maintenance & repairs, insurance, geotab device subscriptions, licence plate renewal, and emissions test.
      - Does not include fuel costs as Oshawa Power fuel costs are consolidated into one invoice with no split per unit.

IRR Table 2-22: Fleet Annual Operational Cost (2020-2024)

Annual Operational Cost (CAD)						
Asset	2020	2021	2022	2023	2024	Total

12	$ 5,283.80	$ 12,778.58	$ 4,937.03	$ 23,362.33	$ 13,874.31	$ 60,236.05
19	$ 2,425.00	$ 24,668.02	$ 25,973.33	$ 13,871.84	$ 37,704.75	$ 104,642.94
27	$ 1,389.17	$ 1,389.17	$ 2,957.57	$ 6,369.38	$ 1,165.00	$ 13,270.29
68	$ 1,165.00	$ 1,165.00	$ 1,583.94	$ 2,360.83	$ 3,456.11	$ 9,730.68
69	$ 5,236.49	$ 5,236.49	$ 5,655.01	$ 9,241.87	$ 1,654.84	$ 27,024.70
83	$ 1,165.00	$ 1,681.32	$ 1,453.04	$ 5,094.07	$ 7,085.37	$ 16,478.80
84	$ 2,489.36	$ 2,315.79	$ 5,169.02	$ 3,866.11	$ 4,045.41	$ 17,885.69
44	$ 2,425.00	$ 16,646.33	$ 13,967.06	$ 17,176.61	$ 7,660.60	$ 57,875.60
531	$ 1,000.00	$ 1,000.00	$ 7,987.15	$ 1,853.96	$ 7,620.21	$ 19,461.32
Total	$ 22,578.82	$ 66,880.70	$ 69,683.15	$ 83,197.00	$ 84,266.60	$ 343,084.87

b. Mileage

- GEOtab, devices used to track vehicles had occasional errors, causing missing data.

IRR Table 2-23: Fleet Mileage (2020-2024)

Mileage (KM)						
Asset	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
12	11,822	6,789	4,520	3,658	3,600	30,389
19	11,951	3,537	1780	9,965	13,735	40,968
27	62,632	25,108	18,638	21,998	2,405	130,781
68	42,651	21,274	20,702	20,813	13,599	119,039
69	75,055	39,592	38,381	7,639	8,621	169,288
83	45,453	25,083	24,221	19,031	28,664	142,452
84	100,870	51,826	49,920	37,936	36,385	276,937
44	8,487	2,638	No data	No data	5,174	16,299
531	-	-	-	-	-	-
Total	358,831	175,844	156,560	121,040	112,183	924,458

c. Utilization Rates

- Utilization = (# of working days x 8.5) – Time spent in OPUC yard / 12
- Average was chosen as it is a better representation of use. Some data is missing due to the issues with the vehicles GPS. Trailers are not tracked via GPS.

IRR Table 2-24: Asset Utilization (2020-2024)

Asset Utilization (Monthly Average Hours)						
Asset	**2020**	**2021**	**2022**	**2023**	**2024**	**Average**
12	137.78	94.18	75.23	63.04	48.27	83.71
19	143.25	118.51	152.20	129.63	128.26	134.37
27	136.07	132.43	147.46	106.18	5.59	105.55
68	144.90	144.24	137.89	139.93	88.65	131.12
69	133.08	130.12	142.28	148.41	137.01	138.18
83	73.39	86.42	89.24	101.38	57.56	81.60
84	60.62	49.48	53.24	66.75	53.29	56.67
44	161.89	162.19	No data	No Date	No data	162.04
531	-	-	-	-	-	-
Average	123.87	114.67	113.93	107.90	74.09	106.89

d. Environmental Impact

IRR Table 2-25: Environmental Impact (2020-2024)

Tonnes of CO_2 emitted						
Asset	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
12	20.4	10.63	7.54	5.49	5.54	49.6
19	27.05	12.95	2.51	12.14	14.59	69.24

27	31.01	13.84	10.86	10.84	1.10	67.65
68	26.47	13.02	12.63	12.40	7.56	72.08
69	31.24	16.51	17.10	3.63	4.61	73.09
83	24.08	13.33	11.61	9.66	13.40	72.08
84	34.92	18.41	17.47	14.78	16.09	101.67
44	8.67	7.67	No Data	No Data	No data	16.34
531	-	-	-	-	-	-
Total	203.84	106.36	79.72	68.94	62.89	

2-CCC-74

Ref. 1: Distribution System Plan, Appendix B – Material Justification Sheets, pp.101-105

Question(s):

a) (PP. 103, 105) If not already filed, please file the “Fleet Management Policy”, any analysis of fleet condition relative to that policy, and the external fleet evaluations.

b) (P. 101) Please provide the actual/forecast maintenance costs for:
   i. 2021-2025 (updated with best available information)
   ii. 2026-2030

c) (P. 101) Please discuss which OM&A category the vehicle maintenance costs can be found in Oshawa PUC Networks’ application.

d) (P. 102-103) Please explain why some purchases for a single vehicle appear to span two years (i.e., 1x50 Aerial Device with spending in 2026 and 2027). With respect to the in-service dates of the vehicles where the purchase costs span multiple years, please advise how that is addressed in the application.

Oshawa Power Response

a) See Attachment 2-10 for Oshawa Power's Fleet Management Policy.

b) See below.

i. Actual/Forecast 2021-2025 maintenance costs.

IRR Table 2-26: Actual Maintenance Costs - Fleet (2021-2025)

2021	2022	2023	2024	Jan - Jul 2025 Actual	Jul - Dec 2025 Forecast
$298,166	$286,186	$309,420	$323,717	$148,234	$102,950

ii. See below forecast 2026-2030 maintenance costs.

IRR Table 2-27: Forecast Flee Maintenance Costs (2026-2030)

2026	2027	2028	2029	2030
$271,534	$279,680	$288,070	$296,713	$305,614

c) Vehicle Maintenance Costs can be found in Appendix 2-JC OMA Programs under the Program "Overhead Lines Operations". Note that Fleet Costs are charged to Overhead Lines Operations with allocations out to individual Capital Projects as appropriate.

d) Purchases for single large vehicles such as the 50' Aerial Device span two years of total manufacture time with the cab and chassis component being manufactured in Year 1 and the aerial device component (which is installed on

the cab and chassis) being manufactured and assembled in Year 2. Both components together make up the completed vehicle.
The spend for the cab and chassis component is captured in Year 1, and the spend for the aerial device component is captured in Year 2. In-service spend is captured in Year 2. The details of spend and the year of spend are found in the table in the Estimated Expenditure Timing section of the Material Justification Sheet pages 2 and 3.

2-Staff-75

End User Hardware/Software Upgrades

Ref. 1: Chapter 2 Appendices, 2-AA

Question(s):

a) Oshawa PUC Networks has budgeted $196k in 2026 and $782k from 2026-2030 for End User Hardware/Software Upgrades. Oshawa PUC Networks has not provided a material narrative for this expenditure. Please provide a benefit versus cost analysis for this expenditure, particularly for the 2026 test year.
b) Why has this program only begun in 2026?

Oshawa Power Response

a) The End User Hardware/Software Upgrades program is a critical investment in Oshawa Power's ability to provide reliable, secure, and responsive service to customers. It ensures employees are equipped with the modern tools necessary to meet customer needs efficiently. This program is for Oshawa Power to replace obsolete and damaged hardware as needed, which typically operates on a four to five-year cycle.

Benefits:

- Protecting Customer Information: By keeping systems current, Oshawa

Power ensures essential security updates are received. This is a crucial line of defense in protecting sensitive customer data from cybersecurity threats.

- Faster Service and Outage Response: Up-to-date technology empowers staff to work more effectively. This translates into faster resolution of customer inquiries, quicker response times during power outages, and more efficient processing of service requests.
- Ensuring Service Reliability: Deferring this investment would lead to a higher risk of system failures and operational disruptions. Such internal issues could directly impact the reliability that customers experience.

Costs:

- The budget reflects the planned replacement of assets reaching end-of-life in the 2026 Test Year and beyond.

End user hardware cannot be used indefinitely and must eventually be replaced. The cost/benefit comparison is not as much whether or not to replace end-user hardware, but how long to wait before replacing such hardware. Oshawa Power follows industry norms of between 4 and 5 years for computing equipment, typically replacing hardware when it is no longer under warranty or support, and when it is either more than 4 years old or requires repair. Replacing on a longer cycle than this will lead to the use of obsolete hardware and will affect productivity.

b) The End User Hardware/Software Upgrades program is not a new initiative but a longstanding operational practice that is vital for providing reliable, secure, and responsive service our customers rely on annually.

2-Staff-76

Immaterial Software/Hardware Projects

Ref. 1: Chapter 2 Appendices, 2-AA

Preamble:

Oshawa PUC Networks has budgeted for several general plant projects/programs starting in 2026. Some of these projects/programs include:

- Cybersecurity upgrades ($40k)
- Enterprise Server Hardware/Software Upgrades ($116k)
- Automation Platform ($125k)
- System Automation ($30k)
- CRM Software ($50k)
- Customer Communication Redesign ($100k)
- GIS Upgrade ($50k)
- Intranet Upgrade ($50k)
- MDM Enhancements ($18k)
- OMS Enhancements ($25k)
- Records Management ($100k)
- Website Redesign ($50k)

Question(s):

a) What has driven Oshawa PUC Networks to begin these projects/programs in the 2026 test year, especially given the spike in 2026 net capital expenditures ($17.0 million) compared to the rest of the forecast period ($16.2 million average) and the historical period ($14.0 million average)?

b) Please confirm if these projects would historically be included in the Information Technology General budget and/or the Office IT & Equipment Upgrades, given that these two programs are null over the forecast period.

c) Oshawa PUC Networks has added a line item in Appendix 2-AA for CRM software in 2025 and in 2026 for $50k. Please confirm whether these are two distinctive projects or duplicate projects.

d) How has Oshawa PUC Networks reflected the benefits of these software enhancements on its administrative expenses?

Oshawa Power Response

a) Many of these projects/programs are incremental and multi-year updates required to support the business transformation program (e.g. Automation Platform, System Automation, MDM Enhancements, OMS Enhancements). Some are needed to address deficiencies in existing systems (e.g. Customer Communications Redesign currently is not adequately notifying customers and we have received complaints), and others are of high importance and should not be deferred (e.g. Cyber Security upgrades are required to maintain compliance with the framework and to keep a secure environment, Records Management is required to ensure document retention policies are being followed). Deferring these would reduce capacity creation that is a prerequisite for future projects, would lead to continue unacceptable customer experiences, or add unacceptable risk to the organization, especially pertaining to cyber security.

b) Confirmed.

c) This is in fact a duplicate and was added into 2025 erroneously. The CRM software project is a 2026 project. This has been addressed in the Revised Appendix 2-AA.

d) The Business Transformation Program, as well as many of these enhancements are with the purpose of reducing the number of new staff needed to manage increasing workload. In general, these projects have reduced the need to add new staff as quickly as would otherwise have been needed, keeping customer to staff ratios at Oshawa Power much higher than for peer LDCs. Capacity has been one of the biggest challenges and risks for the utility and these enhancements aim to alleviate that.

2-SEC-77

Ref. 1: Exhibit 2, p.35

Question(s):

Please explain why substantial increases in capital spending on computer software is required in the Test Year and beyond when annual computer software spending has already increased from 2021 actual to 2025 forecast by 144.6% ($2,563,975 to $6,272,471). Please provide any analyses, studies, presentations, or other documents the Applicant has benchmarking the Applicant's software spending to its peers.

Oshawa Power Response

Please see response a) of 2-Staff-76 for justifications of proposed computer software expenditures. Oshawa Power does not have any benchmarking of software spending relative to its peers.

2-SEC-78

Ref. 1: Exhibit 2

Question(s):

Please restate tables 1, 22, 23, and 27 in the Distribution System Plan with <u>all</u> capital spending and in-service additions, and where applicable system O&M, expected during the period 2026 through 2030.

Oshawa Power Response

Please refer to the revised Appendix 2-AA for this information. Tables 1, 22, 23 and 27 reflect capital spending within the DSP. Please see the response to 1-SEC/CCMBC/VECC-12 for all capital spending and in-service additions.

2-SEC-79

Ref. 1: Exhibit 2, p.15

Question(s):

Please provide all estimates or analyses in the possession of the Applicant of the impact of Green Button on peak and/or total consumption in the 2026-2030 period.

Oshawa Power Response

Oshawa Power has not performed any analysis to determine Green Button access on peak or total consumption in 2026-2030.

2-SEC-80

Ref. 1: Exhibit 2, p.15

Question(s):

Please provide business cases and/or savings estimates for the Grid Enhancements referred to.

Oshawa Power Response

As noted on p. 15 of the DSP, Grid Enhancements noted significant enhancements include the replacement of the switchgear at MS2 and the incorporation of new automation. Information about these enhancements are as follows:

- Replacement of Switchgear at MS2: Refer to Oshawa Power's 2021 rate filing (EB-2020-0048, Exhibit 2, DSP) for justifications of investments such as Municipal Switchgear replacement and distribution automation. Other grid enhancements include SS-01, SS-02, SS-03, SS-04, SS-05, SS-11, SS-12. See pages 91 – 136 and 163 – 174 of the 2021 DSP.
- The 44KV line extension from Enfield TS was reactive to customer needs in the Northwood Business Park Area to connect multiple large industrial and commercial loads.

2-SEC-81

Ref. 1: Exhibit 2, p.20

Question(s):

Please advise if customers with multiple locations, such as school boards, are included in the key account's strategy. If they are not, please advise the reason for the exclusion.

Oshawa Power Response

Confirmed. Customers with multiple locations are/have been included in the key accounts strategy in recognition of their consolidated contribution to Oshawa Power's total load and consumption.

2-SEC-82

Ref. 1: Exhibit 2, p.24

Question(s):

Please provide a copy of the memorandum from the Columbus Landowners Group.

Oshawa Power Response

Oshawa Power refuses this interrogatory on the basis of relevance and commercial sensitivity with no probative value to the OEB's determination on the issues in this proceeding. The requested evidence is highly sensitive customer information regarding proposed development plans that could prejudice the customer in the competitive markets they operate in. In addition, since the conclusion at page 24 of the Distribution System Plan is that a new station is not needed in the forecast period, there is no request for capital funding in this application related to the Columbus Landowners. Oshawa Power has not identified a circumstance when this type of customer connection has been produced in other cost of service applications, nor is it relevant to the issues in this application.

2-SEC-83

Ref. 1: Exhibit 2, p.24

Question(s):

Please advise whether the Applicant has prepared, or plans to prepare, a Cost Allocation Model for the Columbus II planning area.

Oshawa Power Response

Oshawa Power has not prepared a Cost Allocation Model (CAM) for the Columbus II planning area and will evaluate whether to do when more information becomes available to evaluate the financial risks and ratepayer impacts, pursuant to the OEB's guidance that distributors retain discretion over the CAM's eligibility and scope (EB-2024-0092, letter dated June 16, 2025). See 1-SEC/PP-11 for more information about the implementation of the CAM in Oshawa Power's service territory.

2-SEC-84

Ref. 1: Exhibit 2, p.54

Question(s):

Please provide a copy of any presentation or other document showing the results of the comparison of the preliminary investment portfolio to Oshawa PUC Networks' total capital and operating funds, as described.

Oshawa Power Response

Please see Attachment 2-11 for presentation to Oshawa Power's Project Monitoring Committee in July 2024 regarding the preliminary investment portfolio.

2-PP-85

Ref. 1: Exhibit 2, Attachment 2.1 – Distribution System Plan

Preamble:

Oshawa PUC Networks indicates that the Distribution System Plan (DSP) covers ten years [Exhibit 1, Page 6], including a five year forecast period starting with the 2026 Test Year and ending in 2030. However, the DSP in Attachment 2.1 shows a five year range from 2026 to 2030.

Question(s):

a) Please explain if the DSP filed is a ten year plan or a five year plan and if it differs from the previous ten year DSP, what are the changes that were made.
b) If the DSP is the ten year plan that was developed to include the current rate term (2021 – 2025), please explain what updates were made to include update policy and operation changes since the plan was initially developed.

Oshawa Power Response

a) The DSP covers a 10-year duration, with five historical years (2021-2025) and five forecast years (2026-2030). The previous DSP also follows the same logic, where the forecast years in Oshawa Power's 2021 rate application were 2021-2025. The forecast periods do not overlap.
b) Please refer to section 5.2.1.3 in Exhibit 2, DSP.

2-PP-86

Ref. 1: Exhibit 2– Distribution System Plan and DER definition from National Standard Practice Manual - NSPM (nationalenergyscreeningproject.org)

Preamble:

Distributed Energy Resources (DERs) are resources located on the distribution system that are generally sited close to or at customers' facilities. DERs include EE, DR, DG, DS, EVs, and increased electrification of buildings. DERs can either be on the host customer side of the utility interconnection point (i.e., behind the meter) or on the utility side (i.e., in front of the meter). DERs are mostly associated with the electricity system and can provide all or some of host and/or support the utility system by reducing demand and/or providing supply to meet energy, capacity, or ancillary services (time and locational) needs of the electric grid.

Question(s):

a) Please provide the definition of DER that Oshawa PUC Networks is using and explain how it differs (if at all) from the best practice NSMP definition noted above.
b) Please explain what DER resources from the list above are included in the Oshawa PUC Networks modeling and what the gross and net impact for each were. Please also provide the gross and net impact related to each type of DER included in Oshawa PUC Networks' modelling.
c) What local DER forecast does Oshawa PUC Networks rely on for DERs that are not identified and controlled by the IESO? Please provide a copy of the forecast.
d) Please provide the full list of local DERs not controlled by IESO, included in Oshawa PUC Networks' demand model.
e) Please explain how DERs forecasted in Oshawa PUC Networks' gross and net demand forecast are used as a baseline input into the Regional Planning process.

Oshawa Power Response

a) Oshawa Power uses the OEB's definition of a DER from the OEB's Distribution Energy Resources Connection Procedures document version 1.0. Oshawa Power considers this definition to align with the NSMP definition.
b) Oshawa Power's forecast does not incorporate a distributed generation forecast. The IESO, as part of the GTA east regional planning process, provides inputs regarding distribution generation forecasts for the region. This is still in progress and forecasts have not been finalized.
c) Oshawa Power does not have a local forecast for DERs that are not controlled by the IESO.

d) As noted in b) and c), no DERs have been explicitly included in a demand model.
e) Oshawa Power follows the OEB's guidance provided in the Load Forecast Guideline for Ontario when providing inputs into the regional planning process. DG Forecasts are provided by the IESO.

2-PP-87

Ref. 1: Exhibit 2 – Distribution System Plan and Ontario Save on Energy e-DSM Portfolio ([Ontario Launches New Energy Efficiency Programs to Save You Money | Ontario Newsroom]())

Ref. 2: Exhibit 3 – Customer and Load Forecast

Question(s):

a) The Customer and Load Forecast report appears to demonstrate meaningful reductions from customer uptake of CDM (now referred to as e-DSM). Does Oshawa PUC Networks agree? If not, please explain.
b) Has Oshawa PUC Networks assessed the maximum portion of energy and demand savings possible over the rate term (and beyond if available) that could be achieved by e-DSM (formerly called CDM)? If no, please explain why not. If yes, please provide a copy of the analysis, reports, presentation and other related materials.
c) Compared to the maximum potential for e-DSM over the rate term, what portion of this is reflected in the Oshawa PUC Networks plan as filed?
d) Please explain how Oshawa PUC Networks plans to maximize e-DSM results in its service territory from the IESO's Save on Energy program portfolio.

Oshawa Power Response

a) Yes, Oshawa Power agrees that meaningful reductions from customer uptake of CDM/ eDSM should be a part of the load forecast.

b) No, Oshawa Power has not yet assessed the maximum portion of energy and demand savings possible over the rate term. The organization's understanding is that achievable potential was studied by the IESO as a part of the Save On Energy program designs and intends to review their documentation and also request local area results from the IESO (if possible) to understand the impact of Save On Energy on loads. Oshawa Power will also need to examine achievable potential when seeking to design local programs, once that option is open to LDCs in 2026. For clarity, Oshawa Power did not invest in studying energy and demand savings possible over the rate term because it understood that this cost and effort was centrally born by the IESO.

c) Oshawa Power's plan reflects a full scale-up of eDSM activities as allowable under the province's rules and directions. The plan reflects a best efforts attempt to achieve as much eDSM and Save On Energy results as possible, due to the high benefit for rate payers, Oshawa Power's grid assets and community engagement on energy.
d) Please refer to answer 2-PP-88 a). Additionally, Oshawa Power will be seeking collaborations with the Region and City to drive efficiencies as noted in answer 2-PP-37. Finally, Oshawa Power intends to apply for local programs as soon as a local, non-duplicative need is identified.

2-PP-88

Question(s):

What communication or educational information does Oshawa PUC Networks provided to customers to help them understand and consider leveraging e-DSM and other DERs in the most cost-effective manner. Please provide a copy of each.

Oshawa Power Response

eDSM – Oshawa Power is pursuing the newly available opportunity to promote the provincial eDSM Save On Energy programs. The organization signed a copy of the IESO's contribution agreement on May 22, 2025 and is currently developing its eDSM plan for approval. Once the plan is approved, Oshawa Power intends to execute a multi-channel, diverse and ongoing marketing, education and outreach campaign for 2025, 2026 and 2027.

The goal of this educational piece will be to help customers maximize the benefits that align with their specific project designs.

Copies of Oshawa Power's communications and educational information are not yet available as Oshawa Power has not yet submitted a plan and received funding to develop such materials. Some highlights with respect to assisting customers in understanding DER opportunities from the not-yet-submitted plan will include:

- Energy advisor services for key accounts and accounts with multiple locations;
- Outbound project origination services for Save On Energy DERs; and,
- Partnerships with the Regional and Local Area municipalities to drive outreach efficiencies between Save On Energy and the Durham Greener Homes and Greener Buildings programs. Notably, Durham Greener Homes provides custom energy coaching to drive deep home energy retrofits. These programs share scope with Save On Energy in terms of energy equipment and target audiences.
- DERs – DER opportunities are one of the main points of discussion with most key account calls. A sample educational script about Non-Wires Solutions was provided in the Large Customer Report (Exhibit 1, Attachment 1-11).
- Going forward, in recognition of the growing opportunities for DERs in Ontario, Oshawa Power intends to develop a comparison document to help customers explore the differences between the eligibility requirements, operational profiles, contractual requirements and financial benefits of DERs configured under the following initiatives:
    - Save On Energy;
    - Net metering;
    - Non-Wires Solutions;
    - ICI Program;
    - IESO Procurement / Market Participant Opportunities;
    - DER impacts on eligibility for the new EVC RTSR Rate; and,
    - Future potential local DSO market opportunities associated with the DSO project, as noted in response 1-SEC/Staff/CCMBC-15 part a).

2-PP-89

Ref. 1: Exhibit 2, Appendix A, p.2

Preamble:

Oshawa PUC Networks' 2026-2030 DSP does not have any system needs that could be addressed using a NWS.

Question(s):

a) Please reconcile the statement above with the evidence in Exhibit 2, Appendix D that indicates that incremental DERs are expected.
b) Please provide the analysis and documents assessing NWS options and how the conclusion noted above was arrived at.
c) Other LDCs have undertaken DR pilots and programs which have successfully led to managing peak demand. Once recently highlighted example is Toronto Hydro. Why has Oshawa PUC Networks not implemented similar DR programs? If Oshawa PUC Networks has implemented DR programs, please provide the details and results.

Oshawa Power Response

a) To date and to Oshawa Power's knowledge, the incremental DERs that are expected have been planned by facility owners hoping to achieve various energy-related goals including:

   a. Energy cost savings,
   b. Energy cost stabilization,
   c. Participation in provincial energy market opportunities;
   d. Greenhouse gas reductions and/or;
   e. Redundancy/ back-up power.

   To Oshawa Power's knowledge, no known DERs are being implemented as a result of a grid constraint or to avoid a comparatively high cost of a potential wires connection.

b) The analysis and documents assessing NWS options and how the "2026-2030

DSP does not have any system needs that could be addressed by an NWS" was included in section 2.1 subsection "Area of Need #1 – Distribution System Plan Investments of $2M or More" of the NWS business case. This section captures a binary analysis of NWS opportunities. Further exploration was not done, as the binary analysis concluded that NWSs could not meet the system needs in each case. Within the business case, Oshawa Power also commits to providing the required analysis when NWS-eligible activities materialize.

c) Oshawa Power has implemented several DR pilots. Exhibit 1, section 1.8.2 contains table 1-45 "Oshawa Power's Foundational Innovation Projects 2015-2022. Of the projects listed, the following had demand response scope:

- Solar Energy Management Systems (SEMS) Pilot: explored demand response capabilities of residential solar PV + battery energy storage systems at the utility and system-wide levels. Results indicated that SEMS can be operated as virtual power plants (aggregated) to create significant shifts and/or changes in load curves at various grid levels.
- Homebeat App: provided customers with messaging to help them avoid energy use during higher time-of-use periods. In terms of results, the program achieved an approximate 2% energy conservation per household, but was unable to move forward as a CDM program due to statistical constraints regarding the sample size and CDM program evaluation requirements.
- Peak App and Super Peak Pricing: explored the interactive effects of super peak pricing with an AI-enabled app that communicated about demand response in real time with residential customers. In terms of results, the app, in concert with the super peak pricing created significant conservation impacts (sometimes as much as 10%), but did not significantly impact demand response load shifting. The program did not proceed past pilot due to high costs for implementation, the wrap-up of the Super Peak pricing and the unclear results in terms of conservation as opposed to demand response.

The organization is currently delivering three demand response innovation projects, including:

- The NRCan DSO project described in interrogatory response 1-SEC/Staff/CCMBC-15;
- A new project recently funded by the Ontario Centre of Innovation, which will focus on bidirectional vehicle to grid demonstrations in Oshawa, to support technology commercialization (signed in June of 2025); and,
- A managed charging project with Elocity.

2-PP-90

Ref. 1: Exhibit 2, Appendix D - GTA East Needs Assessment Report

Preamble:

With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022 [2]. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP).

Question(s):

a) Please provide details on how Oshawa PUC Networks coordinated input and alignment for Regional Planning assumptions to align with assumptions in the Durham Community Energy Plan and City of Oshawa Community Greenhouse Gas Reduction Plan.
b) Are there any areas of the Oshawa PUC Networks' load forecast that do not align with the Durham Community Energy Plan and City of Oshawa Community Greenhouse Gas Reduction Plan? If yes, please provide what they are.

Oshawa Power Response

a) Oshawa Power relied on the Envision Durham ‑ Draft Official Plan (February 2023) and the Durham Community Energy Plan to inform key elements of its load forecast, including residential growth, commercial growth, and building electrification.

b) Oshawa Power's load forecast directionally aligns with the Durham Community Energy Plan. Targets from these plans were converted into demand impacts using tempered assumptions backed by historical trends so that the resulting forecasts align with municipal direction while avoiding overly aspirational load addition assumptions.

2-PP-91

Ref. 1: Exhibit 2, Appendix D

Project Type	# of Connected DERs	Generation Capacity (kW)
MicroFIT	322	2562.74
FIT	6	940.0
Net-Metering	74	1502.71
CHP	2	2200.0
Microgrid	1	2450.0
BESS	1	500.0
Total	406	10155.45

Table 5 – Summary of Existing DERs Connected to the OPUCN Distribution System

Question(s):

Please provide an equivalent table indicating the change in DERs (number and kW) expected in Oshawa PUC Networks' service territory by the end of the rate term in 2030.

Oshawa Power Response

Oshawa Power does not have firm / binding data from potential third-party DER proponents to be able to provide a forecast of DER penetration onto the grid. The IESO as part of the GTA East regional planning process provides inputs regarding distributed generation forecasts for the region.

2-DRC-92

Ref. 1: Exhibit 2 – Attachment 2-1, Distribution System Plan, Page 50

Ref. 2: Exhibit 8 – Rate Design, Page 10

Question(s):

a) Please provide any and all reports, studies, presentations, data or other documentation with respect to past and forecast (2021 to 2025) electric vehicle ("**EV**") uptake in Oshawa PUC Networks' service territory.

b) Please provide Oshawa PUC Networks' assessment of the specific impacts of the growing customer interest in EVs and the associated increase in EV penetration in Oshawa PUC Networks' service territory on: (i) Oshawa PUC Networks' distribution system planning; (ii) load forecast; (iii) productivity; and (iv) OM&A costs.

c) Please provide any and all analysis, reports, studies, presentations, data or other documentation with respect to past and forecast (2021-2025) distributed energy resource ("**DER**") uptake in Oshawa PUC Networks' service territory.

d) Please provide Oshawa PUC Networks' assessment of the specific impacts of the growing customer interest in DERs and the associated increase in DER penetration in Oshawa PUC Networks' service territory on: (i) Oshawa PUC Networks' distribution system planning; (ii) load forecast; (iii) productivity; and (iv) OM&A costs.

e) Has Oshawa PUC Networks collected any data on use of Ultra-Low Overnight ("**ULO**") rates for customers who are EV drivers? If so, please file any and all related analysis, reports, studies, presentations, data or other documentation.

Oshawa Power Response

a) Oshawa Power has provided reports, studies, data and other documents in Attachment 2-12.

b) The following is a breakdown of specific impacts of the growing customer interest in EVs and the associated increase in EV penetration in Oshawa's service territory:

Distribution System Planning – EVs represent both an area of need as well as potential opportunity for the DSP process, via the Non-Wires Solutions Guidelines and depending on how their loads are incorporated or managed. Strategic management of EVs could become an area of future focus in all DSPs going forward, especially if EV adoption mandates are maintained.

Load Forecast- Oshawa Power will need to comply with new load forecasting methodologies prescribed in recent ministerial directives. These methodologies require electrification scenarios to be considered as a part of forecasting. This forecast will in turn inform the DSP.

Productivity – Initially, LDCs will need to undertake more work with the same staff in order to manage the ramp-up to EV saturation. For example, Oshawa Power will need to incorporate the administration of the new EVC rate into Triple R reporting, key account outreach and billing processes.

OM&A Costs - Eventually OM&A costs may rise to effectively manage EVs. For example, EV load management tools are increasingly digital and will likely be cloud-based. These costs will become necessary for optimizing the grid, but will contribute to higher OM&A.

c) Oshawa Power does not have any documentation with respect to DER uptake in Oshawa’s territory other than the Renewable Energy Generation Investment Plan attached to the DSP as a part of this Application.

d) The following is a breakdown of specific impacts of the growing customer interest in EVs and the associated increase in EV penetration in Oshawa’s service territory:

Distribution System Planning – The NWS Guidelines provide a strong initial sense of how Distribution System Planning will be changed by increases in DERs. Beyond this, Oshawa Power anticipates needing support with grid0scale energy twins and risk management work to understand risks to reliability that may arise from a saturation of DERs causing a variety of load and thermal impacts.

Load Forecast – This will change as per new ministry of energy directives. One challenge will be gaining certainty about planned DERs on the timeline required to fit with DSPs and and infrastructure planning processes. The new planning approaches should at least help create better transparency about load forecasts.

Productivity – Increases in DERs may mean productivity adjustments, as third parties make plans that could require changes in Oshawa Power's grid approach. It is unclear how much third party DERs will change basic infrastructure needs.

OM&A – Similar to managing EVs, Oshawa Power will likely need digital and automated solutions to optimize the use of DERs in the grid. This could look like a DSO market platform, Distributed Energy Resource Aggregation software or other solutions that would likely be considered OM&A under the organization's accounting principles.

e) Oshawa Power has not collected any information with respect to the ultra low rates for EV users. At this time, 137 customers are on ultra-low, making it a relatively small portion of the rate base.

2-DRC-93

Ref. 1: Exhibit 2 – Attachment 2-1, Distribution System Plan, Page 50

Question(s):

a) Please indicate how many (and where applicable the number of MW) of each of the following types of customer connections Oshawa PUC Networks' facilitated in its service territory over the rate period:
   i) single residential unit EV charger connections;
   ii) commercial facility EV charger connections;
   iii) condo EV charger connections; and
   iv) renewable energy and back up generation, including the type of facility (solar roof top, solar thermal, wind, energy storage) and the customer

breakdown for such facilities (residential, general service, commercial/industrial, and/or large industrial).

b) Please indicate how many of each of the following types of customer connections Oshawa PUC Networks anticipates in its service territory over the rate setting period:

   i) single residential unit EV charger connections;
   ii) commercial facility EV charger connections; and
   iii) condo EV charger connections; and
   iv) renewable energy and back up generation, including the type of facility (solar roof top, solar thermal, wind, energy storage) and the customer breakdown for such facilities (residential, general service, commercial/industrial, and/or large industrial).

c) Have any Oshawa PUC Networks customers been prevented from or delayed in installing EV charges as a result of capacity constrains in Oshawa PUC Networks' distribution system? If so, how many customers have been prevented or delayed and for how long?

Oshawa Power Response

a) Please see responses below.

   i. Oshawa Power does not track this data internally. However, please refer to Exhibit 3, section 3.6.1 for best available information surrounding EV connections over the current rate period.
   ii. Same as i.
   iii. Same as i.
   iv. Please refer to Exhibit 2, DSP, Appendix F – Renewable Energy Generation Investment Plan, page 2.

b) Please see responses below.

   i. Oshawa Power does not have an internal forecast for EVs over the rate setting period. However, please refer to Exhibit 3, section 3.6.1 for best available information surrounding EV uptake in the 2026 Test Year.
   ii. Same as i.

iii. Same as i.

iv. Oshawa Power does not have an internal forecast for renewable energy and backup generation. Oshawa Power participates in the GTA east regional planning process where the IESO provides inputs regarding DG forecasts for the region.

c) No.

2-DRC-94

Ref 1: Exhibit 2 – Attachment 2-1, Distribution System Plan

Question(s):

a) Please complete the following chart indicating the breakdown of vehicle type in Oshawa PUC Networks' current vehicle fleet:

Vehicle Type	Fully Electric	Hybrid	Non-EV/Hybrid	Total
Heavy Duty Vehicles	0	0	0	0
Medium Duty Vehicles	0	0	0	0
Light Duty Vehicles	0	5	0	0

b) Please complete the following chart to indicate what proportion of Oshawa PUC Networks' planned fleet renewal investment will involve fully electric vehicles:

Year	2025	2026	2027	2028	2029	2030
Heavy Duty Vehicles						
Medium Duty Vehicles						
Light Duty Vehicles						

c) Please indicate the estimated quantum of efficiency savings (including operations, maintenance, including fuel cost savings) that Oshawa PUC Networks anticipates it will achieve by utilizing EVs rather than traditional internal combustion engine vehicles over the period.

Oshawa Power Response

a) See completed Table below.

IRR Table 2-28: Breakdown by Type of Current Vehicle Fleet

Vehicle Type	Fully Electric	Hybrid	Non-EV/Hybrid (Combustion Engine)	Total
Heavy Duty Vehicles	0	0	12	12
Medium Duty Vehicles	0	0	4	4
Light Duty Vehicles	0	5	17	22

b) See completed Table below.

IRR Table 2-29: Planned Fleet Renewal Investment

Year	2025	2026	2027	2028	2029	2030
Heavy Duty Vehicles	0	0	0	0	0	0
Medium Duty Vehicles	0	0	0	0	0	0
Light Duty Vehicles	0	0	0	0	0	0

c) The newest fleet of light-duty hybrids is being well utilized by employees. While maintenance needs have remained low and fuel costs have decreased slightly, the overall impact has not been significant. As a result, anticipated forecasted savings have not yet been predicted.

2-DRC-95

Ref 1: Exhibit 2 – DSP, p. 91 and Appendix A

Preamble:

Oshawa PUC Networks' Grid Innovation Fund work provides a strong

indication of specific neighbourhoods where EV adoption could initially challenge grid-edge equipment within the next five years.

Question(s):

a) Please provide details as to the areas in Oshawa PUC Networks' service territory experience the highest reliability and safety risks associated with EV adoption and DER connections (such as neighbourhood, number of DERs connected, overview of risks and reliability issues, customer concerns, etc.). If Oshawa PUC Networks is unable to provide further details, please explain why not and whether such information may be obtained in this proceeding or subsequent proceedings.

b) What are the consequences if EV growth rates exceed Oshawa PUC Networks' forecasts? Please include in your response a discussion on what challenges will this present in terms of Oshawa PUC Networks' ability to meet the higher demand and any consequences it may have on Oshawa PUC Networks' ability to meet demand past 2030 if demand continues to accelerate more quickly than anticipated.

c) Please discuss the disadvantages and downside risks to Oshawa PUC Networks' distribution system, customers, investments in EVs and DERs, infrastructure, and/or workforce of underinvesting in EV infrastructure and DER connection and adoption infrastructure if a higher electrification scenario materializes compared to the one relied upon in the Application and Oshawa PUC Networks' DSP. Please also discuss the implications of underinvestment over the rate period (2026-2030), mid-term (2030-2040), and long-term (2040 onwards).

d) Similarly, please discuss any disadvantages where a lower electrification scenario materializes.

e) Please comment on known barriers to EV adoption in Oshawa PUC Networks' service territory, including for multi-unit rental residential, and how the Application seeks to address these barriers and ensure equitable access to charging infrastructure for all customers.

f) Does Oshawa PUC Networks have any programs to support the upgrading of supply infrastructure to enable EV charging infrastructure when Oshawa PUC Networks is planning expansion or upgrades? If yes, please provide details. If no, please discuss what types of programs could be developed to support proactive and future infrastructure upgrades to enable equitable access to EV charging infrastructure.

g) Please provide Oshawa PUC Networks' views on any barriers to EV adoption for residents of multi-unit complexes in Oshawa PUC Networks' service area.

Among any other views, please provide specific comment on whether multi-unit residential complexes represent one of the more challenging venues for EV adoption, and whether Oshawa PUC Networks agrees that addressing those challenges should be prioritized. Please explain Oshawa PUC Networks' position on each of these points.

h) Please describe any ongoing activities or initiatives proposed by Oshawa PUC Networks that can help to address challenges specific to EV transition in multi-unit residences by way of proactive infrastructure upgrades or future upgrades. Please include any planned or anticipated initiatives at the system-wide level in addition to any more localized initiatives.

Oshawa Power Response

a) Oshawa Power does not have a record of reliability or safety risks and it has not received customer concerns regarding connecting these types of equipment, and is well positioned to integrate reasonable DER and EV growth.

b) Oshawa Power follows the OEB's Load forecasting Guideline and works with the GTA East regional planning group to produce a reasonable forecast. Consequences of accelerated EV adoption curve will need coordination with all parties including Hydro one and the IESO to account for upstream constraints. In order to minimize impacts, where possible, Oshawa Power has proposed to use Non-wires Solutions and innovation projects. Please refer to Exhibit 2, DSP, Appendix A for proposed solutions.

c) As noted above, Oshawa Power has proposed some measures to mitigate impacts of accelerated EV and DER adoption.

   As with any underinvestment scenario, Oshawa Power anticipates underinvesting in EV infrastructure and DER connection adoption infrastructure to be:

   Near Term (2026-2030)

   Higher costs associated reactive maintenance or replacements and/or having to design NWSs that were not foreseeably needed;

Potential delays and/or higher equipment costs associated with reactive equipment procurement;

Delays in achieving service upgrades requested by customers; and/or

The need for more regulatory administrative work to facilitate ICMs or new NWS applications.

Mid-Term (2030-2040) / Long-Term (2040 onwards)

A potential for a rate spike/uneven capital program requirements associated with a large number of DER-associated asset renewals;

Constraints developing within the grid, which could have impacts on keynote projects associated with decarbonization or economic development; and/or,

Issues securing up-stream capacity due to underestimation of future transmission capacity and short-circuit capacity allocation needs.

d) Oshawa power does not see major disadvantages with a lower electrification scenario within the 2026-2030 rate period as there are no proposed investments driven primarily by electrification. The flexibility that the proposed Non-Wires Solutions offers also help streamline efforts to areas of need.

e) There are no known barriers at this time with respect to EV adoption. Every new development goes through a thorough review and design process. Depending on customer needs (such as multi-unit complexes with EVs), Oshawa power works with the customer to tailor the distribution system design that to best accommodate them. This may include larger cable, 3 phase transformers, and other system planning considerations.

f) No, Oshawa Power does not have any programs to support upgrading supply infrastructure to enable EV charging infrastructure during planning for expansion or upgrades. Programs could involve customer communications during the planning phase to determine interest in EVs and any equity-related facets of potential upgrade projects. Additionally, Oshawa Power could look at a cost analysis regarding avoided costs associated with proactive upgrades as opposed to retrofits, which tend to be cost prohibitive and drive barriers to inclusion.

g) Please refer to response e). It is difficult to generalize if a certain group such as multi-unit residential complexes have more barriers compared to other groups. Oshawa Power works with customers on a case-by-case basis to find a solution that best accommodates the customers’ needs.

h) Oshawa Power implemented on-street charging in the downtown Oshawa area, to benefit the general public including several multi-unit residential buildings in the vicinity, with funding from the Natural Resources Canada ZEVIP program. The organization continues to review the funding to determine options for supporting the development of useful charging within the community, as evidenced in response 1-SEC/CCMBC-25, part b).

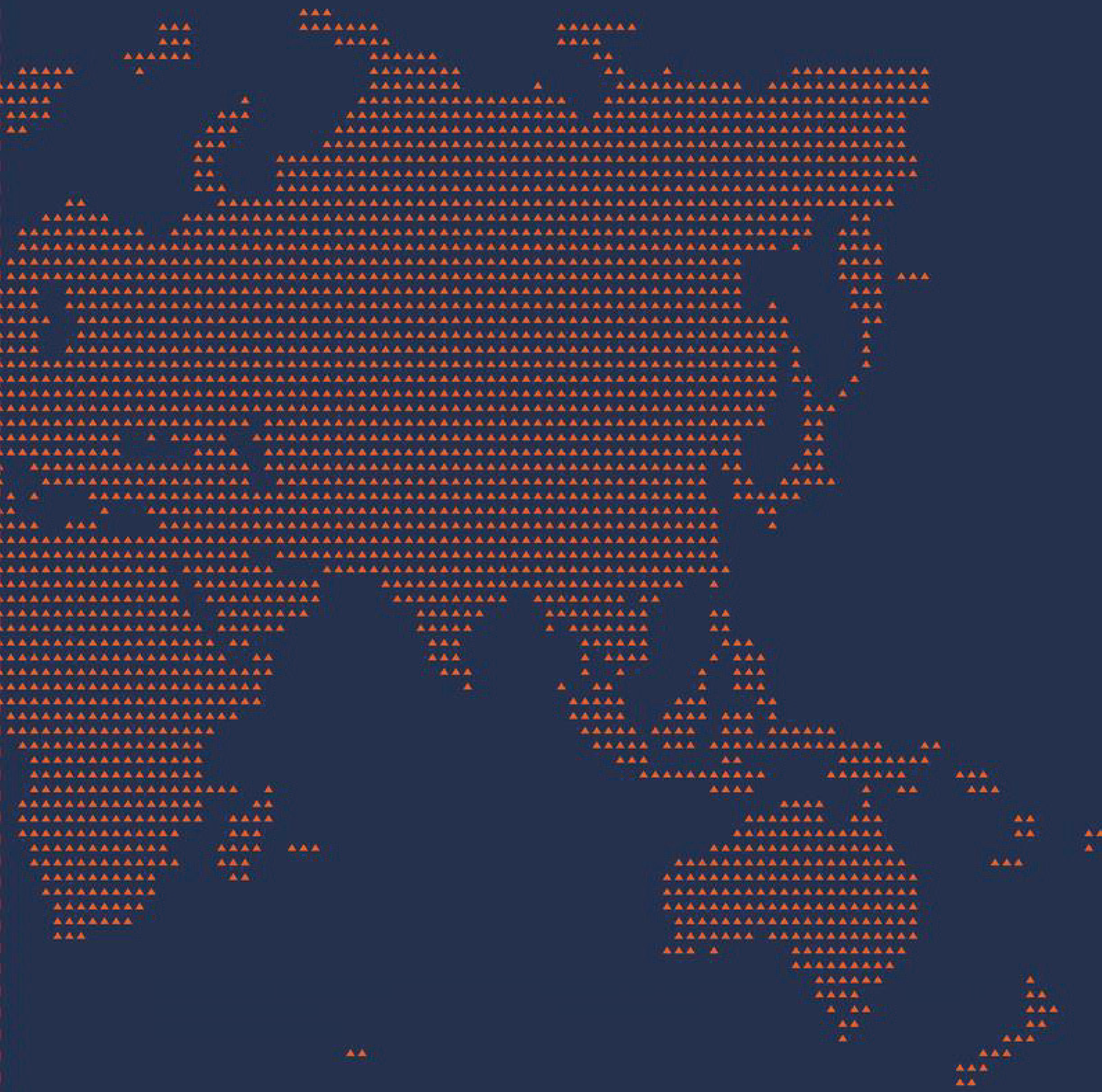
To this end, in the spring of 2025, the Region of Durham held consultations for the development of their public EV charging strategy. Oshawa Power represented the utility industry in these consultations, and assisted with knowledge about community needs, which will help direct municipal investment in EV charging going forward. Access for multi-unit residential EV owners was on element that was considered in the strategic assessment criteria for siting charging infrastructure. The report is in its final stages of development and expected to be presented to council in the fall of 2025.

Attachment 2 – 1

2018 Asset Condition Assessment

METSCO

MAKING IT POSSIBLE



Prepared For:

OSHAWA PUC NETWORKS INC.

ASSET CONDITION ASSESSMENT REPORT 2018

Prepared by

P-18-173

April 2019

Disclaimer

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Asset Condition Assessment Report 2018

Final Report

April 2019

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Executive Summary

This Asset Condition Assessment report contains calculations of current condition of Oshawa PUC Network Inc's (OPUCN) distribution assets, based on the data supplied by the utility in the fourth quarter of 2018. In addition to assessing the condition of assets with available information, the report recommends an asset replacement strategy to maintain the health of the distribution system and ensure a continuous service for OPUCN's customers.

This report summarizes the results of an Asset Condition Assessment (ACA) study carried out by METSCO Energy Solutions Inc. (METSCO) on behalf of OPUCN. The underlying study's main objectives were to generate Health Indices with current condition data of in-service assets deployed in the electricity distribution system and recommend replacement plans. As OPUCN moves towards a risk-based asset management strategy to determine the optimal timing and scope of investment into asset renewal, an ACA is prepared to determine the condition of the utility's asset base. The ACA is the first step in implementing a risk-based asset management framework that is aligned to ISO 5500X standards. A brief outline of implementing a risk-based asset management framework is documented in Section 2. The first step towards the implementation of a risk-based asset management approach is to develop a baseline assessment tool, namely the asset Health Index, that could be employed to measure and benchmark the health and condition of assets going forward. METSCO developed a comprehensive methodology and documented it in Section 3 of the report for assets comprising the scope of this analysis. The methodology in this report has been updated to METSCO Energy Solutions Inc.'s Health Index Formulation to better reflect the accuracy of an asset's condition for further risk management analysis.

The Asset Condition Assessment is based on data compiled in Q4 2018 and covers the following classes of assets owned by OPUCN:

- Distribution Assets
    - Poles
    - Overhead Primary Conductors
    - Underground Primary Cables
    - Transformers
    - Primary & Smart Switches
    - Switchgears
    - Cut-out arrestors
    - Elbows
    - Reclosers
    - Vaults & manholes
- Station Assets
    - Power Transformers
    - Circuit Breakers
    - Switchgears
    - Relays & RTUs

- Battery & Chargers
- Ground Grids
- Fences
- Buildings

For each asset group the Health Index is calculated using the data provided by the utility. Assets are classified in one of five conditions: Very Good, Good, Fair, Poor, or Very Poor. The results of the Asset Condition Assessment are summarized in Figure 0.1.

Figure 0.1: Health Index results

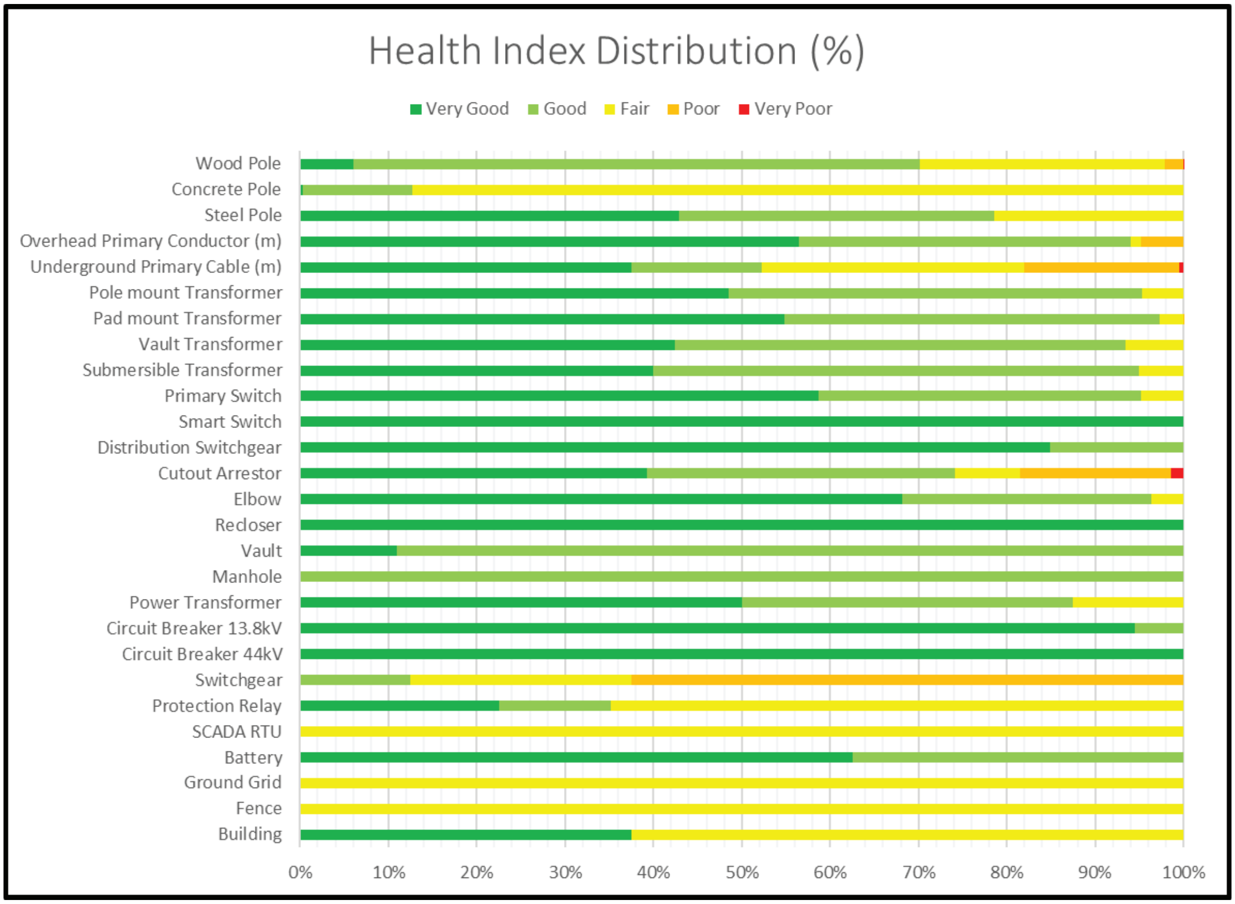

Table 0-1 presents the summary of the Health Index results. For each asset class the following details are given: the total population, average Health Index and the Health Index distribution. The Health Index Formulation (HIF) is derived from METSCO's experience, OPUCN's asset management objectives, the available data and the most material parameters that determine the timeline of expected end of life. For each asset in the following subsections, a Data Availability Indicator (DAI) is presented. The DAI is a percentage of availability of condition parameter data for an asset, as measured against the condition parameters considered in the Health Index Formulation. DAI of 100% for an asset indicates presence of values for all condition parameters defined in the Health Index Formulation and is therefore a measure of the success in meeting its intentioned data collection. OPUCN's current collection of data parameters results in a 100% DAI for the HIF.

The majority of OPUCN's system is in Fair or better condition, which suggests OPUCN's past renewal investments were effective in maintaining the system health. However, there are some assets that can benefit from an increase in asset renewal to improve the age distribution and the condition of the asset class. This may result in a decrease in cost associated with reactive failures and may reduce the number of assets with a condition graded below Fair.

Following our engagement, METSCO's chief recommendation is that OPUCN consider aligning its Health Index Formulation to the Best Practice Health Index Formulation, through the addition of incremental end of life criteria that can supplement the current inspection processes. To assist OPUCN in taking immediate steps towards asset renewal, METSCO has also provided a recommended asset replacement plan for asset renewal, reflective of the current ACA's results. The asset replacement plan is a baseline that identifies the projected quantities of assets that would likely require replacement over the next short-term planning period (years 2019 to 2025) to improve the asset category's Health Index and maintain the overall system health.

Table 0-1: Asset Condition Assessment overall results

Asset Category	Pop.	Health Index Distribution					Avg. Health Index
		Very Good	Good	Fair	Poor	Very Poor	
Wood Pole	9,570	6%	64%	28%	2%	0%	73%
Concrete Pole	869	0%	12%	87%	0%	0%	66%
Steel Pole	14	43%	36%	21%	0%	0%	72%
Overhead Primary Conductor (m)	519,869	56%	38%	1%	5%	0%	86%
Underground Primary Cable (m)	460,325	37%	15%	30%	18%	0%	69%
Pole mount Transformer	2,513	49%	47%	5%	0%	0%	84%
Pad mount Transformer	3,765	55%	42%	3%	0%	0%	85%
Vault Transformer	394	42%	51%	7%	0%	0%	84%
Submersible Transformer	20	40%	55%	5%	0%	0%	83%
Primary Switch	1,001	59%	36%	5%	0%	0%	87%
Smart Switch	15	100%	0%	0%	0%	0%	100%
Distribution Switchgear	33	85%	15%	0%	0%	0%	96%
Cutout Arrestor	2,830	39%	35%	7%	17%	1%	80%
Elbow	7,192	68%	28%	4%	0%	0%	90%
Recloser	4	100%	0%	0%	0%	0%	0%
Vault	146	11%	89%	0%	0%	0%	84%
Manhole	120	0%	100%	0%	0%	0%	83%
Power Transformer	16	50%	38%	13%	0%	0%	83%
Circuit Breaker 13.8kV	72	94%	6%	0%	0%	0%	96%
Circuit Breaker 44kV	16	100%	0%	0%	0%	0%	100%
Switchgear	8	0%	13%	25%	63%	0%	43%
Protection Relay	71	23%	13%	65%	0%	0%	75%
SCADA RTU	8	0%	0%	100%	0%	0%	60%
Battery	8	63%	38%	0%	0%	0%	89%
Ground Grid	16	0%	0%	100%	0%	0%	67%
Fence	8	0%	0%	100%	0%	0%	60%
Building	8	38%	0%	63%	0%	0%	75%

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1 Introduction

This Asset Condition Assessment (ACA) study is carried out by METSCO Energy Solutions Inc. (METSCO) on behalf of Oshawa PUC Network Inc. (OPUCN). The core objective of METSCO's engagement was to generate Health Indices with current condition data of in-service assets deployed across OPUCN's service territory and recommend replacement plans.

The ACA methodology underlying this study assessed multiple categories of assets present in OPUCN's distribution system. Adoption of the recommended ACA methodology would require periodic asset inspections and recording of their condition to identify those most at risk. Additionally, computing the Health Index for distribution assets requires identifying end-of-life criteria for various components associated with each asset type. Each criterion represents a factor that is influential in determining the component's current condition relative to conditions reflective of potential failure. These components and tests shown in the tables are weighted based on their importance in determining a given asset's end-of-life.

The asset classes covered in the report include the following:

- Distribution Assets
    - Poles
    - Overhead Primary Conductors
    - Underground Primary Cables
    - Transformers
    - Primary & Smart Switches
    - Switchgears
    - Cut-out arrestors
    - Elbows
    - Reclosers
    - Vaults & manholes
- Substation Assets
    - Power Transformers
    - Circuit Breakers
    - Switchgears
    - Relays & RTUs
    - Battery & Chargers
    - Ground Grids
    - Fences
    - Buildings

The information contained within this report represents data available in Q4 2018. The report is organized into four sections including this introductory section:

- Section 2 outlines the fundamentals of an evidence-based strategic asset management plan, summarizing standards PAS-55 and ISO 55000/55001/55002, and providing an overview of METSCO's methodology and the ACA process;

- Section 3 describes the Condition Assessment methodology framework and assessment of an asset's age, condition and data collection process;
- Section 4 summarizes our recommendations for OPUCN on data collection improvements for building on the current Health Index frameworks;
- Section 5 summarizes the recommended asset replacement strategy based on the Asset Condition Assessment, without consideration of additional factors such as an asset management plan, resource capacity, or budgetary constraints.

2 Strategic Asset Management Plan

In developing the ACA for OPUCN, METSCO ensured that the methodology was aligned to existing asset management industry standards, including ISO 5500X. Industry standards assist organizations in aligning their processes to one that is recognized internationally. This is further detailed in Section 2.1.

The ACA approach implemented for OPUCN is designed to act as a part of a broader risk-based asset management framework to allow the utility to identify assets for replacement in accordance with industry standards for asset management. This is further discussed in Section 2.2.

The ACA approach described in this report reflects OPUCN's current available data and is modified from the ideal Health Index formulation. The recommended ACA model for OPUCN is further explained in Section 2.3.

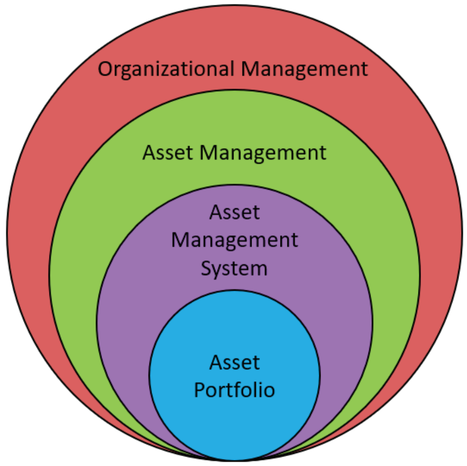
2.1 Industry Standard for Asset Management Planning

The Industry Standard for Asset Management Planning is outlined in standards documents comprising the ISO 5500X framework. Asset Management (AM) generally applies to one of three groups of entities: those looking to establish an asset management system, those seeking to realize more value from an existing asset base, and those seeking to review an asset management system already in place to explore opportunities for improvement. Given this breadth of potential utilization pathways, ISO 5500X is broadly applicable across organizations of different types, adjusting, as necessary, for the purpose, operating context, and financial constraints.[1]

Any item or entity that adds value to the organization can be considered an asset. This can be actual or potential value, expressed in a monetary or other form (i.e. public safety). The hierarchy of an organizational AM framework includes several elements showcased in Figure 2.1. An asset portfolio that contains all known information regarding the assets sits as the core of an organization. Around the asset portfolio is the AM system, which represents a set of interacting elements to establish policy, objectives, and the processes to achieve those objectives. An AM system is comprised of AM practices, which are executed in a coordinated fashion to realize the maximum value of an organization's assets. Finally, the organizational management structure organizes and executes the elements of the underlying hierarchy.[1]

[1] ISO 55000 – Asset management – Overview, principles and terminology

Figure 2.1: Relationship between key Asset Management terms[1]



Asset management is fundamentally grounded in a risk-based evaluation approach. The overarching goal of an AM process it to quantify all risks affecting the assets by their probability and impact (where possible), and then seek to minimize these risks through execution of tasks through asset management operations. Rigorous application of AM processes can yield multiple types of benefits, including: realized financial profits, better defined, classified and managed risks across the asset base, more informed investment decisions, demonstrated compliance across the asset base, increased public and worker safety, and corporate sustainability (among others).[1]

Asset management processes are ideally integrated throughout an entire organization. This requires a well-documented AM framework that is shared between and understood by all relevant agents. In this way, the organization stands to benefit the most from its own on-hand resources, whether via technical experts, those operating and maintaining the assets, or those with an understanding of the financial operations and constraints on the organization. Organizations typically document the key AM principles in a Strategic Asset Management Plan (SAMP). The SAMP should be used as a guide for the organization to apply its asset management principles and practices to its specific-use cases. Distribution of the SAMP should be open within an organization and updated on a regular basis, in order to best quantify the most current and comprehensive asset management practices being implemented. Just as the asset base performance is subject to in-depth review, the asset management process and system should be periodically reviewed with the same rigor.[1]

A well-executed AM framework hinges on an organization's ability to classify its assets using comprehensive and efficient data collection and analysis procedures. This includes but is not limited to collection and storage of technical specifications, historical asset performance information, projected asset behaviour and degradation analysis, configuration of an asset or asset-group within the system, the operational relation of one asset to another, etc. In this manner, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted from its asset base and stored to allow for further analysis to take place. With more asset data on hand, better-informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio.[2]

AM practices can help quantify and drive strategic decisions. A better understanding of the condition of asset portfolio within an organization can enable fluid reorganization or changes in management processes to realize tangible benefits to the organization. This is largely due to AM being a fundamentally risk-based approach, which lends itself to use as a sound framework for creating financial plans driven by evidence from the field. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or a more optimized financial expenditures to maintain the asset base. ISO 5500X states explicitly that all asset portfolio improvements should be assessed using a risk-based approach prior to being implemented.[2]

Finally, asset management should be considered a fluid, flexible process subject to continuous enhancements and revisions. Adopting a framework and an optimized set of practices does not bind the organization or restrict its agency in the future, as the operating strategic context evolves. With time, the goal of any asset management system is to continually improve and realize benefits within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated Strategic Asset Management Plans (SAMPs), and further integration of asset performance analytics into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.[2]

An Asset Condition Assessment (ACA) represents the first step in fully integrating the AM framework outlined by ISO 55000. An organisation determines the current condition scores for each asset by evaluating a current set of available data related to the state of degradation of in-service assets within an asset portfolio. The level of degradation of an asset, knowledge of its configuration within the system, and its corresponding likelihood of failure feed directly into a risk-based assessment. The fundamental purpose of an ACA is to collect, consolidate, and present the results framed by the current organizational dynamics for the purposes of properly quantifying and managing the risks of its asset portfolio. An ACA should provide insights into the current state of an organization's asset base, the risks associated with further degradation, and approaches as to optimal utilization of obtained results to extract the maximum value from the asset portfolio going forward.

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

2.2 Overview of METSCO's Methodology

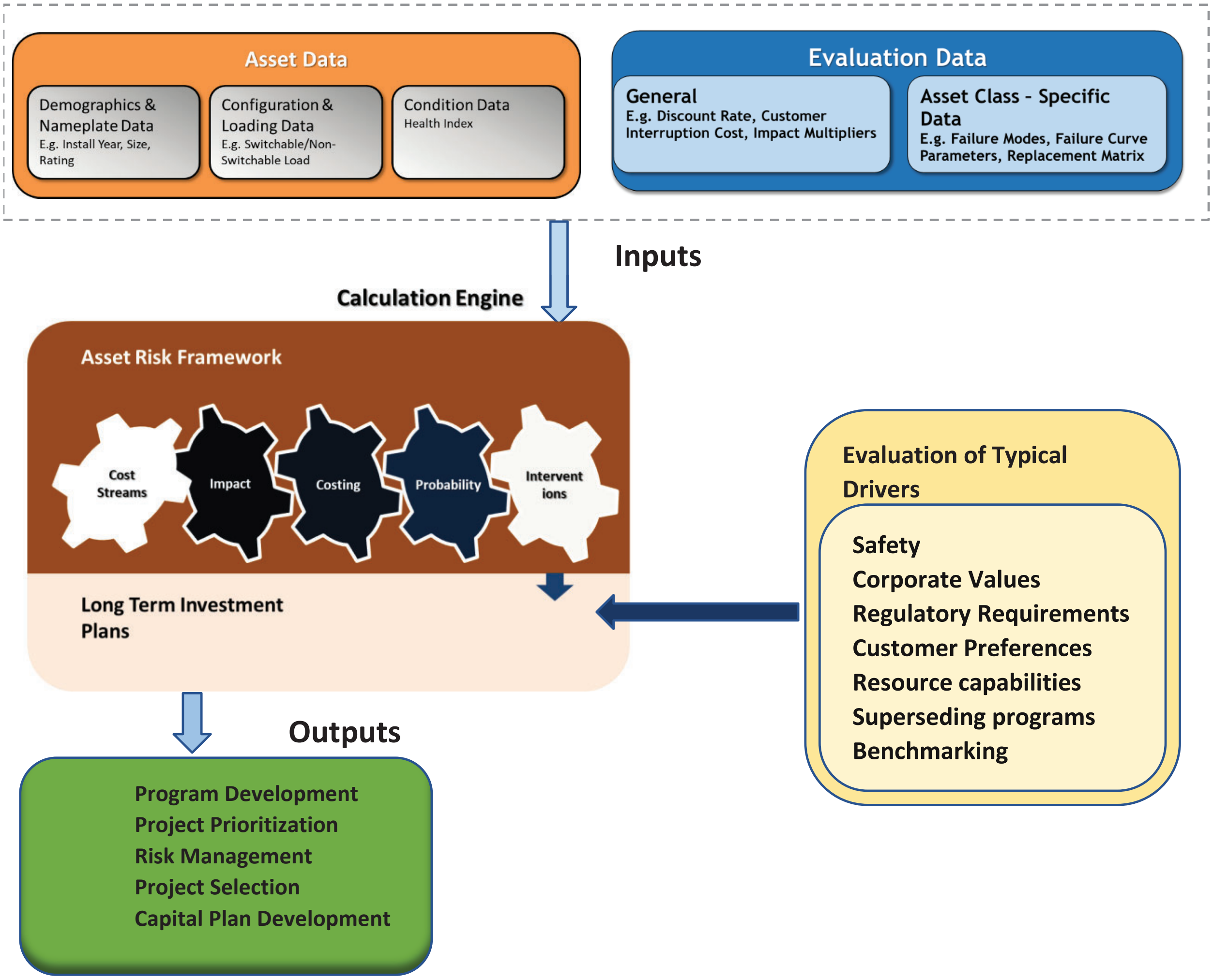
2.2.1 Overall Asset Management Strategy

Decisions involving investments into fixed assets play a major role in determining the performance of distribution systems. Most of investments in fixed assets are triggered by either declining performance in the areas of system reliability, power quality or safety; increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. Under any of these scenarios, investments that are either oversized or made too far in advance of the actual system needs may result in sub-optimal allocation of resources. On the other hand, investments not made in time when warranted by the system needs increase the risk of missing performance targets – thus also resulting in suboptimal capital allocations. Optimal operation of a distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of an Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs to sustain the existing plant – minimizing the combined total costs over the life of an asset.

METSCO is a proponent of Risk-Based Asset Management Strategies, which determine the risk of asset failure based on physical condition of an asset, commonly measured using numerical "Asset Health Indices". This approach computes the valuation of the asset risk based on consequences of asset failure and identifies the economically optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards, through the scope and frequency of preventative maintenance during the asset's service life, – and finally, to the determination of the asset's end-of- life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, enabling highest operating performance, and maintaining lowest initial investment (capital costs) and operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

The overarching objective is to develop a prioritized capital and preventative maintenance investment plans, which are implemented over periods of 10 to 25 years to optimize system performance. Corporate objectives and performance requirements are incorporated in the model by placing appropriate weights and costs on project drivers as shown in Figure 2.2.

Figure 2.2: Model to Identify Assets with Highest Risks



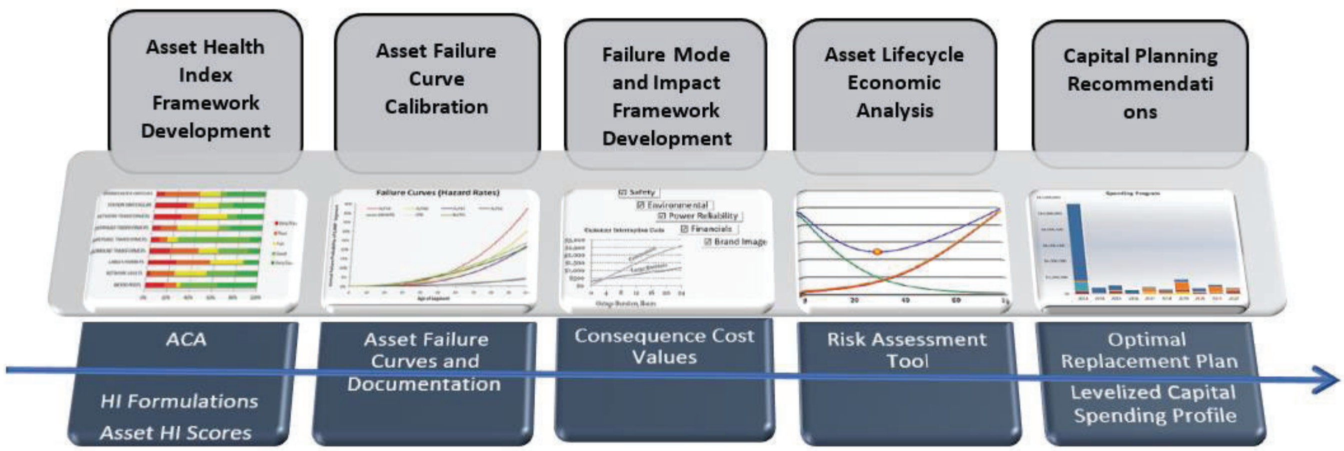
METSCO's overall asset management approach includes executing an assessment across the five components as presented in Figure 2.3. Under the asset Health Index (HI) framework development, an Asset Condition Assessment (ACA) is performed. An ACA is used to produce the HI, which represents a quantified condition score of a given asset. The HI score is ultimately calculated using asset age, inspection and historical performance data (as applicable). Using this technique, a utility may also choose to develop condition-based failure probability information – that is the likelihood of assets failing once degrading past a certain threshold.

Different asset classes and individual assets have different propensity to fail over time on the basis of their observed condition parameters, meaning different failure curves apply to them. Failure curves are calibrated by analyzing actual failure data against the age and/or condition parameters observed at the time of failure. Weibull analysis is a commonly used statistical methodology to develop the failure probability curves.

The calculated failure probability information is used in subsequent risk analysis to determine the likelihood of failure of an asset of a given age in a given year. Failure mode and impact component development calculates the consequence cost values for various asset failure modes – considering customer impacts, collateral damage impact, environmental impact, etc. Once the probability and impact of asset failure have been determined, the risk cost can be calculated, along with the life-cycle costs of the asset. Assets will be recommended for replacement at the point in time when an optimal balance is achieved between capital spending and risk level mitigated, avoiding premature retirements and preventing significant delays in addressing the most pressing problems.

The scope of this report only covers the Asset Health Index Framework Development component of the Overall AM Approach illustrated in Figure 2.3. The remaining components are identified to outline for OPUCN the future steps that can be taken to further enhance their Asset Management practices. However, the Asset Health Index Framework component represents the first step needed to be taken and is the foundation for the remaining identified four components of the Overall AM Approach.

Figure 2.3: Overall AM approach



2.2.2 Asset Condition Assessment Process

The major steps in the ACA are briefly discussed below:

1. Identify Asset Classes: Identify asset classes to be considered in the asset condition assessment study

   Typical asset classes in the distribution system include:

   - Station Transformers
   - Station Circuit Breakers
   - Station Batteries
   - Capacitors

- Controls and Protective Relays
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Transformers
- Switches
- Poles

2. Data Analysis:
   - Collect asset related data such as GIS records, asset demographics, inspection/testing records, etc.
   - Validate the accuracy of data, e.g. check for data discrepancies between files
   - Develop an adjusted "Health Index Formulation" (HIF) for each asset based on the available data, published best practice information and expert assessment of the data parameters which are reasonably obtained and are most indicative of asset end of life.
   - Identify additional asset data needed to determine and evaluate asset condition and assess the potential of collecting additional useful asset condition information to improve accuracy of the condition assessment results.
   - Recommend collecting additional data that is reasonably available (the methods to obtain additional data typically include inspection, testing, sampling, collection of paper records, field work to collect asset data, adopting advanced technology to record inspection/testing data, etc.).
3. Collect additional condition information specific to each asset class.
4. Calculate Data Availability Indicator (DAI): DAI is a percentage of availability of condition parameter data for an asset, as measured against the condition parameters considered in the adjusted HIF. DAI is calculated as a ratio of sum of weighted condition parameters score of available condition parameters to sum of weighted condition parameters score from the recommended HI formulation.

$$DAI = \left(\frac{\sum_{i=1}^{N} Weight_i * CPAF_i}{\sum_{i=1}^{N} Weight_i}\right) x\,100$$

   Where *i* corresponds to the condition number, *N* is the total number of condition parameters considered in the HI calculation, and *CPAF* is the Condition Parameter Availability Factor which is equal to 1 if the condition parameter data is available for the asset otherwise equal to 0.

   DAI of 100% for an asset indicates successful population of values for all condition parameters defined in the adjusted Health Index Formulation for the asset and is therefore a measure of success in meeting its intentioned data collection targets. Typically, the targets for DAI are less than 100% for "sampled" assets such as cables and wood poles, or where the costs to collect additional data are not warranted such as for assets that represent lower risk of in-field failure (as opposed to proactive replacement). Sampling is done on assets where the asset population is significant and cannot be inspected within one year. Therefore, the best and latest available data is used as a representative sample of the total population. Sampling is a viable method to assess the condition of assets given the available condition parameters.

While Health indices can be calculated using a variety of combinations of available information, utilities seeking to improve their In addition, there is a data set representing the "Best Practice Health Index Formulation", which an asset owner may be moving towards. In this case, a recommendation for process improvements may include suggestions to collect additional condition parameters defined in the Best Practice Health Index Formulation for the entire population of assets. With the new data collected, it is expected to increase the accuracy of ACA results.

5. Asset Condition Assessment:

A Health Index (HI) is an indicator of asset remaining life given as a percentage. A new asset should have a HI of 100% and an asset in very poor health should have a HI below 30%. Table 2-1 presents the HI ranges and the corresponding asset condition.

Table 2-1: Asset condition based on health index

Health Index	Condition	Description	Requirements
[85–100]	Very Good	Some ageing 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 condition for an asset, the Health Index formulation is developed using condition criteria that lead to an asset's physical end of life and potential failure. Described modes of degradation are identified through failure analysis reports, subject matter experts and historical failure. A weight is assigned to each condition to indicate the amount of influence the condition has on the overall asset health. When presented with a HI Formulation such as:

Table 2-2: Health Index Calculation Example

#	Condition Criteria	Weight	Condition Grade	Factors	Maximum Score
1	Condition example 1	4	A,B,C,D,E	5,4,3,2,1	20
2	Condition example 2	6	A,C,E	5,3,1	30
3	Condition example 3	6	A,B,C,D,E	5,3,2,1	30
	MAX SCORE				**80**

Asset Health Indices are based on identification of aging mechanisms and failure modes of the assets and their sub-systems and are developed by placing appropriate weights on various parameters indicative of condition, to express the level of degradation of an asset's health along the way to its end-of-life.

The assigned weights are based on the parameter's criticality in determining the overall health and condition of the asset and depending on the ease or difficulty with which these condition parameters could be improved. For example, those that relate to their primary functions and cannot be easily improved without costly rehabilitation/ repair work are assigned higher weights than those that represent ancillary functions or can be improved without incurring high costs.

This assigning of weights for Health Indexing is a continuous improvement and is a continuing effort supported through METSCO's ongoing review of industry practices and techniques for asset inspections and testing. Historical utility surveys and literature search have been performed to support the development of best practice Health Indices. Ongoing efforts are continued at METSCO to further refine its best practice Health Index formulations to accurately reflect current asset construction and testing techniques.

Each condition is ranked from A to E and each rank corresponds to a numerical grade:

Grade	Condition
A – 5	Best Condition
B – 4	Normal Wear
C – 3	Requires Remediation
D – 2	Rapidly Deteriorating
E – 1	Beyond Repair

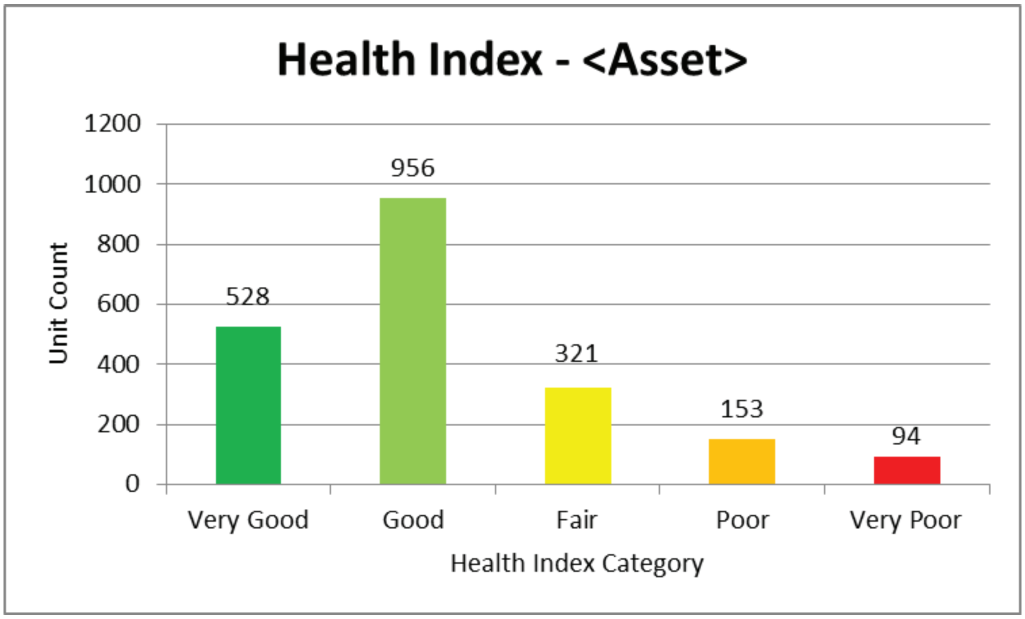
The Health Index is then calculated as follows:

$$HI = \left(\frac{\sum_{i=1}^{N} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100$$

Where *i* corresponds to the condition number, *N* is the total number of condition parameters considered in the HI calculation and the *HI* is a percentage representing the remaining life of the asset.

Figure 2.4 shows the example graph representation of HI conditions for an asset class categorizing assets into Very Good to Very Poor condition.

Figure 2.4: Asset Health Index Graph-Example

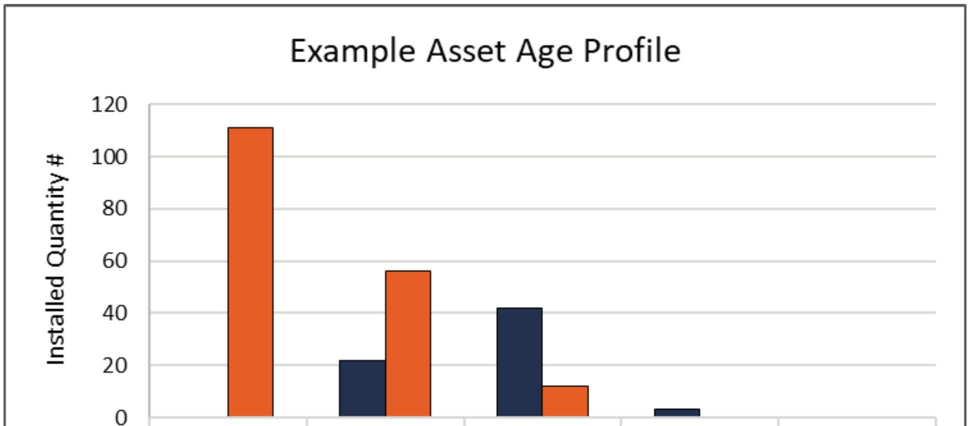


Note – the above graphic is illustrative only and does not represent any factual numbers of OPUCN's assets nor system.

6. Demographic Assessment:

A useful cross-reference to an HI is a representation of asset demographics. Assets are charted based on age from installation date, and other pertinent demographics such as material or manufacturer/type etc. Since many people still consider age when making replacement plans, it is important to document any significant variations between the age-based results and the condition-based HI. As an example, cables are known to have different life expectancies based on the technology available at the time of installation. In other cases, equipment produced by a certain manufacturer may be known to be reaching the end of life and failing at a higher-than-predicted rate. Figure 2.5 represents a typical demographic chart to represent the asset age data.

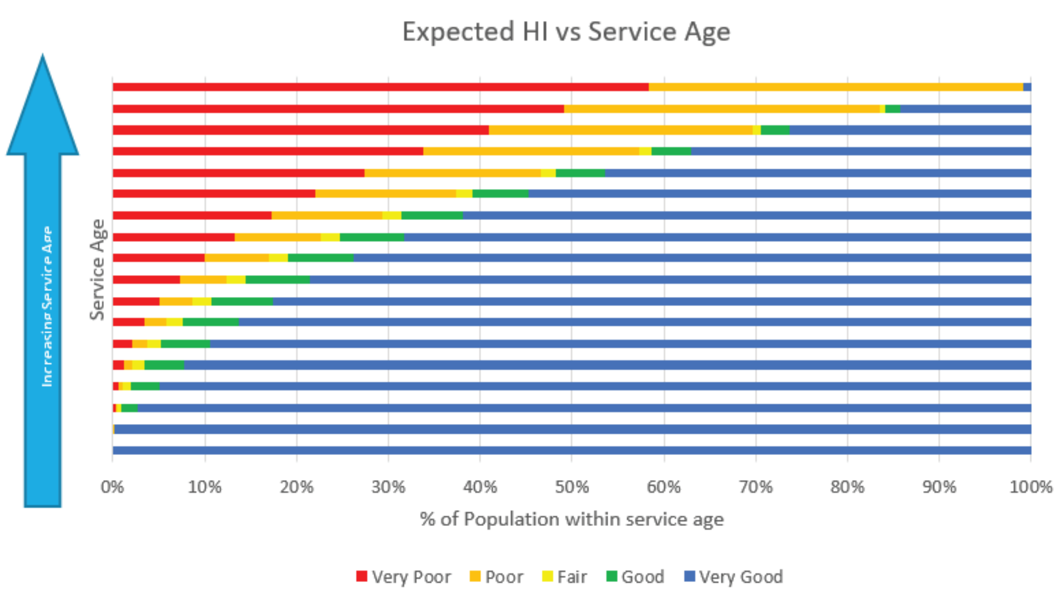
Figure 2.5: A Typical Demographic Chart



	0-10 years 2008-2018	11-20 years 1998-2007	21-30 years 1988-1998	31-40 years 1978-1988	>40 years Before 1978
Type 1	0	22	42	3	0
Type 2	111	56	12	0	0

Figure 2.6 presents an example of an expected relationship between the HI condition and service age. Based on past empirical studies, there is a general expectation that the HI conditions should gradually change from Very Good to Very Poor as the service age of an asset increases. However, deviations within and across specific asset classes may be present due to a number of potential drivers.

Figure 2.6: Expected HI Vs Service Age Trend-Example



7. Recommendations: The last stage of the ACA process entails providing recommendations for OPUCN based on the results of the ACA including a preliminary asset replacement for

sustainable system performance for the next seven years, as well as improvements on data collection process that are expected to increase the validity of HI results.

2.3 ACA Model for OPUCN

The ACA model for OPUCN's system utilized in this study is a function of both OPUCN's data availability and its asset management objectives. Data availability drives the parameter selection for each asset's Health Index as well as their respective index weighting. OPUCN's asset management objectives drives the criticality of assets.

The Health Index Formulation (HIF) for OPUCN includes the following modifications from the Best Practice Health Index Formulation (BHIF) driven by the distributor's specific circumstances:

1. Additional parameters were included for some assets that are usually not included within the BHIF. Additionally, certain related parameters have been merged together, whereas in the BHIF the parameter would ideally be divided into multiple parameters to highlight the criticality. An example of this is for wood poles where in the BHIF, "Wood Rot" and "Defects" would be separated whereas in the OPUCN it is merged as "Overall Condition" since that is how the available data is collected.
2. The weighting of each parameter is different in comparison to the BHIF. Although it deviates from the BHIF, the HIF implemented reflects OPUCN's historical asset performance and condition. Additionally, the weightings align with OPUCN's asset management objectives, identifying parameters that are critical for OPUCN's system and are targeted to reduce the associated risk. The HIF implemented at OPUCN is unique to its own system as every system varies and differs within Ontario. However, OPUCN understands the implemented HIF can continue to be improved upon and intends to be in alignment to the BHIF with respect to the collecting of condition criteria unique to each asset class.
3. The BHIF Health Index formula does not identify weights that will result in a summation score of 100, whereas, OPUCN favors to identify weights that will result in a sum score of 100. As a recap, weights are identified through historical asset failures and subject matter experts in relation to their overall contribution the asset's physical end of life. However, the current approach has limited effect on the final Health Index in comparison to the BHIF. The translation from Ranking to Numerical Grade is identified from 1 to 5 in the adjusted HIF, whereas the BHIF is identified with 0 to 4. Though the Numerical Grade both use a five-level grading, the adjusted HIF Numerical Grade aides the goal of having a total score of 100. However, both methods normalize the Health Index to a total score out of 100 and as such are effectively the same.

The BHIF is METSCO's Health Index Formulation to evaluate the condition and risk of an asset based on industry standard. The BHIF is a tested methodology and has been successfully implemented and used within asset management practices across Ontario. The BHIF was developed based on multiple consultations between subject matter experts on each asset class, identifying parameters that affect the overall condition of the asset and the severity of anticipated impact associated with those parameters. However, the BHIF is dependent on an ideal state of data collection and maturity of asset management. Therefore, the BHIF can be slightly modified to fit OPUCN's database and historical performance while also providing the valuable insight on the asset's condition.

3 OPUCN Asset Base Health Indices

3.1 Distribution Assets

3.1.1 Wood Pole

3.1.1.1 Condition Assessment Methodology

Being an organic material, wood is subjected to degradation processes that are different from other assets on distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and physical stress due to effects of weather. Computing the Health Index of a wood pole requires developing the associated end-of-life criteria. Each criterion represents a factor in determining the asset's condition relative to potential failure.

The Health Index for wood poles is calculated by considering a combination of service age, visual inspections for defects and pole treatment. The best available data is considered for the Health Index calculations within this ACA. Table 3-1 summarizes the methodology to combine these criteria into an overall Health Index for wood poles.

Table 3-1: Wood Pole Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	8	A,B,C,D,E	5,4,3,2,1	40
2	Overall Condition	8	A,B,C,D,E	5,4,3,2,1	40
3	Component Condition	2	A,B,C,D,E	5,4,3,2,1	10
4	Pole Treatment	2	A,C,E	5,3,1	10
				MAX SCORE	**100**

Table 3-2 translates service age into a condition rating. Given that service age provides a reasonably good measure of the remaining life of the asset, and we employ it as a discrete assessment parameter.

Table 3-2: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 40 years
D	41 to 50 years
E	Over 50 years or Unknown

Different aspects of the wood pole are visually inspected by qualified staff during line patrols. OPUCN inspects a variety of components described below and utilizes a four-level grading system to rank the overall pole condition: Good, Fair, Fair-Poor, Poor. Visual inspection can detect the following types of wood pole damage:

- Fibre damage that may occur when wind hits a wood pole with force beyond the pole's bearing capacity;

- Animal and/or insect damage and infestation;
- Partial damage that may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only a part of a pole's cross-section, the utility may keep the pole in-service while noting a reduced factor of safety;
- Mis-orientation from excessive transverse forces that may result in pole tilting as well as "stretching" (i.e. loosening) and breaking of guys and guying systems;
- Burning from conductor faults and insulator flashovers may damage the wood poles reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire incidents;
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter; and
- Various types of wood rot in possible locations visually seen by the inspector.

Table 3-3 is used to translate visual inspection results into a condition rating.

Table 3-3: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Pole is in "as new" condition
B	Pole has normal wear expected with age
C	Pole has many minor problems or a major problem that requires close attention and monitoring
D	Pole has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Pole requires immediate replacement

Additionally, OPUCN inspects the component hardware found on poles. Incorporating the component hardware as a criterion to determine the Health Index of the pole is in alignment to OPUCN's asset management practices to assist in identifying deficiencies or non-standard hardware on poles that can be easily corrected.

Degradation of reduction in strength of insulator hardware may occur due to the following:

- Loss of galvanization and corrosion of steel members;
- Loss in strength due to fatigue;
- Loosening of hardware due to conductor vibrations; or
- Hardware failure during major storm events.

Close-up visual inspection can generally determine the extent of degradation. Different components of the pole line, including cross-arms, hardware, insulators and pole grounding are visually inspected by qualified staff during line patrols. By considering the results of these inspections, the health and condition of each component is scored in accordance with Table 3-4.

Table 3-4: Criteria for Component Condition

Condition Rating	Corresponding Condition
A	Component is in "as new" condition
B	Component has normal wear expected with age
C	Slight deficiencies visible on component
D	Moderate deficiencies visible on component
E	Extensive deficiencies visible on component

Since the rate of pole degradation is affected by the effectiveness of the preservative treatment, wood pole treatment is employed within the Health Index formulation. Table 3-5 is used to translate the wood pole's treatment to a condition rating.

Table 3-5: Criteria for Pole Treatment

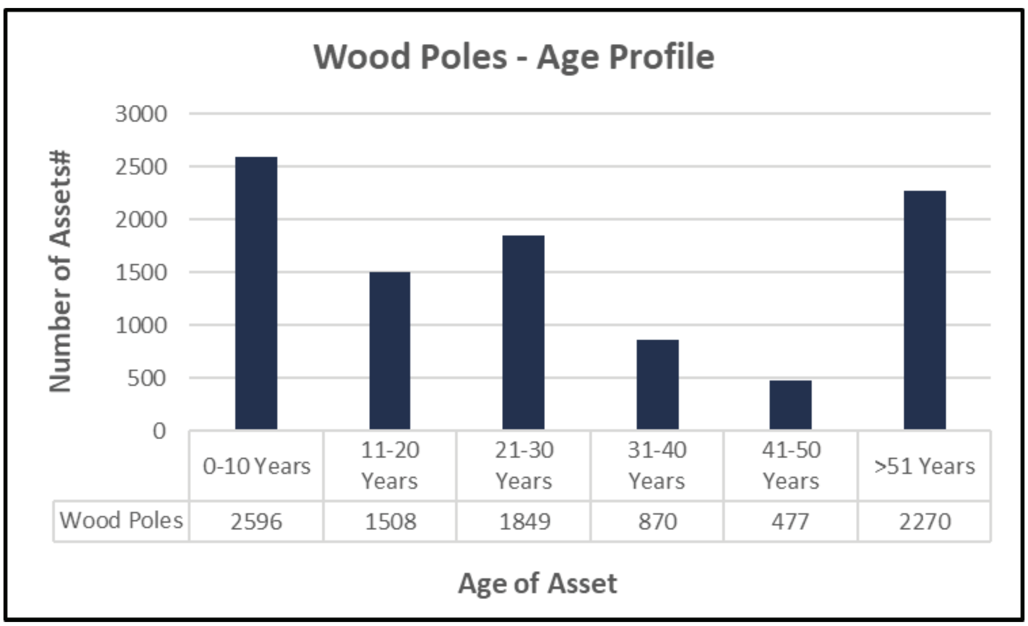
Condition Rating	Corresponding Condition
A	Fully treated
C	Butt treated
E	No treatment

3.1.1.2 Results of Analysis

Age Assessment

OPUCN currently owns 9570 wood poles in-service within its service territory. Figure 3.1 presents the age distribution. Through discussion with OPUCN, OPUCN believes poles with an unknown installation year are assumed to be 51 years or older. This accounts for 2.3% of total OPUCN poles. Asset service age is currently calculated with end year 2017.

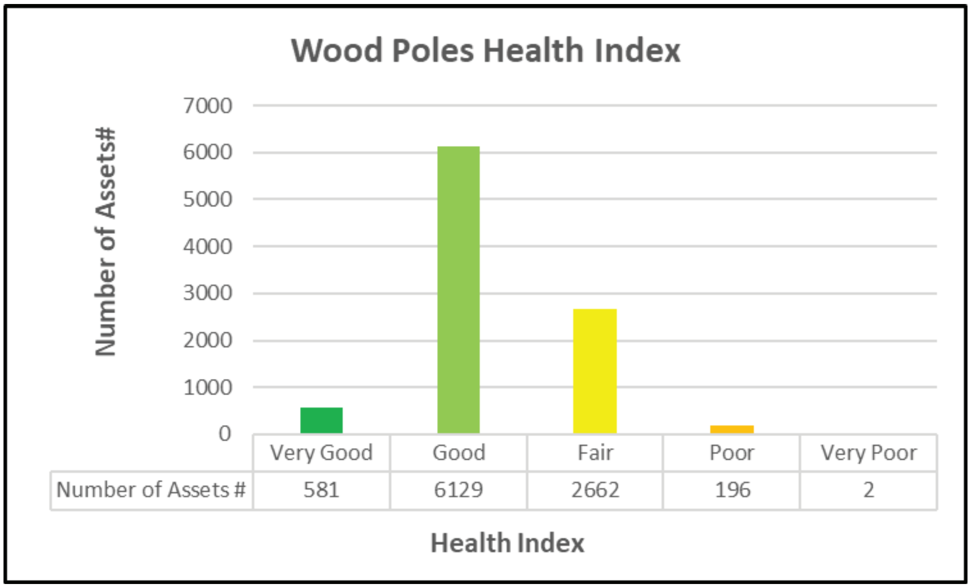
Figure 3.1: Wood Pole Age Demographic



Condition Assessment

OPUCN's pole inspections were completed by a third-party contractor and the results were used to calculate the Health Index based on the criteria provided in Table 3-1. The Health Index values were calculated for each wood pole asset using the best available data. The overall Health Index distribution is presented in Figure 3.2. In this analysis, wood poles with an unknown age have received a rating of "E" for service age.

Figure 3.2: Wood Pole Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for wood pole data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.2 Concrete and Steel Pole

3.1.2.1 Condition Assessment Methodology

Computing the Health Index of a concrete pole requires developing end-of-life criteria. Each criterion represents a factor in determining the asset's condition. The Health Index for concrete and steel poles is calculated by considering a combination of visual deficiencies and service age. The best available data is considered for the Health Index calculations within this ACA. Table 3-6 summarizes the methodology to combine these criteria into an overall Health Index for concrete and steel poles.

Table 3-6: Concrete and Steel Poles Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	8	A,B,C,D,E	5,4,3,2,1	40
2	Defects/Overall Condition	8	A,B,C,D,E	5,4,3,2,1	40
3	Out of Plumb	4	A,B,C,D,E	5,4,3,2,1	20
				MAX SCORE	**100**

Table 3-7 and Table 3-8 is used to translate service age into a condition rating. Since service age provides a reasonably good measure of the remaining life of the asset, it is employed as an assessment parameter.

Table 3-7: Criteria for Service Age – Steel Pole

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 40 years
D	41 to 50 years
E	Over 50 years or Unknown

Table 3-8: Criteria for Service Age - Concrete Pole

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 40 years
D	41 to 50 years
E	Over 50 years or Unknown

Different components of concrete and steel poles are visually inspected by qualified staff during line patrols. OPUCN inspects a number of components and utilizes a four-level grading system: Good, Fair, Fair-Poor, Poor. Table 3-9 is used to translate visual inspection into a condition rating. Table 3-10 is used to translate the concrete and steel pole components inspection results to a condition rating.

Table 3-9: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Pole is in “as new” condition
B	Pole has normal wear expected with age
C	Pole has many minor problems or a major problem that requires close attention and monitoring
D	Pole has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed or is replaced within a few years
E	Pole requires immediate replacement

Table 3-10: Criteria for Out of Plumb Condition

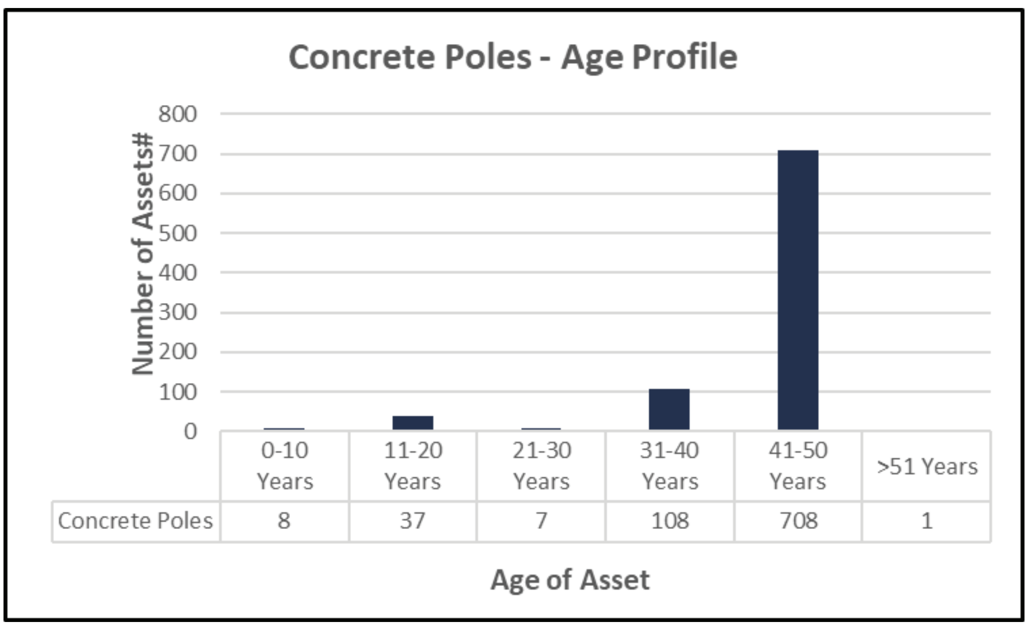
Condition Rating	Corresponding Condition
A	Pole in "as new" condition
B	Pole has normal wear expected with age
C	Pole out of Plumb - Slight
D	Pole out of Plumb - Moderate
E	Pole out of Plumb - Extensive

3.1.2.2 Results of Analysis

Age Assessment

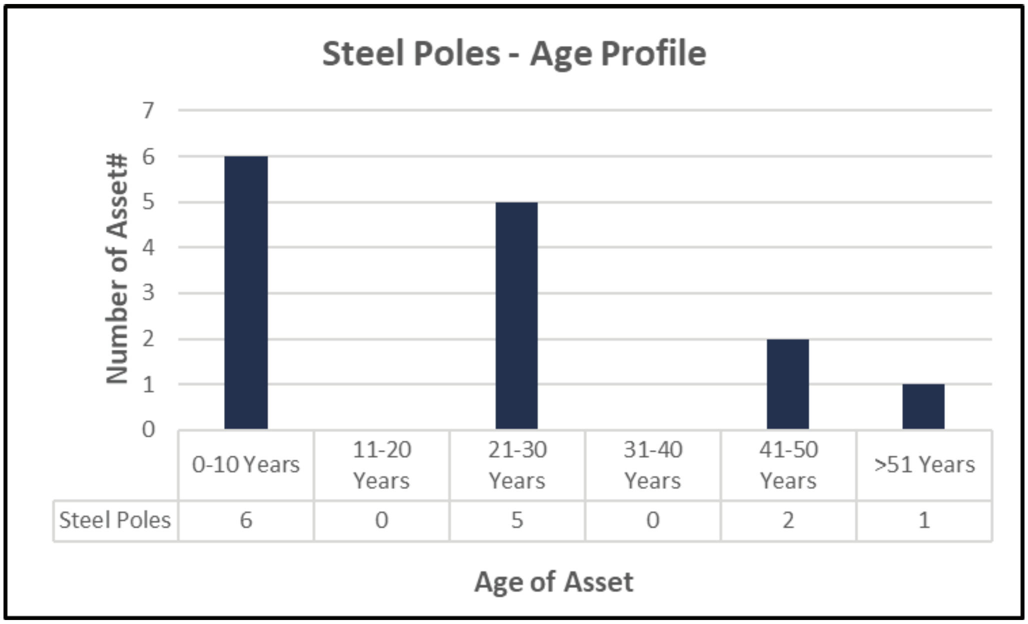
OPUCN owns 869 concrete poles in-service within its service territory. Figure 3.3 presents the age distribution for concrete poles. Asset service age is currently calculated with end year 2017.

Figure 3.3: Concrete Pole Age Demographic



OPUCN owns 14 steel poles in-service within its service territory. Figure 3.4 presents the age distribution for steel poles. Asset service age is currently calculated with end year 2017.

Figure 3.4: Steel Pole Age Demographic



Condition Assessment

OPUCN's pole inspections were used to calculate the Health Index based on the criteria provided in Table 3-6. The Health Index values were calculated for each concrete and steel pole asset. The overall Health Index distribution is presented in Figure 3.5 and Figure 3.6.

Figure 3.5: Concrete Pole Health Index Demographic

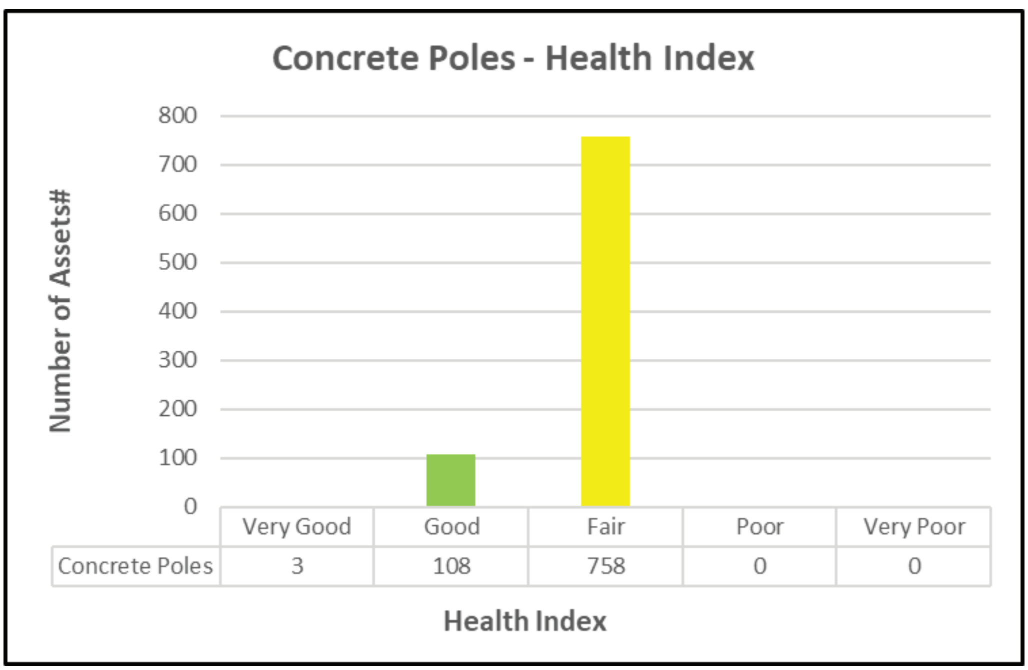
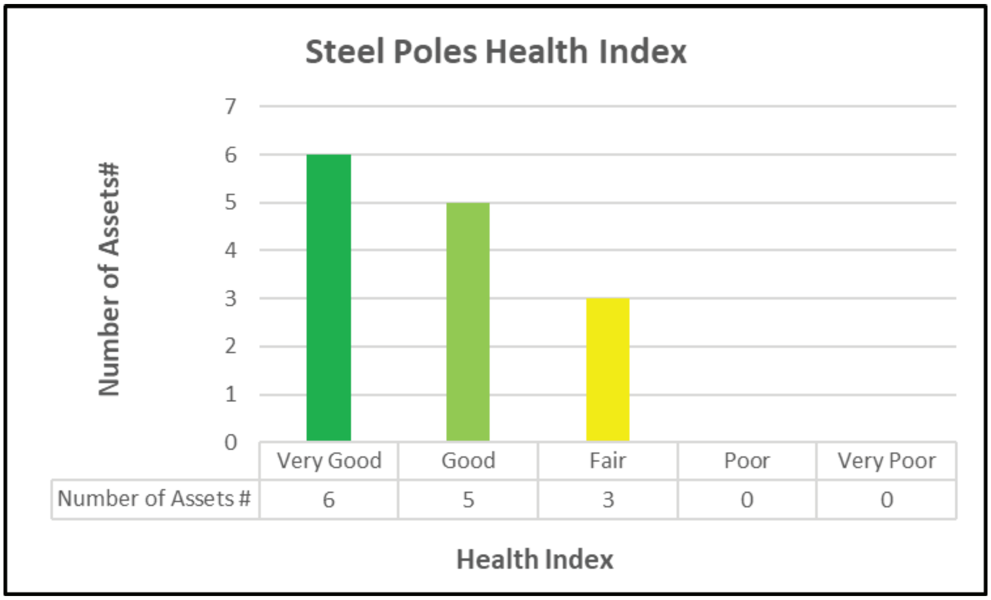


Figure 3.6: Steel Pole Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for concrete and steel pole data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.3 Overhead Primary Conductor

3.1.3.1 Condition Assessment Methodology

Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. As a general observation, overhead primary conductors on distribution lines often outlive the poles and are not usually on the critical path to determine the end of life for a line section.

The only exception to the above rule might be where small copper conductors susceptible to frequent breakdowns are in use, or where line conductors are too small for line loads resulting in suboptimal system operation due to high line losses.

The Health Index for overhead primary conductors is calculated by considering a combination of service age and small conductor risk. The best available data is considered for the Health Index calculations within this ACA. Table 3-11 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-11: Overhead Primary Conductor Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Small Conductor Risk*	10	A,E	5,0	50
				MAX SCORE	**100**

**Note: If Small Conductor Risk is present, the Health Index is divided by two to highlight the high risk of asset failure and condition.*

The service age provides a reasonably good measure of the remaining strength of conductors with the lack of visual inspection for cable defects. Table 3-12 is used to translate service age into a condition rating.

Table 3-12: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 50 years
D	51 to 70 years
E	71 years and older

Historical performance of small-sized conductors has exhibited a high safety concern to the public observed in multiple utilities across Ontario. Furthermore, the small-sized conductors do not align to the current best practice and industry standards for overhead conductor installation. Since small-sized conductors sometimes pose a serious safety risk, the value of this criteria is scored separately, presented in Table 3-13.

Table 3-13: Criteria for Small Size Conductor Risk

Condition Rating	Corresponding Condition
A	Absence of small sized conductors
E	Presence of small sized conductors (#4 to #6 copper)

3.1.3.2 Results of Analysis

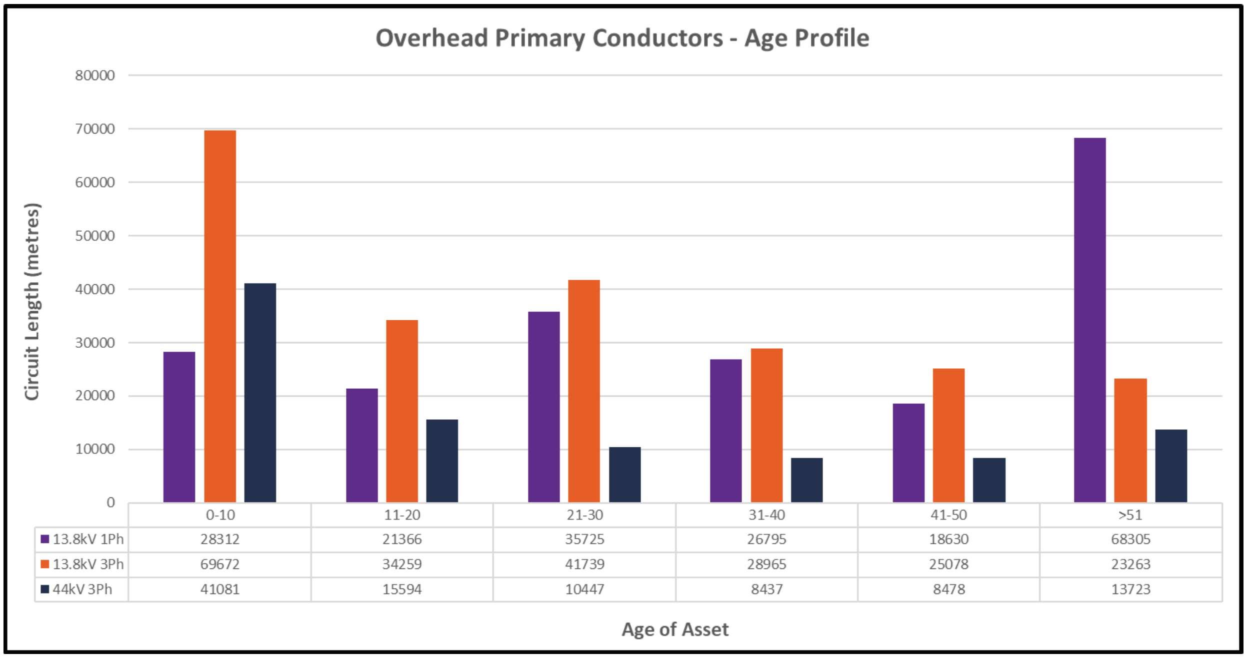
Age Assessment

OPUCN owns approximately 520 km of overhead primary conductors within its service territory. For overhead primary conductors with unknown service age, OPUCN applied two assumptions on the service age of the asset:

1) utilize the neighboring asset information within a 10-meter distance mapping to the oldest age of the poles (this accounts for 247kms or 47% of OPUCN total overhead conductors); and

2) where it was not possible to determine the age of the conductors by using neighboring asset information, the age of the conductor asset is fixed to 40 years old (this accounts for 24kms or 4.6% of OPUCN total overhead conductors). Figure 3.7 presents the age distribution for each major system voltage. Asset service age is currently calculated with end year 2017.

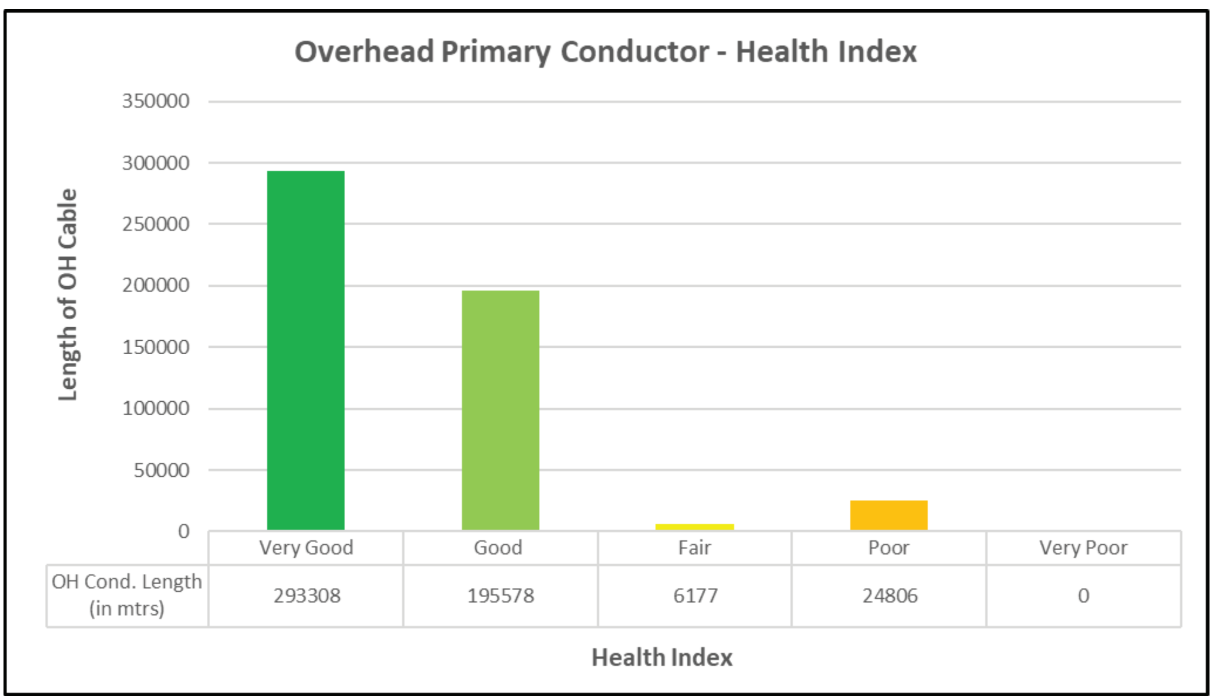
Figure 3.7: Overhead Primary Conductor Age Demographic



Condition Assessment

OPUCN's 2017 GIS conductor data was used to calculate the Health Index based on the criteria provided in Table 3-11. The overall Health Index distribution is presented in Figure 3.8.

Figure 3.8: Overhead Primary Conductor Health Index Demographic



Overhead Conductor Quick Sleeves

Sleeves are used to splice overhead primary conductor lines for circuit separation and for connecting two different primary conductor materials which are adjacent. OPUCN employs two types of sleeves: quick sleeves and compression sleeves. The jaws found in the quick sleeve clamp down on the primary conductors as tensile stress is applied to hold conductor wires together.. However, they may not last the entire life of the conductors they are installed on, as demonstrated by the failures. Compression sleeves are used as permanent splices in distribution systems. Compression sleeves are built to last for the entirety of the conductor's life, reducing the probability of potentially falling from an energized line. Compression sleeve integrity depends on several factors:

- Proper cleaning and roughening of the conductor strands
- Proper centering of the inner core within the sleeve
- Appropriate use of corrosion inhibitor

There are approximately 90 compression sleeves and 100 quick sleeves on 44kV primary overhead conductor lines in the OPUCN network, however, the total number of sleeves on the 13.8kV network is currently unknown.

Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for overhead primary conductor data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.4 Underground Primary Cable

3.1.4.1 Condition Assessment Methodology

Distribution underground primary cables are among the more challenging assets on electricity systems from a condition assessment and asset management perspective. Although test techniques such as partial discharge testing have become available over the recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The adopted approach to managing cable systems has been to monitor cable failure rates and quantify the potential failure impact. The failure impacts of the cables are monetized in relation to (but not limited to) reliability, safety, environment, and operations. When the costs associated with in-service failures become higher than the annualized cost of cable replacement, the cables are then determined to be at their end of their economic useful life and should be replaced.

The Health Index for underground primary cable is calculated by considering the service age and the evidence of historic failures. The best available data is considered for the Health Index calculations within this ACA. Table 3-14 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-14: Underground Primary Cable Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	11	A,B,C,D,E	5,4,3,2,1	55
2	Historic Rates of Circuit Failures	9	A,B,C,D,E	5,4,3,2,1	45
				MAX SCORE	**100**

The service age provides a reasonably good measure of the remaining strength of conductors with the lack of visual inspection for cable defects. Table 3-15 is used to translate age into a condition rating. Table 3-16 is used to translate historical failure rates of underground primary cable on each circuit within the last 5 years.

Table 3-15: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 25 years
C	26 to 35 years
D	36 to 45 years
E	46 years and older

Table 3-16: Criteria for Historic Failure Rates

Condition Rating	Corresponding Condition
A	Less than 0.5 failure per 10 km in the last 5 years
B	0.5 to 1.0 failure per 10 km in the last 5 years
C	1.0 to 1.5 failures per 10 km in the last 5 years
D	1.5 to 2.0 failures per 10 km in the last 5 years
E	2.5 or more failures per 10 km in the last 5 years

3.1.4.2 Results of Analysis

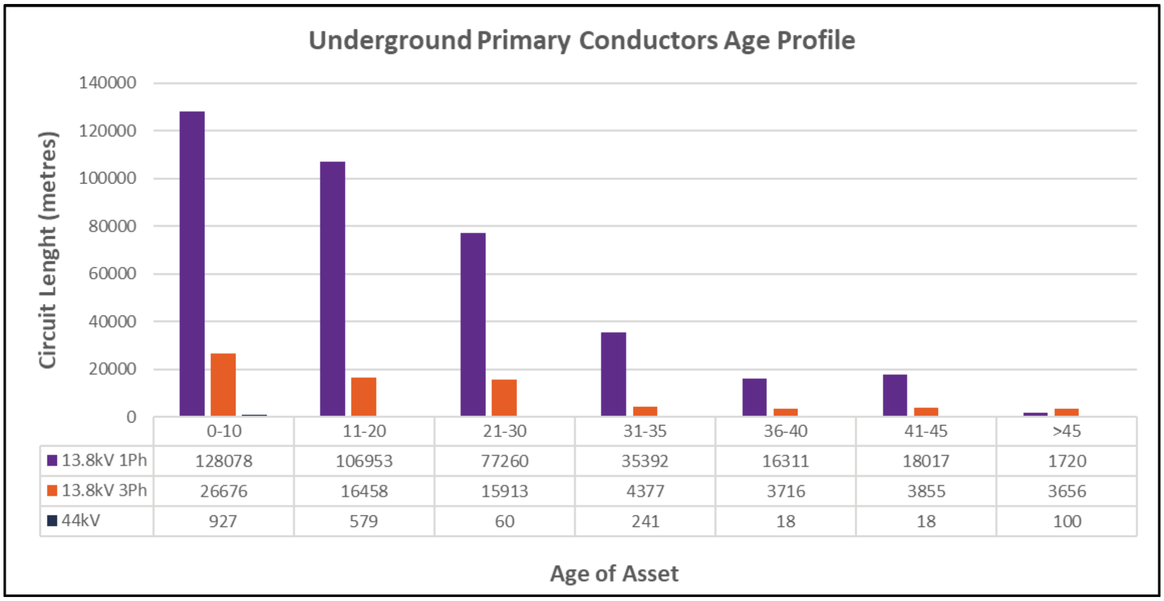
Age Assessment

OPUCN owns approximately 460.3 km of underground primary cable within its service territory. For the underground primary cables with unknown service age, OPUCN applied two assumptions on the service age:

1) utilize the neighboring asset information within a 10-meter distance mapping to the oldest age (this accounts for 5.5kms or 1.2% of OPUCN total underground cable); and

2) where it was not possible to determine the age of the conductors by using neighboring asset information, the age of the conductor asset is fixed to 25 years old (this accounts for 15kms or 3.3% of OPUCN total underground cable). Figure 3.9 presents the age distribution by system voltage. Asset service age is currently calculated with end year 2017.

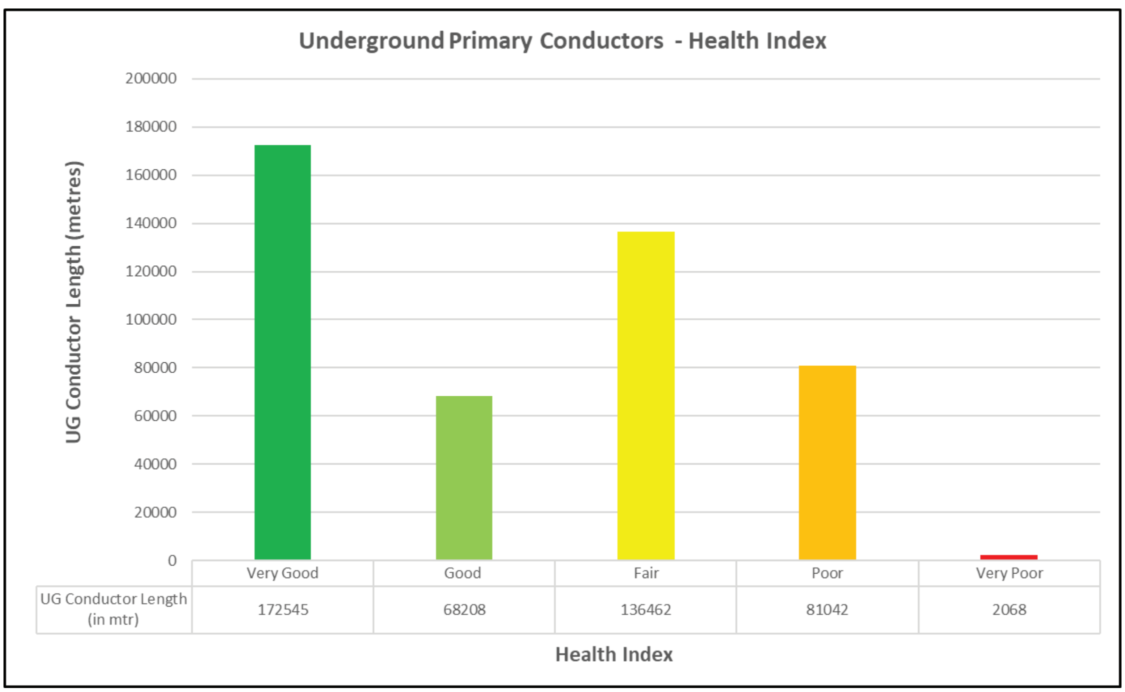
Figure 3.9: Underground Primary Cable Age Demographic



Condition Assessment

OPUCN's 2017 GIS conductor data was used to calculate the Health Index based on the criteria provided in Table 3-14. The overall Health Index distribution is presented in Figure 3.10 for each major system voltage.

Figure 3.10: Underground Primary Cable Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for underground primary cable data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.5 Distribution Transformer

Four types of distribution transformers are assessed within this report:

- Pad mounted transformer
- Pole mounted transformer
- Submersible transformer
- Vault transformer

3.1.5.1 Condition Assessment Methodology

Generally, utilities replace distribution transformers as part of overhead or underground rebuild projects or when they are assessed as having a high risk of failure. Within the industry, apart from rust proofing, painting of the tanks, replacing a damaged bushing or repairing a leaky gasket, very little invasive preventative maintenance or testing is carried out on distribution transformers.

The Health Index for distribution transformers is calculated by considering a combination of service age, overall condition and loading history. The best available data is considered for the Health Index calculations within this ACA. Table 3-17 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-17: Distribution Transformers Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	6	A,B,C,D,E	5,4,3,2,1	30
2	Overall Condition	8	A,B,C,D,E	5,4,3,2,1	40
3	Peak Loading	6	A,B,C,D,E	5,4,3,2,1	30
				MAX SCORE	**100**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, Table 3-18.

Table 3-18: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years and older

A visual inspection includes the following data entries:

- Presence of oil leaks
- Condition of cable terminations
- Presence of rust

Table 3-19 presents the condition rating based on the outstanding visual inspection issues for the distribution transformers. Additionally, the peak load in relation to the transformers rating can be utilized to assess the transformers' condition. A transformer exposed to longer durations or frequent peak loads above the manufacturer's rating will promote accelerated degradation of the transformer's internal components. Table 3-20 provides the condition rating based on loading level.

Table 3-19: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad-mounted transformers
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects

Table 3-20: Criteria for Peak Loading

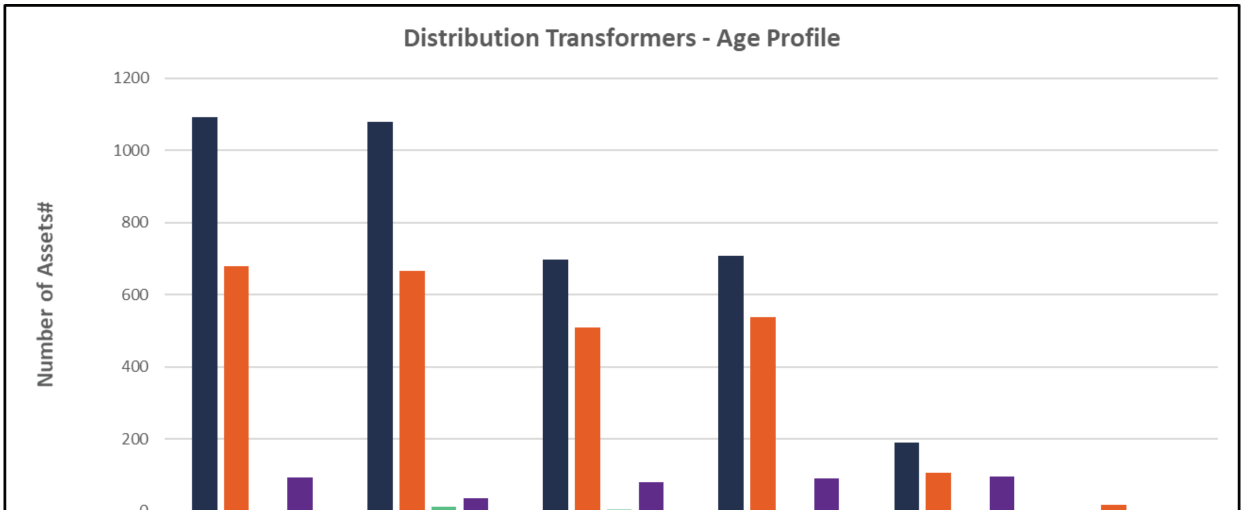
Condition Rating	Corresponding Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peal load of greater than 125% of its rating

3.1.5.2 Results of Analysis

Age Assessment

OPUCN owns 3765 pad mount transformers, 2513 pole mount transformers, 20 submersible transformers and 394 vault transformers within its service territory. For transformers with no known install dates, OPUCN applies the following assumptions in priority to back-fill the service age: date asset was received, manufacturer date. Figure 3.11 presents the age distribution by transformer types. Asset service age is currently calculated with year-end 2017.

Figure 3.11: Distribution Transformer Age Demographic



	0-10	11-20	21-30	31-40	41-50	>51
PADMOUNT	1092	1078	697	707	190	1
POLEMOUNT	679	666	508	537	105	18
SUBMERSIBLE	0	13	3	2	1	1
VAULT	92	35	81	90	96	

Condition Assessment

OPUCN's 2017 transformer inspections records and 2014 peak loading data was used to calculate the Health Index based on the criteria provided in Table 3-17. For transformers with peak loading percentage greater than 100% that require further analysis and data confirmation, OPUCN applies an assumption of a condition score of "D" to be assigned for the parameter peak loading. This accounts for 5% of the total OPUCN distribution transformers. The overall Health Index distribution is presented in Figure 3.12 to Figure 3.15 for each transformer type.

Figure 3.12: Pad Mount Transformer Health Index Demographic

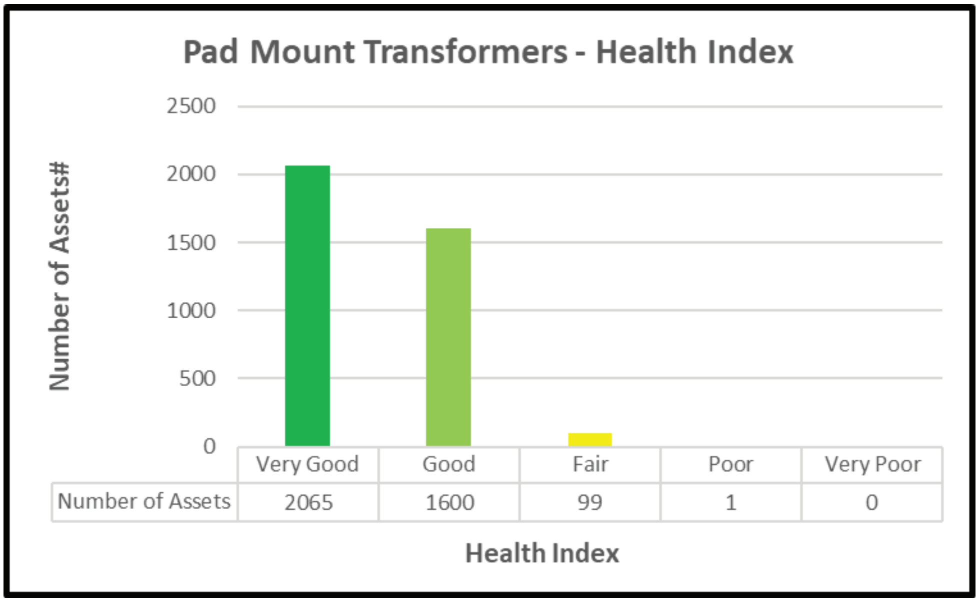


Figure 3.13: Pole Mount Transformer Health Index Demographic

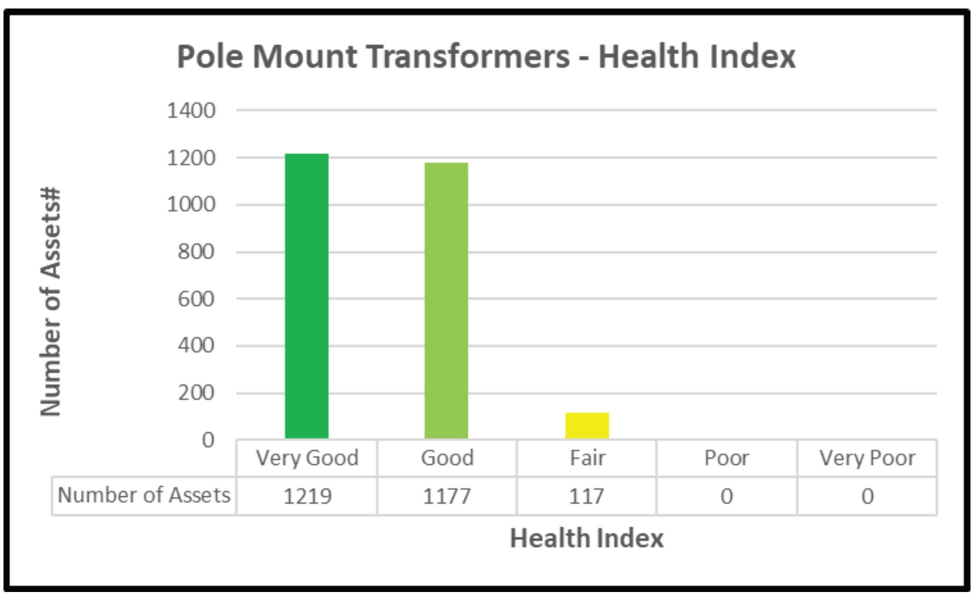


Figure 3.14: Submersible Transformer Health Index Demographic

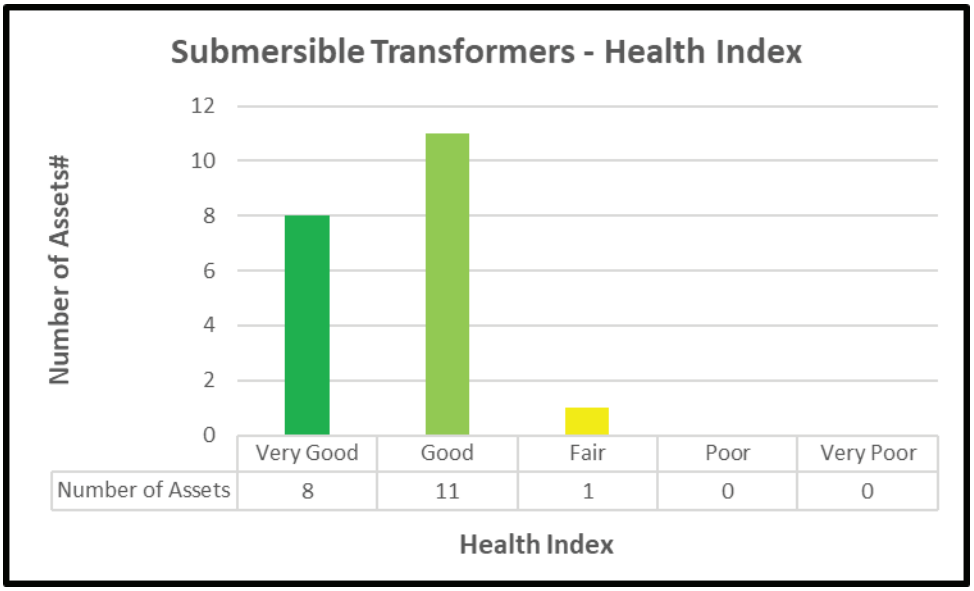
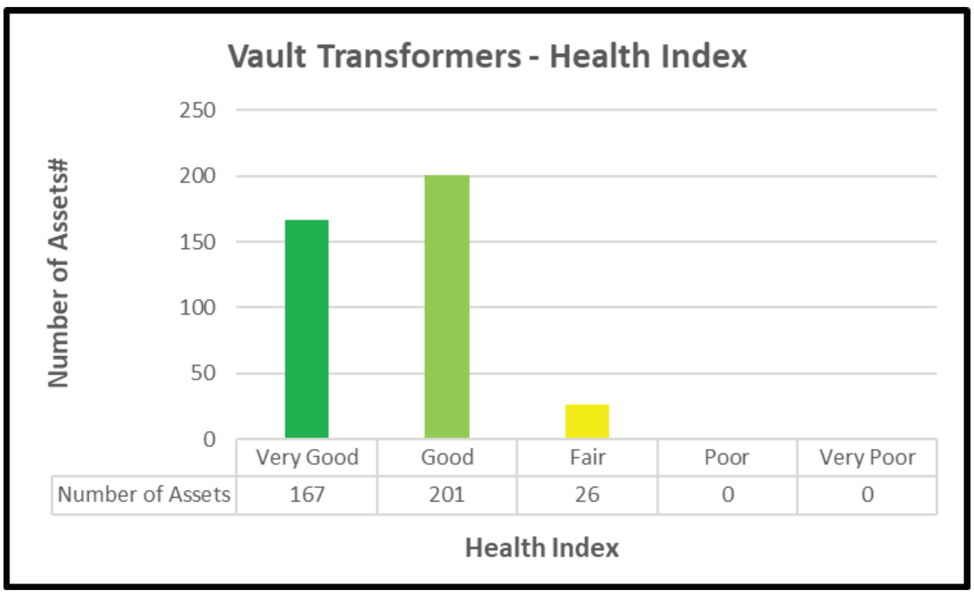


Figure 3.15: Vault Transformer Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for transformer data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.6 Primary and Smart Switch

3.1.6.1 Condition Assessment Methodology

Disconnect switches provide the means of load disconnection and isolation for equipment, such as underground laterals or distribution transformers. The Health Index for primary and smart switches is calculated by considering a combination of service age and visual inspections for defects. The best available data is considered for the Health Index calculations within this ACA. Table 3-21 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-21: Primary and Smart switch Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Overall Condition	10	A,B,C,D,E	5,4,3,2,1	50
				MAX SCORE	**100**

Since the service age provides a reasonably good measure of the remaining life of switches, it is employed as an assessment parameter, shown in Table 3-22.

Table 3-22: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Visual inspections can provide a good indication of the physical condition of switches and are graded using Table 3-23.

Table 3-23: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust and corrosion, operating mechanism in excellent condition and no hotspot detected
B	Only minor wear, no defects, or minor hotspot detected
C	No more than one of the above indicated defects present but does not impact safe operation or Intermediate hotspot detected
D	Two or more of above indicated defects, but they can be repaired, or serious hotspot detected
E	Two or more of the above indicated defects, but they cannot be repaired, or critical hotspot detected

3.1.6.2 Results of Analysis

Age Assessment

OPUCN owns a total of 1001 primary switches and 15 smart switches within its service territory. For primary switches with no known install dates, OPUCN applies the assumption that the assets are fixed to age 30, which accounts for 16% of OPUCN total primary switches. Figure 3.16

presents the age distribution for primary switches, and Figure 3.17 presents the age distribution for smart switches. Asset service age is currently calculated with end year 2017.

Figure 3.16: Primary Switch Age Demographic

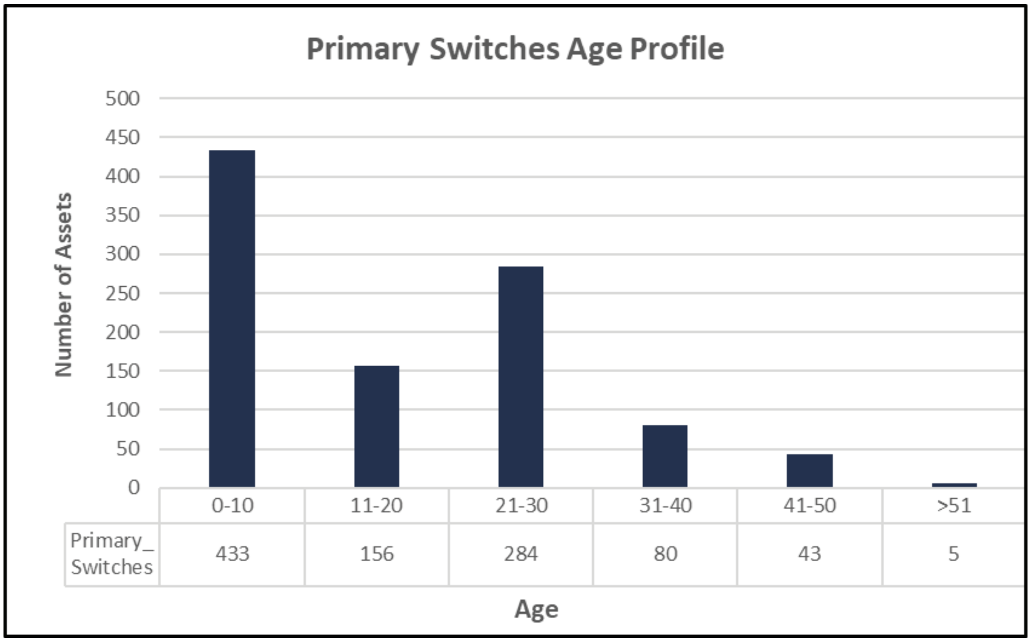
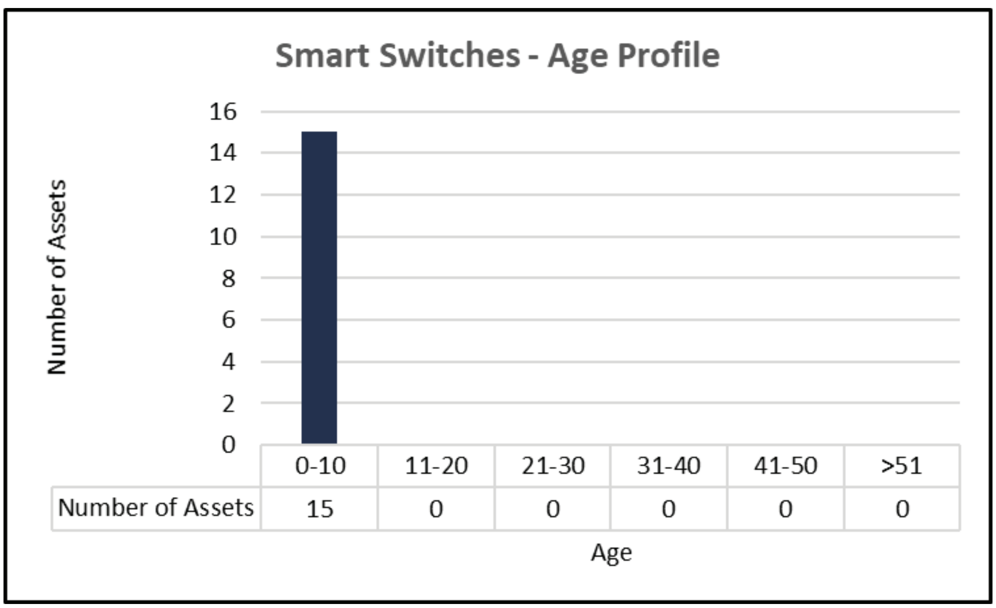


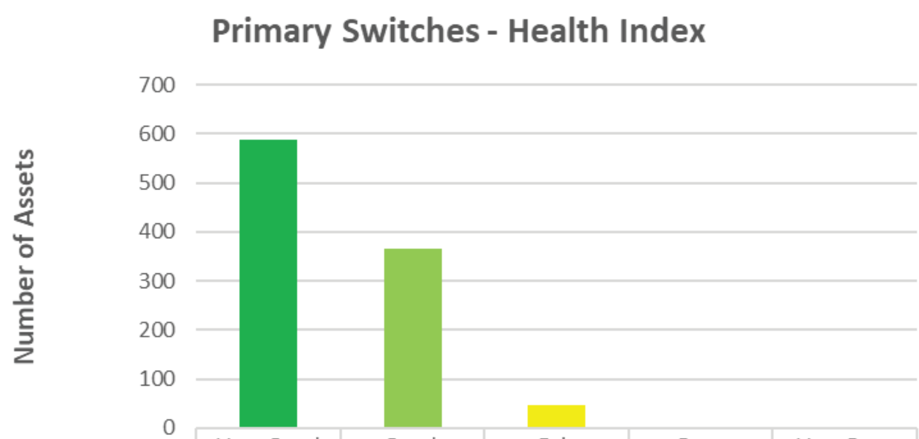
Figure 3.17: Smart Switch Age Demographic



Condition Assessment

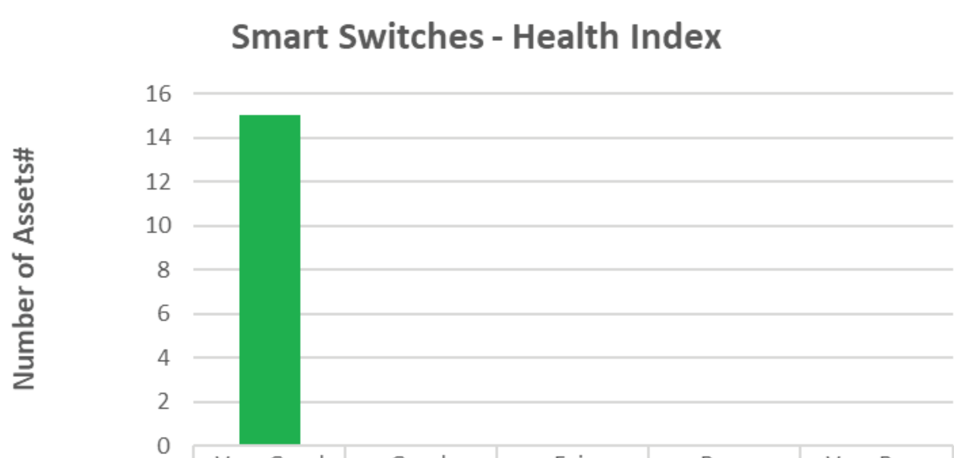
OPUCN's 2017 switch visual inspections was used to calculate the Health Index based on the criteria provided in Table 3-21. The Health Index values were calculated for each asset with best available data. The overall Health Index distribution is presented in Figure 3.18 for primary switches and Figure 3.19 for smart switches.

Figure 3.18: Primary Switch Health Index Demographic



	Very Good	Good	Fair	Poor	Very Poor
Primary Switches	588	365	48	0	0

Figure 3.19: Smart Switch Health Index Demographic



	Very Good	Good	Fair	Poor	Very Poor
Smart_Switches	15	0	0	0	0

Data Assessment

The Data Availability Indicator (DAI) is created to measure the current collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for switch data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.7 Switchgear

3.1.7.1 Condition Assessment Methodology

Switchgear is the second major sub-class of the switch asset group in OPUCN. OPUCN's asset management continues to manage the asset's risk of failure through regular visual inspections. The Health Index for switchgears, both pad and vault sub-types, is calculated by considering end of life criteria. Table 3-24: summarizes the methodology to generate the assets Health Index. Table 3-25: to Table 3-27: provide the criteria condition rating breakdown for switchgears.

Table 3-24: Switchgear Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	7	A,B,C,D,E	5,4,3,2,1	35
2	Component Overall Condition	9	A,B,C,D,E	5,4,3,2,1	45
3	Condition of Pad	4	A,C,E	5,3,1	20
				MAX SCORE	**100**

Table 3-25: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-26: Criteria for Component Overall Condition

Condition Rating	Corresponding Condition
A	No rust and corrosion, operating mechanism in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation or Intermediate hotspot detected
D	Two or more of above indicated defects, but they can be repaired.
E	Two or more of above indicated defects, but they cannot be repaired.

Table 3-27: Criteria for Condition of Pad

Condition Rating	Corresponding Condition
A	Condition of the pad is in excellent condition
C	Condition of the pad is in fair condition
E	Condition of the pad is in worst condition

3.1.7.2 Results of Analysis

Age Assessment

OPUCN owns 20 vault switchgears and 13 pad mount switchgears for a total of 33 in-service switchgears. Figure 3.20 and Figure 3.21 presents the age profile for vault and padmount switchgears, respectively.

Figure 3.20: Vault Switchgear Age Demographic

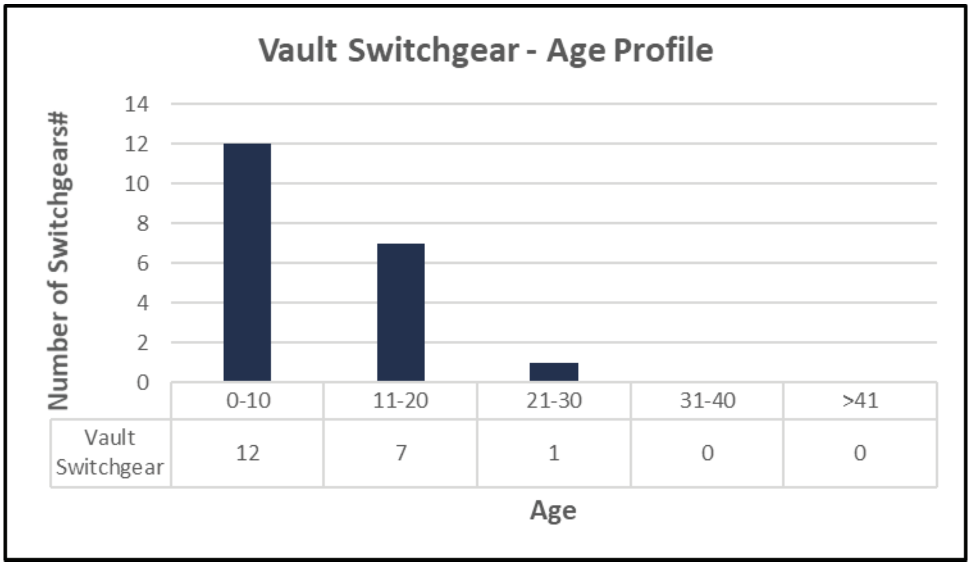
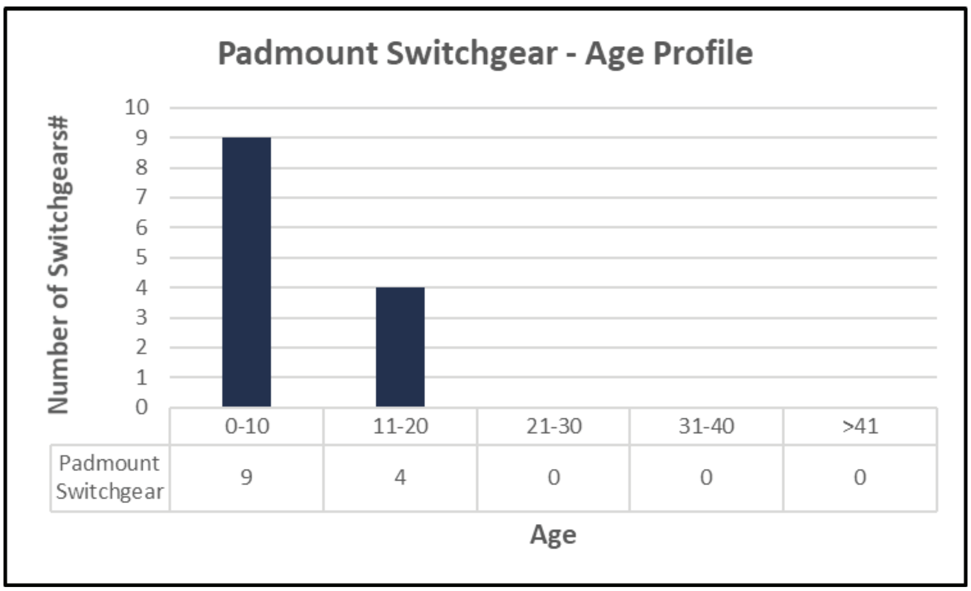


Figure 3.21: Padmount Switchgear Age Demographic



Condition Assessment

OPUCN's 2017 switchgear data was used to calculate the Health Index based on the end of life criteria identified. The overall Health Index distribution is shown in Figure 3.22 and Figure 3.23

for vault and padmount switchgears, respectively. OPUCN manages the failure risk through its maintenance programs and remedy actions. Currently, there are no in-service switchgears that are critical or at-risk of failing on the basis of data assessment.

Figure 3.22: Vault Switchgear Health Index Demographic

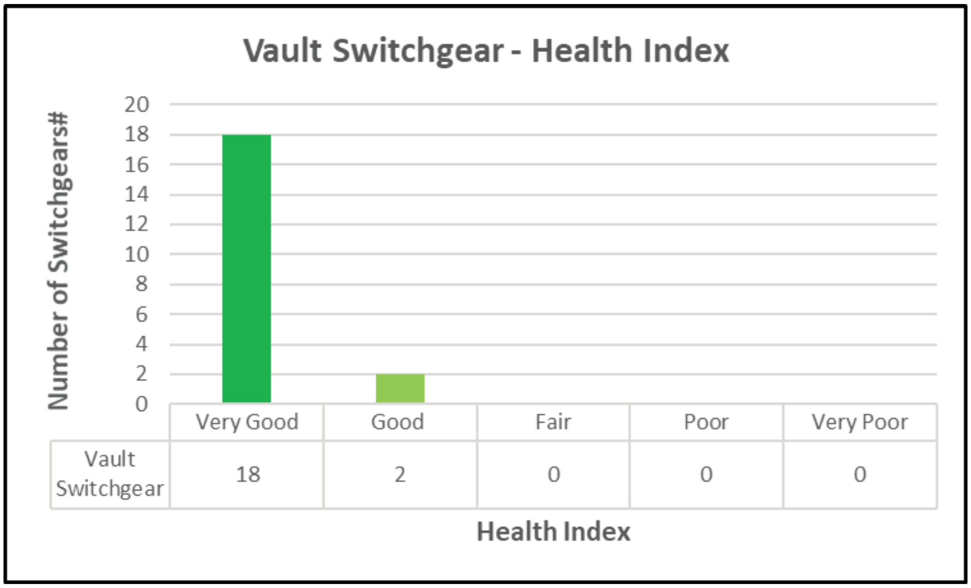
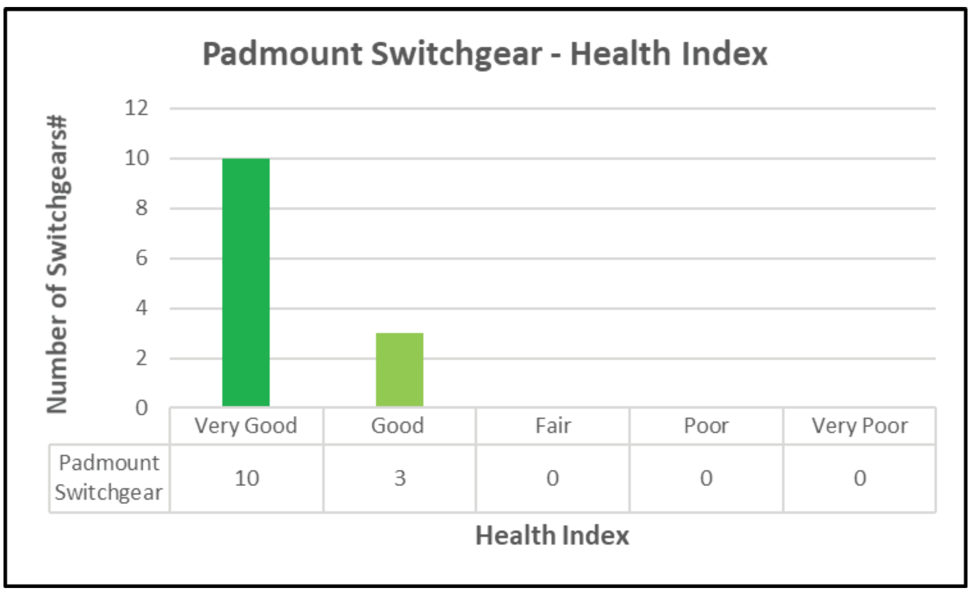


Figure 3.23: Padmount Switchgear Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonably collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. For the given asset class and attributes collected to date, the DAI is 100% with assumptions applied.

Section 4.0 provides additional recommendations for data collection for HI calculation improvement.

3.1.8 Cut-Out Arrestor and Insulator

3.1.8.1 Condition Assessment Methodology

The Health Index for cut-out arrestors is calculated by considering a combination of visual inspection records and service age. The best available data is considered for the Health Index calculations within this ACA. Table 3-28 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-28: Cut-out Arrestor Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Overall Condition	2	A,B,C,D,E	5,4,3,2,1	10
2	Service Age	8	A,B,C,D,E	5,4,3,2,1	40
3	Type of Material*	10	A,E	5,1	50
				MAX SCORE	**100**

**Note: If Type of Material is rated as 'E', the Health Index is divided by two to highlight the risk of unfavorable asset conditions. Furthermore, if Type of Material is rated as 'A', the Health Index Formulation readjusts to the former two condition criteria. See Table 3-31.*

Visual inspections are performed for cut-out arrestors, checking for the following items:

- Rust/Corrosion presence and/or contamination of insulator surface
- Damage to bushings
- Condition of operating mechanism and blades

In addition to the visual inspections, OPUCN undertakes Infrared (IR) Scans. Table 3-29 presents the condition rating based on the observed visual inspection deficiencies, including IR scan results. Since the service age provides a reasonably good measure of the remaining life of cut-out arrestors, it is employed as an assessment parameter, shown in Table 3-30.

Table 3-29: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust or corrosion, operating mechanism and in excellent condition and no hotspot detected.
B	Only minor wear and no defects or minor hotspot detected.
C	No more than one of the above indicated defects present but does not impact safe operation or Intermediate hotspot detected.
D	Two or more of above indicated defects, but they can be repaired, or serious hotspot detected.
E	Two or more of the above indicated defects, but they cannot be repaired, or critical hotspot detected.

Table 3-30: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-31: Criteria for Type of Material

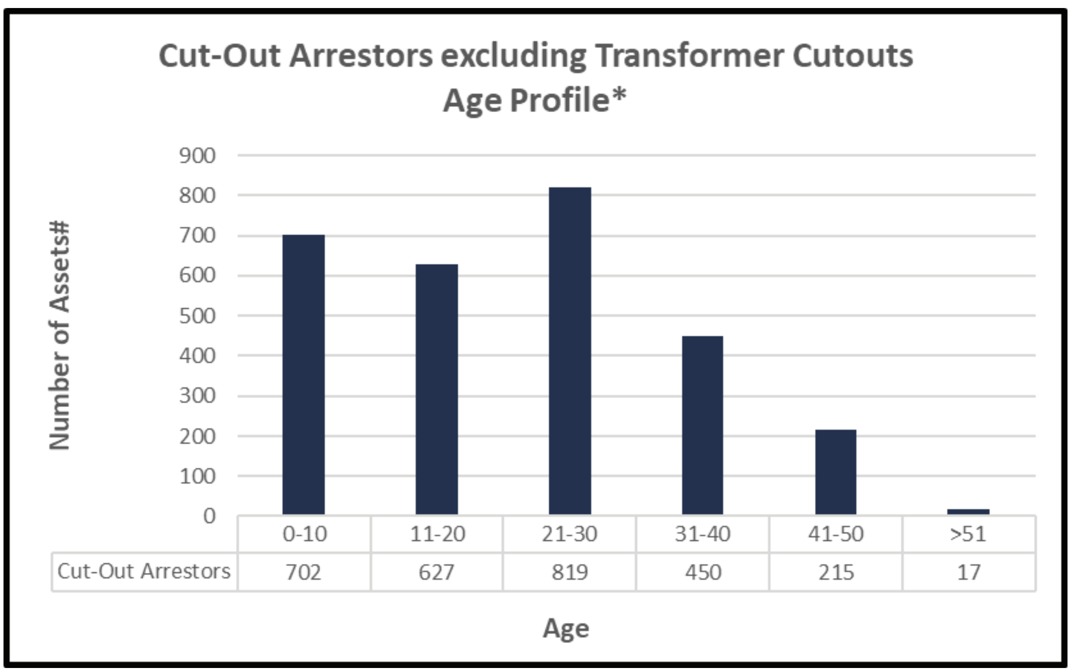
Condition Rating	Corresponding Condition
A	Polymer Cut-out Arrestor
E	Porcelain Cut-out Arrestor

3.1.8.2 Results of Analysis

Age Assessment

Based on current records and best available information, OPUCN identified 2830 cut-out arrestors and 3083 transformer cut-outs within its service territory. For the cut-out arrestors with unknown service ages, OPUCN applied the assumption of assigning a fixed age of 30 (~6% of total population). Figure 3.24 presents the age distribution. Asset service age is currently calculated with year-end 2017. Furthermore, the total number of OPUCN porcelain insulators is approximately 1726.

Figure 3.24: Cut-Out Arrestor Age Demographic

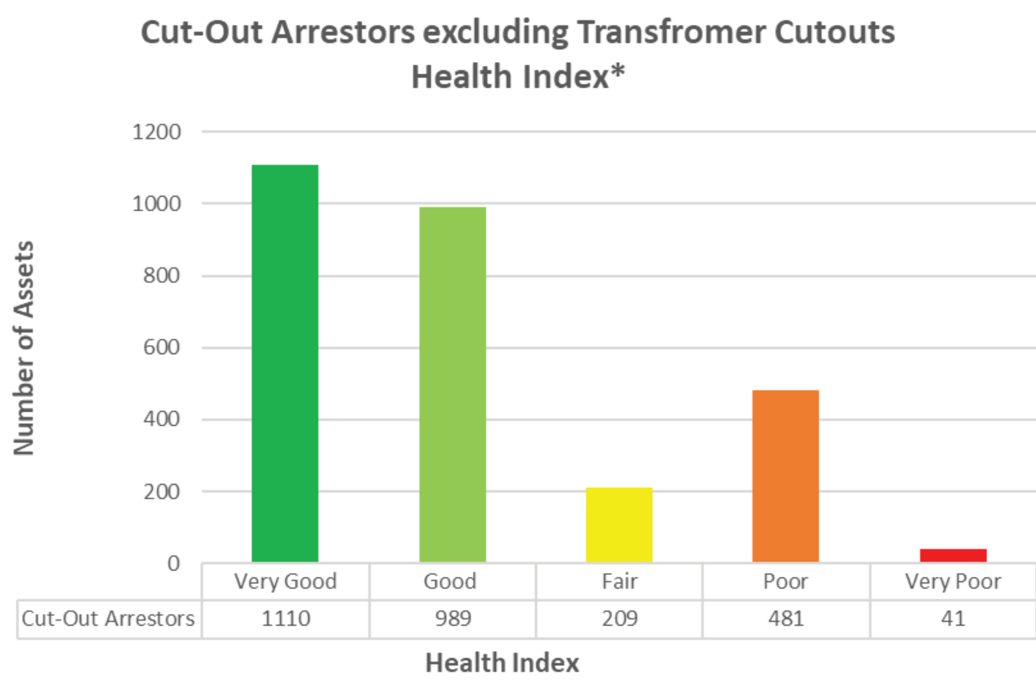


*This data includes approximately 540 porcelain riser cut-out arrestors (approximately 19% of the total OPUCN cut-out arrestors) excluding transformer cut-outs. The ages are best estimates by OPUCN subject matter experts.

Condition Assessment

OPUCN's 2017 visual inspection and IR scan data was used to calculate the Health Index based on the criteria provided in Table 3-28. The Health Index values were calculated for each asset with best available data. The overall Health Index distribution is presented in Figure 3.25.

Figure 3.25: Cut-Out Arrestor Health Index Demographic



	Very Good	Good	Fair	Poor	Very Poor
Cut-Out Arrestors	1110	989	209	481	41

*This data includes approximately 540 porcelain riser cut-out arrestors excluding transformer cut-outs, where OPUCN has categorized the assets as "Poor" or "Very Poor" condition based on the type of material, visual inspection and due to the number of failures in the field. The information for the porcelain cut-outs is best estimates by OPUCN's subject-matter experts.

Overhead Fuse Cut-Outs & Porcelain Insulators

Fuse cut-outs are pole-mounted switching devices, used to disconnect or reconnect pole mounted equipment to the line, such as distribution transformers or underground laterals. Porcelain insulated cut-outs have been in use in the electrical industry for many decades. Porcelain was also the material of choice for most other electrical equipment that required insulation, such as line insulators, arrestors and bushings. In the early 1980's large numbers of porcelain insulators began failing, particularly in cold climate regions. "Cement growth" (build-up of debris on surface) was causing insulators to crack due to moisture ingress and freeze/thaw cycling. The expansion and contraction of the adhesive interface which joined the porcelain to the hardware (connector) cause stresses on the porcelain. These stresses cause small cracks to appear in the porcelain which eventually lead to an electrical and/or mechanical failure of the porcelain insulator. Cracked porcelain cut-outs can also result in pole fires resulting in more extensive plant replacement.

Transmission insulators and distribution insulators had been the focus of the industry's attention throughout most of the 1980's and 1990's, resulting in expenditure of millions of dollars to rectify the problem of defective porcelain units. During the past several years, many utilities throughout North America have seen increasing failures of their porcelain insulated cut-outs. The mode of failure is very similar to that of insulators. Small cracks in the porcelain initially appear near the interface between the porcelain and hardware. These fractures eventually lead to a mechanical failure of the cut-out. Cement growth is the likely cause of the initial cracks.

The breakage of porcelain insulated cut-outs is a concern from a safety and reliability perspective. During cut-out operation the porcelain can break, causing the cut-out to separate into two parts. This creates a hazard to line personnel operating the cut-out and can cause outages to customers. The common industry solution to this problem has been replacement of porcelain-insulated cut-outs with polymer-insulated cut-outs.

OPUCN has been experiencing repeated failures of porcelain-fused cut-outs during the past several years. Some failures have resulted in electrical failure of the insulation, while other cases the insulator has cracked and broken resulting in pole fires. The failing cut-outs do present a high risk of injury to public or utility employees.

OPUCN has adopted a program beginning before 2014 under which porcelain cut-outs are being systematically replaced with polymer cut-outs to mitigate safety risks. This program will continue until all high-risk porcelain cutouts have been replaced. Currently, of the 2830 riser cut-out arrestors, there are 540 porcelain riser cut-out arrestors, which is approximately 19% of the total OPUCN cut-out arrestors excluding transformer cut-outs assumed. Additionally, there are 1175 porcelain transformer cut-out arrestors, which is approximately 38% of the total OPUCN transformer cut-out arrestors assumed. The information for the porcelain riser cut-outs and porcelain transformer cut-outs is not available in the OPUCN GIS System, however, OPUCN has been actively working on compiling a database since 2014.

3.1.9 Elbow

3.1.9.1 Condition Assessment Methodology

The Health Index for elbows is calculated by considering a combination of visual inspection records and service age. The best available data is considered for the Health Index calculations within this ACA. Table 3-32 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-32: Elbow Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Overall Condition	10	A,B,C,D,E	5,4,3,2,1	50
2	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
				MAX SCORE	**100**

Visual inspections are performed for cutout arrestors, checking for the following items:

- Rust presence
- Visual damage and deficiencies
- Condition of operating mechanism

Table 3-33 presents the condition rating based on the observed visual inspection deficiencies. Since service age provides a reasonably good measure of the remaining life of the asset, it is employed as an assessment parameter. Since the service age provides a reasonably good measure of the remaining life of elbows, it is employed as an assessment parameter, shown in Table 3-34.

Table 3-33: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust and no damage, operating mechanism in excellent condition
B	Only minor wear and no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of the above indicated defects, but they cannot be repaired

Table 3-34: Criteria for Service Age

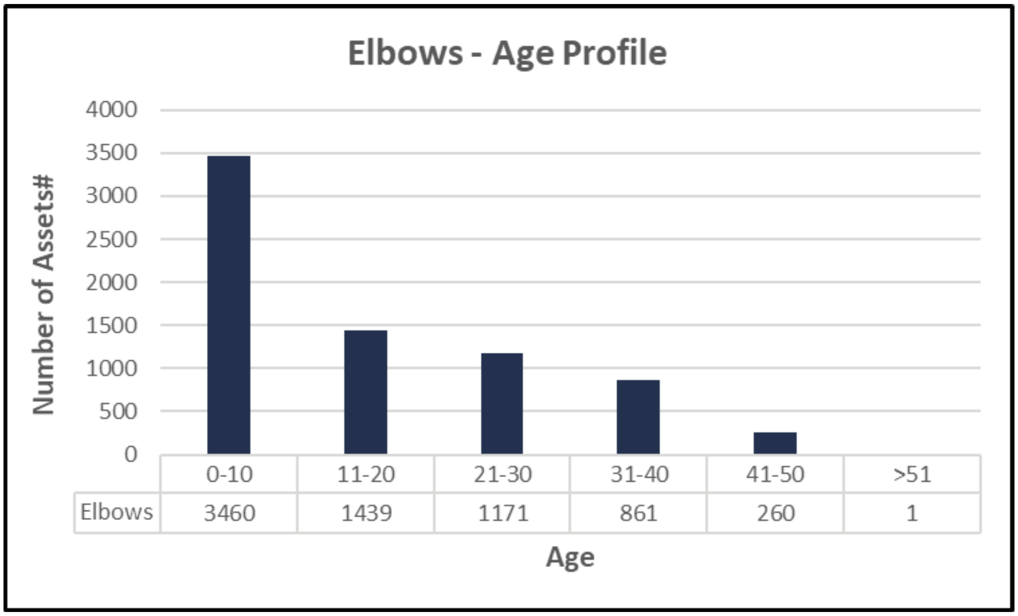
Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

3.1.9.2 Results of Analysis

Age Assessment

OPUCN owns 7192 elbows within its service territory. Elbows with unknown service age, OPUCN matches the elbow to the age of the pad mount transformer. The OPUCN assumption applies to 4842 elbows which is 67.3% of the total OPUCN elbows in-service. Additionally, if there was an unknown service age for the pad mount transformer, OPUCN applied an assumption of fixing the age to 25. This assumption applies to 29 elbows which is 0.4% of the total OPUCN elbows in-service. Figure 3.24 presents the age distribution. Asset service age is currently calculated with end year 2017.

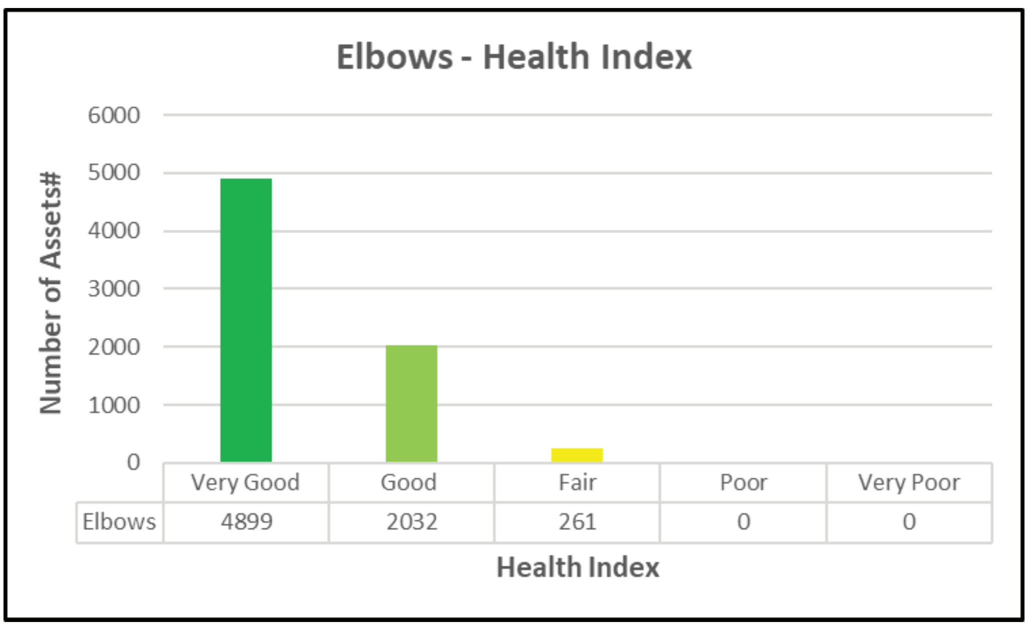
Figure 3.26: Elbow Age Demographics



Condition Assessment

OPUCN's 2017 asset data was used to calculate the Health Index based on the criteria provided in Table 3-32. The Health Index values were calculated for each asset with best available data. The overall Health Index distribution is presented in Figure 3.27.

Figure 3.27: Elbow Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for elbow data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.1.10 Recloser

3.1.10.1 Condition Assessment Methodology

OPUCN owns four reclosers that are all in-service. Table 3-35: highlights the end of life criteria used to generate the Health Index for reclosers. Additionally, Table 3-36: and Table 3-37: present the condition grading criteria for each end of life criteria.

Table 3-35: Recloser Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,C,E	5,4,3,2,1	50
2	Overall Condition	10	A,C,E	5,4,3,2,1	50
				MAX SCORE	**100**

Table 3-36: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-37: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rusting and any damage to the equipment
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of above indicated defects, but they cannot be repaired

3.1.10.2 Results of Analysis

All four reclosers were installed in 2015 and have exhibited very little to none asset degradation. Therefore, all four reclosers are determined to be in Very Good condition and require no immediate rehabilitation, only continuous monitoring and inspections. The DAI for recloser data is 100% with assumptions applied.

3.1.11 Vault and Manhole

3.1.11.1 Condition Assessment Methodology

The Health Index for vaults and manholes is calculated by considering a combination of structural integrity, historical flooding and mitigation devices, and size and access of the civil assets. The best available data is considered for the Health Index calculations within this ACA. Table 3-38 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-38: Vaults and Manholes Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Structural Integrity	6	A,C,E	5,3,1	30
2	Flooding and mitigation	6	A,C,E	5,3,1	30
3	Size and access	8	A,C,E	5,3,1	40
				MAX SCORE	**100**

Table 3-39 to Table 3-41 represent the gradings for each criterion to evaluate the condition of OPUCN's vaults and manholes.

Table 3-39: Criteria for Structural Integrity

Condition Rating	Corresponding Condition
A	No deficiencies in the vault or manhole
C	Only minor deficiencies
E	Major deficiencies requiring immediate repairs/replacement

Table 3-40: Criteria for Flooding and Mitigation

Condition Rating	Corresponding Condition
A	No incidents of flooding at this location
C	Occasional flooding, working sump pumps and drains
E	Frequent flooding, no sump pumps or drains

Table 3-41: Criteria for Size and Access

Condition Rating	Corresponding Condition
A	Adequate ergonomic size and safe access to vault
C	Vault size slightly smaller than ideal, but adequate for safe working and reasonable access to vault
E	Vault size or access inadequate for safe working or worker rescue during an accident; immediate repairs/replacement

3.1.11.2 Results of Analysis

Condition Assessment

OPUCN owns 146 vaults and 120 manholes in service. OPUCN's 2017 inspection data was used to calculate the Health Index based on the criteria provided in Table 3-38. The Health Index values were calculated for each asset with best available data. The overall Health Index distribution for OPUCN's vaults and manholes are presented in Figure 3.28 and Figure 3.29, respectively.

Figure 3.28: Vault Health Index Demographic

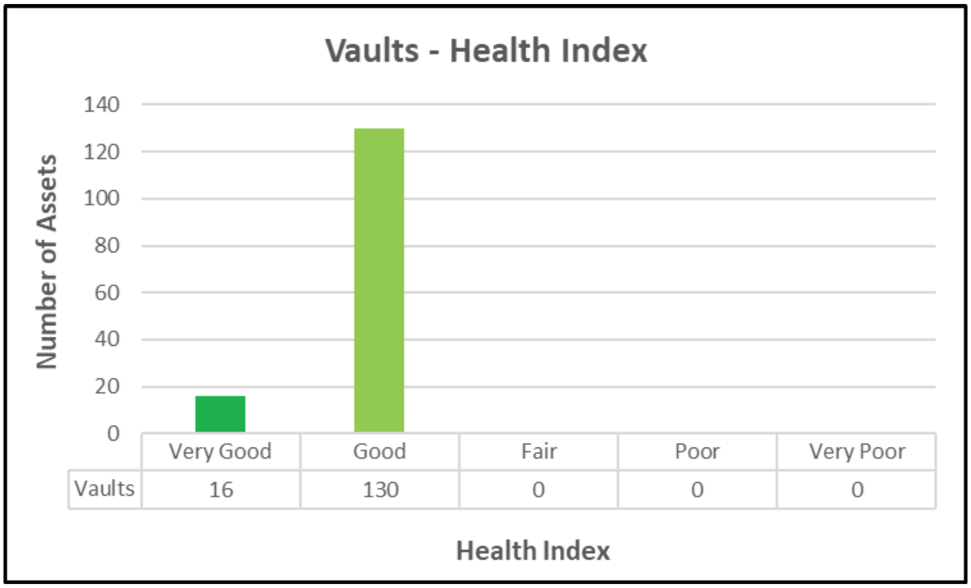
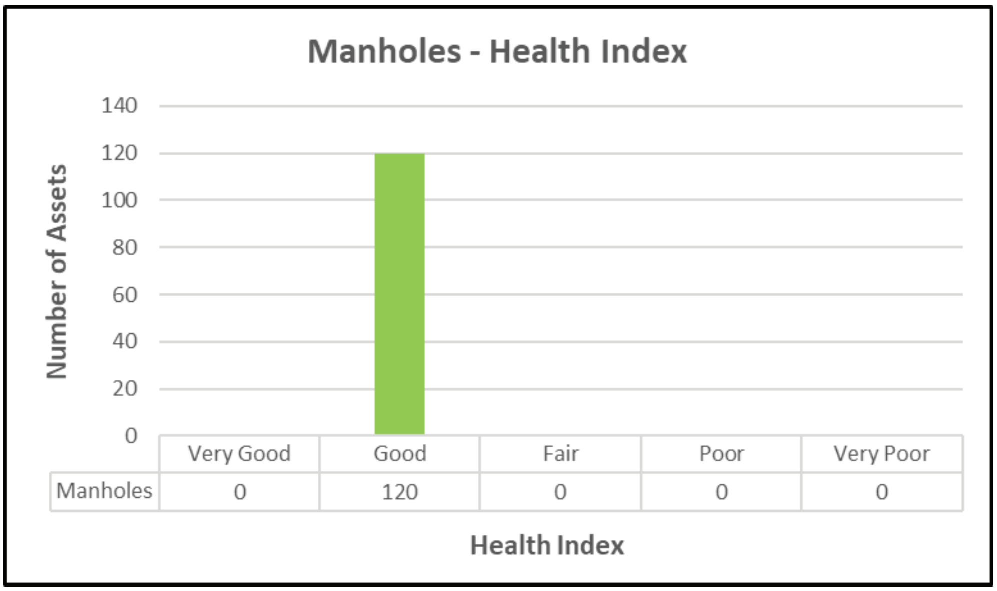


Figure 3.29: Manhole Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the current collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for vault and manhole data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

3.2 Station Assets

There are a total eight distribution substations owned and managed by OPUCN. These substations step down power from 44 kV to 13.8/8.0 kV. Each substation contains the following assets that are included within this report:

- Substation power transformer
- Substation circuit breaker
- Substation switchgear
- Substation protection relay and RTU
- Substation battery and charger
- Substation ground grid
- Substation fence and building

3.2.1 Power Transformer

3.2.1.1 Condition Assessment Methodology

Computing the Health Index of a transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor in determining the component's condition relative to potential failure. The Health Index for substation power transformers is calculated by considering a combination of service age, analysis of test results, load history and visual inspection results. The best available data is considered for the Health Index calculations within this ACA. Table 3-42 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-42: Power Transformers Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Load History	6	A,B,C,D,E	5,4,3,2,1	30
2	Service Age	4	A,B,C,D	5,4,3,2	20
3	Overall Condition	2	A,B,C,D,E	5,4,3,2,1	10
4	Testing Analysis	8	A,B,C,D,E	5,4,3,2,1	40
				MAX SCORE	**100**

The rate of insulation degradation is directly related to the operating temperature, which is itself directly related to transformer loading levels. Peak loading level of transformers expressed in percent of nameplate rating can therefore be employed as an indicator of transformer health. OPUCN collects the substation load history monthly, recording the monthly peak load over the last twelve months. Table 3-43 presents the grades and ranges of load history.

Table 3-43: Criteria for Load History

Condition Rating	Corresponding Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

Table 3-44 presents the grading based on service age for substation power transformers. Since service age provides a reasonably good measure of the remaining life of the asset, it is employed as an assessment parameter.

Table 3-44: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 20 years
B	21 to 40 years
C	41 to 60 years
D	60 years and older

Visual inspections can provide a good indication of the physical condition of transformers. Table 3-45 presents the grading for visually inspected components.

Table 3-45: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Station transformer is externally clean and corrosion-free. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems mounted on the station transformer are in good condition. No external evidence of overheating or internal overpressure. No sign of oil leaks and forced air cooling fully functional. Appears to be well maintained with service records readily available.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable – repairable.
E	More than two of the above characteristics are unacceptable – damaged beyond repair.

A combination of electrical, physical and chemical tests is performed to establish preventive maintenance procedures, avoid premature failure and costly shutdown and plant maintenance such as oil reclamation or replacement. Table 3-46 presents the grading for power transformers test analysis. The Weidmann Annual Test results are considered for the condition assessment.

Table 3-46: Criteria for Test results

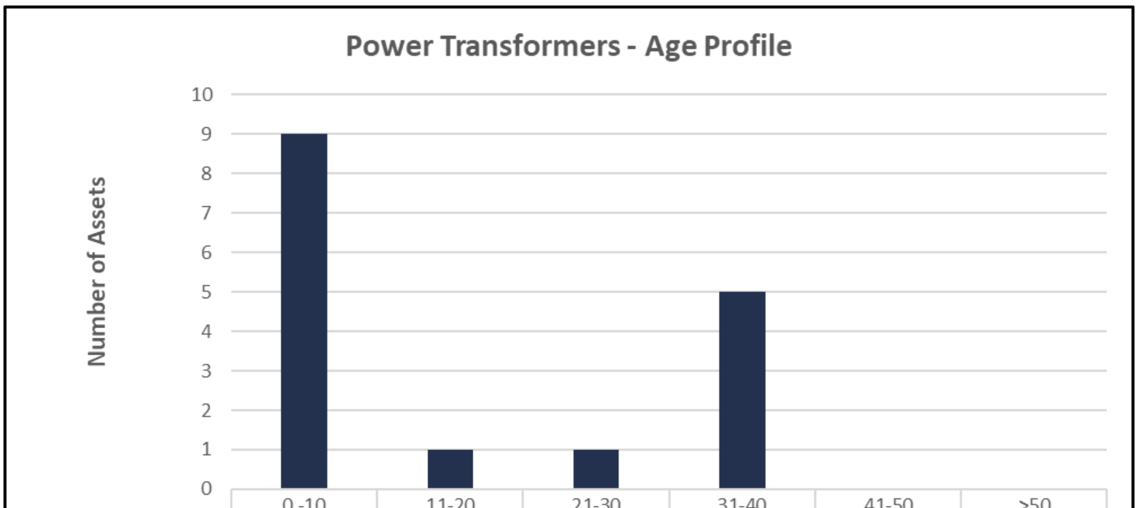
Condition Rating	Corresponding Condition
A	Test results indicate excellent installation condition, no indication of moisture, arcing, overheating or degradation of paper.
B	Tests indicate normal aging, no concerns about insulation health
C	Tests indicate slightly above average but stable moisture content or presence of arcing overheating related gases
D	Some of the tests indicates significant concerns about insulation condition or presence of significant arcing overheating related gases
E	Two or more of the tests indicate rapidly deteriorating insulation condition or presence of significant arcing overheating of two or more related gases

3.2.1.2 Results of Analysis

Age Assessment

OPUCN operates 16 in-service substation power transformers. Figure 3.30 presents the age profile of power transformers in-service. Power transformer MS14-T2 is the oldest power transformer at OPUCN. Asset service age is currently calculated with end year 2017.

Figure 3.30: Power Transformer Age Demographic

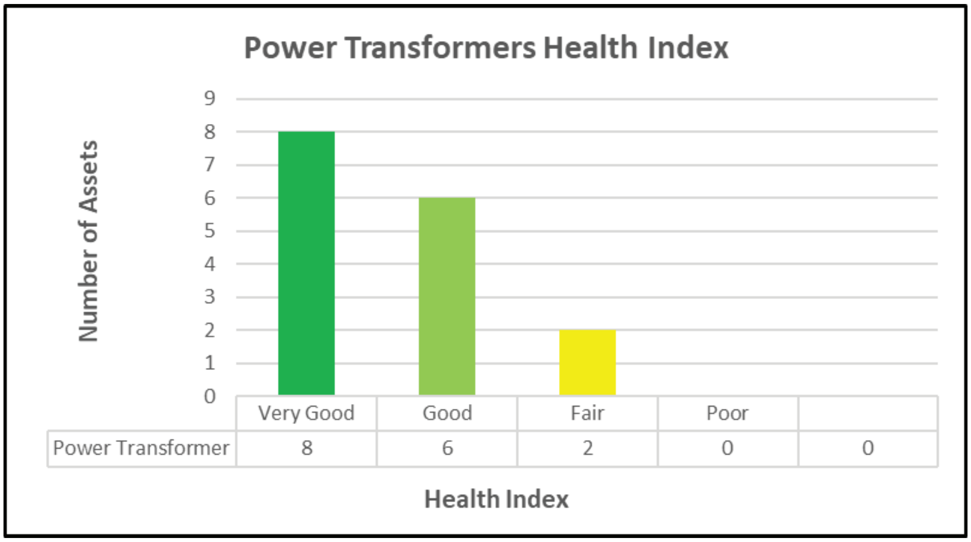


	0 -10	11-20	21-30	31-40	41-50	>50
Power Transformers	9	1	1	5	0	0

Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score is summarized in Figure 3.31 for OPUCN owned power transformers. Majority of OPUCN's power transformers are in good condition.

Figure 3.31: Power Transformer Health Index Demographic



3.2.2 Circuit Breaker

Computing the Health Index of a circuit breaker requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The Health Index for substations circuit breakers is calculated by considering a combination of service age, test results and visual inspections. The best available data is considered for the Health Index calculations within this ACA. Table 3-47 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-47: Circuit Breaker Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	5	A,B,C,D,E	5,4,3,2,1	25
2	Test Results	8	A,B,C,D,E	5,4,3,2,1	40
3	Overall Condition	7	A,B,C,D,E	5,4,3,2,1	35
				MAX SCORE	**100**

Service age provides a reasonably good measure of the remaining life of circuit breakers. Table 3-48 and Table 3-49 provides the grading for outdoor circuit breakers and indoor circuit breakers service age, respectively.

Table 3-48: Criteria for Service Age – indoor circuit breaker

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-49: Criteria for Service Age – outdoor circuit breaker

Condition Rating	Corresponding Condition
A	0 to 7 years
B	8 to 15 years
C	16 to 24 years
D	25 to 32 years
E	33 years and older

Various tests can be interpreted by an expert to rank the overall condition of breaker system. Table 3-50 presents the grading for test results. The Weidmann Annual Test and OPUCN monthly test results are considered for the condition assessment. Additionally, Table 3-51 presents the grading for the overall condition circuit breakers with visual inspections.

Table 3-50: Criteria for Test results

Condition Rating	Corresponding Condition
A	Tests results indicate excellent condition of contacts, operating mechanism, insulation condition and controls
B	Normal aging, each of the four indicators within specific limits
C	One of the above four indicators is slightly beyond the specified limits
D	Two or more of the above four indicators beyond the specified limits
E	Two or more of the indicators beyond the specifications and cannot be brought to comply with the specifications

Table 3-51: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leaks
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects of the cooling fans do not work

3.2.2.1 Results of Analysis

Age Assessment

OPUCN operates 16 44kV and 72 13.8kV circuit breakers in service. The age profile of circuit breakers is shown in Figure 3.32 and Figure 3.33. Asset service age is currently calculated with end year 2017.

Figure 3.32: Circuit Breaker (44kV) Age Demographic

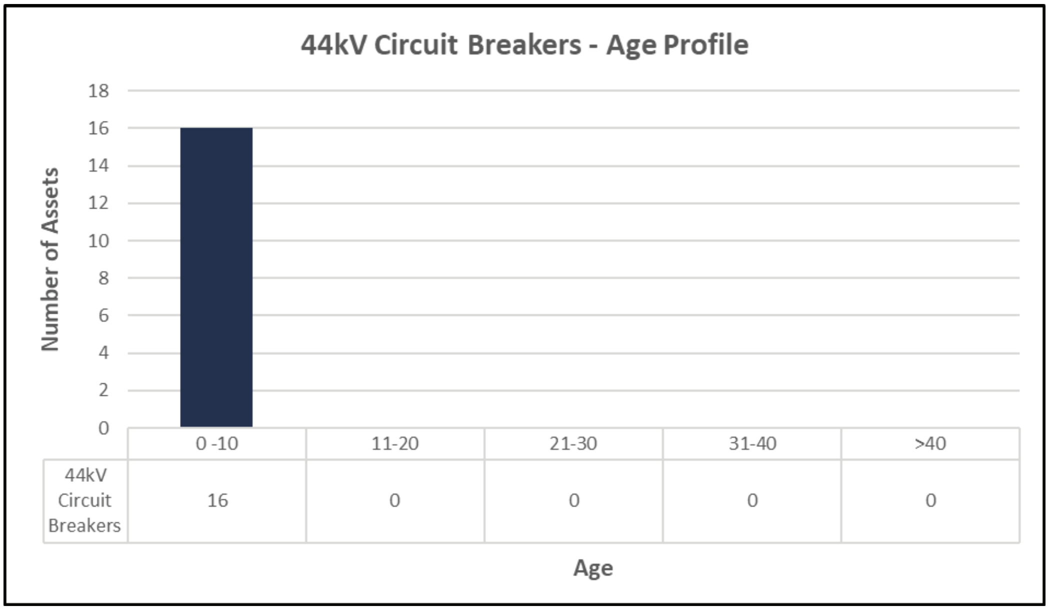
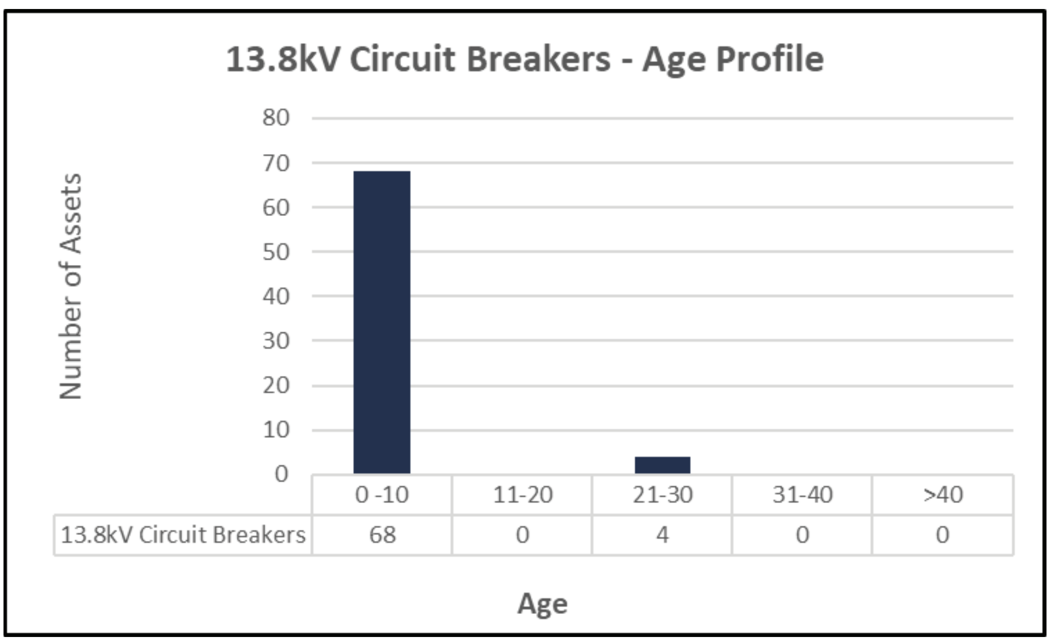


Figure 3.33: Circuit Breaker (13.8kV) Age Demographic



Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for circuit breakers is summarized in Figure 3.34 and Figure 3.35.

Figure 3.34: Circuit breaker (44kV) Health Index Demographic

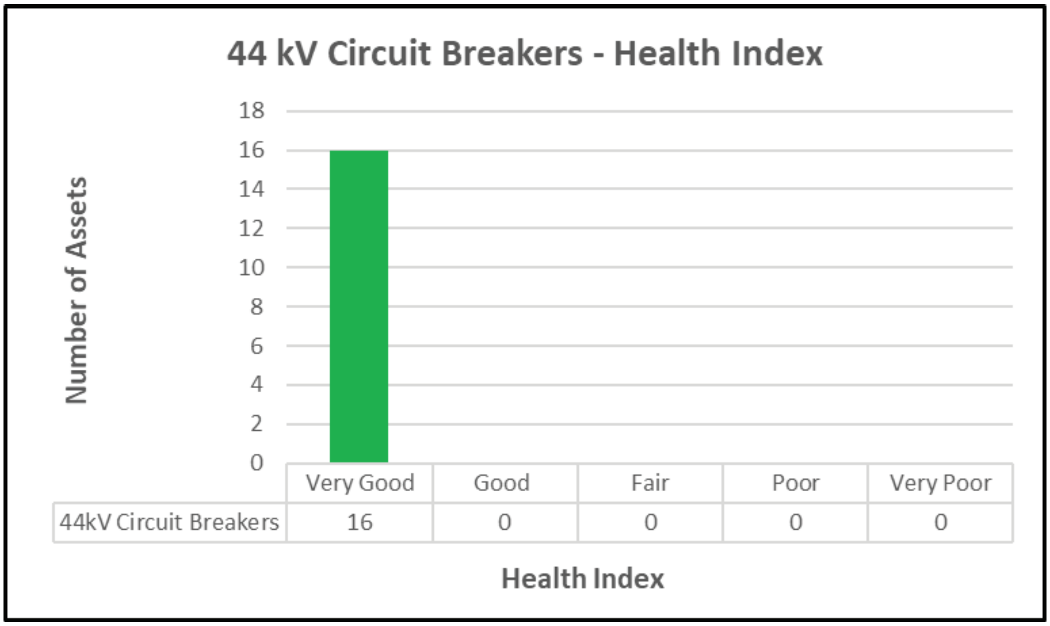
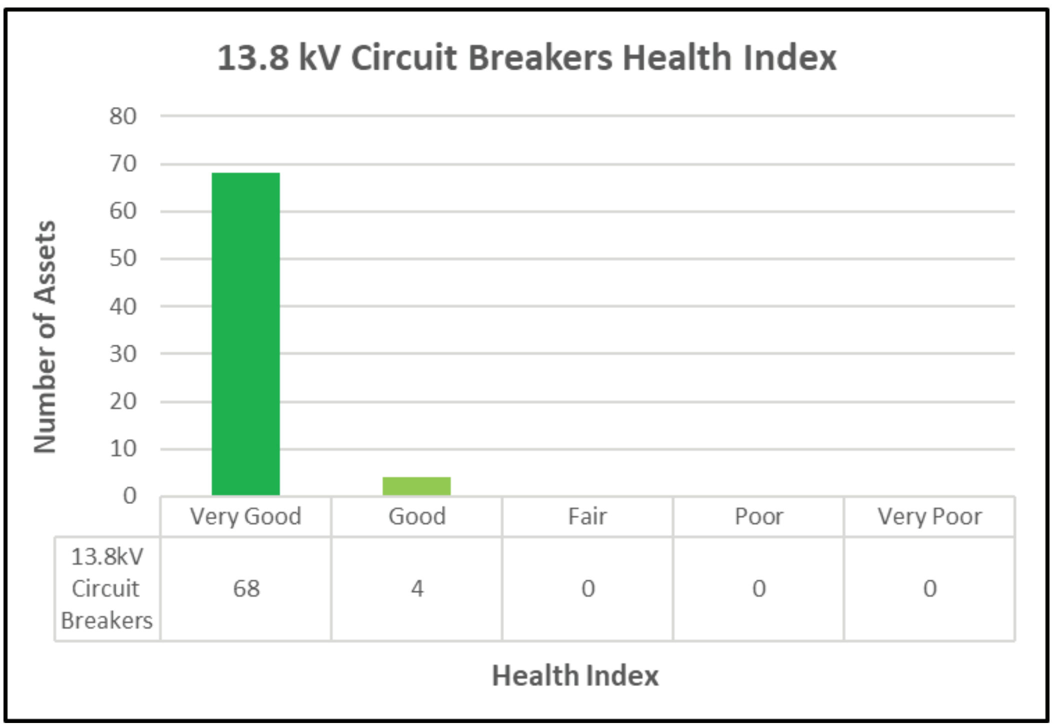


Figure 3.35: Circuit breaker (13.8kV) Health Index Demographic



3.2.3 Switchgear

Computing the Health Index of a switchgear requires developing end-of-life criteria. Each criterion represents a factor critical in determining the asset' condition relative to potential failure. The Health Index for switchgears is calculated by considering a combination of service age and visual inspections. The best available data is considered for the Health Index calculations within this ACA. Table 3-52 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-52: Switchgear Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Overall Condition	10	A,B,C,E	5,4,3,2,1	50
				MAX SCORE	**100**

Table 3-53 and Table 3-54 provide the grading breakdown for each end-of-life condition criteria for switchgears.

Table 3-53: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years and older

Table 3-54: Criteria for Overall Condition

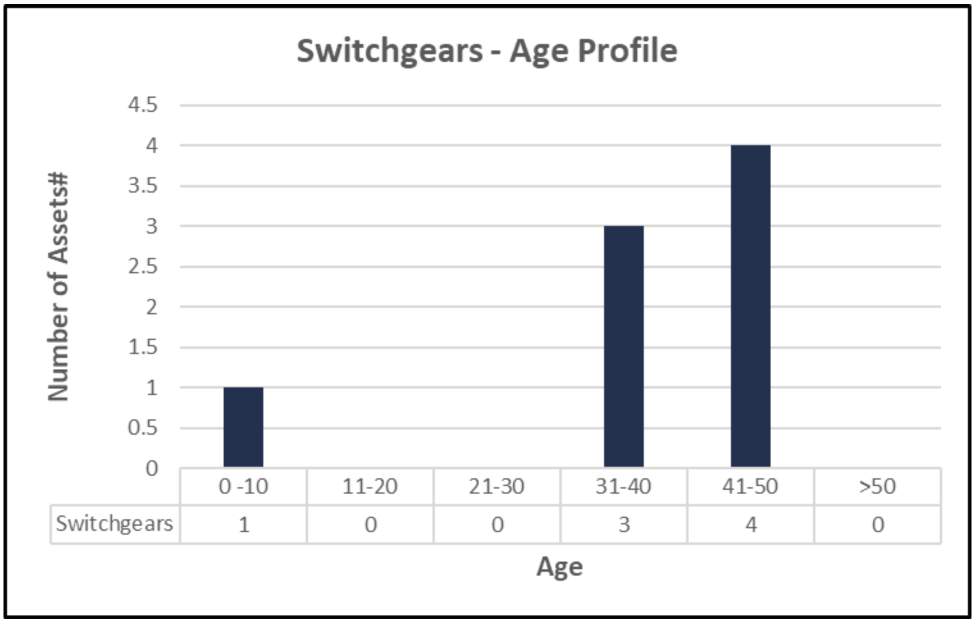
Condition Rating	Corresponding Condition
A	No rust and corrosion, operating mechanism in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation. No intermediate hotspot detected.
D	Two or more of above indicated defects but can be repaired.
E	Two or more of above indicated defects but cannot be repaired.

3.2.3.1 Results of Analysis

Age Assessment

OPUCN owns eight switchgears in service. Figure 3.36 presents the age profile of switchgears in-service at OPUCN. Asset service age is currently calculated with end year 2017.

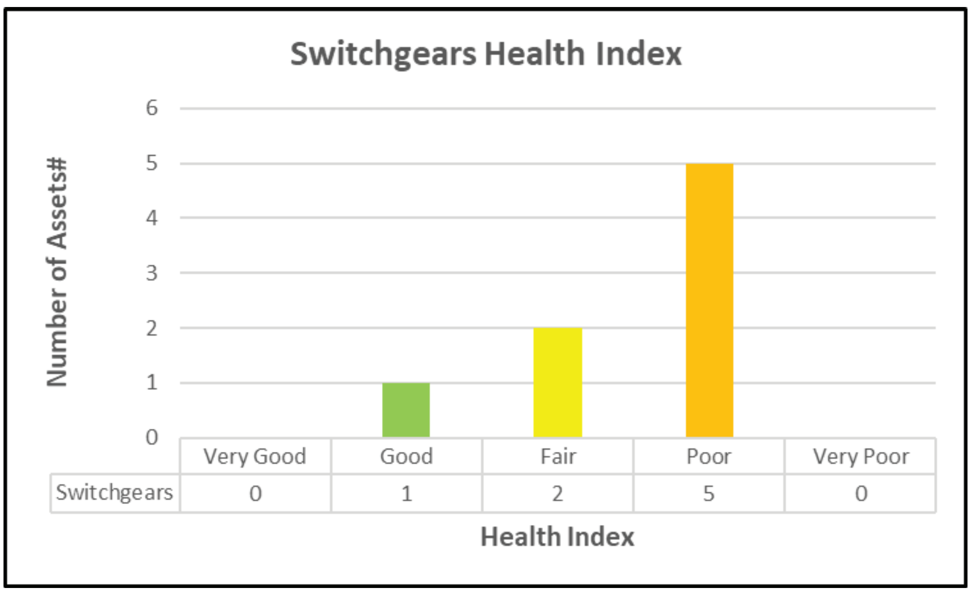
Figure 3.36: Switchgear Age Demographic



Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for protection relays and SCADA RTUs is summarized in Figure 3.37.

Figure 3.37: Switchgear Health Index Demographic



3.2.4 Protector Relay and RTU

The Health Index for substations protection relays and RTUs is calculated by considering a combination of service age and test results. The best available data is considered for the Health Index calculations within this ACA. Table 3-55 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-55: Protector Relays and RTUs Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Test Results	10	A,B,C,E	5,4,3,1	50
				MAX SCORE	**100**

Service age provides a reasonably good measure of the remaining life of protection relays and RTUs. Table 3-56 provides the grading for protection relays service age.

Table 3-56: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 3 years
B	4 to 6 years
C	7 to 10 years
D	11 to 15 years
E	16 years and older

Calibration tests can be interpreted by an expert to rank the overall condition of protection relays. Table 3-57 presents the grading for test results.

Table 3-57: Criteria for Test results

Condition Rating	Corresponding Condition
A	Excellent operating condition, calibration well within specified limits
B	Normal aging, calibration within the specified limits
C	Frequent calibration required, but it is possible to meet specified limits
E	Not possible to calibrate the relays to bring settings to specified limits

3.2.4.1 Results of Analysis

Age Assessment

OPUCN owns 71 protection relays and eight RTUs in service. Figure 3.38 presents the age profile of protection relays in-service at OPUCN. Figure 3.39 presents the age profile of RTUs. Asset service age is currently calculated with end year 2017.

Figure 3.38: Protection Relay Age Demographic

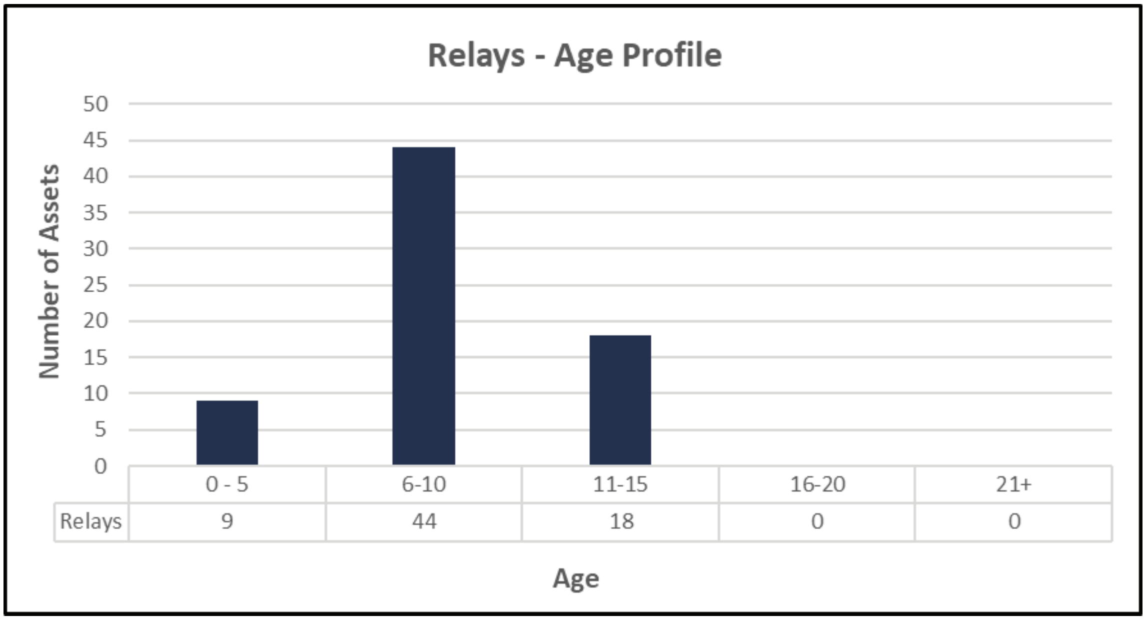
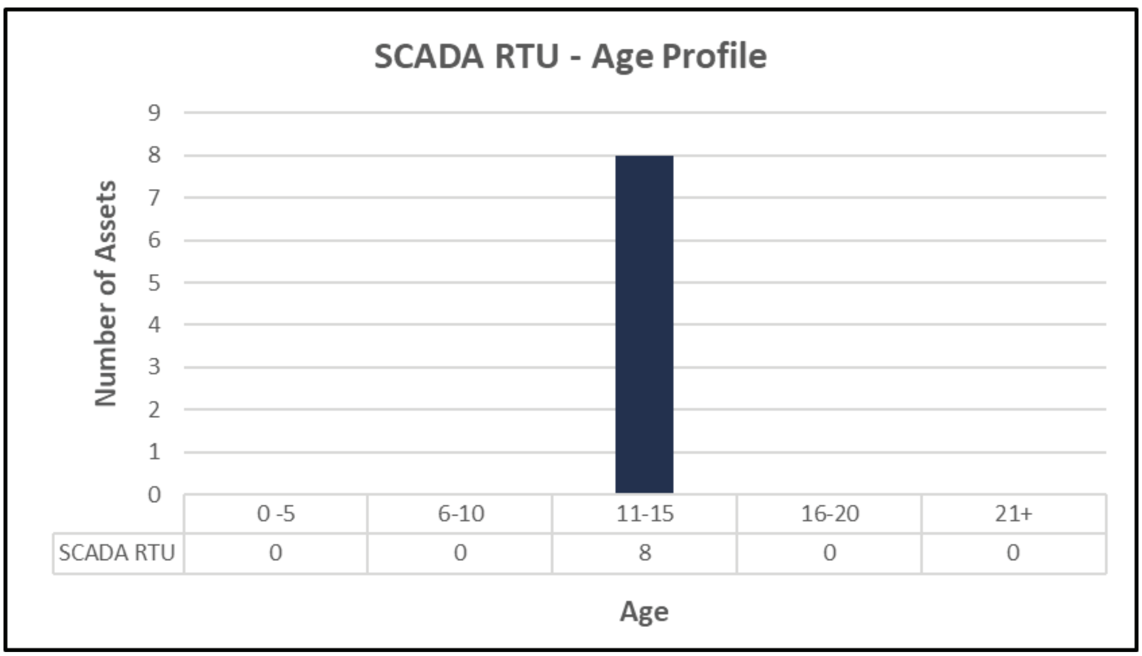


Figure 3.39: SCADA RTU Age Demographic



Condition Assessment

Based on the condition assessment criteria defined above and best available data, the Health Index score for protection relays and SCADA RTUs is summarized in Figure 3.40 and Figure 3.41.

Figure 3.40: Protection relay Health Index Demographic

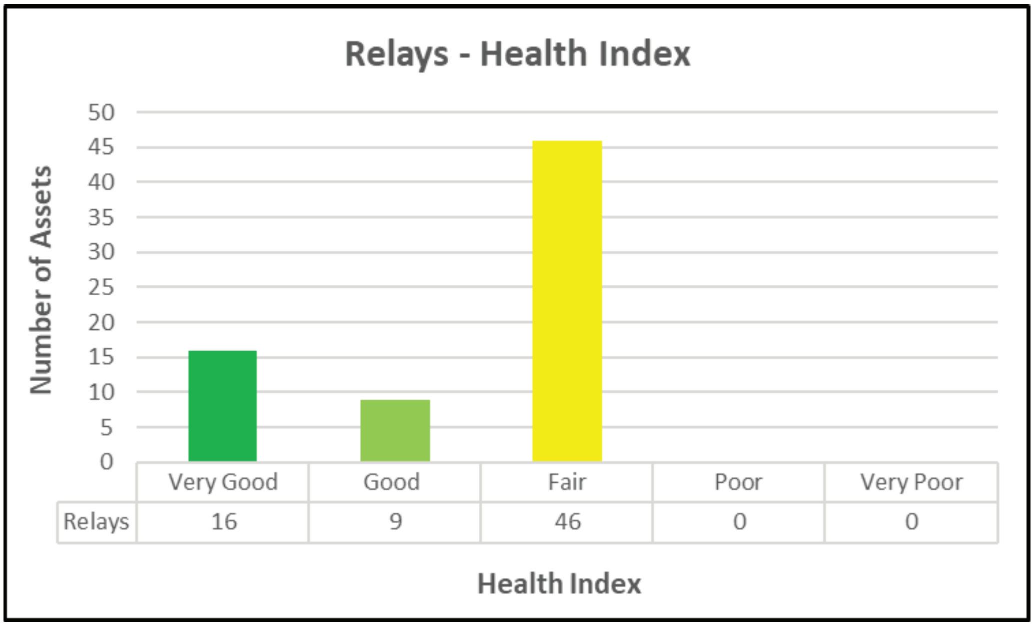
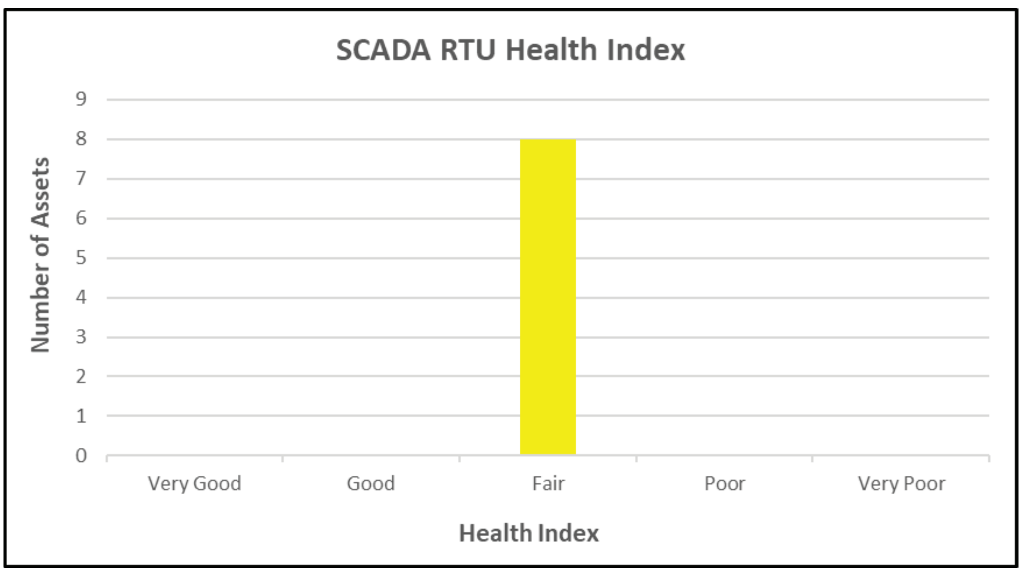


Figure 3.41: SCADA RTU Health Index Demographic



3.2.5 Battery and Charger

The purpose of substation batteries is to provide power for critical control functions such as trip coils of circuit breakers. Batteries are carefully sized to store adequate energy for system operation during an AC power failure. Both the electrodes and electrolyte in control batteries undergo aging with repeated charge and discharge cycles, which result in gradual reduction of battery storage capacity. The end of life is reached when the battery is no longer able to retain adequate charge for required functions. Battery chargers can experience component failures, but these can be easily replaced and as a result the charger often outlasts the battery. The Health Index for substations batteries is calculated by considering a combination of service age and test results. The best available data is considered for the Health Index calculations within this ACA. Table 3-58 summarizes the methodology to combine these criteria into an overall Health Index.

Table 3-58: Battery Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	10	A,B,C,D,E	5,4,3,2,1	50
2	Test Results	10	A,C,E	5,3,1	50
				MAX SCORE	**100**

Since different types of batteries can have significantly different life expectancy, age related scoring needs to be measured in terms of "Effective Life Expectancy". Table 3-59 provides the grading for station batteries effective life. Table 3-60 presents the grading for battery test results.

Table 3-59: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 25% of Effective Life Expectancy
B	Less than 50% of Effective Life Expectancy
C	Less than 75% of Effective Life Expectancy
D	Less than 100% of Effective Life Expectancy
E	More than Effective Life Expectancy

Table 3-60: Criteria for Test results

Condition Rating	Corresponding Condition
A	Battery capable of storing full rated energy
C	Battery stores marginally less than full rated energy, but still adequate for required functions
E	Battery stores significantly less than the full rated energy, inadequate for required functions

3.2.5.1 Results of Analysis

Age Assessment

OPUCN maintains eight batteries and chargers, one for each substation with majority of them being under 10 years old. Figure 3.42 and Figure 3.43 present the age profile of batteries and chargers, respectively. Asset service age is currently calculated with end year 2017.

Figure 3.42: Battery Age Demographic

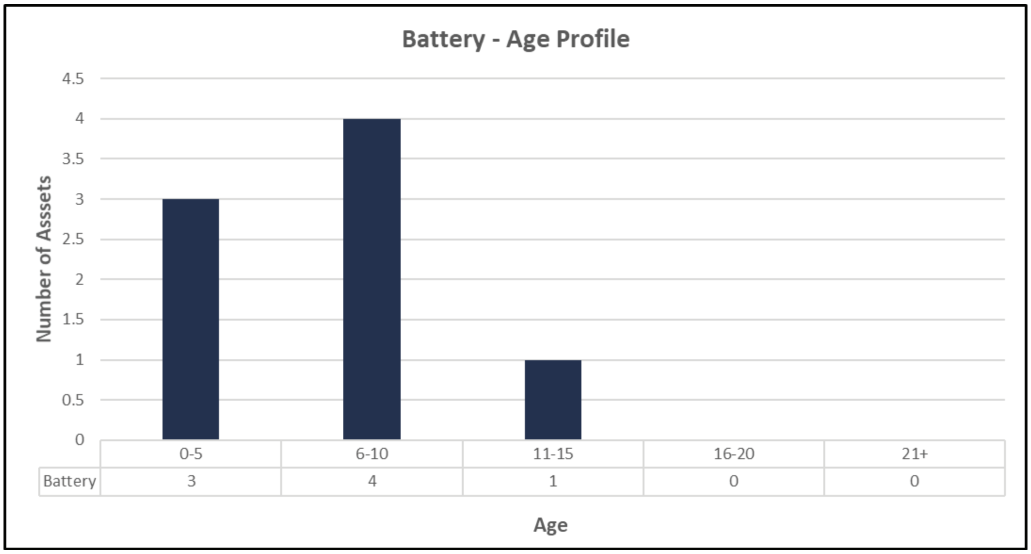
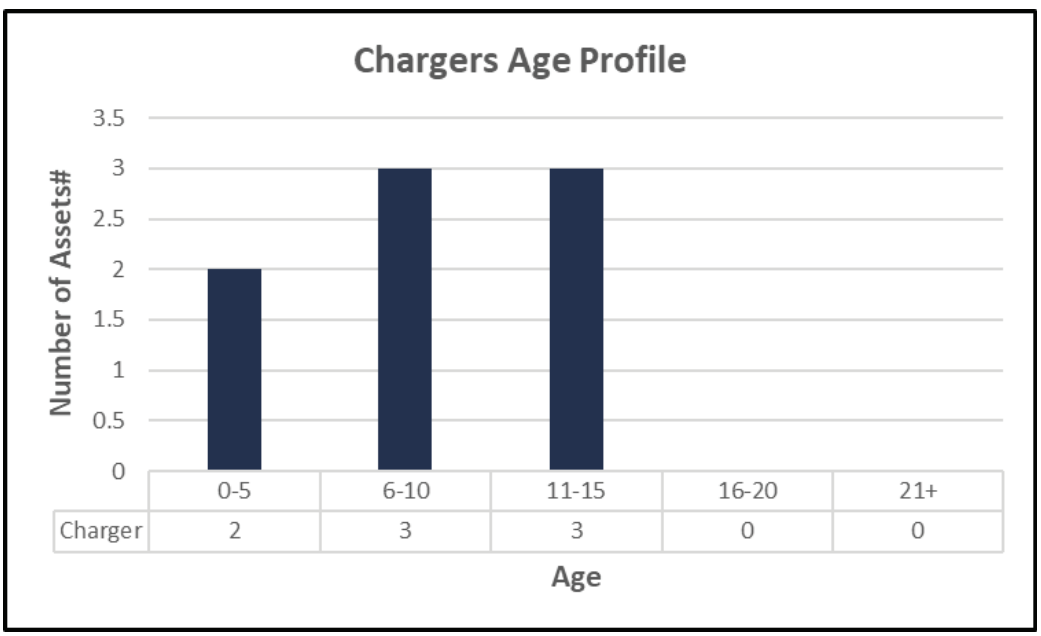


Figure 3.43: Charger Age Demographic



Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for batteries and chargers is summarized in Figure 3.44 and Figure 3.45, all considered 'Very Good'.

Figure 3.44: Battery Health Index Demographic

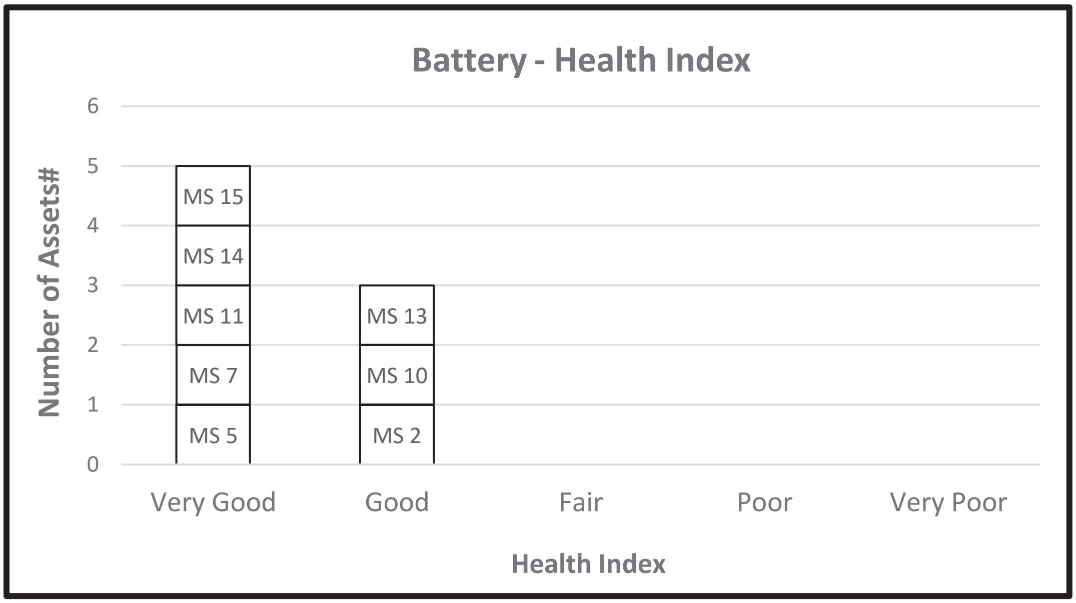
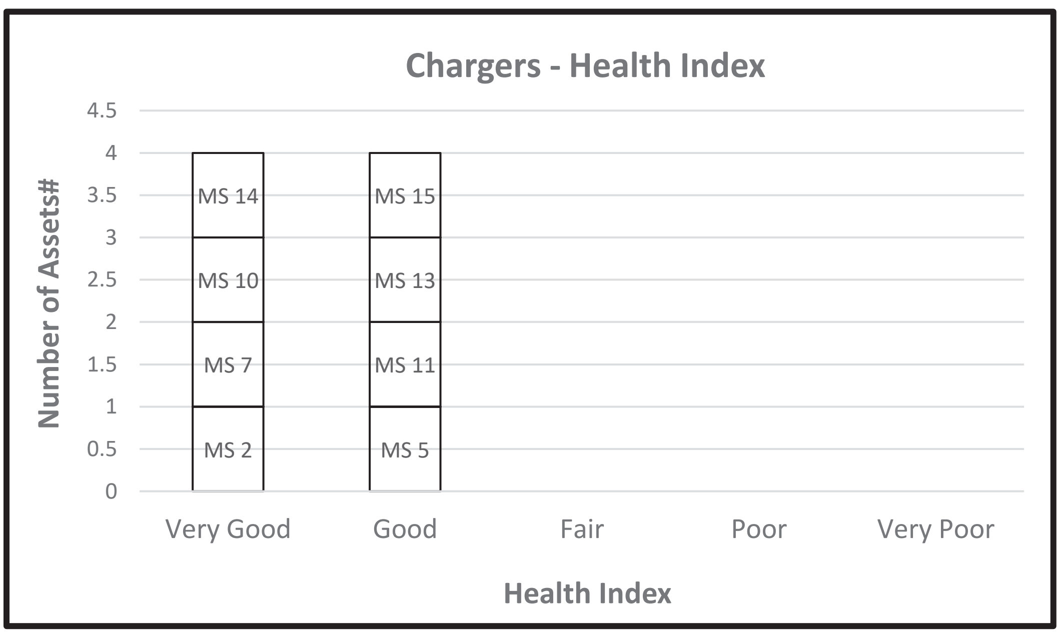


Figure 3.45: Charger Health Index Demographic



3.2.6 Ground Grid

The Health Index for substations ground grids is calculated by considering a combination of service age, visual inspections and testing. The best available data is considered for the Health Index calculations within this ACA. Table 3-61 summarizes the Health Index algorithm for station ground grids.

Table 3-61: Ground Grid Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	5	A,B,C,D,E	5,4,3,2,1	25
2	Electrode resistance test	8	A,C,E	5,3,1	40
3	Condition of surface stone	7	A,C,E	5,3,1	35
				MAX SCORE	**100**

Service age provides a reasonably good measure of the remaining life of station grids. Table 3-62 provides the grading for ground grid service age. Additionally, Table 3-63 and Table 3-64 provide the additional grading for the remaining identified condition criterions for the Health Index algorithm.

Table 3-62: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Ground Electrode less than 10 years old
B	Ground Electrode between 10 and 20 years old
C	Ground Electrode between 20 and 30 years old
D	Ground Electrode between 30 and 40 years old
E	Ground Electrode more than 40 years old

Table 3-63: Criteria for Electrode resistance test

Condition Rating	Corresponding Condition
A	Ground electrode resistance and GPR within safe limits, all electrode components pass integrity test
C	Ground electrode resistance and GPR within safe limits but a few electrode components do not pass integrity test
E	Ground electrode resistance or GPR not within safe limits or many electrode components do not pass integrity test

Table 3-64: Criteria for Condition of surface stone

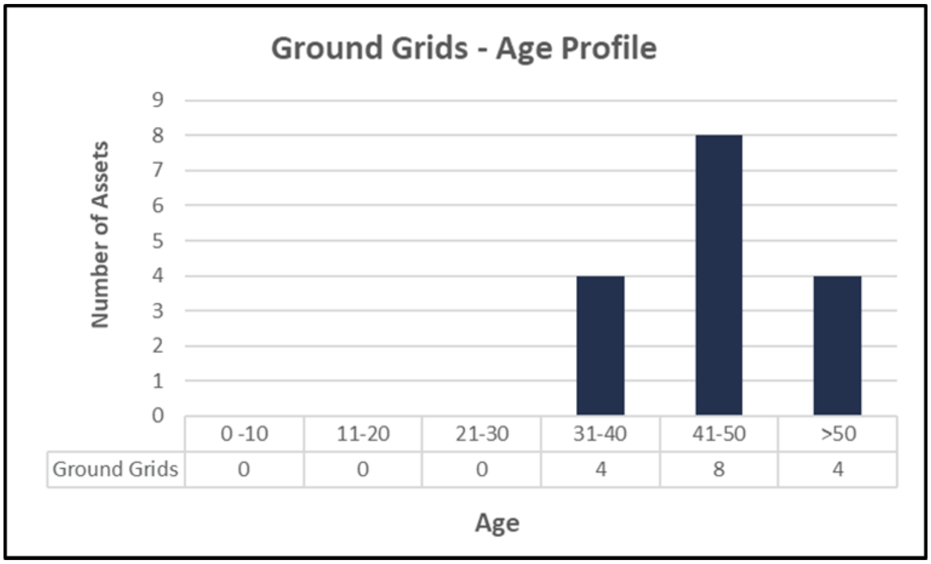
Condition Rating	Corresponding Condition
A	Resistivity of surface stone >3000 Ohm-m, no sign of vegetation growth
C	Resistivity of surface stone marginally less than <3000 Ohm-m, but no sign of vegetation growth
E	Resistivity of surface stone significantly less than <3000 Ohm-m, and signs of vegetation growth

3.2.6.1 Results of Analysis

Age Assessment

OPUCN operates and maintains 16 substation ground grids. Figure 3.46 presents the age profile of ground grids in-service at OPUCN. Asset service age is currently calculated with end year 2017.

Figure 3.46: Ground Grid Age Demographic

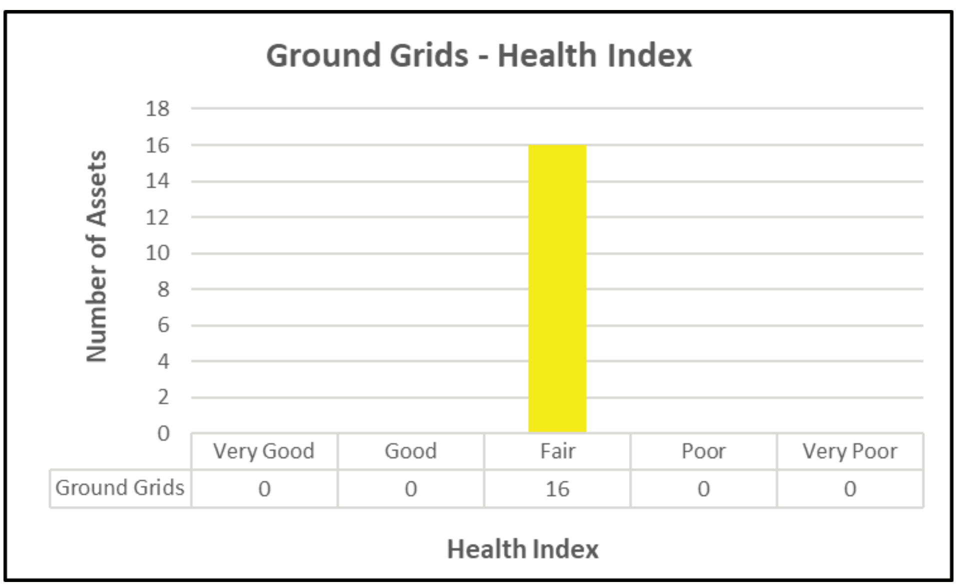


	0 -10	11-20	21-30	31-40	41-50	>50
Ground Grids	0	0	0	4	8	4

Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for ground grids is summarized in Figure 3.47.

Figure 3.47: Ground Grid Health Index Demographic



	Very Good	Good	Fair	Poor	Very Poor
Ground Grids	0	0	16	0	0

3.2.7 Fence & Building

The Health Index for substations fences and buildings is calculated by considering only visual inspections. Table 3-65 highlights the Health Index algorithm for both fences and buildings. The assets are considered individual within this report but use the same Health Index algorithm.

Table 3-65: Fence and Buildings Health Index Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Overall Condition	20	A,C,E	5,3,1	100
				MAX SCORE	**100**

Table 3-66 highlights the condition grading table used for both station fences and station buildings.

Table 3-66: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No deficiencies
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

3.2.7.1 Results of Analysis

Condition Assessment

Based on the condition assessment criteria defined and best available data, the Health Index score for fences and buildings is summarized in Figure 3.48 and Figure 3.49.

Figure 3.48: Fence Health Index Demographic

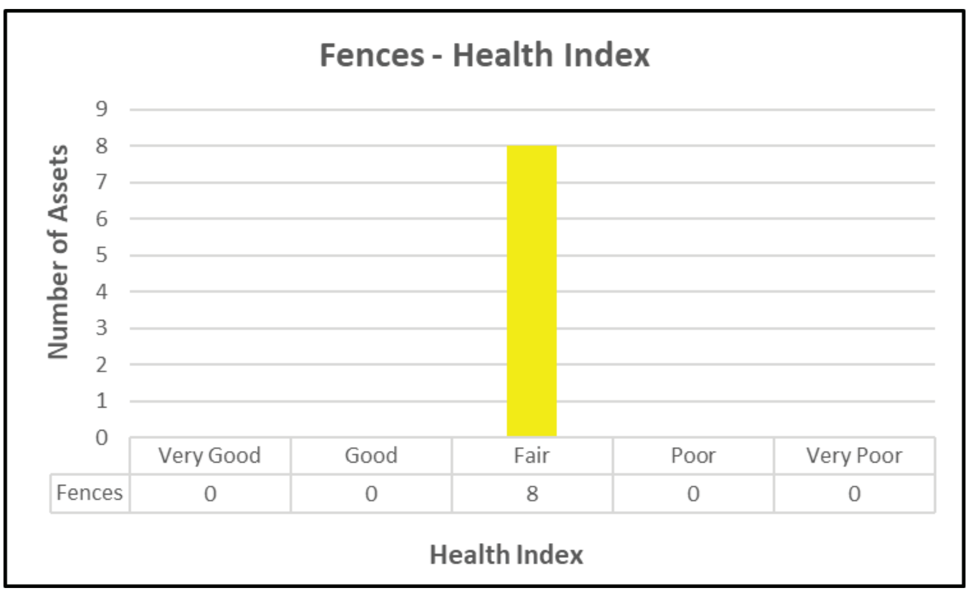
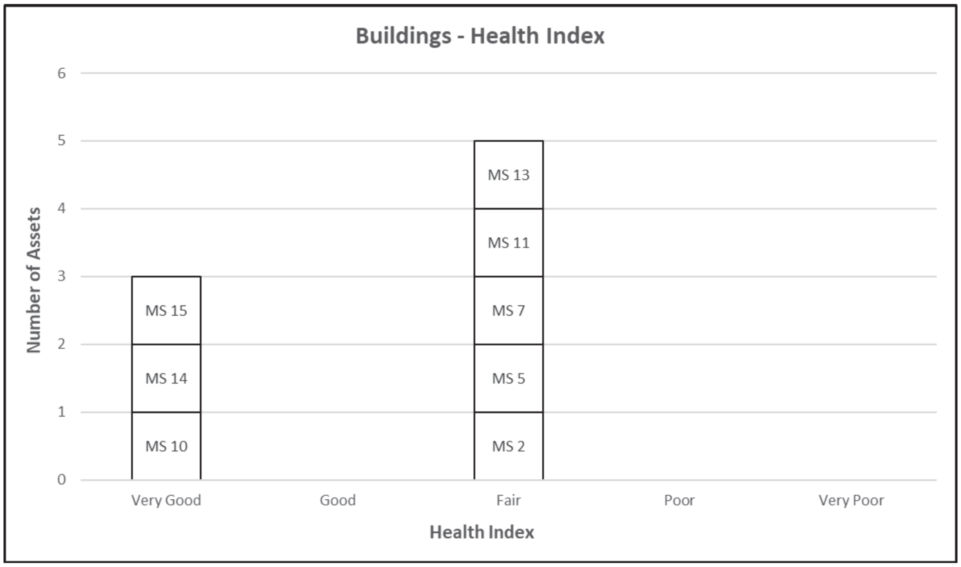


Figure 3.49: Building Health Index Demographic



Data Assessment

The Data Availability Indicator (DAI) is created to measure the reasonable collected data to date by the utility for completion regarding parameters used in the Health Index algorithm. The DAI for all station asset data is 100% with assumptions applied. Section 4 provides additional recommendations for data collections for Health Index formulation expansion.

4 Recommendations

Recommendations for further data points that can be collected are aggregated into this section and are provided for each asset group. Improvements can always be made to further justify the asset renewal, capital and operational expenditures, maintenance activities, or to enhance the ACA framework. Additionally, keeping records of asset condition is a good operating practice, as it may assist in planning and assessing the quality of in-service assets being replaced.

METSCO recommends that OPUCN incorporate a five-level grading scheme for any asset condition inspections, where applicable to bring its practices closer to the ISO5500X recommended approaches. A five-level grading scheme will allow for more discrepancy between assets and their respective Health Index values that will be used for prioritizing assets. Furthermore, METSCO recommends for OPUCN to perform annual validations of its ACA model for continuous improvements of the Health Index algorithms. There are several algorithms used by OPUCN that are not in alignment with the industry standard that can be realigned. Furthermore, additional algorithms have not yet fully been matured or developed and require additional data parameters. As OPUCN progresses with its asset inspection and data collection efforts, OPUCN is expected to be able to fully develop its ACA model.

As always, the decisions regarding enhancements to the testing, inspection and index calculation methodologies should incorporate the balance of financial considerations related to incremental costs of these tests, and the anticipated value of insights (e.g. value of risks mitigated) that these investments would bring about.

4.1 Pole

We recommend for OPUCN to continue periodically testing their poles for remaining strength and collecting visual indicators based on the OEB-recommended inspection cycle to capture the most recent asset condition. Table 4-1 identifies asset condition criteria that affect the life expectancy for this asset class. A priority classification in terms of criteria contributing to the life expectancy for the asset is provided below and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Furthermore, we recommend for OPUCN to refine the current HIF framework that separates the Overall Condition criteria into two sub-criteria (Wood Rot and Defects). The drawback with aggregate data is the underlying data may be lost moving forward and can be difficult to identify the main reason why a pole has an Overall Condition score of Poor. With the data split, should the HI of the pole be low, a system planner would be able to easily identify the reasons and make any necessary changes to prevent future assets experiencing similar degradations.

Table 4-1: End-of-Life Criteria for Poles

Criteria	Reasoning	Priority
Remaining Pole strength	Pole strength is blended in the general overall condition within OPUCN ACA data. METSCO recommends separating the associated strength parameters from the overall condition for further visibility and use in the HI formula. Measuring the strength of the in-service pole provides a valuable benchmark on the poles condition. This parameter is regarded to be the best parameter to use for identification of the pole's condition as the visual component of the pole may be only a slight representation of what is within the pole and affecting its strength.	**High**
Wood Rot	Wood rot is identified in the general condition comments part of the inspection process. METSCO recommends separating the associated "rot" fields away from the general "defects" field for further visibility and use in the HI formula.	**Medium**
Out of Plumb	Identifying poles that are already leaning present a higher risk to safety. Severely leaning poles should be targeted for replacement. Easily identifiable through pre-determined inspection cycles.	**Medium**

4.2 Overhead Primary Conductor

The Health Index for overhead primary conductors is determined with the use of two criteria: age and small conductor risk, both of which are found in the current HIF. Due to this fact, there are no immediate recommendations to be made regarding the HIF. Small conductor risk is a criterion as it is sometimes identified as having increased risk of becoming brittle and failing. OPUCN notes there are no small conductor's in-service, resulting in the HIF to be age dependent. However, if small conductors are in-service, it is recommended to update the Health Index values to accurately represent the current condition of the asset.

4.3 Underground Primary Cable

Table 4-2 identifies additional condition criteria that affect the life expectancy for underground primary cables and can contribute to the HIF. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their HIF.

Replacing underground cable can be a high capital expense for any utility especially if it is direct buried. We recommend that OPUCN consider the additional condition criteria moving forward to expand the HIF to assist with prioritization of asset replacement. Additionally, we recommend for OPUCN to reach out to external vendors that can provide these services to assist OPUCN to better understand the condition of their underground cable and what are optimal intervention methods to manage cable performance.

Table 4-2: End-of-Life Criteria for Underground Primary Cables

Criteria	Reasoning	Priority
Cable Failure	Identifying water tree samples throughout the service territory and varying age, the utility would be able to have an improved view on cable condition within the system. Sampling the distribution system would be a viable alternative. Currently, OPUCN collects historical cable failures, which may represent a good indication of the performance of cables in the surrounding areas.	**High**
Field Testing	Many test labs are offering partial discharge (PD) measurements to assess the condition of cables in service. Partial discharge testing of cables is performed online without disrupting the plant or facilities or offline when required. The data obtained from partial discharge test can provide critical information regarding the quality of cable insulation and its impact on cable system health.	**High**
Condition of Concentric Neutral	Corrosion of concentric neutrals is another mode of degradation. Insulation degradation and cable failures can be accelerated if cable jacket is damaged allowing moisture to enter into the insulation system. Concentric neutral corrosion is a major problem particularly on unjacketed cables or when the neutrals of the cable are exposed to excessive moisture over time. The corrosion can lead to premature cable failures and / or cause touch potential risks. Time Domain Reflectometry (TDR) tests are performed to determine the degree of corrosion on concentric neutral cables.	**Medium**
Loading History	Cable degradation can also occur due to overheating under overloading or short circuit conditions. Over stressing of insulation during voltage surges can also lead to cable failures.	**Low**

4.4 Distribution Transformer

OPUCN identifies and collects the major parameters that can be incorporated into a Health Index algorithm for distribution transformers. Additionally, OPUCN collects data through visual inspection cycles as well as IR scans and manages the asset risks through its maintenance routine.

4.5 Primary Switch, Smart Switch & Switchgear

Table 4-3: identifies asset condition criteria that affect the life expectancy for this asset class. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Currently, OPUCN collects data through visual inspection cycles as well as IR scans and manages the asset risks through its maintenance routine. However, we recommend for OPUCN to refine the current HIF framework that separates the Overall Condition criteria into multiple sub-criteria. The drawback with aggregate data is the underlying data may be lost moving forward and can be difficult to identify the main reason why the asset has an Overall Condition score of Poor. With the data fragmented, a system planner would be able to easily identify the reasons and make any necessary changes to prevent future assets experiencing similar degradations.

Table 4-3: End-of-Life Criteria for Switch & Switchgear

Criteria	Reasoning	Priority
Visual Inspection - Condition of Enclosure	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection - Condition of Interphase Barriers	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection and/or Corona testing - Condition of Terminations	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection - Condition of Blades	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Medium**
Visual Inspection - Condition of Operating Mechanism	Criterion affects life expectancy of switch. Identification of condition over time leads to degradation information of asset.	**Low**
Visual Inspection - Condition of Pad (If applicable)	The civil infrastructure that holds the asset is an important component to look at as it contributes to the foundation of the asset and as a barrier to the outside environment.	**Low**

4.6 Cut-out Arrestor & Elbow

OPUCN recognizes the major parameters that can be incorporated into the HIF for each asset group. There no major recommendations being made towards the HIF.

4.7 Recloser

Table 4-4: and Table 4-5: identify the condition criteria that affect the life expectancy for each recloser type. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation.

Table 4-4: End-of-Life Criteria for Oil Insulated Recloser

Criteria	Reasoning	Priority
Visual Inspection – Condition of Oil	Criterion affects life expectancy of a recloser. Identification of oil quality over time leads to degradation information of an asset.	High
Visual Inspection - Condition of Tank	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Medium
Visual Inspection - Condition of Terminations	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Medium
Counter Readings	Criterion affects life expectancy of a recloser. Identification of operation use over time leads to degradation information of an asset.	Medium
Visual Inspection - Condition of Operating Mechanism	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Low
Visual Inspection – Oil Leaks	Criterion affects life expectancy of a recloser. Identification of oil leaks over time leads to degradation information of an asset.	Medium

Table 4-5: End-of-Life Criteria for Vacuum Insulated Recloser

Criteria	Reasoning	Priority
Visual Inspection – Integrity of Vacuum Bottle	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	High
Visual Inspection - Condition of Enclosure	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Medium
Visual Inspection - Condition of Terminations	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Medium
Counter Readings	Criterion affects life expectancy of a recloser. Identification of operation use over time leads to degradation information of an asset.	Medium
Visual Inspection - Condition of Operating Mechanism	Criterion affects life expectancy of a recloser. Identification of condition over time leads to degradation information of an asset.	Low

4.8 Vault & Manhole

OPUCN identifies and collects the major parameters that can be incorporated into a HIF for vaults and manholes. However, METSCO recommends OPUCN to consider isolating the condition of the roof of the asset as a separate criterion as this component experiences the most wear and can be refurbished or renewed without needing to replace the whole structure.

4.9 Substation Power Transformer

Table 4-6: identifies the additional recommended condition criteria that affect the life expectancy for this asset class. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Moving forward, it is recommended to isolate testing results as individual criteria parameters into the Health Index Formulation in comparison to the current framework that aggregates all test results under one score. It is also advised for OPUCN to validate the data inputs and quality with respect to each of the identified end-of-life criteria in the current HIF. Additionally, METSCO recommends for OPUCN to refine the current HIF into a more detailed framework that explicitly highlights the end-of-life criteria rather than aggregating the sub-criteria into one criterion used in the HIF.

Table 4-6: End-of-Life Criteria for Power Transformer

Criteria	Reasoning	Priority
Infrared Scanning	To identify if the transformer is operating within normal temperature ranges – excess temperature would require further investigation.	**High**
Dissolved Gas Analysis	Increase of gas presence accelerates the degradation process. Identifying abnormal gas readings may present opportunity to intervene at an optimal time.	**High**
Oil Quality Test	Oil quality degradation affects the life expectancy of the asset. Continuous monitoring leads to degradation information over time.	**High**
Power Factor	Power factor assists in understanding how much a utility is required to generate the appropriate volt-amperes to supply real power to clients. More power required affects the whole distribution system and carries an increase in cost and risk.	**High**
Visual Inspection and/or Corona testing - Bushing Condition	Identifying defects to the bushings provides valuable condition data and more importantly if the issue is reoccurring after being addressed.	**Medium**
Visual Inspection - Main Tank Corrosion	Identifying presence of corrosion compromises the strength of the tank. Both the location and degree (low, medium, high) of rust presence should be captured over time.	**Medium**
Visual Inspection - Cooling Equipment	Identifying presence of corrosion/wear compromises the equipment. Both the location and degree (low, medium, high) of rust/wear presence should be captured over time.	**Medium**
Visual Inspection - Oil Tank Corrosion	Identifying presence of corrosion compromises the strength of the tank. Both the location and degree (low, medium, high) of rust presence should be captured over time.	**Medium**
Visual Inspection - Foundation	Identifying presence of wear compromises the foundation. Both the location and degree (low, medium, high) of wear presence should be captured over time.	**Low**

Field testing - Grounding	Identification of wear over time provides condition data of the grounding unit found in station transformers.	**Low**
Visual Inspection - Gaskets and Seals	Identification of wear over time provides condition data of the gaskets/seals found in station transformers.	**Low**
Visual Inspection - Connectors	Identification of wear over time provides condition degradation data of the asset.	**Low**
Visual Inspection - Oil Leaks	Identification of oil leaks, or residue and markings of oil leaks on equipment provides condition degradation data on the asset. Continuous problems would be addressed immediately for safe operation of asset.	**Low**
Visual Inspection - Oil Level	Identifying the oil level is within acceptable range of operation from previous inspection.	**Low**

4.10 Circuit Breakers

Table 4-7: identifies asset condition criteria that affect the life expectancy for this asset class. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Moving forward, it is recommended to isolate testing results as individual criteria parameters into the Health Index Formulation. Similarly seen for other assets, METSCO recommends for OPUCN to refine the current HIF into a more granular framework that explicitly highlights the end-of-life criteria rather than aggregating the sub-criteria into one criterion used in the HIF.

Lastly, OPUCN has recently installed SF6 circuit breakers. Though the condition of the assets has yet to be collected, METSCO provides OPUCN the asset criteria recommendations believed to be incorporated within a HIF.

Table 4-7: End-of-Life Criteria for SF6 Circuit Breakers

Criteria	Reasoning	Priority
SF6 Gas Analysis	Criterion affects life expectancy of a circuit breaker. Identification of gas quality over time leads to degradation information of an asset.	**High**
Visual Inspection - Condition Bushing Insulators	Criterion affects life expectancy of a circuit breaker. Identification of condition over time leads to degradation information of an asset.	**Medium**
Visual Inspection - Condition of Operating Mechanism	Criterion affects life expectancy of a circuit breaker. Identification of condition over time leads to degradation information of an asset.	**Medium**
Timing/Travel tests	Criterion affects life expectancy of a circuit breaker. Identification of operation use over time leads to degradation information of an asset.	**Medium**
Contact Resistance Tests	Criterion affects life expectancy of a circuit breaker. Identification of operation use over time leads to degradation information of an asset.	**Medium**
Visual Inspection – SF6 Leaks	Criterion affects life expectancy of a circuit breaker. Identification of leaks over time leads to degradation information of an asset.	**Medium**
Visual Inspection – Contact Resistance Tests	Criterion affects life expectancy of a circuit breaker. Identification of condition over time leads to degradation information of an asset.	**Low**

4.11 Relays & RTUs

Table 4-8: identifies asset condition criteria that affect the life expectancy for this asset class. A priority in terms of criteria contributing to the life expectancy for the asset is provided and can be used as a guideline for OPUCN to further enhance their Health Index Formulation. Moving forward it is recommended to isolate testing results as individual criteria parameters into the Health Index Formulation.

Table 4-8: End-of-Life Criteria for Protection Relays & RTUs

Criteria	Reasoning	Priority
Mean Time Between Failures	Objective test performed on the asset to determine MTBF values. Removes the subjectivity from the condition parameter within the Health Index.	**High**
Service Age	Basic age information of the asset will be able to align to the asset's typical useful life.	**High**
Obsolescence	Strategy driven from asset management or through manufacturer quality audits.	**High**
Overall Condition	Identifying external defects such as corrosion, connection conditions, evidence of overheating, counter readings for number of operations provides condition information for the asset's overall feature.	**High**
Defect and Test Reports	Objective reports performed on the asset to determine defects and test results. Removes the subjectivity from the condition parameter within the Health Index.	**High**

4.12 Substation Switchgears

OPUCN utilizes an under-developed Health Index algorithm for its substation switchgears, however it complements the current data collection by OPUCN. Table 4-9 identifies asset condition criteria that affect the life expectancy for this asset class that METSCO recommends for OPUCN to collect. A priority in terms of criteria contributing to the life expectancy for the asset is provided. Each criterion is identified as 'High' since the current Health Index algorithm is currently under-developed. Furthermore, METSCO recommends for OPUCN to refine the current HIF into a more detailed framework that explicitly highlights the end-of-life criteria rather than aggregating the sub-criteria into one criterion used in the HIF.

Table 4-9: End-of-Life Criteria for substation Switchgears

Criteria	Reasoning	Priority
Metal Clad Cubicle and Components	Visual condition rating of the cubicle and components provides a good indication of the condition of asset	**High**
Breaker Truck Condition	Visual condition rating of the breaker truck provides a good indication of the condition of asset	**High**
Control & Operating Mechanism	Visual condition rating of the control and operating mechanism provides a good indication of the condition of asset	**High**
Time/Travel Tests	Defined test provides unbiased indication of how the asset is performing and its condition	**High**
Contact Resistance Tests	Defined test provides unbiased indication of how the asset is performing and its condition	**High**
Oil Leaks	Criteria used for oil-type switchgears	**High**
Oil Analysis Test	Criteria used for oil-type switchgears	**High**
Arc Chutes	Criteria used for air-type switchgears	**High**
SF6 Leaks	Criteria used for SF6-type switchgears	**High**
SF6 Gas Tests	Criteria used for SF6-type switchgears	**High**
SF6 Coil Signature Test	Criteria used for SF6-type switchgears	**High**
Vacuum Bottle Integrity	Criteria used for vacuum-type switchgears	**High**

4.13 Battery & Charger, Ground Grids, and Fences

OPUCN recognizes the major parameters that can be incorporated into a HIF for these asset classes. METSCO recommends OPUCN to continue monitoring the asset's condition through regular maintenance inspection cycles and collecting all necessary data to evaluate the asset's condition.

5 Asset Replacement Plan

5.1 Purpose

Based on the condition assessment of major assets employed in substations, overhead lines and underground distribution system, this section provides the projected quantities of assets that would likely require replacement for the next short-term planning years 2019 to 2025.

The following major classes of assets are considered:

- Distribution Assets
  - Poles
  - Underground Primary Cable
  - Transformers
  - Switches
  - Switchgears
  - Cut-Out Arrestors & Elbows
  - Vaults & Manholes
- Station assets
  - Power Transformers
  - Circuit Breakers
  - Switchgears
  - Relays
  - Battery & Chargers
  - Ground Grids

Overhead conductors typically outlive the poles which support them. Therefore, they are typically replaced when poles are being renewed, and as such are not presented within this section. The exception is if the overhead conductor were to be a small sized conductor that carried a large risk of failing prematurely. If the exception is met, it is advised for the overhead conductor segment to be replaced as soon as possible. The long-term trending approach considers expected aging and degradation for each asset and attempts to smooth investment requirements over the planning period.

5.2 Approach

The ACA provides the Health Index distribution for each asset. The Health Index is a percentage score between 0 and 100, used to assess the condition of an asset. The condition-based intervention approach is shown in Table 5-1. This is a general approach, which can vary between assets and based on budget constraints. For each asset type, a range of quantity of asset replacements in each year is estimated. However, the replacements are based on Health Index, testing and field inspection of assets performed on the samples. Continuous monitoring of the asset by inspectors will provide current asset's condition assessment.

Table 5-1: Health Index definition and intervention approach

Health Index (%)	Condition	Intervention Approach
85 - 100	Very good	None
70 - 85	Good	None
50 - 70	Fair	Replace within 3-10 years
30 - 50	Poor	Replace within 1-3 years
0 - 30	Very poor	Replace immediately

In addition to the condition of the assets, the asset's age, specifically the Typical Useful Life (TUL), can be a determining driver for asset renewal because as the asset reaches and passes the TUL, the rate at which the asset's condition deteriorates increases. Furthermore, visual inspection records may result in a calculated Health Index to be in a favorable condition for an asset reaching or exceeding its TUL. However, the asset may carry an increased risk of failing and quickly deteriorating from a favorable condition (Very Good/Good) to an unfavorable condition (Very Poor) within a short period of time. Minimum, maximum and TUL values for OPUCN are assumed based on the *Asset Depreciation Study for the Ontario Energy Board* in 2010[3], as summarized in Table 5-2.

Table 5-2: Useful life measures for selected asset classes

Asset Class	Min. UL	TUL	Max. UL
Wood pole	35	45	75
Concrete pole	50	60	80
Steel pole	60	60	80
Underground cable (TR-XLPE direct buried)	25	30	35
Pole-mount transformer	30	40	60
Pad-mount transformer	25	40	45
Submersible / Vault transformer	25	35	45
Primary overhead switch / Smart switch	30	45	55
Switchgear	20	30	45
Recloser	25	40	55
Power transformer	35	45	60
Circuit breaker	35	45	65
Digital relay	15	20	20
Battery	10	15	15
Charger	20	20	30
Vault	40	60	80
Manhole	50	60	80

[3] Asset Depreciation Study for the Ontario Energy Board, Kinectrics Inc., 2010

5.3 Pole

The age and Health Index demographics are depicted in Table 5-3 and Table 5-4, respectively.

Table 5-3: Age distribution for pole

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Wood Pole	2596	1508	1849	870	477	2270
Concrete Pole	8	37	7	108	708	1
Steel Pole	6	0	5	0	2	1

Table 5-4: Health Index distribution for pole

Asset	Very Good	Good	Fair	Poor	Very Poor
Wood Pole	581	6129	2662	196	2
Concrete Pole	3	108	758	0	0
Steel Pole	6	5	3	0	0

To manage the in-service equipment failure at the current condition levels and managing the asset age demographic, Table 5-5 provides the replacement recommendation for asset renewal of poles expected to reach the end of their useful service life within the next seven years.

The replacement plan for wood poles prioritizes those poles that are rated as Poor and Very Poor and are past the TUL of a wood pole. Based on the large number of poles past the TUL, it is recommended for OPUCN to replace a portion of poles each year to manage the risk of poles failing due to age. However, the condition data collected to date does not support that wood poles past the TUL are experiencing unfavorable conditions and require attention for replacement. METSCO recommends for OPUCN to conduct a visual inspection on a subset of wood poles past the TUL to determine if the wood poles are in fact in acceptable service conditions or require asset intervention (i.e. asset renewal).

It is expected that with good risk management, the TUL could be extended to 55 years, in which case a decrease of wood pole replacement per year can be determined. With an optimal and balanced risk management, benefits can be realized within the asset management process. Benefits may include favorable customer service satisfaction, as there is a reduced need for planned outages, a consistent and decreased renewal budget that will reflect in minimal bill impacts and maintains the service reliability of the system.

Table 5-5: Projected replacement for pole

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Wood Pole	326	320	320	320	320	330	330
Concrete Pole	4	7	7	7	7	8	9

5.4 Underground Primary Cable

The age and Health Index demographics are depicted in Table 5-6 and Table 5-7, respectively.

Table 5-6: Age distribution for underground primary cable

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-45 Years	45+ Years
Underground Primary Cable (m)	155,681	123,990	93,233	60,055	21,890	5,476

Table 5-7: Health Index distribution for underground primary cable

Asset	Very Good	Good	Fair	Poor	Very Poor
Underground Primary Cable (m)	172,545	68,208	136,462	81,042	2,068

To keep the current levels of condition for the asset class, Table 5-8 provides the replacement recommendation for asset renewal of underground primary cable expected to reach the end of their useful service life within the next seven years. The replacement plan for underground primary cables prioritizes those that are rated as Poor and Very Poor and are past the TUL. By year 2025, approximately 60% of the currently identified Poor and Very Poor cables are targeted for replacement. The pace allows for OPUCN to manage replacement costs and to gradually replace the defective underground cables. METSCO recommends testing cables for replacement using proven test techniques to validate the condition of the cable is unfavorable and should be replaced. This will further assist OPUCN in correctly selecting which cables are to be replaced and which can remain in-service without accumulating additional capital costs.

Table 5-8: Projected replacement for underground primary cable

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Underground Primary Cable (km)	7.05	7.3	7.05	7.2	7.3	7.05	7.05

5.5 Transformer

The age and Health Index demographics are depicted in Table 5-9 and Table 5-10, respectively.

Table 5-9: Age distribution for distribution transformer

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Pole-mount transformer	679	666	508	537	105	18
Pad-mount transformer	1092	1078	697	707	190	1
Vault transformer	92	35	81	90	96	0
Submersible transformer	0	13	3	2	1	1

Table 5-10: Health Index distribution for distribution transformer

Asset	Very Good	Good	Fair	Poor	Very Poor
Pole-mount transformer	1219	1177	117	0	0
Pad-mount transformer	2065	1600	99	1	0
Vault transformer	167	201	26	0	0
Submersible transformer	8	11	1	0	0

To manage the asset age demographic, Table 5-11 provides the replacement recommendation for asset renewal of transformers expected to reach the end of their useful service life within the next seven years. Continuous monitoring of the asset's condition throughout the years will identify if any further condition degradation continues and if it is necessary to be replaced.

Distribution transformers are often managed on a run to failure scenario, or are replaced as a part of larger, planned renewal projects to minimize service disruptions impacts and maximize efficiency. The run to failure case is particularly true for overhead distribution transformers. Both cases will influence the replacement rate that OPUCN will plan for in the short term. Furthermore, old pole-mount transformers are typically found on old or failed wood poles and are replaced simultaneously for efficiency.

Pad-mount transformers near busy intersections that are exposed to salt and exhibit accelerated rusting should be replaced as soon as possible prior to failure. Pad-mount transformer that are not fully enclosed present a safety risk to the public and therefore should be managed on a proactive replacement.

The replacement plan for distribution transformers largely prioritizes assets that are beyond the TUL since there are limited numbers of transformers found in the Poor and Very Poor category. However, it is recommended for OPUCN to continue to inspect transformers planned for replacement. It is recommended for a transformer to be replaced if the condition of the transformer has deteriorated, otherwise OPUCN should consider continuing to operate and maintain the existing asset until a later date.

Table 5-11: Projected replacement for distribution transformer

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Pole-mount transformer	56	38	38	38	38	38	38
Pad-mount transformer	51	50	50	50	55	55	55
Vault transformer	11	11	12	12	11	12	11
Submersible transformer	0	1	1	0	0	0	0

5.6 Switch

The age and Health Index demographics are depicted in Table 5-12 and Table 5-13, respectively.

Table 5-12: Age distribution for switch

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Primary switch	433	156	284	80	43	5

Table 5-13: Health Index distribution for switch

Asset	Very Good	Good	Fair	Poor	Very Poor
Primary switch	588	365	48	0	0

To reduce the amount of assets beyond their TUL, Table 5-14 provides the recommended replacement for asset renewal of primary switches expected to reach the end of their useful service life within the next seven years. The replacement plan for primary switches prioritizes those that are approaching or past the TUL.

Table 5-14: Projected replacement for switch

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Primary switch	16	11	8	5	5	4	4

5.7 Switchgear

The age and Health Index demographics are depicted in Table 5-15: and Table 5-16:, respectively.

Table 5-15: Age distribution for switchgear

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Vault Switchgear	12	7	1	0	0	0
Padmount Switchgear	9	4	0	0	0	0

Table 5-16: Health Index distribution for switchgear

Asset	Very Good	Good	Fair	Poor	Very Poor
Vault Switchgear	18	2	0	0	0
Padmount Switchgear	10	3	0	0	0

Based on the ACA and age analysis, there is no recommended replacements within the next seven years. Should the switchgears continue to receive frequent maintenance, it is expected the assets will continue to perform well during tests.

5.8 Cut-Out Arrestor and Elbow

The age and Health Index demographics are depicted in Table 5-17: and Table 5-18, respectively.

Table 5-17: Health Index distribution for cut-out arrestor and elbow

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Cut-Out Arrestor	702	627	819	450	215	17
Elbow	3460	1439	1171	861	260	1

Table 5-18: Age distribution for cut-out arrestor and elbow

Asset	Very Good	Good	Fair	Poor	Very Poor
Cut-Out Arrestor	1110	989	209	481	41
Elbow	4899	2032	261	0	0

Table 5-19 provides the recommended replacement for asset renewal expected to reach the end of their useful service life within the next seven years. Continuous condition monitoring should be considered to capture additional datapoints to identify assets that may experience accelerated degradation. The replacement plan for these assets prioritizes those that are rated as Poor and Very Poor or to mitigate high-impact failures.

Furthermore, OPUCN has approximately 1175 porcelain transformer cut-out arrestors and 543 porcelain riser cut-out arrestors in-service. The target year OPUCN has set to completely remove porcelain assets from service is 2025 due to the associated safety risks.

Table 5-19: Projected replacement for cut-out arrestor and elbow

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Cut-Out Arrestor	50	52	52	50	62	69	65
Elbow	5	10	10	15	15	15	15

5.9 Recloser

Reclosers are a new asset class introduced in OPUCN system within the last 10 years. Based on the ACA and age analysis, there is no recommended replacements for reclosers within the next seven years.

5.10 Vault & Manhole

The Health Index demographics for vaults and manholes are depicted in Table 5-20.

Table 5-20: Health Index distribution for vault

Asset	Very Good	Good	Fair	Poor	Very Poor
Vault	16	130	0	0	0
Manhole	0	120	0	0	0

Based on the ACA analysis, there is no recommended replacements for vaults and manholes within the next seven years.

5.11 Power Transformer

The age and Health Index demographics are depicted in Table 5-21 and Table 5-22, respectively. No power transformers are beyond the TUL nor experiencing extreme condition degradation.

Table 5-21: Age distribution for power transformer

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Power transformer	9	1	1	5	0	0

Table 5-22: Health Index distribution for power transformer

Asset	Very Good	Good	Fair	Poor	Very Poor
Power transformer	8	6	2	0	0

To maintain the condition of in-service equipment and to improve the age distribution, Table 5-23 provides the recommended replacement for asset renewal of power transformers expected to reach the end of their useful service life within the next seven years. Although all transformers were rated as Fair or better, there are few transformers identified that OPUCN may consider completing a refurbishment or renewal.

MS10-T2 has a recommended target year of 2019 due to the latest test results receiving a Poor rating for the *Test Parameter* criteria for the HIF. This power transformer's condition should be continued to be monitored in case it experiences further degradation. The remaining identified power transformers have also received a less than acceptable oil quality analysis and should be targeted for asset replacement or rejuvenation. In addition, thee identified transformers in the table will reach the TUL of 45 years. Assets that are past or approaching the TUL may have positive visual inspection records resulting in an assets health to be in Fair condition. However, the asset carries an increased risk of failing and can quickly deteriorate from Fair to Very Poor. Therefore, it is beneficial for OPUCN to replace the power transformer prior to failing.

In addition, power transformers MS7-T1 and MS5-T2 have an anticipated replacement within the next planning period as they will approach the TUL between 2025-2031.

Table 5-23: Projected replacement for power transformer

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Power transformer	MS10-T2				MS14-T2	MS14-T1	MS7-T2

5.12 Circuit Breaker

The age and Health Index demographics are depicted in Table 5-24 and Table 5-25, respectively.

Table 5-24: Age distribution for circuit breaker

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Circuit breaker – 13.8kV	68	0	4	0	0	0
Circuit breaker – 44kV	16	0	0	0	0	0

Table 5-25: Health Index distribution for circuit breaker

Asset	Very Good	Good	Fair	Poor	Very Poor
Circuit breaker – 13.8kV	68	4	0	0	0
Circuit breaker – 44kV	16	0	0	0	0

Based on the ACA and age analysis, there is no recommended replacements within the next seven years. Should the circuit breakers continue to receive frequent maintenance, it is expected the assets will continue to perform well during tests.

5.13 Substation Switchgear

The age and Health Index demographics are depicted in Table 5-26 and Table 5-27 respectively, for substation switchgears.

Table 5-26: Age distribution for switchgear

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Switchgear	1	0	0	3	4	0

Table 5-27: Health Index distribution for switchgear

Asset	Very Good	Good	Fair	Poor	Very Poor
Switchgear	0	1	2	5	0

To manage the condition of in-service equipment at current levels and to manage the asset deterioration, Table 5-28 provides the recommended replacement for asset renewal of substation switchgears expected to reach the end of their useful service life within the next seven years. In multiple station locations, both switchgear buses have deteriorated, and both should be replaced within a short period between each installation for resource efficiency and adequate system planning.

Table 5-28: Projected replacement for switchgear

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Switchgear	-	MS13	MS7	MS11	MS5	MS2	MS10

5.14 Relay and RTU

The age and Health Index demographics are depicted in Table 5-29: and Table 5-30:, respectively.

Table 5-29: Age distribution for relay and RTU

Asset	0-5 Years	6-10 Years	11-15 Years	16-20 Years	>20 Years
Relay	9	44	18	0	0
RTU	0	0	8	0	0

Table 5-30: Health Index distribution for relay and RTU

Asset	Very Good	Good	Fair	Poor	Very Poor
Relay	16	9	46	0	0
RTU	0	0	8	0	0

To manage the age distribution of the in-service equipment, Table 5-31: provides the recommended replacement for asset renewal of relays and RTUs expected to reach the end of their useful service life within the next seven years. Continuous monitoring of the asset's condition throughout the years will identify if any further condition degradation continues and if it is necessary to be replaced. The replacement plan targets those assets approaching the TUL.

Table 5-31: Projected replacement for relay and RTU

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Relay	0	0	2	3	1	1	1
RTU	0	0	0	1	1	1	1

5.15 Battery and Charger

The age and Health Index demographics are depicted in Table 5-32 and Table 5-33, respectively.

Table 5-32: Age distribution for battery and charger

Asset	0-5 Years	6-10 Years	11-15 Years	16-20 Years	>20 Years
Battery	3	4	1	0	0
Charger	2	3	3	0	0

Table 5-33: Health Index distribution for battery and charger

Asset	Very Good	Good	Fair	Poor	Very Poor
Battery	5	3	0	0	0
Charger	4	4	0	0	0

To improve the age distribution of in-service equipment, Table 5-34 provides the recommended replacement for asset renewal of batteries that may reach the end of their useful service life within the next seven years. Batteries should be tested periodically, and should they begin to degrade, it is optimal to replace the asset. Chargers should be replaced if their test performance degrades.

Table 5-34: Projected replacement for battery

Quantity of Assets Recommended for Replacement							
Year	2019	2020	2021	2022	2023	2024	2025
Battery	-	MS10	MS2	MS13	MS11	MS15	MS7

5.16 Ground Grids

The age and Health Index demographics are depicted in Table 5-35 and Table 5-36, respectively.

Table 5-35: Age distribution for ground grid

Asset	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	51+ Years
Ground Grid	0	0	0	4	8	4

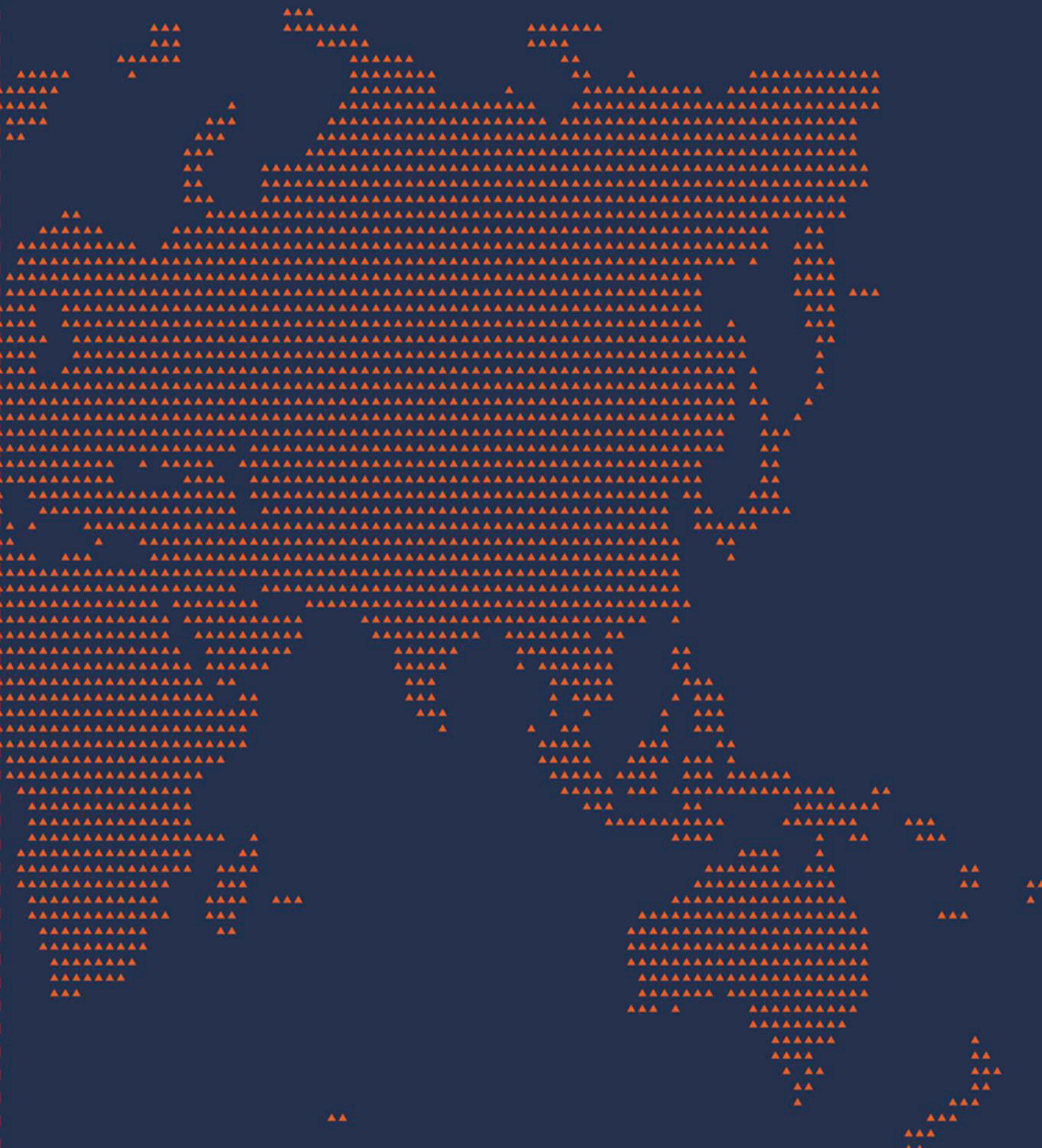
Table 5-36: Health Index distribution for ground grid

Asset	Very Good	Good	Fair	Poor	Very Poor
Ground Grid	0	0	16	0	0

Based on the ACA and age analysis, there are no recommended replacements within the next seven years. Should the ground grids continue to receive good maintenance, it is expected the assets will continue to perform well during tests. Should a ground grid receive a lower test result, an investigation should be completed to determine the root cause as well as appropriate remedial actions.

6 References

[1] International Organization for Standardization (2014). *ISO 55000*. Geneva: ISO.



Attachment 2 – 2

TRS Calculation

PROJECT PRIORITIZATION FORM

Invetment Category	System Renewal
Project Name	Pole Replacement Program
Cost	$2,374,750.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Very Likely (>95%)	High	491	147.42	Remote (<5%)	High-Medium	20	6.03
Reliability	**20%**	Very Likely (>95%)	High-Medium	181	36.15	Unlikely (5 to 25%)	Medium	15	2.96
Customer Focus	**20%**	Very Likely (>95%)	High-Medium	181	36.15	Remote (<5%)	Medium	7	1.48
Stewardship	**20%**	Very Likely (>95%)	High	491	98.28	Remote (<5%)	High-Medium	20	4.02
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**318.00**				**14.48**
Δ TRS		**303.52**							

PROJECT PRIORITIZATION FORM

Invetment Category	System renewal
Project Name	Overhead System Rebuild Program
Cost	$5,459,350.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Likely (65 to 95%)	High	382	114.66	Remote (<5%)	High-Medium	20	6.03
Reliability	**20%**	Likely (65 to 95%)	Low	7	1.40	Remote (<5%)	Low	1	0.20
Customer Focus	**20%**	Likely (65 to 95%)	Low	7	1.40	Remote (<5%)	Low	1	0.20
Stewardship	**20%**	Remote (<5%)	Low	1	0.20	Remote (<5%)	Low	1	0.20
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**117.66**				**6.63**
Δ TRS		**111.03**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Renewal
Project Name	UG System Rebuild - Program
Cost	$4,021,907.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Very Likely (>95%)	Medium	67	19.95	Remote (<5%)	Medium-Low	3	0.82
Reliability	**20%**	Very Likely (>95%)	High-Medium	181	36.15	Unlikely (5 to 25%)	Medium-Low	5	1.09
Customer Focus	**20%**	Very Likely (>95%)	Medium	67	13.30	Unlikely (5 to 25%)	Medium-Low	5	1.09
Stewardship	**20%**	Remote (<5%)	Low	1	0.20	Remote (<5%)	Low	1	0.20
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**69.60**				**3.19**
∆ TRS		**66.41**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Renewal
Project Name	Cable Injection Program
Cost	$540,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Somewhat Likely (25 to 65%)	Medium	37	11.08	Remote (<5%)	Medium	7	2.22
Reliability	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Remote (<5%)	Medium	7	1.48
Customer Focus	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Remote (<5%)	Medium	7	1.48
Stewardship	**20%**	Somewhat Likely (25 to 65%)	Low	5	1.00	Remote (<5%)	Low	1	0.20
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**26.86**				**5.37**
∆ TRS		**21.49**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Renewal
Project Name	Firon Switch Replacement Program
Cost	$1,250,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Likely (65 to 95%)	Medium	52	15.52	Remote (<5%)	Medium-Low	3	0.82
Reliability	**20%**	Likely (65 to 95%)	Medium	52	10.34	Remote (<5%)	Low	1	0.20
Customer Focus	**20%**	Likely (65 to 95%)	Medium	52	10.34	Remote (<5%)	Low	1	0.20
Stewardship	**20%**	Likely (65 to 95%)	Medium	52	10.34	Remote (<5%)	Low	1	0.20
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**46.55**				**1.42**
∆ TRS		**45.14**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Renewal
Project Name	Quick Sleeve Replacement Program
Cost	$1,000,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Somewhat Likely (25 to 65%)	High	273	81.90	Remote (<5%)	High	55	16.38
Reliability	**20%**	Somewhat Likely (25 to 65%)	High-Medium	100	20.09	Remote (<5%)	High-Medium	20	4.02
Customer Focus	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Remote (<5%)	High-Medium	20	4.02
Stewardship	**20%**	Somewhat Likely (25 to 65%)	Low	5	1.00	Remote (<5%)	Low	1	0.20
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**110.37**				**24.61**
∆ TRS		**85.76**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Renewal
Project Name	Overloaded Transformer Replacement Program
Cost	$1,068,524.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Somewhat Likely (25 to 65%)	Medium-Low	14	4.08	Remote (<5%)	Medium-Low	3	0.82
Reliability	**20%**	Very Likely (>95%)	Medium	67	13.30	Remote (<5%)	Medium-Low	3	0.54
Customer Focus	**20%**	Unlikely (5 to 25%)	Medium-Low	5	1.09	Remote (<5%)	Low	1	0.20
Stewardship	**20%**	Unlikely (5 to 25%)	Medium-Low	5	1.09	Remote (<5%)	Low	1	0.20
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**19.55**				**1.76**
Δ TRS		**17.79**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Renewal
Project Name	Distribution Switchgear Replacement Program
Cost	$1,172,695.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Unlikely (5 to 25%)	Medium	15	4.43	Remote (<5%)	Medium	7	2.22
Reliability	**20%**	Likely (65 to 95%)	High-Medium	141	28.12	Remote (<5%)	High-Medium	20	4.02
Customer Focus	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Remote (<5%)	Medium	7	1.48
Stewardship	**20%**	Somewhat Likely (25 to 65%)	Medium-Low	14	2.72	Remote (<5%)	Low	1	0.20
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**42.66**				**7.91**
∆ TRS		**34.75**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Renewal
Project Name	MS Switchgear Replacement Program
Cost	$5,357,774.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Likely (65 to 95%)	High-Medium	141	42.18	Remote (<5%)	Medium	7	2.22
Reliability	**20%**	Very Likely (>95%)	High-Medium	181	36.15	Remote (<5%)	Medium	7	1.48
Customer Focus	**20%**	Likely (65 to 95%)	High-Medium	141	28.12	Remote (<5%)	Medium	7	1.48
Stewardship	**20%**	Likely (65 to 95%)	High-Medium	141	28.12	Remote (<5%)	Medium	7	1.48
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**134.57**				**6.65**
∆ TRS		**127.92**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Renewal
Project Name	Meter Replacement Program
Cost	$5,500,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Very Likely (>95%)	Medium-Low	24	7.34	Remote (<5%)	Low	1	0.30
Reliability	**20%**	Very Likely (>95%)	Medium-Low	24	4.89	Remote (<5%)	Low	1	0.20
Customer Focus	**20%**	Very Likely (>95%)	Medium	67	13.30	Remote (<5%)	Low	1	0.20
Stewardship	**20%**	Very Likely (>95%)	Medium	67	13.30	Remote (<5%)	Low	1	0.20
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**38.83**				**0.90**
∆ TRS		**37.93**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Service
Project Name	3 New Feeders MS9
Cost	$1,000,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Somewhat Likely (25 to 65%)	Medium	37	11.08	Remote (<5%)	Medium-Low	3	0.82
Reliability	**20%**	Somewhat Likely (25 to 65%)	High-Medium	100	20.09	Remote (<5%)	Low	1	0.20
Customer Focus	**20%**	Somewhat Likely (25 to 65%)	High-Medium	100	20.09	Remote (<5%)	Low	1	0.20
Stewardship	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Remote (<5%)	Low	1	0.20
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**58.64**				**1.42**
∆ TRS		**57.23**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Service
Project Name	OH Automated Self Healing Switches
Cost	$1,695,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Somewhat Likely (25 to 65%)	Medium	37	11.08	Unlikely (5 to 25%)	Low	2	0.60
Reliability	**20%**	Likely (65 to 95%)	Medium	52	10.34	Unlikely (5 to 25%)	Low	2	0.40
Customer Focus	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Unlikely (5 to 25%)	Low	2	0.40
Stewardship	**20%**	Unlikely (5 to 25%)	Medium-Low	5	1.09	Unlikely (5 to 25%)	Medium-Low	5	1.09
Innovation	**10%**	Somewhat Likely (25 to 65%)	High	273	27.30	Very Likely (>95%)	Low	9	0.90
Total Risk Score (TRS)					**57.20**				**3.39**
Δ TRS		**53.82**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Service
Project Name	SCADA Equipment Upgrade
Cost	$350,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Unlikely (5 to 25%)	Medium	15	4.43	Unlikely (5 to 25%)	Medium	15	4.43
Reliability	**20%**	Likely (65 to 95%)	Medium	52	10.34	Unlikely (5 to 25%)	Medium	15	2.96
Customer Focus	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Unlikely (5 to 25%)	Low	2	0.40
Stewardship	**20%**	Unlikely (5 to 25%)	Low	2	0.40	Remote (<5%)	Low	1	0.20
Innovation	**10%**	Somewhat Likely (25 to 65%)	Medium-Low	14	1.36	Remote (<5%)	Low	1	0.10
Total Risk Score (TRS)					**23.93**				**8.09**
Δ TRS		**15.84**							

PROJECT PRIORITIZATION FORM

Invetment Category	System Service
Project Name	Non Wire Solutions
Cost	$715,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Remote (<5%)	Low	1	0.30	Remote (<5%)	Low	1	0.30
Reliability	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Remote (<5%)	Medium	7	1.48
Customer Focus	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Remote (<5%)	Medium	7	1.48
Stewardship	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Remote (<5%)	Medium	7	1.48
Innovation	**10%**			0	0.00			0	0.00
Total Risk Score (TRS)					**22.47**				**4.73**
Δ TRS		**17.73**							

PROJECT PRIORITIZATION FORM

Invetment Category	General Plant
Project Name	Enterprise Server Hardware / Software Upgrades
Cost	$955,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Likely (65 to 95%)	Low	7	2.10	Remote (<5%)	Low	1	0.30
Reliability	**20%**	Likely (65 to 95%)	Medium-Low	19	3.81	Remote (<5%)	Low	1	0.20
Customer Focus	**20%**	Likely (65 to 95%)	Low	7	1.40	Remote (<5%)	Low	1	0.20
Stewardship	**20%**	Likely (65 to 95%)	Low	7	1.40	Remote (<5%)	Low	1	0.20
Innovation	**10%**	Likely (65 to 95%)	Medium	52	5.17	Remote (<5%)	Low	1	0.10
Total Risk Score (TRS)					**13.88**				**1.00**
∆ TRS		**12.88**							

PROJECT PRIORITIZATION FORM

Invetment Category	General Plant
Project Name	ERP Software
Cost	$500,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Somewhat Likely (25 to 65%)	Low	5	1.50	Remote (<5%)	Low	1	0.30
Reliability	**20%**	Somewhat Likely (25 to 65%)	Low	5	1.00	Remote (<5%)	Low	1	0.20
Customer Focus	**20%**	Likely (65 to 95%)	Medium-Low	19	3.81	Remote (<5%)	Low	1	0.20
Stewardship	**20%**	Somewhat Likely (25 to 65%)	Low	5	1.00	Remote (<5%)	Low	1	0.20
Innovation	**10%**	Likely (65 to 95%)	High	382	38.22	Remote (<5%)	Low	1	0.10
Total Risk Score (TRS)					**45.52**				**1.00**
Δ TRS		**44.52**							

PROJECT PRIORITIZATION FORM

Invetment Category	General Plant
Project Name	Fleet Replacement Program
Cost	$2,300,000.00

OT		**Before**				**After**			
		Likelihood	**Consequence**	**Risk Value**	**Risk Score**	**Likelihood**	**Consequence**	**Risk Value**	**Risk Score**
Safety	**30%**	Likely (65 to 95%)	Medium	52	15.52	Unlikely (5 to 25%)	Medium	15	4.43
Reliability	**20%**	Somewhat Likely (25 to 65%)	Medium	37	7.39	Unlikely (5 to 25%)	Medium	15	2.96
Customer Focus	**20%**	Remote (<5%)	Low	1	0.20	Unlikely (5 to 25%)	Low	2	0.40
Stewardship	**20%**	Somewhat Likely (25 to 65%)	Medium-Low	14	2.72	Unlikely (5 to 25%)	Low	2	0.40
Innovation	**10%**	Unlikely (5 to 25%)	Medium-Low	5	0.54	Remote (<5%)	Low	1	0.10
Total Risk Score (TRS)					**26.37**				**8.29**
∆ TRS		**18.08**							

Attachment 2 – 3

Final Switchgear Invoice & SR-08 Material Justification Sheet

Remit To:

Black & McDonald Limited
75 COMMERCE VALLEY DRIVE EAST
MARKHAM ON L3T 7N9
Telephone: 647 794–2300
Fax: 905 881–0405

INVOICE

Black&McDonald

Invoice To:

Oshawa PUC Networks Inc.
100 SIMCOE ST S
OSHAWA ON L1H 7M7

Attention: AP

For Work At:

100 SIMCOE ST S
OSHAWA ON L1H 7M7

Invoice No.	**42–1624293**
Invoice Date	Apr 23 / 24
Our Division	4203–Substations
Our Job No.	42030301
Our Customer No.	139631
Your Ref. No.	63051

Project: OPUC MS2 NEW SWITCHGEAR
Removal and Replacement of 15K

Application for Holdback Release (10% of $2,658,053.75)

Progress Application No.	7		
Original Contract Amount		2,230,750.00	
Approved Changes To Date		644,178.75	
Revised Contract Amount		2,874,928.75	
Work Completed To	Mar 31 / 24		2,658,053.75
Less: Previously Invoiced			2,658,053.75
Release of Holdback			265,805.38

Subtotal	265,805.38
HST	34,554.70

Please Pay This Amount: CAD 300,360.08

TERMS: **Due Upon Receipt**
Interest at 18% per annum charged on overdue accounts

GST/HST No. **100537976**

R5648507A_BME002

Back–Up Detail

Invoice No.: 42–1624293 **Our Job No.:** 42030301 **Invoice Date:** Apr 23 / 24

Contractor: Black & McDonald Limited **Your Ref. No.:** 63051 **Work Completed To:** Mar 31 / 24 **Progress Application No.:** 7

Item No	Description of Work	Scheduled Value	To Date		Previous		This Period		Remaining Balance	
			%	$	%	$	%	$	%	$
	Original Contract									
1	AWARD	223,075.00	100.0%	223,075.00	100.0%	223,075.00	0.0%	0.00	0.0%	0.00
2	DECOMMISSIONING MS–2	328,500.00	100.0%	328,500.00	100.0%	328,500.00	0.0%	0.00	0.0%	0.00
3	CABLE DELIVERY	167,306.25	100.0%	167,306.25	100.0%	167,306.25	0.0%	0.00	0.0%	0.00
4	SWITCHGEAR DELIVERY	334,612.50	100.0%	334,612.50	100.0%	334,612.50	0.0%	0.00	0.0%	0.00
8	MOBILIZATION	369,000.00	100.0%	369,000.00	100.0%	369,000.00	0.0%	0.00	0.0%	0.00
9	ENERGIZATION OF SITE MS–2	176,274.95	100.0%	176,274.95	100.0%	176,274.95	0.0%	0.00	0.0%	0.00
10	CABLE INSTALL MS–2	151,443.80	100.0%	151,443.80	100.0%	151,443.80	0.0%	0.00	0.0%	0.00
11	COMPLETION OF TOTAL PERFORMANC	369,000.00	100.0%	369,000.00	100.0%	369,000.00	0.0%	0.00	0.0%	0.00
17	COMPLETION OF ENGINEERING	111,537.50	100.0%	111,537.50	100.0%	111,537.50	0.0%	0.00	0.0%	0.00
	Subtotal	**$2,230,750.00**	0.0%	**$2,230,750.00**	0.0%	**$2,230,750.00**	0.0%	**$0.00**	0.0%	**$0.00**
	Original Contract Total	**$2,230,750.00**	100.0%	**$2,230,750.00**	100.0%	**$2,230,750.00**	0.0%	**$0.00**	0.0%	**$0.00**

Item No	Description of Work	Scheduled Value	To Date %	To Date $	Previous %	Previous $	This Period %	This Period $	Remaining Balance %	Remaining Balance $
	Approved Changes									
CO–01	BAE Battery and Charger	15,500.00	100.0%	15,500.00	100.0%	15,500.00	0.0%	0.00	0.0%	0.00
CO–02	Hardware for SCADA	15,000.00	100.0%	15,000.00	100.0%	15,000.00	0.0%	0.00	0.0%	0.00
CO–03	New LV Control wire/conduit an	35,000.00	100.0%	35,000.00	100.0%	35,000.00	0.0%	0.00	0.0%	0.00
CO–04	S&I Add'l CopperCab (867.5K/4)	216,875.00	100.0%	216,875.00	100.0%	216,875.00	0.0%	0.00	0.0%	0.00
CO–05	S&I Add'l CopperCab (867.5K/4)	216,875.00	0.0%	0.00	0.0%	0.00	0.0%	0.00	100.0%	216,875.00
CO–06	Duct Banks & Riser Poles	127,000.00	100.0%	127,000.00	100.0%	127,000.00	0.0%	0.00	0.0%	0.00
CO–07	Foundation Removal	17,928.75	100.0%	17,928.75	100.0%	17,928.75	0.0%	0.00	0.0%	0.00
	Subtotal	**$644,178.75**	0.0%	**$427,303.75**	0.0%	**$427,303.75**	0.0%	**$0.00**	0.0%	**$216,875.00**
	Approved Changes Total	**$644,178.75**	66.3%	**$427,303.75**	66.3%	**$427,303.75**	0.0%	**$0.00**	33.7%	**$216,875.00**

Back–Up Detail

Invoice No.: 42–1624293 **Our Job No.:** 42030301 **Invoice Date:** Apr 23 / 24

Contractor: Black & McDonald Limited **Your Ref. No.:** 63051 **Work Completed To:** Mar 31 / 24 **Progress Application No.:** 7

Item No	Description of Work	Scheduled Value	To Date		Previous		This Period		Remaining Balance	
			%	$	%	$	%	$	%	$
	Total	**$2,874,928.75**	92.5%	**$2,658,053.75**	92.5%	**$2,658,053.75**	0.0%	**$0.00**	7.5%	**$216,875.00**

Submitted By: ______________________________ Date:____________________________________

Approved By: ______________________________ Date:____________________________________

STATUTORY DECLARATION

DOMINION OF CANADA

IN THE MATTER OF A SUBCONTRACT entered into with:

Oshawa PUC Networks Inc.
Removal & Replacement of 15KV Switchgear
MS-2

Your Ref No. 63051
Our Job# 42030301

Province of Ontario

To Wit:

I Tedi Gura of the City of Toronto in the Province of Ontario do solemnly declare:

1. That I am Assistant Controller of Black & McDonald Limited (the "Corporation") and as such have personal knowledge of the facts hereunder declared and the ability to bind the Corporation.

2. That, other than amounts withheld by reason of legitimate dispute, all the sub-contractors, labour, and accounts for materials, products, services and equipment due and owing by the Corporation in the performance of the work as required by the Subcontract have been duly paid up to and including the last progress payment received.

3. That, if applicable, the wages paid are in all cases the same as or above those set out in the Schedule of Wages attached to and forming part of the said Subcontract.

4. That all amounts owing, up to and including the last progress payment received, for workmen's compensation, employees' income tax deducted at source, unemployment insurance deducted from wages and salaries, vacation with pay allowances and all other charges of whatsoever nature due or payable, by reason of the performance of that portion of the work covered by the said Subcontract, have been duly deducted and/or paid according to law.

And I make this solemn declaration conscientiously believing it to be true and knowing that it is of the same force and effect as if made under oath and by virtue of the *Canada Evidence Act*.

DECLARED BEFORE ME AT

the City of Toronto

County of York

this 23rd day of April 2024

Signature of Declarant

A Commissioner for taking oaths, etc.

Lawrence Ho-Yin Ip, a Commissioner, etc.,
Province of Ontario, for Black & McDonald Limited
and its subsidiaries, associated companies,
and affiliates.
Expires October 28, 2026.

Your clearance(s) / Vos certificats de décharge

We confirm that the business(es) listed below are active and in good standing with us.
Nous confirmons que la ou les entreprises énumérées ci-dessous sont actives et que leurs comptes sont en règle.

Contractor legal or trade name / Raison sociale ou appellation commerciale de l'entrepreneur	Contractor address / Adresse de l'entrepreneur	Contractor NAICS Code and Code Description / Code du SCIAN de l'entrepreneur et description	Clearance certificate number / Numéro du certificat de décharge	Validity period (dd-mmm-yyyy) / Période de validité (jj-mmm-aaaa)
BLACK & MCDONALD LIMITED / SOUTHERN ONTARIO ELECTRICAL UTILITY REGION	75 COMMERCE VALLEY DR E, ATTN SALARY PAYROLL DEPARTMENT, THORNHILL, ON, L3T7N9, CA	237130: Power and communication line and related structures construction 238210: Electrical contractors and other wiring installation contractors	A0000J1CJD	20-Feb-2024 to 19-Aug-2024

Under Section 141 of the *Workplace Safety and Insurance Act*, the WSIB waives our right to hold the principal (the business that has entered into a contractual agreement with the contractor/subcontractor) liable for any unpaid premiums and other amounts the contractor may owe us for the validity period specified.
Aux termes de l'article 141 de la *Loi sur la sécurité professionnelle et l'assurance contre les accidents du travail*, la WSIB renonce à son droit de tenir l'entrepreneur principal (l'entreprise qui a conclu une entente contractuelle avec l'entrepreneur ou le sous-traitant) responsable de toute prime impayée et autre montant que l'entrepreneur pourrait lui devoir pour la période de validité indiquée.

A. General Information (5.4.3.2.A)					
Project/Activity	Municipal Substation Switchgear Replacement Program				
Project Number	SR-08				
Investment Category	System Renewal				
	2021	2022	2023	2024	2025
Capital Cost	$1,800,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$1,800,000	$1,800,000	$1,800,000	$1,800,000	$1,800,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					

Customer Attachments and Load are not expected to change with the execution of this program, however improvements to system components will positively affect the following:

Customer Attachments: approximately 40,000 customers
Load: 120 MW

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	$900,000	$900,000	-
Project Summary				

Existing switchgears including relays and e-house at MSs – MS2, MS5, MS7, MS11 and MS13 have been identified in the ACA as having a poor condition and exceeding their TUL. These switchgears require replacement within the next six years (2021-2025) as they are a reliability risk serving more than half of OPUCN’s customer base. The existing line-up will be replaced with a new switchgear that meets current industry standards.

The age of the switchgears as of 2020 are as follows:

Substation	Age
MS2	36
MS5	46
MS7	52
MS11	52
MS13	52

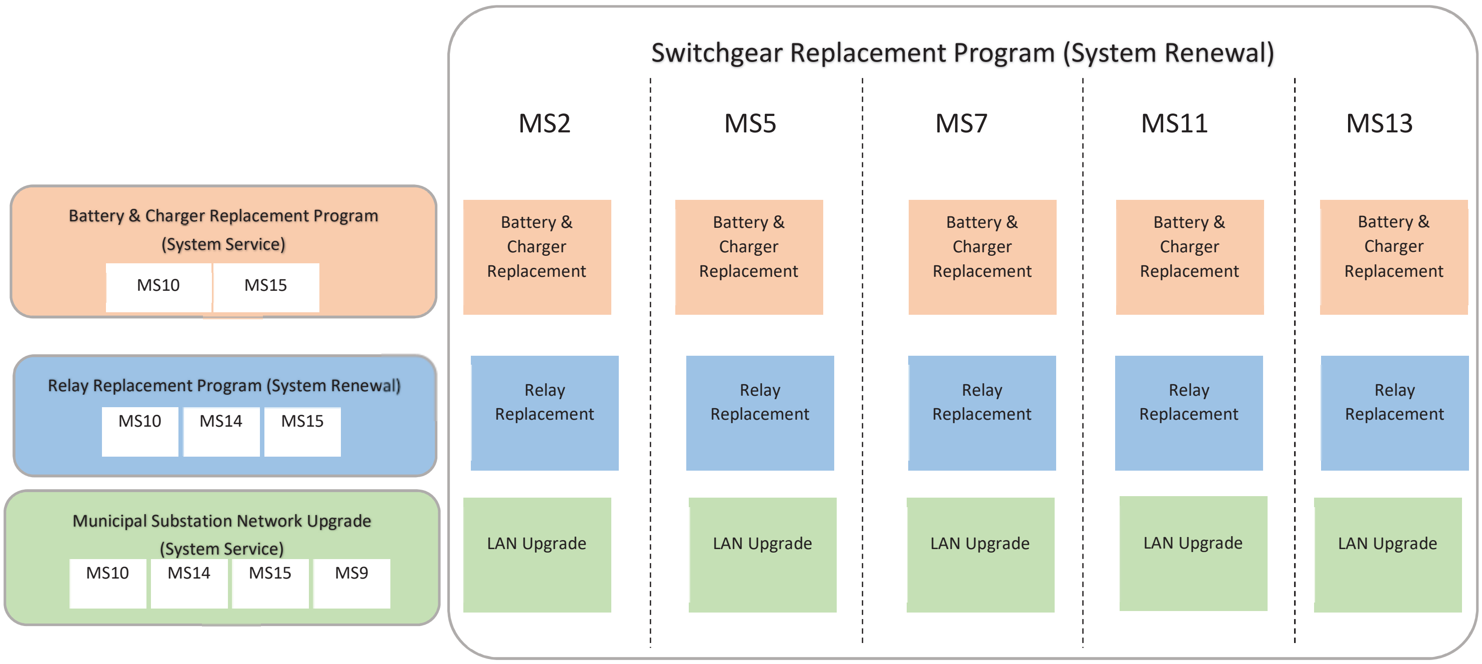


Figure 30-Coordination of Interdependent Substation Projects

The Switchgear Replacement Program will be incorporating new MS battery charger & battery condition monitoring (see Station Battery and Battery Charger Replacement under System Service), relay replacements and new LAN network (See Substation Cybersecurity LAN Upgrade under System Service) for the above-mentioned switchgears. The individual Battery & Charger Replacement Program (System Service), Relay Replacement Program (System Renewal) and Municipal Substation LAN Upgrade Program (System Service) will address other MSs that the Switchgear Replacement Program will not be addressing.

Risk Identification & Mitigation

Scheduling Risk – The main risk is manufacture lead/delivery time. The risk will be mitigated by developing the project plan and placing the equipment order well in advance.

Resource Risk – Timely consultation among the design and construction teams ensures proper resource allocation to complete the work on schedule. OPUCN employs contract resources as necessary, to mitigate the scheduling risks.

Comparative Information on Expenditures for Equivalent Projects/Activities

A 15 kV switchgear including e-house and relays was replaced in 2014 at a total project cost of $1.63 million, as seen in Appendix AA. The proposed total estimated cost of the switchgear and relay replacement has increased to $1.8 million per switchgear due to inflation and changes to equipment cost.

REG Investment Details including Capital and OM&A costs

The protection relays are modern based relays that are capable of dealing with reverse power flow to accommodate REG applications but there does not exist a direct REG investment on this project.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Please refer to the ACA in Appendix B.

The following are images of a recent 2020 outage incident due to short circuit in one of OPUCN's MS switchgear being proposed to replace.

Figure 31: Images of a recent outage at a OPUCN owned switchgear

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)

Efficiency, Customer Value & Reliability – Investment Main Driver

This program falls under System Renewal Investment driver and aimed at addressing existing reliability concerns. When a MS switchgear fails, outages can be extensive and may last for extended periods of time. This program will reduce the risk of prolonged power interruptions and reduce the frequency of power interruptions due to the equipment failure. This program will

also address Operational Efficiency and Safety. Allowing old and deteriorating equipment in the field can result in significant safety and reliability concerns to OPUCN staff and customers. This project aligns with the guidelines of the Grid Modernization Plan. The installation of advanced communication (substation LAN) and new relays will facilitate a better communication traffic (e.g. lower latencies, more bandwidth) for a smarter grid. The installation of battery condition monitoring system will utilize new technology to provide real-time condition of the station back-up power.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objectives are to mitigate the risk of lengthy customer interruptions.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
The source of the information used to justify this project investment is the ACA which was prepared taking into account all the information pertaining to the condition of the assets.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
This program will replace switchgears in poor condition and at the end of their service life to prevent potential failures that can cause extended outages and safety risks.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
Priority is very high due to the poor condition of this equipment and its potential impact to a large number of customers in the event of a failure. This program also addresses most of OPUCN's AM objectives identified in Section 5.3.1 receiving the highest priority in all capital investment projects and programs identified in the DSP. A failure could result in a complete loss of supply from the MS requiring load transfer to another MS. Each transfer could be very challenging which may take several hours and may result in overloading conditions to other facilities.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
A planned replacement is the preferred alternative for these assets because it allows OPUCN to proactively mitigate the failure risk posed by end-of-life and poor condition of MS switchgears within the distribution system and thereby, reduce the risk of outages to customers. The replacement will also provide better system operation efficiency and will minimize preventative maintenance work required.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Customers will benefit from a more reliable electrical infrastructure. Net benefits accruing to the customers have been qualitatively described above but have not been quantitatively calculated because accurate information on the customer interruption costs is not readily available.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages

The switchgear replacement program will maintain or improve reliability by reducing the risk of prolonged outages which will also mitigate outage costs.
Project Alternatives (Design, Scheduling, Funding/Ownership)
The alternative to replacing the switchgear is to do nothing. This alternative is not feasible because allowing old and deteriorating equipment in the field stay in service can result in significant safety concerns, lengthy customer outages and increased in O&M costs.
Safety
These investments are directly linked to the public and worker safety, as they aim to eliminate the switchgear with high risks of catastrophic failure. Additionally, modern protection and controls, capable of responding automatically to mitigate unsafe conditions will provide better public safety.
Cyber-Security, Privacy (where applicable)
Switchgear units will be controlled remotely through a restricted and dedicated substation private fiber loop and SCADA. Switchgears will include new substation LAN design which segregates the substation LAN from other substation LANs as a security control for cybersecurity. Please refer to "Municipal Substation Network Upgrade" project for more details.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Switchgears and relays will conform to ESA, CSA, IEEE and other applicable standards. The cybersecurity components is based on OEB Cybersecurity Framework which was developed following the National Institute of Standards and Technology (NIST) Standards.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The protection relays will be modern relays that will be capable of integrating and interacting with future smart grid devices. This project also include new technology with battery condition monitoring (see Station Battery and Battery Charger Replacement under System Service), IEC61850 interoperable relays and new substation LAN design (refer to "Municipal Substation Network Upgrade" project).
Environmental Benefits (where applicable)
There are no significant environmental benefits as a result of these investments.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity

The protection relays will be modern relays that will be capable of integrating and interacting with future smart grid devices. This project also include new technology with battery condition monitoring (see Station Battery and Battery Charger Replacement under System Service), IEC61850 interoperable relays and new substation LAN design (refer to "Municipal Substation Network Upgrade" project).

C. Category-Specific Requirements – System Renewal (5.4.3.2.C)
Asset Performance-Related Operational Targets & Asset Lifecycle Optimization Policies and Practices
Assets planned for replacement in this program are deteriorated to the point that they must be replaced. Proceeding with these projects will improve the operational effectiveness of the system and maintain SAIDI and SAIFI performance.
Information on the Condition of the Assets Relative to their Typical Life-Cycle and Performance Record
At the time of the replacement, the existing switchgears will be more than 45 years old on average. Please refer to the ACA for additional information on the existing condition.
The Number of Customers in Each Class Potentially Affected by Failure of the Assets
Number of Residential Customers: 41007 Number of Commercial Customers: 3039 Number of Industrial Customers: 450 Others (Generation Connection): 275
Quantitative Customer Impacts
The main impact of this project on the customers is mitigating the risk of SAIDI and SAIFI worsening due to the anticipated failures of the equipment determined to be in poor or very poor condition. The quantitative customer impacts beyond the completion of the project are indeterminate.
Qualitative Customer Impacts
Failure of this equipment will negatively impact the electricity supply to many residential, commercial and industrial customers.
Value of Customer Impact in Terms of Characteristics of Customers Potentially Affected by Failure that have Bearing on the Criticality and/or Cost of Failure
The customers will receive value through reduced unplanned outages and enhanced reliability.
Timing and Priority of the Project
5 switchgears will be replaced over the forecast period. Although all are considered to be of high or very high priority, priorities among these may shift.
Consequences for System O&M Costs
The switchgear replacement program will help reduce system O&M costs through reductions in reactive maintenance spending.
Impact on Reliability Performance and/or Safety

The proposed switchgear replacement equipment is more reliable and safer due to arc resistant construction. The modern protection relays and new switchgear will offer major benefits for public and worker safety by reacting to the faults on the system.
Analysis of Project Benefits and Timing
This project offers a high benefit for risk mitigation and maintaining service quality with enhanced reliability.
Like for Like Renewal Analysis, Alternative Comparison (Like for Like vs. Not Like for Like, Timing, Rate of Replacements, etc.)
The switchgear and relay replacement program will be designed to improve operating and maintenance efficiencies. All of the equipment and designs will be specified to meet the current version of applicable standards and to fully meet the current and the future needs of the customers.

Attachment 2 – 4

Capital Change Management Form

CAPITAL PROJECT CHANGE MANAGEMENT FORM

Capital Change Management #: C20-224-CCM2020 Date: 4/Nov/20

Work Order Number	C20-224	**Rate Application Ref. #**	N/A
DSP Budget Item (Y/N)	N		
Project Title	Simcoe/Winchester - System Reliability Improvements		
Investment Category	System Service		

Lifetime Budget: $829,293.04 **Requestor:** Zeeshan Syed

	Unplanned Addition	Carried Forward	Cancelled	Advanced Spending
Change				

2020 Adjusted Plan: $829,293.04

Create Form

Sign-Off:

Requestor:	Zeeshan Syed	05th Nov 2020 **Date**
Capital Coordinator:		**Date**
Executive:		NOV 5/20 **Date**

Unplanned Addition unpl

New Project?

Budget Adjustment?

Budgeted in Other Years? YES **If yes, from which year?**

N/A Future

Reason for Unplanned Addition:

Due to reliability issues in the north part of the city. Project C13-258 was aimed to reduce the reliability issues in the north part of the city as well relocate the assets for the region of Durham. However, the job was planned in such a way that it had future scope of work attached with, and completing the job without performing the future work in not going to help the reliability issue. We would like to advance this future project because of the construction feasibility and actually acheiveing the reliability target as follows: 1- Reducing number of customers on 7F4, 2- Express feed for rural oshawa, 3-Transferring load to MS9

Carried Forward **Delayed to Budget Year:** carr

Reason for amount Carried Forward :

Cancelled canc

Reason for Cancellation :

Advanced Spending adva

Advance spending in which year(s)?

Reason for Advance Spending:

Zeeshan Syed

From: Lee Bayley
Sent: Wednesday, September 9, 2020 4:08 PM
To: Zeeshan Syed
Subject: RE: Simcoe Winchester Scope Planning

Ok, do you want me to take one out? And a new Capitol Enhancement one? Eg. C20-224

From: Zeeshan Syed <zsyed@opuc.on.ca>
Sent: September 9, 2020 4:04 PM
To: Lee Bayley <lbayley@opuc.on.ca>
Subject: RE: Simcoe Winchester Scope Planning

Hi Lee,

No, that is for the 44kV extension to 407 through Mike's job.

This will be new work order number.

Regards,
Z

From: Lee Bayley <lbayley@opuc.on.ca>
Sent: Wednesday, September 9, 2020 4:00 PM
To: Zeeshan Syed <zsyed@opuc.on.ca>
Subject: RE: Simcoe Winchester Scope Planning

HI Z,
Is the work order number for this going to be C20-220?
Thanks
Lee

From: Zeeshan Syed <zsyed@opuc.on.ca>
Sent: August 28, 2020 2:13 PM
To: Lee Bayley <lbayley@opuc.on.ca>; Mathias Ng <mng@opuc.on.ca>; Matthew Strecker <mstrecker@opuc.on.ca>; Len Koech <lkoech@opuc.on.ca>; Roger Ersil <rersil@opuc.on.ca>; Marie Hoecke <mhoecke@opuc.on.ca>; Mike Weatherbee <mweatherbee@opuc.on.ca>; Zowie Vonkalckreuth <ZVonkalckreuth@opuc.on.ca>
Subject: RE: Simcoe Winchester Scope Planning

Hi All,

This is with reference to our conversation yesterday, please find our action items below:

1. Lee will providing quick estimate of the increased scope of work.
2. Z and Zowie will compare the estimate with the amount of money left from Enfield budget.
3. Z will get the project change management process initiated and get it approved by Matt.
4. Lee and Z will get the extra material ordered by the end of next week.

5. Lee to ask Westmore for extras related to this change in scope.

Please include if I missed anything.

Regards,
Z

-----Original Appointment-----
From: Lee Bayley <lbayley@opuc.on.ca>
Sent: Friday, August 14, 2020 9:47 AM
To: Lee Bayley; Zeeshan Syed; Mathias Ng; Matthew Strecker; Len Koech; Roger Ersil; Marie Hoecke; Mike Weatherbee; Zowie Vonkalckreuth
Subject: Simcoe Winchester Scope Planning
When: Thursday, August 27, 2020 12:00 PM-1:00 PM (UTC-05:00) Eastern Time (US & Canada).
Where: Included drawings and Len's proposed schematic with Meeting invite.

Good morning,
Here is the meeting to talk about what the scope of the next Phase will be at Simcoe and Winchester.
Please forward this meeting to anyone I might have missed that might be interested.
Thanks
Lee

Please join my meeting from your computer, tablet or smartphone.
https://www.gotomeet.me/ZeeshanEjaz/war-room

You can also dial in using your phone.
Canada: +1 (647) 497-9391<tel:+16474979391,,774495581>

Access Code: 774-495-581

More phone numbers
United States: +1 (312) 757-3129<tel:+13127573129,,774495581>

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https://global.gotomeeting.com/install/774495581

Zeeshan Syed

From:	Len Koech
Sent:	Thursday, July 30, 2020 1:18 PM
To:	Zeeshan Syed; Lee Bayley
Cc:	Roger Ersil; Control Room; Mike Weatherbee; Mathias Ng; Matthew Strecker
Subject:	Simcoe and Winchester Rebuild
Attachments:	13KV DIAGRAM_Rev19 May 30 ip Simcoe Winchester Reconfig.dwg; 13KV DIAGRAM_Rev19 May 30 ip Simcoe Winchester Reconfig-Revised.pdf; 2019 10-23 Distribution System Planning Meeting Minutes.docx

Team,

Upon further review of the duct bank schematic drawing, we can still configure the Simcoe Winchester intersection optimally if we consider the attached configuration. I have attached both AutoCad and PDF for easier access.

Initially, the plan was to transfer load from 7F2 to the 9F1 through Conlin as per the drawing. This plan would further improve reliability and balance the load between feeders servicing this area. We had a feasibility meeting With Mike Lugtenburg and Lori, and that plan was put on hold as the Region is planning to widen the road on Conlin in the next few years. All this is captured in the attached Distribution System Planning meeting minutes. Also in the minutes document, you can see the interim solution reached was to Switch around the 9F2 to feed to just north of Conlin on Simcoe. This would achieve 3 goals, reduce customer count on the 7F4, reduce loading at MS7 and separate Rural Oshawa customers from the Subdivisions which was agreed upon in one of the reliability meetings. That is why we were surprised when the Construction drawings came out for this intersection

Loading has been an issue at MS7, just a few weeks ago, we had the Wilson M18 lockout that was feeding half of M7, the T2. When it locked out, 7T2 load was transferred to 7T1 through the station tie. This transfer increased loading on the T1 transformer to 1600 amps, it is rated for 1381 amps or 33MVA on Full cooling. This lockout happened after hours and it's a good thing the PME's respond to Feeder lockouts and were able to immediately respond and check how the transformer was handling it and if all fans were running.

In the Re-config drawing, 1 position is left for future growth, once 9F1 feeder is built and put in service, we will have little to no load on the 9F2 that can feed any potential growth in the North. Please have a look and advise.

Thanks,

Oshawa Power
Proudly Serving Oshawa with a Lifetime of Power

Len Koech
Distribution System Operator | Oshawa Power
(905) 723-4626 x5235 | Cell (905) 439-0216
lkoech@opuc.on.ca | www.opuc.on.ca

Oshawa Power	**DISTRIBUTION SYSTEM PLANNING MEETING MINUTES** Meeting Date: October 23, 2019 10:00AM – 10:30AM EST Meeting Location: Meeting Room, Oshawa Power

Attendees	E Andres (EA), L Bootsma (LB), R Ersil (RE), L Koech (LK), M Lugtenburg (ML)
Prepared by:	EA
Reviewed by:	

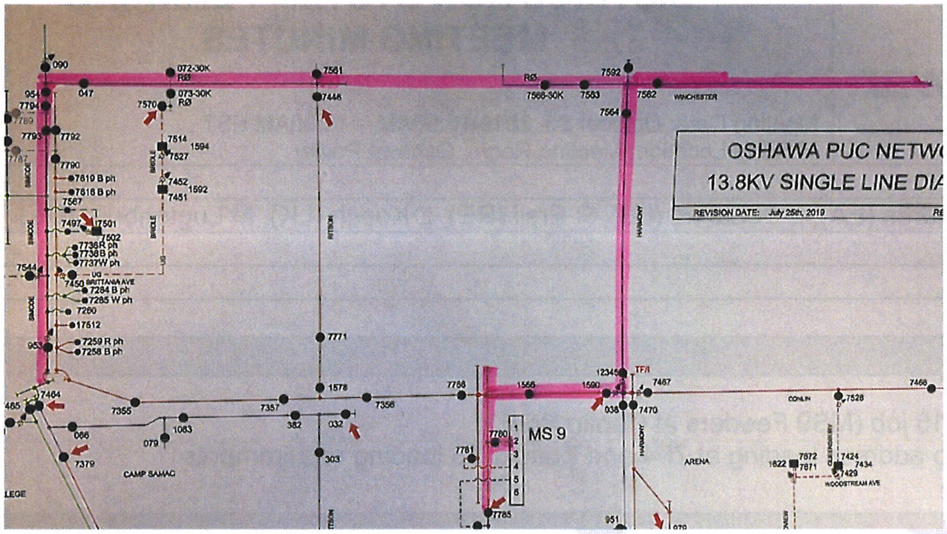
Agenda

1. Review of C18-215 job (MS9 Feeders at Conlin Rd E)
2. Interim solution to address loading at 7F4 and Enfield TS loading requirements

Minutes

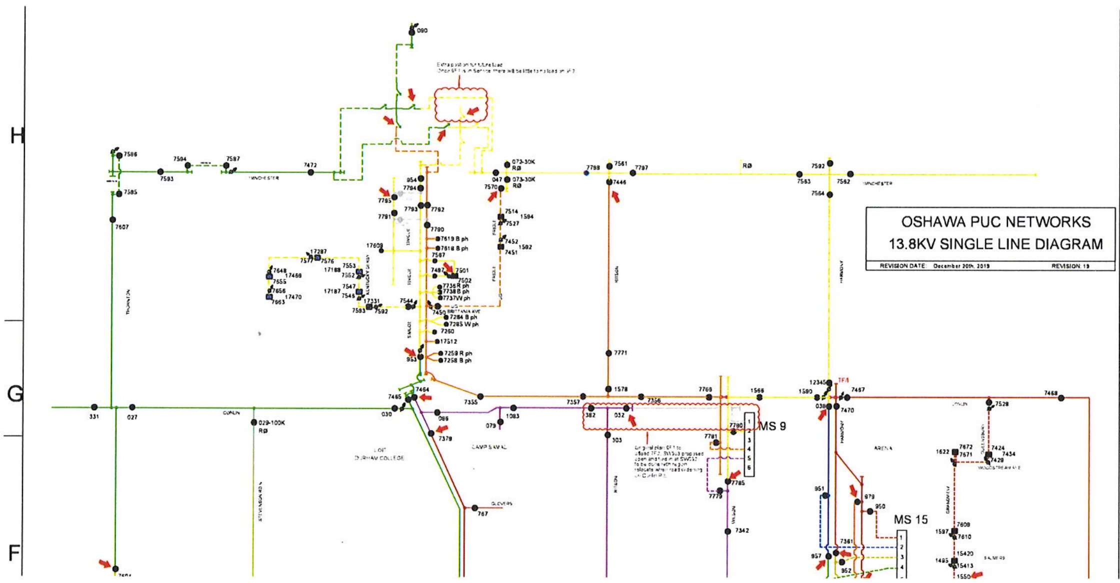
#	Item Description	Action	Due Date
1	C18-215 MS9 Feeders at Conlin Rd E • This project was initially created to address the increasing load in north Oshawa particularly 7F4 as part of the MS9 and Enfield TS station work. The completion of this project will enable Oshawa Power to transfer load and customers to MS9 and ultimately Enfield TS. This will also further improve reliability and balance the load between feeders servicing this area. However, several constraints have been identified that restricts the ability to proceed with the project including the following: 1. Timing of the project – the Region is currently planning to widen Conlin Rd by 2022-2023 timeline. Completing the work now would require rework when the poles are relocated to its ultimate location. 2. Design restrictions – the existing pole design poses some challenges with the proposed stringing of a new feeder to existing pole line. Additional guying and anchoring will be required on some poles that require easements in private properties with no guarantees of approval from the landowners. It is recommended to wait until the Region completes land acquisition. (Lori please review and provide additional comments here)	Info	
2	Interim Solution to Address 7F4 Loading and Enfield TS Loading Requirements • In order to address the initial objectives of stringing new feeder at Conlin Rd (C18-215), an interim solution has been recommended to transfer load to MS9 and alleviate the loading conditions of 7F4 as well as meet the loading requirements of Enfield TS. It is recommended to switch feeder 15F2 to 9F2 through SW1590 and connect to feeder 7F4 at Ritson Rd N and Winchester Rd E as soon as the construction has been completed at Winchester Rd E. The	Tech Services, LK	TBD

<table>
<tr>
<td></td>
<td>following provides a single line diagram of the interim solution (highlighted):



Operations will further review the load and customer impacts of the proposed interim solution to 15F2, 7F4 and 9F2 to ensure that the reliability of these feeders are maintained.
Tech Services will incorporate in the design the provision to switch sections of feeders 15F2 and 7F4 to 9F2.
(Len, Lori and Mike to further review and comment on these notes)</td>
<td></td>
<td></td>
</tr>
</table>

Next Meeting: TBD


OSHAWA PUC NETWORKS
13.8KV SINGLE LINE DIAGRAM
REVISION DATE: December 20th, 2019
REVISION: 19
H
G
F
MS 9
MS 15

Attachment 2 – 5

SS Material Justification Sheet

A. General Information (5.4.3.2.A)					
Project/Activity	Expansion of Overhead Automated Switching				
Project Number	SS-02				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$200,000	$200,000	$200,000	$200,000	$200,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$200,000	$200,000	$200,000	$200,000	$200,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					
Number of Customers: Approximately 13,000 Load Impacted: Approximately 55 MW					

Start Date	2021-2025	In-Service Date	2021-2025

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	-	-	$200,000
Project Summary				

This project is a part of OPUCN's efforts towards improving service reliability and modernizing the existing grid into a smart grid system. During the period of 2021-2025, OPUCN will continue to replace existing 13.8kV manual switches with remotely operated & automated switches. These new smart switches will allow remote operation through Control Room operator and will work in automation - under outage conditions locate faults, automatically isolate faulted sections of powerlines and restore power to remaining sections. Approximately 15 smart switches will be installed at strategic locations of the system.

This project will work in tandem with Deployment of Automation Controller & Network Connected Devices project to increase the number of devices that work together in automation thereby further increasing operational efficiencies & improving reliability.

This project will include extending the communication network to these smart switches. Network planning will include this project, Deployment of Automation Controllers and Network Connected Devices project, and SCADA Operated 44kV OH Switches project.

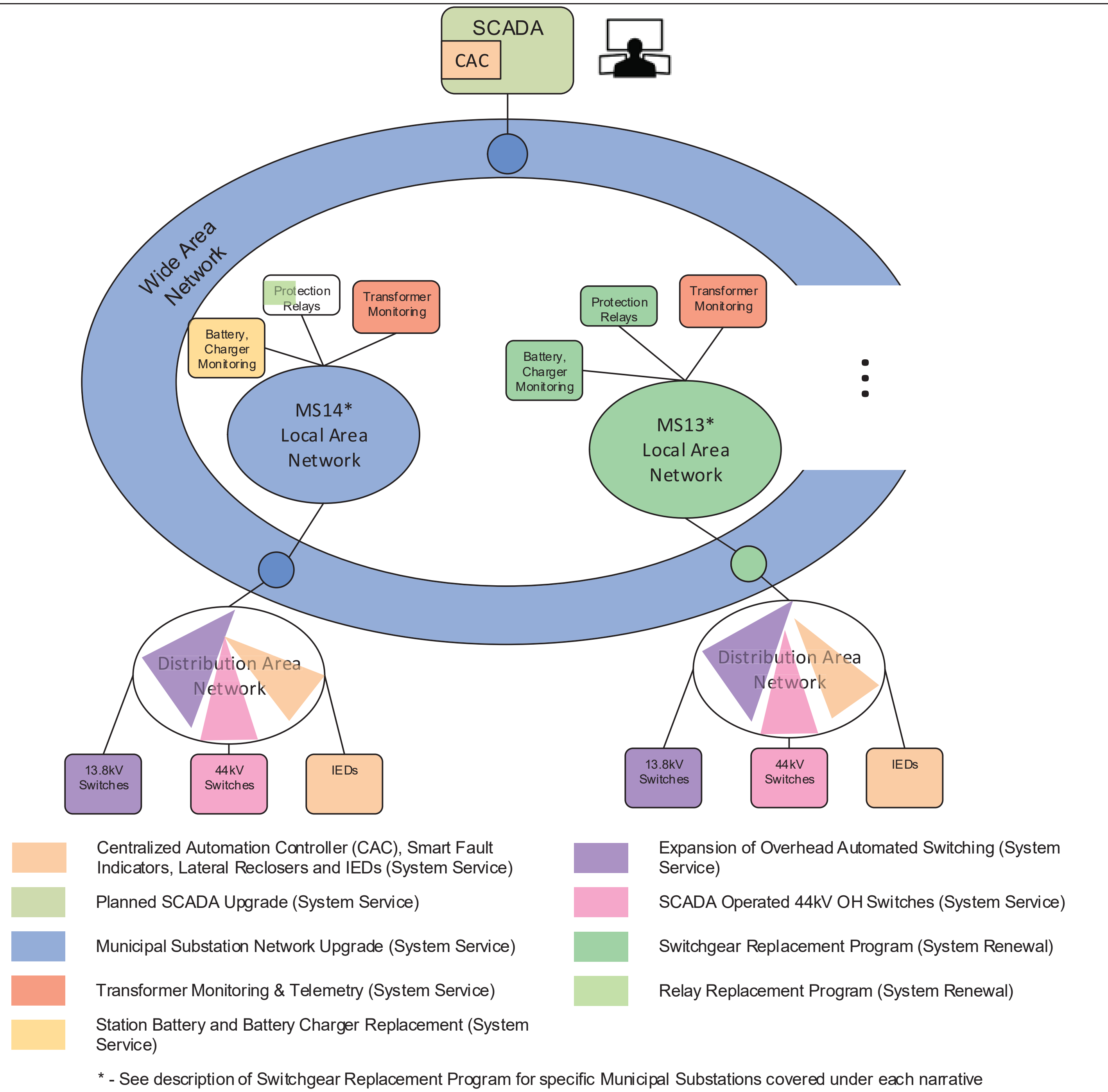


Figure 38- Scope Comparison of SCADA Related Projects

Please see above Figure 38- Scope Comparison of SCADA Related Projects which illustrates how the scope of this project is related with other SCADA related projects.

Risk Identification & Mitigation

Scheduling Risk – Timely delivery of equipment is important to complete the project in time. OPUCN proposes to initiate procurement of switches well in advance and work in coordination with supplier to avoid risk of delay.

Resource Risk – Resource to complete the required design and installation is important for successful completion of the project. OPUCN has resources and experience available in-house and also through approved, experienced contractors, to complete the design and installation.

Budget Risk – During initial assessments, some additional work may be required to accommodate the installation of the new automated switches and to comply with current installation standards including replacement of old hydro poles and expansion of wireless/fibre communication network. This may pose a risk of incurring additional cost and scheduling risk due to additional scope. To mitigate this risk, OPUCN will plan its communication network expansion together with the SCADA Operated 44kV OH Switches and Deployment of Automation Controllers and Network Connected Devices project. OPUCN will use the pole replacement program to address any poor condition poles.

Please refer to the diagram above which illustrates how the scope of this project is related with other SCADA related projects.

Comparative Information on Expenditures for Equivalent Projects/Activities

OPUCN has installed the last smart switch in 2018 costing approximately $55,000 per unit including installation, communication (wireless) and additional materials and equipment.

Replacing existing manual 13.8kV switches with remote & automated switches allow for faster redirection of 13.8kV power flow through remote operation of switches from a Control Operator. Operators will be given real-time information about fault conditions and loading. Remote overhead switches allow faster restoration to customers.

Past installations involved independent groups of switches which performed relatively simple switching operations. To deploy the use of automated switches throughout the system in 2021-2025 would require interdependent groups of switches from several feeders and MSs that need to coordinate over a larger MS/distribution network. Additional costs are expected to install communication modules to accomplish this.

Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	646	261	-	50	200	200	200	200	200

REG Investment Details including Capital and OM&A costs

The smart switch will provide voltage and power flow information remotely to the control room and will automatically isolate faults. Therefore, the project will help OPUCN to monitor power quality and use power flow information in planning, accommodating and integrating Distributed Energy Resources (DERs).

OPUCN has a number DERs/REGs connected at the 13.8kV distribution system. These 13.8kV automated switches will allow DERs to connect to the system more easily through remote switching of the 13.8kV power lines as there will be easier transitioning of 13.8kV feeders onto other sources when planned or unplanned interruptions occur. The benefits to each DER/REG will be assessed on a case by case basis.

This project supports future REG connections but does not contain any capital investments or OM&A costs that are directly attributable to REGs.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.
Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

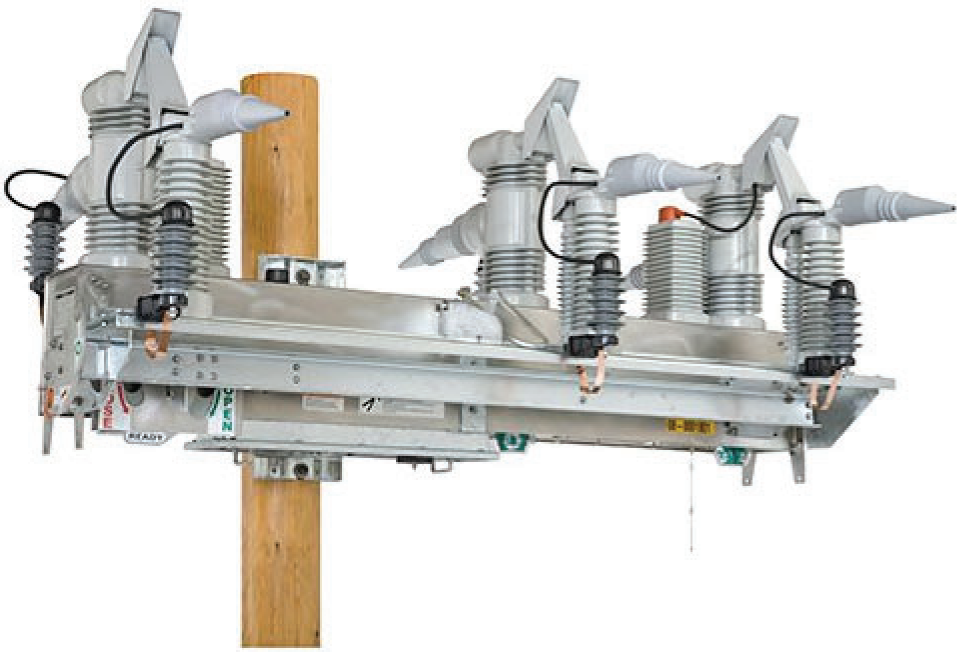


Figure 39-13.8kV Automation Switches

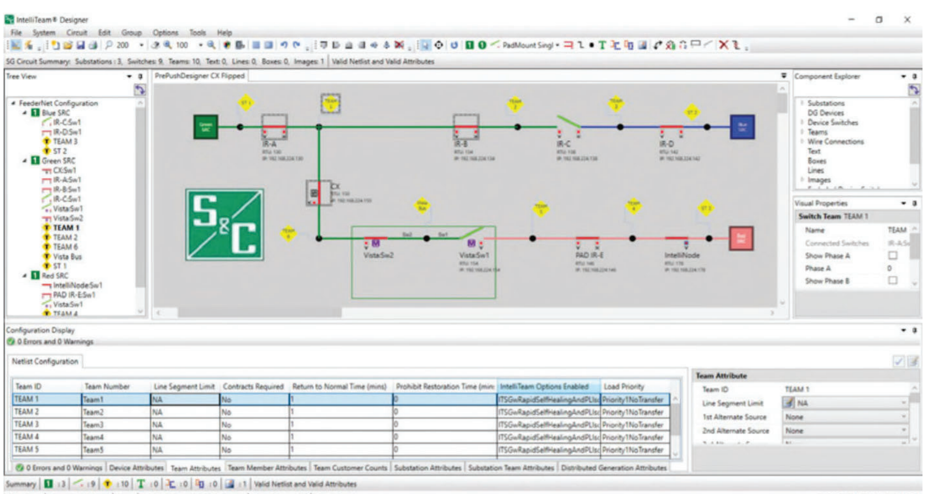


Figure 40-Software interface used to configure switches to work in teams

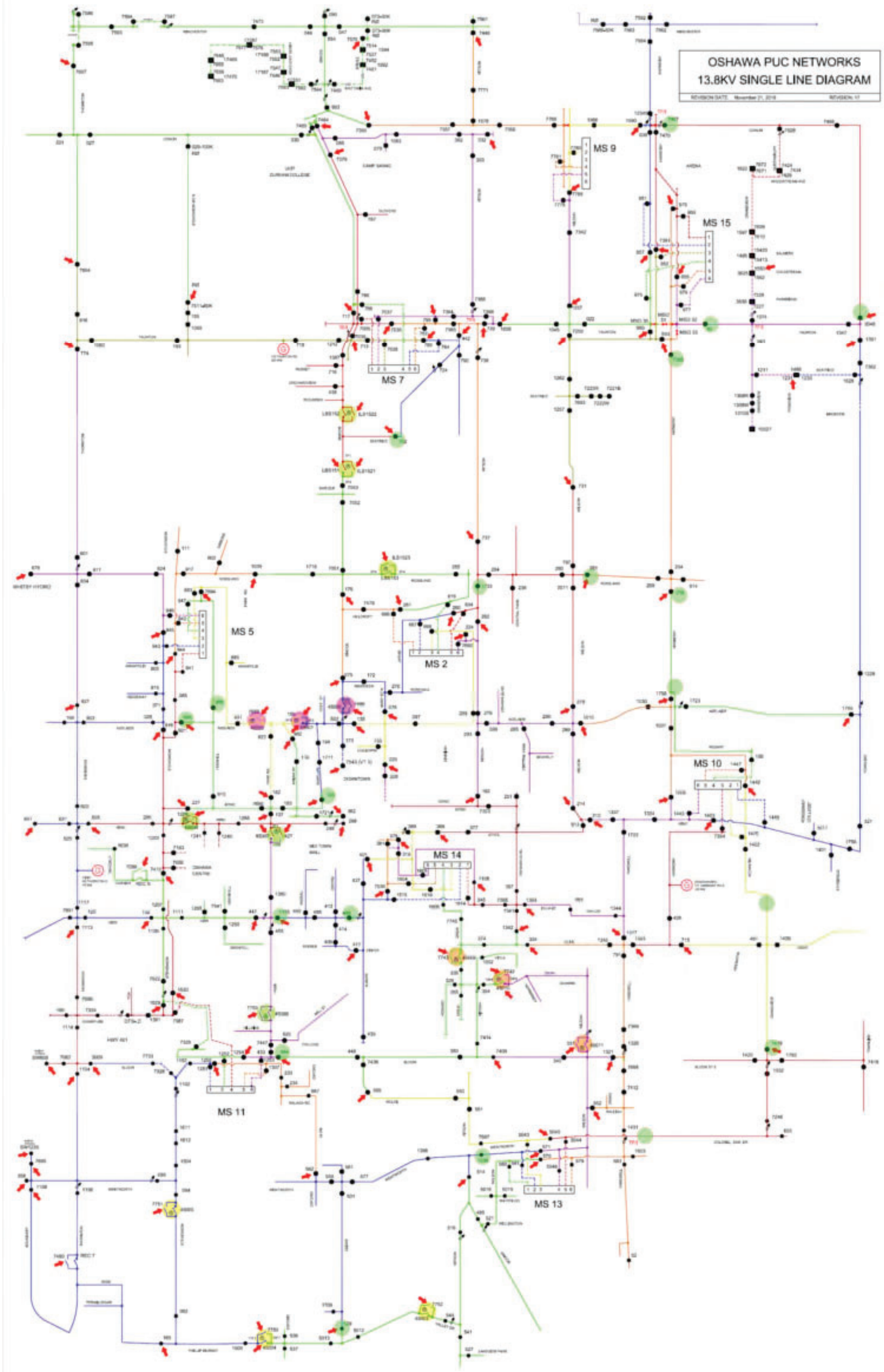


Figure 41- OPUCN 13.8kV Distribution System & Overhead Switch Locations (Potential Automated Switches Highlighted in Green)

Figure 42 - An Automated Switch Mounted On A Pole That Was Struck By A Vehicle

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
Service Reliability & Operational Efficiency is the main driver for this project. The automated switches provide faster & more accurate fault locations which reduces durations and length of feeder patrols. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage. This project will help OPUCN reduce the outage duration through automated and remote switching to sectionalize fault. System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The automated switches will provide ability to perform automatic and remote switching without dispatching line crew, improving operational efficiency and reduce operating cost. Automated switches will also provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system. This project aligns with the guidelines of the Grid Modernization Plan. The installation of automated switches will create a smarter-grid.
Efficiency, Customer Value & Reliability – Investment Secondary Driver
Not Applicable.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
The investment objective is to improve service reliability and operational effectiveness by mitigating the number of customers affected during an outage. New switches will replace existing manual switches and will improve operational effectiveness as switches can be operated remotely without the need of sending field staff. New switches will also be able perform fault locating, isolation and system restoration (FLISR) reducing outage duration and customers interrupted.

The investment objective is to improve Operational Effectiveness as outlined in OEB's annual scorecard for OPUCN. Some specific scorecards measures affected are namely "Average Number of Hours that Power to a Customer is Interrupted", "Average Number of Times that Power to a Customer is Interrupted", "Total Cost per Customer" and "Total Cost per Km of Line".
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
Service Reliability & Operational Efficiency will be improved by the installation of automated switches. The automated switches provide faster & more accurate fault locations which reduces durations and length of feeder patrols. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage. This project will help OPUCN reduce the outage duration through automated and remote switching to sectionalize fault. System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The automated switches will provide ability to perform automatic and remote switching without dispatching line crew, improving operational efficiency and reduce operating cost. Automated switches will also provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system. According to feedback from OPUCN's customers, approximately 92% of customers want OPUCN to "look for ways to use technology to safeguard the electricity network or get more out of the equipment" (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) and approximately 88% of customers surveyed want OPUCN to invest in smart grid technologies including system automation, making grid technology one of the top five priorities to customers. This project aims to focus on these priorities. This project is aligned with the guidelines in OPUCN's Grid Modernization Plan which identifies key projects that will help OPUCN use technology to make the distribution system a smarter grid and improve the way the system operates. OPUCN's Grid Modernization Plan has identified that this smart grid project will provide advantageous benefits to the Outage Management System and enable Fault Locating, Isolation, and System Restoration (FLISR). Please see this specific project in Grid Modernization Plan Section 10 Project Descriptions and Benefits. The Grid Modernization Plan has identified a high score on this project (see Section 9 Project Cost and Impact Scores).
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
The project will improve service reliability & operational efficiency by allowing remote switching from the control room rather than sending field staff to operate switches. Service reliability will be further improved through automated switching to restore power in the situation of a sustained power outage.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
The project has been determined as a high priority to be included in the DSP due to the need for improving system reliability and operating efficiencies as well as meetings aspects of the AM objectives identified in Section 5.3.1.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
The project will address the need for improving system reliability and operating efficiencies. Information used to support this investment include the Grid Modernization Plan. Automated Switches will create a better OMS that is able to respond quickly to outages and also support FLISR. Since the project is tied to improvements in the OMS (see this specific project in Section 10 Project Descriptions and Benefits), DA and FLISR, the project has been given a high score. Doing nothing or replacing existing switches with new manual switches would not take advantage of operational efficiencies available through use of new technologies to fault locate, isolate and perform system restoration.

Analysis of Project & Alternatives – Net Benefits Accruing to Customers
The net benefits accruing to Customers will be service reliability and operational efficiencies as mentioned in “Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness” above.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The installation of smart switches will be able to provide fast restoration of 13.8kV customers. The installation of automated switches will reduce SAIFI and SAIDI values as the switches will be able to perform fault locations to send field staff closer to the outage location thereby reducing outage durations. Also the switches will be able to automatically isolate and perform system restoration of remaining power lines further limiting the amount of customers affected by an outage. By doing nothing there will be no incurring benefit of using new technologies to reduce outage duration and number of customers affected by an outage. Operational efficiency will not be improved as switches will require sending out field staff to perform manual operation.
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are no other practical and cost-effective design or funding alternatives, or co-ownership options available.
Safety
New design of switch, remote switching functionality and the real- time status information through SCADA will improve safety for the line crew. The installation of automatic and remote switches eliminates exposing staff to arc-flashes that may occur due to operating defective overhead switches. The installation will be built in compliance with O.Reg. 22/04 and new utility installation standards to ensure safety for the general public.
Cyber-Security, Privacy (where applicable)
The communication required for these devices will use OPUCN’s dedicated fiber and radio communication which would restrict access for cyber-security purposes. This will ensure (PR.DS-2 OEB Cybersecurity Framework) Data-in-transit is protected as a Security Control. This ensures that only authorized staff have access to critical information that operates power delivering equipment. Equipment installed will comply with NIST cyber security standards and OEB’s cyber security framework.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
The controller for the remote switches will be specified to offer secure communication using DNP3 protocols, to meet the interoperability standards. This will ensure devices will be able to communicate with Control Room SCADA system and other IEDs.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The controller for the remote switches will provide additional functionality in communication with the existing automatic restoration software and with multiple other SCADA operated switches to achieve advance level of coordinated Fault Detection, Isolation and Restoration capability.
Environmental Benefits (where applicable)

Installation of automated switches will enable remote operation of switches by either control room staff or pre-programmed routine, without requiring to dispatch crew(s) /truck roll in case of outages. The avoided truck rolls therefore will help reduce GHG emissions.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The controller for the remote switches will provide additional functionality in communication with the existing automatic restoration software and with multiple other SCADA operated switches to achieve advance level of coordinated Fault Detection, Isolation and Restoration capability.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
According to OPUCN's 2019 Distribution System Plan Customer Engagement Report, this project will cost a portion of a monthly average cost of 15.3 cents (overall total cost of system service projects), which the majority (60%) of customers surveyed supported (see Figure 14 – System Service Investment Chart). In addition, 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies, making grid technology one of the top five priorities to customers. Service Reliability & Operational Efficiency will be improved by the installation of automated switches which will produce better service reliability and improved costs to customers. The automated switches provide faster & more accurate fault locations which reduces durations and length of feeder patrols. Also automated switches in tandem with centralized automated outage isolation & restoration (see Centralized Automation Controller, Smart Fault Indicators, Lateral Reclosers and IEDs Project Narrative) will produce larger coverage areas to further reduce the number of customers affected during each outage. System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The automated switches will provide ability to perform automatic and remote switching without dispatching line crew, improving operational efficiency and reduce operating cost. Automated switches will also provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system. This will further enable connection of Distributed Energy Resources (DERs) on the system as operators will be able to reconfigure the system to allow DERs resources onto they system.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
The controller for the smart switches will provide additional functionality in communication with the existing automatic restoration software and with multiple other smart switches to achieve advance level of coordinated Fault Detection, Isolation and Restoration functionality.

Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
The investment in automated switch will improve system reliability and visibility. It will also reduce the operational cost as it will reduce the need to dispatch and engage line crew to perform manual switching operations. There will be an added level of safety due to remote operation as field staff will not be required to operate switches manually.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
The project has been given a high priority (see Grid Modernization Plan Section 9 – Project Cost and Impact Scores and this specific project in Section 10 Project Descriptions and Benefits) because it offers a high benefit for improving operational efficiency, reliability and visibility through improvements of the Outage Management System. OPUCN will provide appropriate weightage on the vintage of the existing switch in selecting location to leverage the opportunity for asset renewal. OPUCN will be taking advantage of the timing to replace existing 13.8kV switches that are past their service to renew the system with smart switches that will improve service reliability and operation efficiency.
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
By doing nothing, OPUCN will continue operating the existing switches manually and continue without improving operational efficiencies and grid visibility. This is not a proactive approach for grid modernization.

A. General Information (5.4.3.2.A)

Project/Activity	SCADA Operated 44kV OH Switches				
Project Number	SS-03				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$100,000	$100,000	$100,000	$100,000	$100,000
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$100,000	$100,000	$100,000	$100,000	$100,000
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-

Customer Attachments and Load

Number of Customers approximately 15,828
Load Impacted: Approximately 61 MW

Start Date	2021-2025	In-Service Date	2021-20225

Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	-	$100,000	-

Project Summary

This project is a part of OPUCN's efforts towards improving service reliability and modernizing the existing grid into a smart grid system. During the period 2021-2025, OPUCN will purchase approximately 5 SCADA operated 44kV switches that will be installed at key locations on our 44kV distribution system to enhance the utility's ability to perform switching operations during normal and emergency conditions.

This project will include extending the communication network to existing and new smart switches. Network planning will include this project, Deployment of Automation Controllers and Network Connected Devices project, and Expansion of Overhead Automated Switching project.

Please see Figure 33- Scope Comparison of SCADA Related Projects which illustrates how the scope of this project is related with other SCADA related projects.

Risk Identification & Mitigation

Scheduling Risk - Timely delivery of equipment is important to complete the project in time. OPUCN proposes to initiate procurement of switches well in advance and work in coordination with supplier to avoid risk of delay.

Resource Risk - Resource to complete the required design and installation is important for successful completion of the project. OPUCN has resources and experience available in-house and also through approved, experienced contractors, to complete the design and installation.

Budget Risk - Additional work may be required to be performed including replacement pf pole(s) to comply with the current installation standards while installing the new 44kV switches and connection of wireless/fibre communication network to the new switches. This may pose a risk of incurring additional cost and time. To mitigate this risk, OPUCN will plan its communication network expansion together with the Expansion of Overhead Automated Switching project and Deployment of Automation Controllers and Network Connected Devices project. OPUCN will use the pole replacement program to address any poor condition poles.

Comparative Information on Expenditures for Equivalent Projects/Activities

OPUCN has installed one 44 kV overhead switch in 2019 at a total of $80,000 as part of an existing project. This cost excludes extending communication to the remote switch and pole replacement.

Replacing existing manual 44kV switches with remote switches allows for faster redirection of 44kV power flow through remote operation of switches through a Control Operator. Operators will be given real-time information about fault conditions and loading. Remote overhead switches allow faster restoration to customers.

Historical Costs ($ '000)						Forecast Costs ($ '000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	125	100	100	100	100	100

This program was introduced in 2020 and will continue during the planning year. 2020 is a budget cost.

REG Investment Details including Capital and OM&A costs

The SCADA operated 44 kV overhead switch will provide voltage and power flow information remotely to the control room. Therefore, the project will help OPUCN to monitor power quality and use power flow information in planning, accommodating and integrating of DERs/REGs.

OPUCN's largest DERs/REGs are connected at the 44kV distribution system. These DERs/REGs will be able to connect more easily onto the distribution system through remote 44kV switching as there will be easier transitioning of 44kV feeders onto other sources when planned or unplanned interruptions occur. The benefits to each DER/REG will be assessed on a case by case basis.

This project supports future REG connections but does not contain any capital investments or OM&A costs that are directly attributable to REGs.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Figure 43- Remote 44kV Switch

Figure 44-Motorized Controller of 44kV Switch

descriptive-bulletin
-761-30.pdf

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)

Efficiency, Customer Value & Reliability – Investment Main Driver

Service Reliability & Operational Efficiency is the main driver for this project. The switches provide rapid and efficient operation as staff are not required to be sent to perform manual switching. Outage durations will be reduced through remote switching. The SCADA operated switch will also allow monitoring of the switch which will also help reduce the risk of power interruptions due to in-service equipment failures.

This project aligns with the guidelines of the Grid Modernization Plan. The installation of automated switches will create a smarter-grid.

Efficiency, Customer Value & Reliability – Investment Secondary Driver

There are no secondary drivers.

Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets

The investment objectives are to mitigate the risk of service reliability falling below the performance targets as outlined in OEB's annual scorecard for OPUCN. New switches will replace existing manual switches and will improve operational effectiveness as switches can be operated remotely without the need of sending field staff.

The investment objective is to improve Operational Effectiveness as outlined in OEB's annual scorecard for OPUCN. Some specific scorecards measures affected are namely "Average Number of Hours that Power to a Customer is Interrupted", "Total Cost per Customer" and "Total Cost per Km of Line".

Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

The source of information for support of this project include the ACA which identifies the need for replacing primary switches expected to reach or already past their TUL within the planning period. Although not explicitly stated in the ACA report, the study determined that the majority of 44kV switches will be past their minimum useful life.

Service Reliability & Operational Efficiency will be improved by the installation of remote 44kV switches – higher service reliability and improved costs to customers. This project will help OPUCN reduce the outage duration through remote switching of the 44kV distribution. All of OPUCN's customers are fed through the 44kV distribution including customers fed from the 13.8kV distribution (which are fed through step down MS transformers). As a result, the use of 44kV remote switches have a large impact to customers.

System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The remote switches will provide ability to perform remote switching without dispatching line crew, improving operational efficiency and reduce operating cost. Remote switches will also provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system.

According to feedback from OPUCN's customers, approximately 92% of customers want OPUCN to "look for ways to use technology to safeguard the electricity network or get more out of the equipment" (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) and approximately 88% of customers surveyed want OPUCN to invest in smart grid technologies including system automation, making grid technology one of the top five priorities to customers.

Using SCADA operated switches during replacement of the old primary switches will provide an opportunity at low incremental cost, to modernize the grid into a 'smart grid' as identified in OPUCN's Grid Modernization Plan. This project uses Distribution Automation (DA) to improve the OMS and enables Fault Locating (see this specific project description in Grid Modernization Plan, Section 10-Project Descriptions and Benefits). As a result, the Grid Modernization Plan has determined a high score on this project (see Section 9- Project Cost and Impact Scores).

Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

The project will improve service reliability and operational efficiency by remotely operating the switch to restore power instead of dispatching a field staff to operate a switch. In addition, this project will take advantage of replacing poor condition switches (according to the ACA) with new switches. This will also make the grid ready for an Advanced Distribution Management System (ADMS) implementation in the future.

Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment

The project has been determined as a high priority due to the condition of existing switches. It will also address the need for improving system reliability and operating efficiencies which are some of OPUCN's AM objectives identified in Section 5.3.1.

Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness

The project will address the need for improving system reliability and operating efficiencies. Information used to support this investment include the Grid Modernization Plan. Automated Switches will create a better OMS that is able to respond quickly to outages and also support fault locating (FL). Since the project is tied to improvements in the OMS (see section 9 – Project Cost and Impact Scores in OPUCN's Grid Modernization Plan) and DA and FL, the project has been given a high score.

Doing nothing or replacing existing switches with new manual switches would not take advantage of operational efficiencies available through use of new technologies to fault locate, isolate and perform system restoration.

A retrofitted existing switch is not likely to yield the same benefits of a new remote switch since a large portion of existing switches are past their service life. These switches may not be able to handle many operations and will likely incur more Operational & Maintenance costs. This option would incur higher overall maintenance cost of the switch and risks (e.g. motor mechanism incompatibility) which would outweigh the benefits. In addition, a retrofitted assembly would not have the voltage and current sensing capabilities of a newly installed integrated switch that help determine fault locations.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
The net benefits accruing to Customers will be a better service reliability and operational efficiencies as mentioned in "Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness" above.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The installation of 44kV SCADA switches will be able to provide fast restoration to customers and mitigate the number of customers affected during a power outage. The installation of remote 44kV switches will reduce SAIDI values as the time to perform switching operations would be greatly reduced compared to sending field staff to perform manual operations. The alternative of doing nothing will not take advantage of new technologies to remotely operate switches and reduce customer outage duration. Operational efficiency will remain the same as switches will require sending out field staff to perform manual operation. Doing nothing will incur a risk of not being able to operate on switches which have passed their service life. The alternative of a retrofitted switch is not likely to yield the same reliability performance since a large portion of existing switches are past their service life. These switches may not be able to handle many operations and in the event of a failed switching operation would prolong the outage. Also a retrofitted assembly would not have the voltage and current sensing capabilities of a newly installed integrated switch that help determine fault locations.
Project Alternatives (Design, Scheduling, Funding/Ownership)
There are no other practical and cost-effective design or funding alternatives, or co-ownership options available.
Safety
New design of switch, remote switching functionality and the real-time status information through SCADA will improve safety for the line crew. The installation of automatic and remote switches eliminates exposing staff to arc-flashes that may occur due to operating defective overhead switches. The installation will be built in compliance with O.Reg. 22/04 and new standards to ensure safety for the general public.
Cyber-Security, Privacy (where applicable)
The communication with SCADA operated switches will be implemented using OPUCN's dedicated fiber or a secure wireless network for SCADA communication loop which will ensure (PR.DS-2 OEB Cybersecurity Framework) Data-in-transit is protected as a Security Control. This ensures that only authorized staff have access to critical information that operates power delivering equipment. Access to the control system will be managed according to LDC's IT/OT standards in compliance to NIST cyber security standards and OEB's cyber security framework.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
The controller for the SCADA operated switches will be procured using specification that includes, but not limited to, secure communication using DNP3 protocols, compliance to applicable industry standards including IEEE and NIST, to meet the

interoperability requirements. This will ensure devices will be able to communicate with Control Room SCADA system and other IEDs.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
The controller for the SCADA operated switches will provide additional functionality and will be provisioned to form a communication backbone to a network of multiple SCADA operated switches.
Environmental Benefits (where applicable)
Installation of SCADA operated switches will enable remote operation of switches by control room staff, without requiring dispatching of crew(s)/ truck during normal and in case of outages. The avoided truck rolls therefore will help reduce GHG emission.
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
The controller for the SCADA operated switches will provide additional functionality and will be provisioned to form a communication backbone to a network of multiple SCADA operated switches.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
According to OPUCN's 2019 Distribution System Plan Customer Engagement Report, this project will cost a portion of a monthly average cost of 15.3 cents (overall total cost of system service projects), which the majority (60%) of customers surveyed supported (see Figure 14 – System Service Investment Chart). In addition, 92% of customers surveyed want OPUCN to "look for ways to use technology to safeguard the electricity network or get more out of the equipment" and 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies, making grid technology one of the top five priorities to customers. Customer will benefit due to reduced outage duration and faster restoration that will be achieved with the new SCADA operated switches. Customer satisfaction for the service quality will be improved. Also, customers will benefit from improved costs due to remote switching capabilities of the new switches. This project takes advantage of replacing existing 44kV switches which are past their TUL and new technology to provide operation efficiencies. The new remote switches will reduce overall costs to operate the switch. This project will help OPUCN reduce the outage duration through remote switching of the 44kV distribution. All of OPUCN's customers are fed through the 44kV distribution including customers fed from the 13.8kV distribution (which are fed through step down 44kV to 13.8kV MS transformers). As a result, the use of 44kV remote switches will have a large positive impact to customers.

System Operators will receive fault detection alerts indicating when fault conditions have occurred downstream of overhead switches which further reduces outage durations. The remote switches will provide ability to perform remote switching without dispatching line crew, improving operational efficiency and reduce operating cost.

Remote switches will also enable DERs. The remote switches provide real-time power flow information to system operators who will be able to efficiently reconfigure the electrical distribution system. OPUCN's largest DERs are connected to the 44kV system. These switches will further enable customer DER connection as operators will be able to reconfigure the system to allow DERs onto they system.

Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process

Not Applicable

Description of how Advanced Technology has been Incorporated (where applicable)

The controller for the SCADA operated switches will provide additional functionality and will form a communication backbone to a network of multiple SCADA operated switches.

Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects

This program will improve system reliability and will provided added visibility to the grid. It will also reduce the operational cost as it will reduce the need to dispatch and engage line crew to perform manual switching operations.

There will be an added level of safety due to remote operation as field staff will not be required to operate switches manually.

Identification and Explanation of the Factors Affecting Implementation Timing/ Priority

The project has been given a high priority because it offers a high benefit for improving operational efficiency, reliability and visibility. OPUCN will provide appropriate weightage on the vintage of the existing switch in selecting location to leverage the opportunity for asset renewal. OPUCN will be taking advantage of the timing to replace existing 44kV switches that are past their service to renew the system with smart switches that will improve service reliability and operational efficiency.

Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives

By doing nothing, OPUCN will continue operating the existing switches manually and continue without improving operational efficiencies and grid visibility. This option also incurs an added risk of operating switches that are past their service life. This is not a proactive approach for grid modernization.

The other alternative is to retrofit the existing load break switches with motorized operator and necessary SCADA communication gateway box. However, this alternative is not preferred due to challenges and overall reliability associated with field assembly of components vs. that of factory assembled equipment. A retrofitted assembly would not have the voltage and current sensing capabilities of a newly installed integrated switch. As a result of this, the switch would not be able to help aid in fault locating and sending field staff closer to the location of the faulted power line.

A. General Information (5.4.3.2.A)					
Project/Activity	SCADA Integration and Deployment of Automation Controllers and Network Connected Devices				
Project Number	SS-04				
Investment Category	System Service				
	2021	2022	2023	2024	2025
Capital Cost	$250,000	$100,000	$100,000	$100,000	-
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$250,000	$100,000	$100,000	$100,000	$-
O&M Cost	2021	2022	2023	2024	2025
	-	-	-	-	-
Customer Attachments and Load					

The total number of customers impacted and the connected load will be determined when the specific project is determined.

Start Date	2021-2024	In-Service Date	2021-2024	
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4
	-	-	$100,000	$150,000
Project Summary				

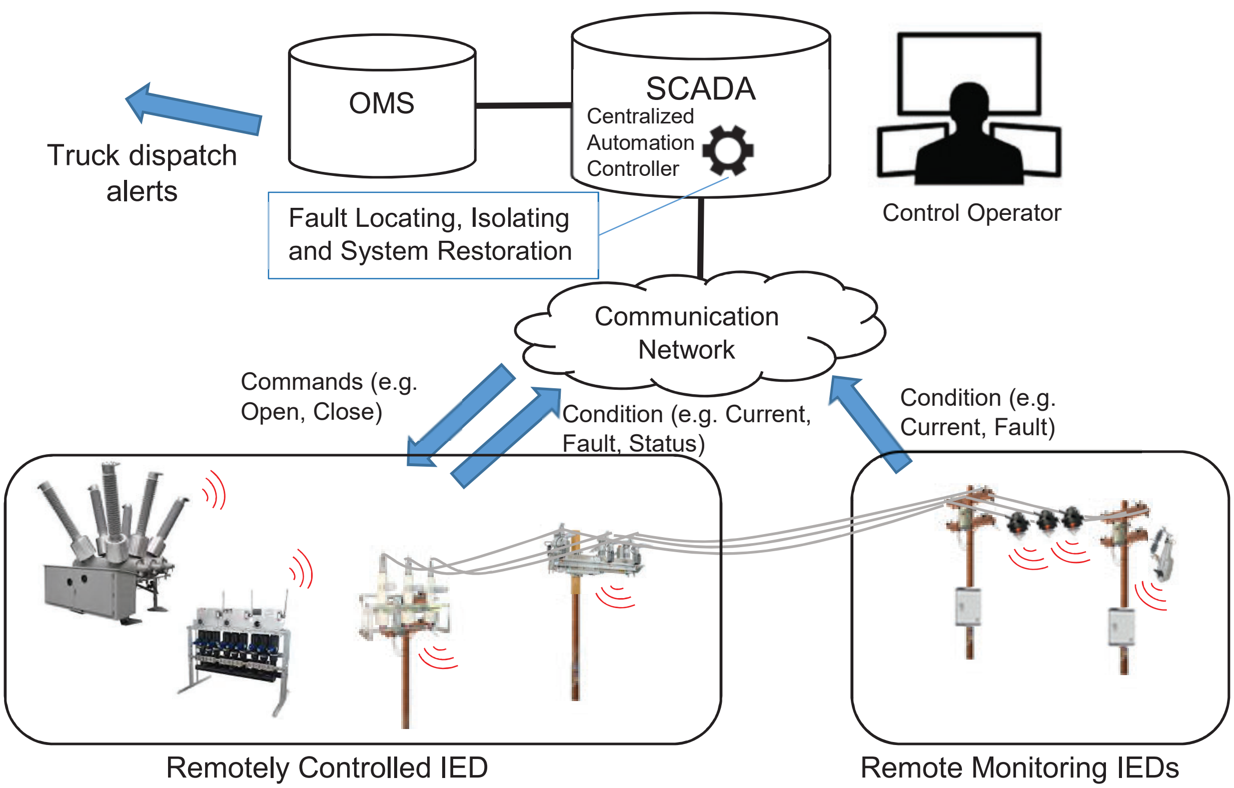


Figure 45- Centralized Controller Functioning with Intelligent Electronic Devices (IEDs)

During the period of 2021-2024, OPUCN will purchase and install a Centralized Automation Controller (CAC) that enables SCADA integration and automation across non-vendor specific smart devices. Automation enables automatic fault locating, automatic fault isolation of faulted powerlines and restoration of power to remaining sections thereby increasing operational efficiencies and reliability.

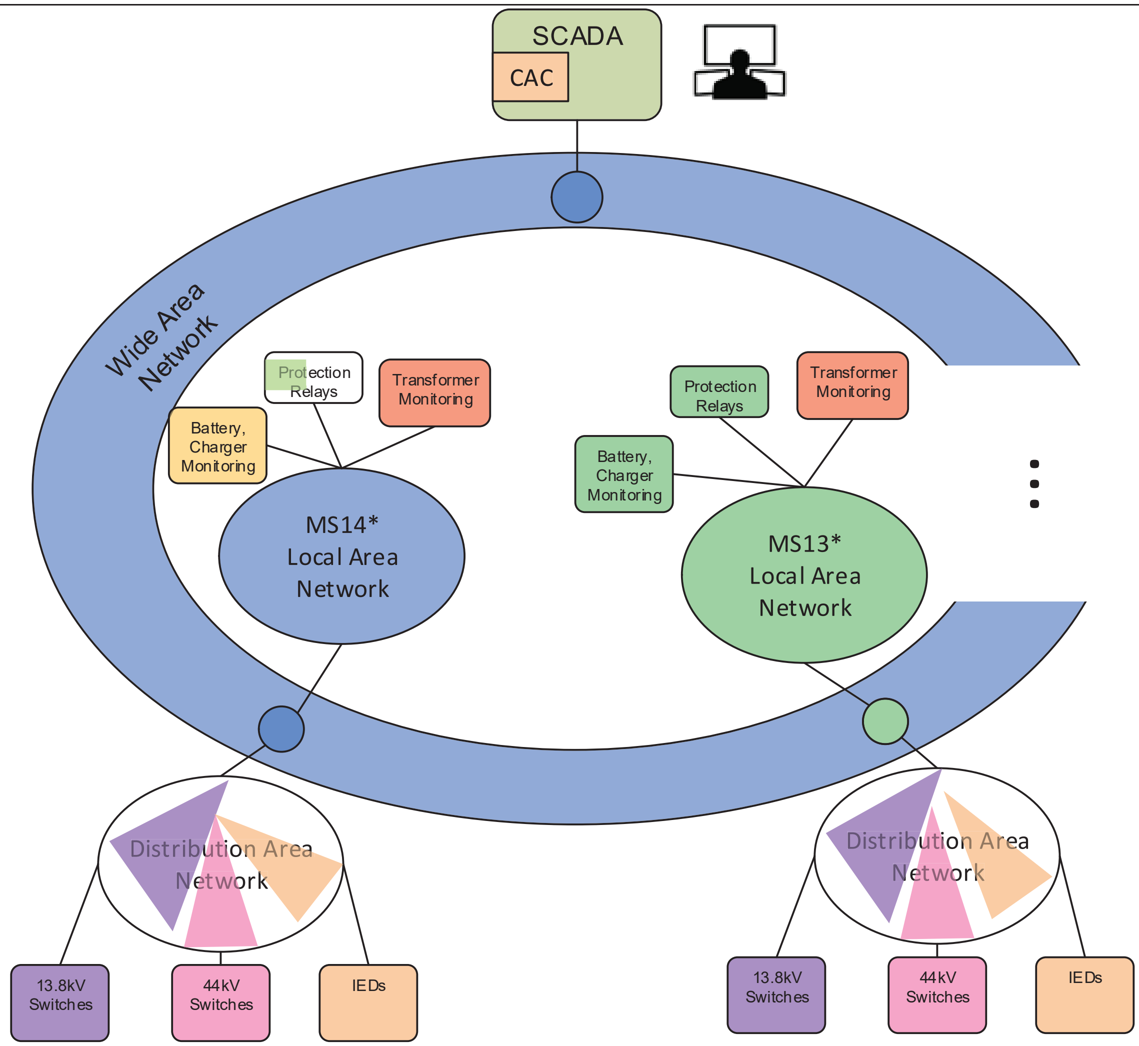
It is critical that this Centralized Automation Controller be installed as it will be a major enabler of automation:

- This Controller will enable automation that is vendor agnostic. OPUCN's existing implementations of automation are tied to specific vendors and does not allow easy interoperability with other vendors of smart devices.
- This controller will enable automation across different types of IEDs to perform faster restoration. OPUCN's existing automation only includes switches which do not include other devices such as MS breakers and other reclosers. Greater operational efficiencies and reliability improvements can be realized when these devices are included as an integrated group of automation devices.
- This controller will be installed at the Control Room and has the potential to be used throughout the system. Existing automation implementations limit automation to a few 13.8kV feeders. With the Centralized Controller, it can be expanded to all feeders.

This project will work in tandem with Expansion of Overhead Automatic Switching project to allow more smart grid devices to work together in automation.

This project will also include extending use of other IEDs or smart grid devices such as smart fault indicators and lateral recloser. The project will also include investigating into using other intelligent electronic devices (IEDs) or smart network devices such as intelligent line sensors and power quality (PQ) monitors. Quantities and type of devices may vary depending on the feeder topology and configuration.

This project will include extending the communication network to new and existing IEDs. Network planning will include this project, Expansion of Overhead Automated Switching project, and SCADA Operated 44kV OH Switches project. Please see below which illustrates how the scope of this project is related with other SCADA related projects.



Centralized Automation Controller (CAC), Smart Fault Indicators, Lateral Reclosers and IEDs (System Service)

Planned SCADA Upgrade (System Service)

Municipal Substation Network Upgrade (System Service)

Transformer Monitoring & Telemetry (System Service)

Station Battery and Battery Charger Replacement (System Service)

Expansion of Overhead Automated Switching (System Service)

SCADA Operated 44kV OH Switches (System Service)

Switchgear Replacement Program (System Renewal)

Relay Replacement Program (System Renewal)

* - See description of Switchgear Replacement Program for specific Municipal Substations covered under each narrative

Figure 46- Scope Comparison of SCADA Related Projects

The project has a risk of delay in completion due to delivery of equipment. OPUCN proposes to initiate procurement activities accordingly in consultation with the respective supplier to avoid delay.

Another risk is integration of the devices with the existing SCADA and OMS system. OPUCN proposes to include the integration requirements in the specifications for each device and will perform scrutiny for compliance with the industry standards and specific technical requirements of OPUCN.

Comparative Information on Expenditures for Equivalent Projects/Activities

There is no comparative information to the Centralize Automation Controller from past installations as this will be the first that OPUCN will install a system Automation controller.

This program commenced in 2020 with expected completion by 2024.

Historical Costs ($ ‘000)						Forecast Costs ($ ‘000)				
2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
-	-	-	-	-	50	250	100	100	100	-

During 2016-2018, each year, OPUCN completed implementation of smart fault circuit indicators at 2 locations at an approximate cost of $12,500 per location using cellular communication. The new estimate is based on lateral reclosers (installation in progress), smart fault circuit indicators and communication using fiber connection – which may vary depending on location of installation and feeder configuration.

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Figure 47-Centralized SCADA Automation Controller

Figure 48 - Smart Fault Indicators and Data Concentrator

Figure 49- Lateral recloser

Figure 50- IED Data concentrator

Figure 51- Power Quality Monitors/Power Line Monitor

Figure 52- Radio communication

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
Service Reliability & Operational Efficiency is the main driver for this project. The Centralized Controller and IEDs provide faster & more accurate fault locations which reduces outages times and field staff patrolling. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage.

This project aligns with the guidelines of the Grid Modernization Plan (see this specific project in Section 10 Project Descriptions and Benefits). The installation of the Centralized Controller will be a major component of the grid that uses technology to create a smarter-grid.

Efficiency, Customer Value & Reliability – Investment Secondary Driver

There are no secondary drivers.

Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets

The investment objectives are to mitigate the risk of service reliability falling below the performance targets.

In addition, the investment objective is to improve Operational Effectiveness as outlined in OEB's annual scorecard for OPUCN. Some specific scorecards measures affected are namely "Average Number of Hours that Power to a Customer is Interrupted", "Average Number of Times that Power to a Customer is Interrupted", "Total Cost per Customer" and "Total Cost per Km of Line".

Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment

Service Reliability & Operational Efficiency will be improved by the implementation of the Centralized Controller and IEDs. The installation of the Centralized Controller and IEDs provide faster & more accurate fault locations which reduces outages times and field staff patrolling. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage. In addition, since the Centralized Controller will be implemented at control centre and is IED vendor agnostic, this project provides long term benefits for integrating smart grid devices to provide automated power restoration – long term Service Reliability & Operational Efficiency.

Approximately 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies including system automation, making grid technology one of the top five priorities to customers.

This project is aligned with the guidelines in OPUCN's Grid Modernization Plan which identifies key projects that will help OPUCN use technology to make the distribution system a smarter grid and improve the way the system operates.

OPUCN's Grid Modernization Plan has identified that this project will provide advantageous benefits to the Outage Management System and enable Fault Locating, Isolation, and System Restoration (FLISR). Please see this specific project in Grid Modernization Plan Section 10 Project Descriptions and Benefits. As a result, the Grid Modernization Plan has given a high score on this project (see Section 9 Project Cost and Impact Scores).

Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges

This project will help OPUCN reduce the outage duration through real time information related to outage data transmitted by the faulted circuit indicators and lateral reclosers to the existing SCADA and OMS in order to automatically dispatch the crew and to implement advance application of fault detection, isolation and restoration in integration. The lateral recloser will also provide enhanced protection for the lateral circuits, which will reduce momentary interruptions on entire feeder in case of faults downstream.

This project will be coordinated with the SCADA upgrade, to ensure that the Centralized Automation Controller and IEDs functions are migrated to the new SCADA platform. OPUCN is strategic partnerships on both projects to ensure success.

Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment

The project will address the need for improving system reliability and operating efficiencies. Information used to support this investment include information taken from the Grid Modernization Plan. A Centralized Automation Controller and IEDs will create a better OMS that is able to respond quickly to outages and also support FLISR. Since the project is tied to improvements in the OMS (see the specific project in Section 10 Project Descriptions and Benefits of the Grid Modernization Plan) and meets AM objectives identified in Section 5.3.1, the project has been given a high priority.

Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness

Continuing to Only Install Smart Fault Indicators
This option will only provide small incremental benefits to the system in operational efficiency and reliability improvements. This solution will not include integration with other automation systems.

Do Nothing
This option is not economical as the system would continue to run as status quo without use of additional smart technology to modernize the grid and improve operational efficiency and reliability.

Install Centralized Automation Controller & IEDs (Including Smart Fault Indicators)
Major benefits to the distribution system are possible when data from various smart devices (e.g. breakers, switches, reclosers and smart fault indicators) are centralized to perform better decisions. The proposed project to install a Centralize Automation Controller is a wholistic program to tie in various smart devices & IEDs to better perform fault locating, isolation and restoration.

Analysis of Project & Alternatives – Net Benefits Accruing to Customers

The net benefits accruing to Customers will be a better service reliability and operational efficiency.

Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages

SAIDI and SAIFI will be improved significantly due to enhanced outage management from the Centralized Automation Controller compared with doing nothing or installing only Smart Fault Indicators. The Centralized Automation Controller will gather critical fault data (e.g. breakers, switches, reclosers and smart fault indicators) to determine the location of faults in the system, automatically switch to isolate the fault and restoring remaining power lines. The Controller will provide alerts to send field staff directly to the fault location reducing SAIDI.

Project Alternatives (Design, Scheduling, Funding/Ownership)

There are no other practical and cost-effective design or funding alternatives, or co-ownership options available.

Safety

The installation will be built in compliance with O.Reg. 22/04 and new utility standards to ensure safety for the general public. The current sensor built in these IEDs will provide additional information to the operation control room that will be utilized in creating safer working environment for the line crew.

Cyber-Security, Privacy (where applicable)

Communication between IEDs and Centralized Automation Controller will be implemented using secured channel using free-wave radio or dedicated fiber which will ensure (PR.DS-2 OEB Cybersecurity Framework) Data-in-transit is protected as a Security Control. Access to IEDs will be managed according to standards that comply with NIST cyber security standards and OEB's cyber security framework security controls.

Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)

The IEDs will be procured using specification that includes but not limited to secure communication using DNP3 protocols which will ensure interoperability with other Operational Technology devices. IEDs will be in compliance to applicable industry standards including IEEE and NIST to meet the interoperability requirements.
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
OPUCN will ensure that the selected IED meets or exceeds the interoperability requirements for future implementation of an Advanced Distribution Management System (ADMS) and Fault Location, Isolation Scheme and Restoration type functionality which will ensure IEDs will be able to communicate with one another and with the centralized controller for faster fault location, isolation and system restoration.
Environmental Benefits (where applicable)
Implementing this project will provide location information in case of the sustained outage which will help in reducing time to patrol lines and outage duration- translating into reduced truck rolls (and reduction of GHG emissions).
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
OPUCN will ensure that the selected IED meets or exceeds the interoperability requirements for future implementation of an Advanced Distribution Management System (ADMS) and Fault Location, Isolation Scheme and Restoration type functionality which will ensure IEDs will be able to communicate with one another and with the centralized controller for faster fault location, isolation and system restoration.

C. Category-Specific Requirements – System Service (5.4.3.2.C)
Assessment of Customer Benefits Based on Project Objectives and Cost Impact
According to OPUCN's 2019 Distribution System Plan Customer Engagement Report, this project will cost a portion of a monthly average cost of 15.3 cents (overall total cost of System Service projects), which the majority (60%) of customers surveyed supported (see Figure 14 – System Service Investment Chart). In addition, 88% of customers surveyed (see OPUCN's 2019 Distribution System Plan Customer Engagement Report, Figure 2 – Customer Priority Table) want OPUCN to invest in smart grid technologies, making grid technology one of the top five priorities to customers. Service Reliability & Operational Efficiency will be improved by the implementation of the Centralized Controller and IEDs – which will result in improved service reliability and improved costs for customers. The installation of the Centralized Controller and IEDs provide faster & more accurate fault locations which reduces outages times and field staff patrolling. Also automated outage isolation & restoration through the Centralized Automation Controller and IEDs will reduce the number of customers affected during each outage. Implementing this project will reduce patrol lines and outage duration translating into reduced truck rolls which improves Operational Efficiency and overall cost customers.

Since the Centralized Controller will be implemented at the control centre where automated control can be applied to any field device communicating remotely to the control centre and this solution is IED vendor agnostic, this project provides long term future benefits for integrating smart grid devices to provide automated Fault Locating, Isolation, and System Restoration (FLISR) – long term benefits of Service Reliability & cost improvement to customers.
Information on Regional Electricity Infrastructure Requirements Identified in the Regional Planning Process
Not Applicable
Description of how Advanced Technology has been Incorporated (where applicable)
The IEDs and communication technologies will be used to integrate into existing SCADA, OMS and automatic restoration software, which will provide platform for future implementation of ADMS. This will ensure IEDs will be able to communicate with the centralized controller for faster fault location, isolation and system restoration .
Identification of any Reliability, Efficiency, Safety and Coordination Benefits or Affects
The investment in IEDs and the Centralized Automation Controller will improve system reliability and efficiency. The Centralized Automation Controller will gather critical fault data (e.g. breakers, switches, reclosers and smart fault indicators) from various IEDs to determine the location of faults in the system, automatically switch to isolate the fault and restoring remaining power lines. The Controller will provide alerts to send field staff directly to the fault location reducing SAIDI.
Identification and Explanation of the Factors Affecting Implementation Timing/ Priority
The project offers a high benefit for improving service reliability, operational efficiency and visibility. This project will take advantage of past and ongoing implementations of smart grid devices to centralize information and control to perform better fault locating, fault isolation and system restoration. If implementation is delayed, existing devices will continue to work independently and benefits to service reliability, operational efficiency and visibility in an integrated smart grid control will not be secured.
Analysis of Project Benefits and Costs Comparing to a) Doing Nothing and b) Technically Feasible Alternatives
<u>Continuing to Only Install Smart Fault Indicators</u> This option will expand existing use of smart fault indicators but would only provide incremental benefits to fault locating which would reduce duration of an outage. This option would not increase operational efficiency and reliability improvements with isolation and system restoration. This solution will not take advantage of existing smart devices (e.g. switches and breakers) that can further drive improvements in number of customers affected by an outage. <u>Do Nothing</u> By doing nothing, OPUCN will continue operating the existing system the same way as today, without obtaining the benefits of advance monitoring and communication technologies to improve fault location, isolation and system restoration. This is not a proactive approach for grid modernization.

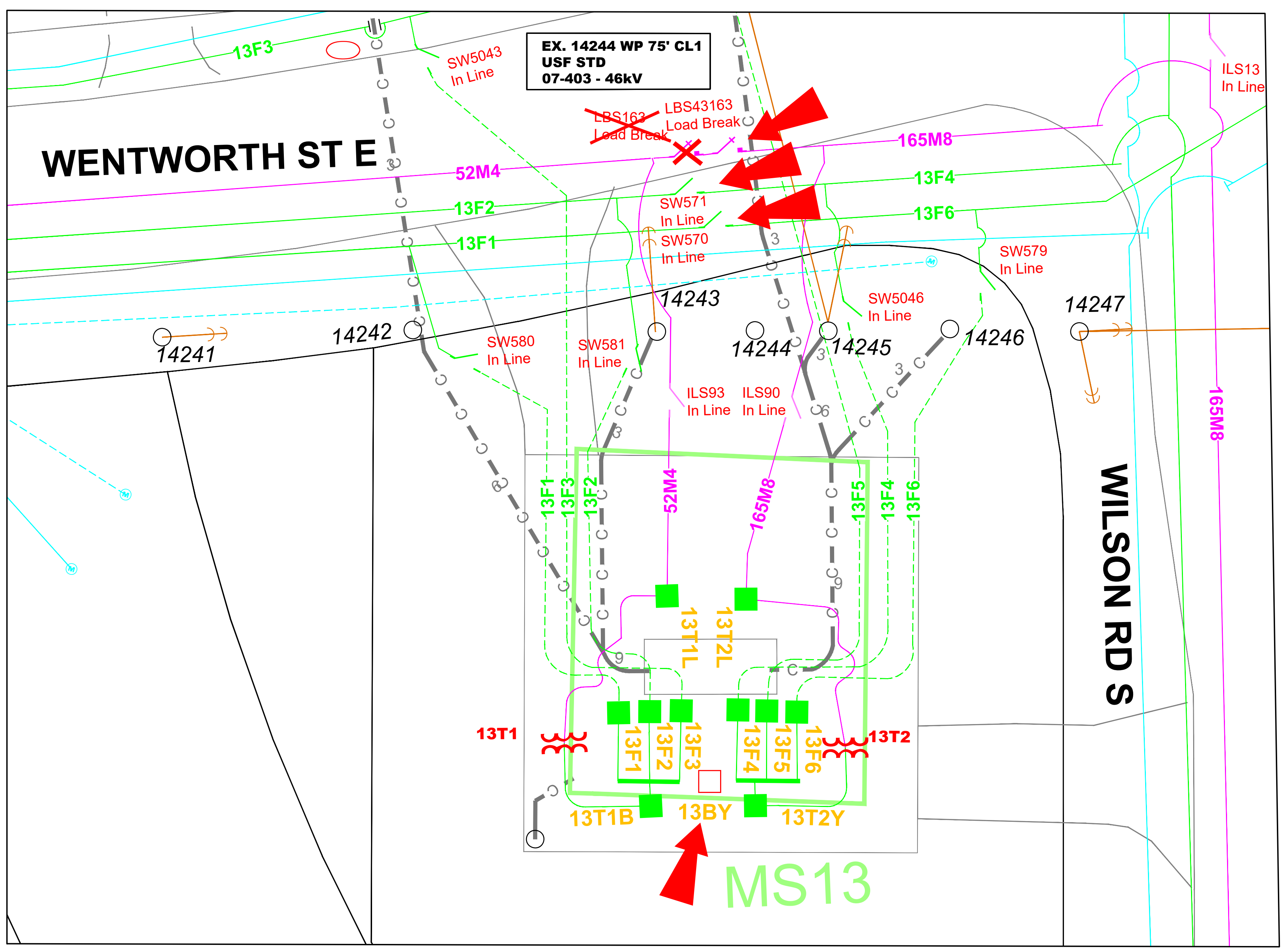
Attachment 2 – 6

OH Distribution C22-269 & C21-279

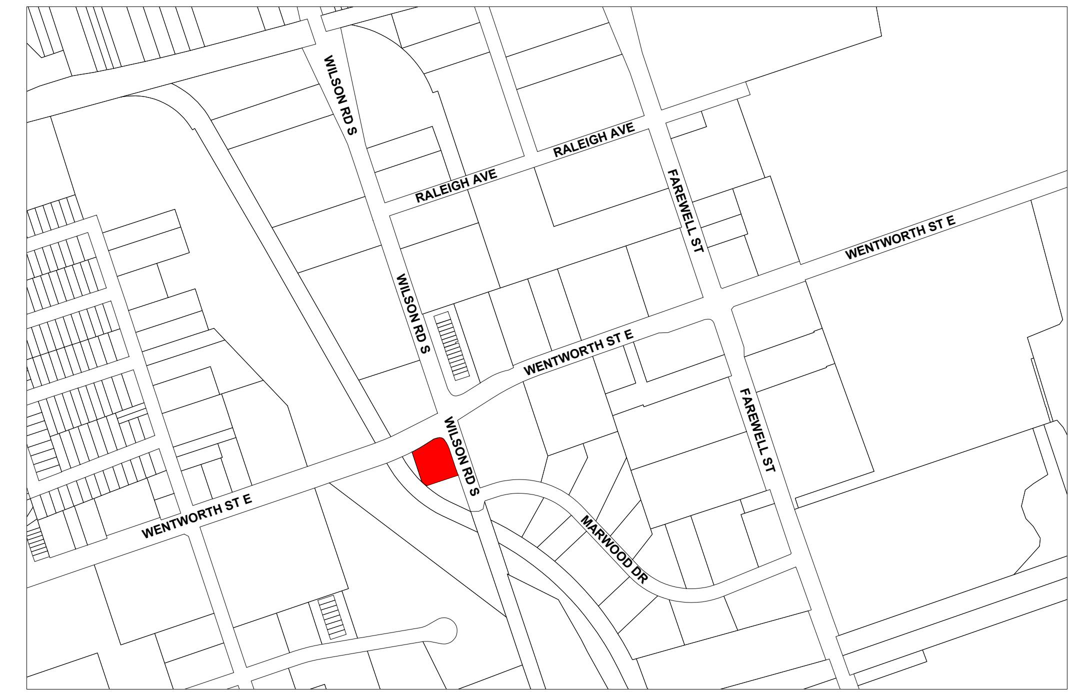
OH DISTRIBUTION C22-269 :

LBS163 Load Break — LBS 43163 Load Break

REMOVE/INSTALL 44 kV LOAD BREAK SWITCH LBS163 WITH LBS43163 ON POLE #14244 AS INDICATED



KEY MAP — NTS



LEGEND

- 14244 — EXISTING OPUCN POLES & NUMBERS
- EXISTING ANCHOR
- 165M8 — EXISTING OH 44 kV PRIMARY CONDUCTOR AND CIRCUIT ID'S
- 13F6 — EXISTING OH 13.8 kV PRIMARY CONDUCTOR AND CIRCUIT ID'S
- EXISTING OH SECONDARY CONDUCTOR
- EXISTING UG 13.8kV PRIMARY
- EXISTING UG 120/240V SECONDARY CONDUCTOR
- EXISTING STREETLIGHT FIXTURE
- EXISTING CONDUIT
- EXISTING OPEN POINT
- SW579 In Line — EXISTING 13.8kV IN LINE SWITCH
- ILS93 In Line — EXISTING 44kV IN LINE SWITCH
- 13T2 — EXISTING SUBSTATION TRANSFORMER
- 13T2L — EXISTING SUBSTATION BREAKER

OPUCN DISTRIBUTION SIGN OFF

- ☐ CONSTRUCTED AS PER ORIGINAL DRAWING
- ☐ ALL AS-CONSTRUCTED CHANGES SHOWN ON DRAWING

SIGNED ____ NAME ____ DATE ____

REV	DATE	BY	APP	DESCRIPTION

REVISIONS

Oshawa PUC Networks Inc.

100 SIMCOE STREET SOUTH
OSHAWA, ONTARIO
L1H 7M7

905-723-4623
www.opuc.on.ca

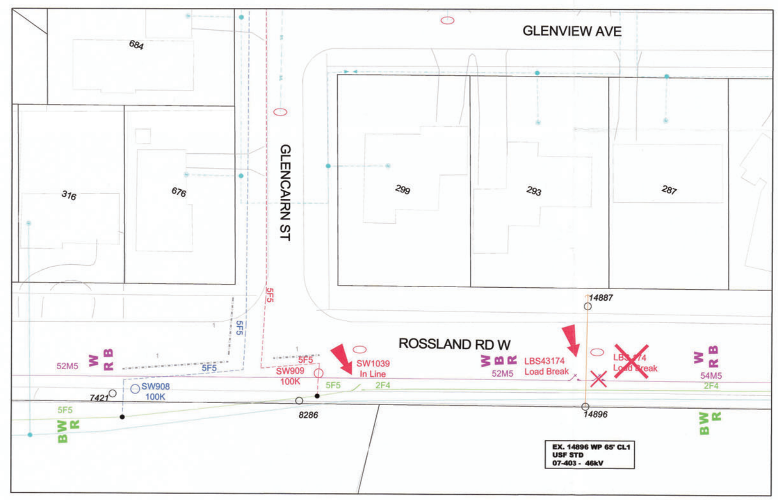
REMOVE/INSTALL 44kV LBS163 WITH LBS43163
POLE # 14244

DRAWN: ac:ML	CHECKED: LB	APPROVED: JH
DATE: April 28, 2022	SCALE: NTS	
W.O. #: C22-269 (WO)	DRAWING NUMBER: C22 - 050	REV: 0

X:\ATechTeam AutoCAD dwgs\2022 Projects\C22-269 - Automated Switching\DWG C22-050

OH DISTRIBUTION C21-279 :

REMOVE/INSTALL 44 kV LOAD BREAK SWITCH LBS174 WITH LBS43174 ON POLE #14896 AS INDICATED



KEY MAP NTS

LEGEND

14896	EXISTING OPUCN POLES, ANCHORS & NUMBERS
52M5 54M5	EXISTING OH 44 kV PRIMARY CONDUCTOR AND CIRCUIT ID'S
5F5 2F4	EXISTING OH 13.8 kV PRIMARY CONDUCTOR AND CIRCUIT ID'S
	EXISTING OH SECONDARY CONDUCTOR
14 14	EXISTING STREETLIGHT CONDUCTOR
	EXISTING UG 8.0kV PRIMARY
	EXISTING UG 120/240V SECONDARY CONDUCTOR
	EXISTING STREETLIGHT FIXTURE
1	EXISTING CONDUIT
SW909 100K	EXISTING SINGLE PHASE CUTOUT
	EXISTING OPEN POINT
	EXISTING PREMISES
SW1039 In Line	EXISTING IN LINE SWITCH
BW R / W BR	EXISTING 13.8 & 44kV PHASING LABELS

OPUCN DISTRIBUTION SIGN OFF

- [x] CONSTRUCTED AS PER ORIGINAL DRAWING
- [ ] ALL AS-CONSTRUCTED CHANGES SHOWN ON DRAWING

SIGNED	NAME	DATE
R. Rechanicz	R. RECHANICZ	JAN4/22

REV	DATE	BY	APP	DESCRIPTION

REVISIONS

Oshawa PUC Networks Inc.

100 SIMCOE STREET SOUTH
OSHAWA, ONTARIO
L1H 7M7

905-723-4623
www.opuc.on.ca

REMOVE/INSTALL 44kV LBS174 WITH LBS43174
POLE # 14896

DRAWN: ML	CHECKED: JH	APPROVED: LB
DATE: SEPTEMBER 29, 2021	SCALE: NTS	
W.O. #: C21-279 (WO)	DRAWING NUMBER: C21 - 098	REV: 0

X:\ATechTeam AutoCAD dwgs\2021 Projects\C21-279 - New Load Break Switch Installation - Rossland Rd W east of Park Rd N (Pole #14896)

Attachment 2 – 7

GP-06 Material Justification Sheet

A. General Information (5.4.3.2.A)					
Project/Activity	IT Systems Upgrade				
Project Number	GP-06				
Investment Category	General Plant				
	2021	2022	2023	2024	2025
Capital Cost	$251,500	$230,500	$494,250	$186,000	$418,250
Capital Contribution	N/A	N/A	N/A	N/A	N/A
Net Cost	$251,500	$230,500	$494,250	$186,000	$418,250
O&M Cost	2021	2022	2023	2024	2025
	$26,800	$26,800	$29,800	$29,800	$29,800
Customer Attachments and Load					
Not Applicable					
Start Date	2021-2025	In-Service Date	2021-2025		
Expenditure Timing for the Planning Horizon	2021Q1	2021Q2	2021Q3	2021Q4	
	$175,000	$25,000	$25,000	$26,500	

Project Summary

- Upgrade and planned refresh of retired hardware including laptops, desktops, networking gears, storage capacity, UPS and battery systems, phone systems, data back-up and the server infrastructure.
- Equipment & Consulting services for network and systems enhancement/upgrade including domain controller, email systems and network segmentation.

Risk Identification & Mitigation

- Many of the system upgrade and implementation task may require specialized skill set which is not available internally that may delay the implementation of the project.
  - Use external resources to fill in the gap and speed up the implementation process.
- Risk of going over budget due to inflation and the lower exchange rate since most of the equipment purchased from USA based vendor and the product is quoted in USD$.
  - The mitigation strategy is to find an alternative local sources, and if that is not available then plan to purchase equipment when the foreign exchange rate is higher.
- Delayed equipment delivery since most of the equipment sourced from foreign vendors. Historically, delivery takes longer than anticipated time.
  - To mitigate the risk, OPUCN will plan to order equipment earlier to ensure on time delivery or find the alternative local sources.
- OPUCN continues to focus on security and privacy as required to comply with all applicable laws, standards and best IT security practices.
- Ensure that current and future EOSL (end of serviceable life) equipment is replaced on schedule.

Comparative Information on Expenditures for Equivalent Projects/Activities

Year	Actual	Budget
2015	$ 117,549.00	$ 130,000.00
2016	$ 93,294.00	$ 130,000.00
2017	$ 140,960.00	$ 80,000.00
2018	$ 291,481.00	$ 280,000.00
2019	$ 127,000.00	$ 80,000.00
2020		$ 314,000.00
2021		$ 251,000.00
2022		$ 230,500.00
2023		$ 494,250.00
2024		$ 186,000.00
2025		$ 418,250.00

2015	2016	2017	2018	2019
104,672	79,976	187,535	282,572	126,791

The above table depicts the capital expenditures and budget for 2015 – 2019. During this time frame, project projections and spending was fairly low, with minimum allocations for system upgrades, maintenance, and disaster recovery as it relates to mitigating end of supportable life, supporting effective disaster recovery and maintaining cybersecurity standards relating to OEB Framework and Industry best practices. The table below depicts required activities and related expenditures by year for the 2020 to 2025 timeframe. 2020 is a budget cost and part of historical expenditure within this DSP.

Project		2020	2021	2022	2023	2024	2025
New IT Equipment Upgrades (work stations & laptops)		87000	89000	90500	92000	94000	96000
Network Segmentation project		30000	0	0	0	0	0
Storage System Refresh		0	0	115000	25000	0	0
Switches & Routers/ Firewall upgrade		0	91000	0	0	0	40000
UPS System Refresh and Batteries		0	9000	0	0	34000	0
Data Backup Refresh		67000	0	0	25000	0	0
Phone System Refresh		0	0	0	50000	0	250000
Domain Controller and Email System Upgrade		50000	0	0	0	0	0
Servers Upgrades in Production and DRP - EOSL		60000	40000	0	275000	28000	0
Mobile Phone Refresh		20000	22500	25000	27250	30000	32250
	Total	**314000**	**251500**	**230500**	**494250**	**186000**	**418250**

REG Investment Details including Capital and OM&A costs

As this project is not associated with any REG investment, no REG related capital or OM&A costs will be incurred.

Leave to Construct approval under Section 92 of the OEB Act

This project is below 50 kV and therefore Leave to Construct is not required, as per OEB.Reg. 161/99.

Attach Other Project Reference Material i.e. Images, Drawings and/or Reference Material

Not Applicable

B. Evaluation Criteria and Information Requirements for Each Project/Activity (5.4.3.2.B)
Efficiency, Customer Value & Reliability – Investment Main Driver
The driver is in the General Plant Investment Category aimed at maintaining and improving operational efficiencies by upgrading the infrastructure with latest technology thereby eliminating aged and unsupported systems. Equally, upgrades directly support control requirements outlines in the OEB Cyber Security Frame
Efficiency, Customer Value & Reliability – Investment Secondary Driver
There are no secondary drivers.
Efficiency, Customer Value & Reliability – Investment Objectives and/ or Performance Targets
Reliability and operational performance improvements. Substantially reduce the risk of equipment failure and downtime.
Efficiency, Customer Value & Reliability – Source and Nature of the Information Used to Justify the Investment
This is based on the best practices to enhance the reliability and the overall performance of the OPUCN IT infrastructure.
Efficiency, Customer Value & Reliability – Addressing Reliability and Adapting to Future Challenges
Procurement of the new hardware infrastructure to meet emerging business needs. Upgrade will also maximize the ability to port existing assets as well as ensure the future extensibility and portability of future systems that will be deployed.
Efficiency, Customer Value & Reliability – Priority Level/ Project Prioritization and Reasoning. Priority Relative to Other Investment
This program meets multiple AM objectives identified in Section 5.3.1 and is a high priority that will maintain and improve operational efficiencies. This is also an essential investment to address business requirements and cybersecurity.
Analysis of Project & Alternatives – Effect of the Investment on System Operation Efficiency and Cost-Effectiveness
OPUCN has received alternatives quotations from three different vendors. OPUCN will be reviewing the alternatives and adopt a selection process based upon best fit, cost effective and most preferred vendor.
Analysis of Project & Alternatives – Net Benefits Accruing to Customers
Improved systems/network reliability, operational efficiencies and cost efficiencies. Maintaining legacy systems is more costly than upgrading to newer more efficient systems.
Analysis of Project & Alternatives – Impact of the Investment on Reliability Performance Including Frequency and Duration of Outages
The investment in a new system will improve the ability to respond to changes, increase reliability and performance of the customer facing systems thereby enhancing customer service ability, better responsiveness and timely updates to customers and employees.
Project Alternatives (Design, Scheduling, Funding/Ownership)
The project alternative that was considered is to “do-nothing,” however, maintaining legacy systems is more costly and limits ability to utilize new technological developments in support of business needs.
Safety

This project does not directly relate to safety.
Cyber-Security, Privacy (where applicable)
OPUCN continues to focus on security and privacy as required to comply with all applicable laws, standards and best IT security practices. Project initiatives directly support Cyber Security requirements as mandated by the OEB Cyber Security Framework as well as Industry best practices.
Co-ordination, Interoperability Recognized Standards, Co-ordination with Utilities, Regional Planning, and/or 3rd party Providers (where applicable)
Not Applicable
Co-ordination, Interoperability Future Technological Functionality and/or Future Operational Requirements (where applicable)
Procurement of the new hardware infrastructure to meet emerging business needs. Upgrade will also maximize the ability to port existing assets as well as ensures the future extensibility and portability of future software deployment.
Environmental Benefits (where applicable)
Not Applicable
Conservation and Demand Management – Assessment of Cost Benefits to Customers (where applicable)
Not Applicable
Conservation and Demand Management – Number of Proposed CDM program and Number of Years of Project Deferral (where applicable)
Not Applicable
Conservation and Demand Management – Description of Incorporation of Advance Technology, Interoperability and Cybersecurity
Not Applicable

C. Category-Specific Requirements – General Plant (5.4.3.2.C)
Results of Quantitative and Qualitative Analyses
New hardware will enable the end user to work faster and more efficiently, increasing the return on investment (ROI). Similarly, older systems that crash regularly, or otherwise keep end users from working efficiently will contribute to productivity issues. Hardware is typically purchased with a maintenance/warranty period that is defined based on normal wear and tear that contributes to poor performance.
Business Case Documenting the Justifications for Expenditure, Alternatives, Benefits (Long Term/Short Term), Cost Impacts

Although there is a capital investment involved, leveraging refreshed systems could enable OPUCN to save over the long-term through reduced maintenance and support cost and improved efficiency and staff productivity.

If we were to ‘Do Nothing’ there is a higher probability of system failure and cybersecurity incidents. Vendors often will not extend warranties beyond the serviceable life which increases support risks. The business operation could be negatively impacted if systems are not maintained and/or replaced. If IT systems are not upgraded OPUCN would expect additional maintenance fees or higher than usual upgrade costs in the long-term.

Attachment 2 – 8

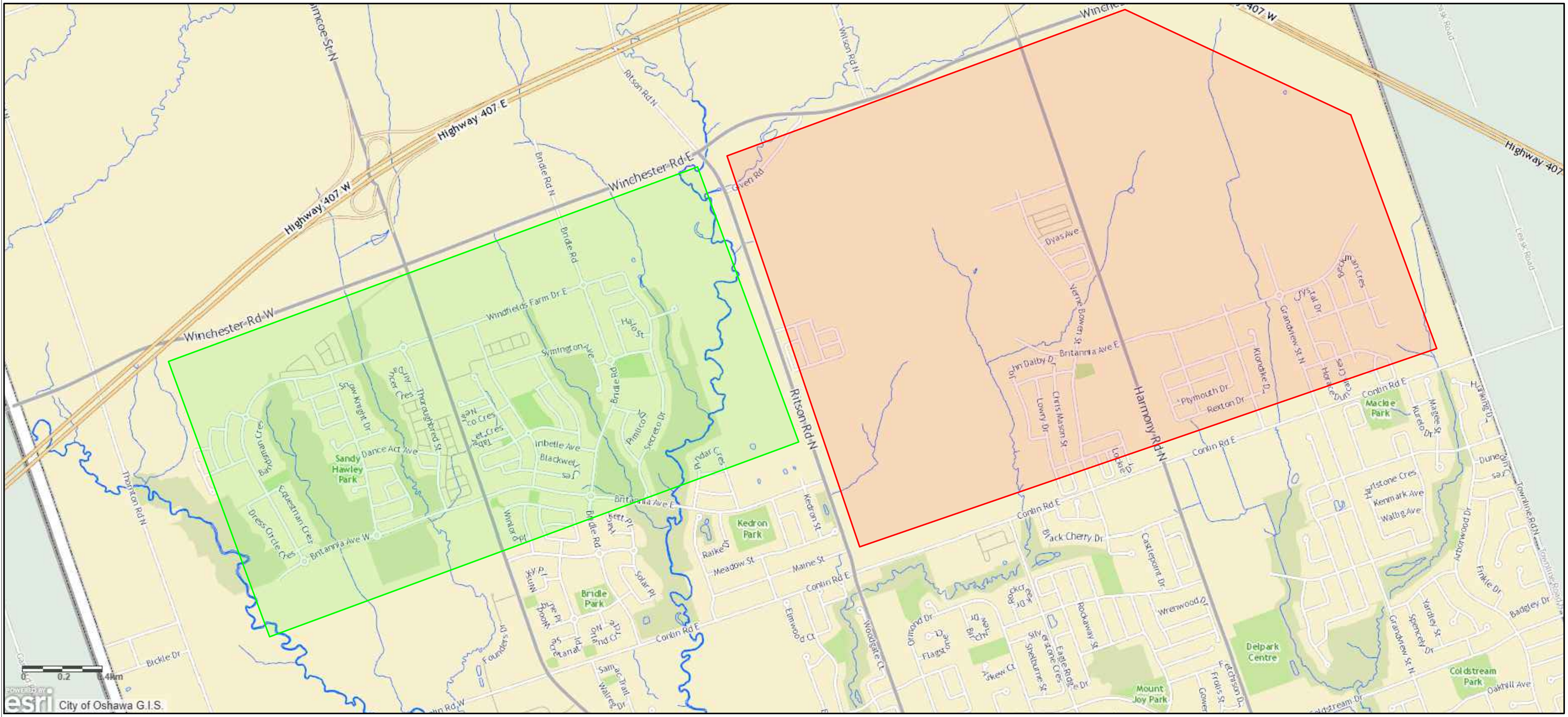
Third Party Relocation Project Details

				2026	2027	2028	2029	2030	Km
SA	1a	Simcoe St/ Russett Ave Intersection	$ 26,250.00					$ 26,250.00	Intersection
SA	1b	Winchester Rd. / Bridle Rd Intersection	$ 138,750.00			$ 138,750.00			Intersection
SA	1c	Ritson Rd./Beatrice St. Intersection	$ 105,000.00		$ 105,000.00				Intersection
SA	1d	Ritson Rd. from north of Taunton Rd to Conlin Rd	$ 562,500.00			$ 562,500.00			2.0
SA	1e	Rossland Rd from Park Rd to Simcoe St	$ 600,000.00		$ 600,000.00				0.6
SA	1f	Rossland Rd from Ritson Rd to Harmony Rd	$ 675,000.00		$ 675,000.00				0.9
SA	1g	Thronton Rd from north of Stellar Dr to King St	$ 600,000.00				$ 600,000.00		0.8
SA	1h	Phillip Murray Ave/Stevenson Rd Intersection	$ 90,000.00		$ 90,000.00				Intersection
SA	1i	Stevenson Rd/Laval Dr Intersection	$ 60,000.00			$ 60,000.00			Intersection
SA	1j	Stevenosn Rd from CPR Belleville to Bond St	$ 450,000.00		$ 450,000.00				1.2
SA	1k	Stevenson Rd from Bond St to Rossland Rd	$ 1,361,250.00		$ 1,361,250.00				2.0
SA	1l	Townline Rd from Beatrice St to Taunton Rd	$ 281,250.00	$ 281,250.00					0.9
SA	1m	Gibb St from east of Stevenson Rd to Simcoe St	$ 1,000,000.00		$ 1,000,000.00				1.4
SA	1n	Wentworth St/Thornton Rd Intersection	$ 120,000.00					$ 120,000.00	Intersection
SA	1o	73-0453 Conlin-Wilson Roundabout / 73-0454 Conlin Road East	$ 531,000.00	$ 531,000.00					Intersection
SA	1p	73-0455 Conlin Road East	$ 184,125.00	$ 184,125.00					1.0
SA	1q	73-0456 Northwood Roads	$ 632,250.00		$ 632,250.00				New road
SA	1r	73-0457 Columbus Road / 73-0486 Ritson/Columbus Roundabout	$ 1,951,500.00	$ 1,951,500.00					Intersection
SA	1s	73-0459 Central Oshawa Hub Infrastructure Improvements	$ 345,750.00	$ 345,750.00					-
SA	1t	73-0460 Ritson Road North	$ 406,500.00		$ 406,500.00				2.0
SA	1u	73-0479 Britannia Ave W / 73-0492 Britannia Ave West Bridge	$ 585,000.00		$ 585,000.00				0.6
SA	1v	GWP 2601-19-00, 2146-20-00 - Hwy 401/Bloor/Harmony Interchange Reconstruction - OPUC	$ 250,000.00	$ 250,000.00					Intersection

Attachment 2 – 9

Development Areas

2025 & 2026 New Developments



LEGEND

High Concentration of New Developments

Medium Concentration of New Developments

Attachment 2 – 10

Fleet Management Policy

FL - 100 Fleet Management Policy

1.0 Policy Statement

Oshawa Power, is committed to the proper maintenance, management, and purchase of vehicles to be used in the organizations fleet. This policy is intended to outline the processes for monitoring the condition of all vehicles and the criteria for evaluation, and for the procurement and removal of company vehicles.

2.0 Scope

This policy applies to all vehicles owned and operated by Oshawa Power.

3.0 Roles & Responsibilities

The management of the Oshawa Power, fleet of vehicles shall be overseen by the Fleet Management Committee ("Committee"), which is comprised of the following:

Title	Committee Role
Director of Operations	Executive Sponsor
Manager, Distribution Construction	Operations Manager
Supervisor, Distribution Construction	Operations Representative
Manager, HSSE, Fleet & Facilities	Chair
Coordinator, HSSE	Health & Safety Representative
Manager, Supply Chain	Procurement Representative
Powerline Technician	Operations Representative
Powerline Technician on JHSC	Operations/JHSC Representative

The Powerline Technician can be altered to be either a Power Maintenance Electrician or a Meter Technician, depending upon vehicle under review.

The **Committee Chair** is responsible for:

- Conducting an annual review and revising this policy as necessary;
- Communicating changes to staff;
- Coordinating fleet condition assessments;
- Ensuring Committee meetings are held on a regular basis, and at least annually;
- Ensuring all vehicles are maintained and in a good state of repair, as well as ensuring all safety issues are dealt with appropriately and forthwith;
- Escalating major, emerging or systemic fleet problems or concerns to the Committee.

Committee Members are responsible for:

- Contributing to the effective and fiscally responsible management of fleet assets in accordance with this policy by;
    - Ensuring all functional, operational, health & safety, and regulatory requirements are met and addressed in a timely manner;
    - Reviewing fleet asset information used to make procurement decisions.

4.0 Fleet Management Process

4.1 Committee Function

The Committee will meet regularly (at a minimum annually) to review fleet asset information, discuss fleet management issues and help determine any vehicle procurement decisions.

The information to be review will include:

- Key performance indicators and trends for all vehicles such as fleet utilization, engine hours, kilometers, and maintenance expenses;
- Fleet condition assessments; and
- Operational, functional, regulatory and/or health and safety concerns.

Fleet condition assessments will be conducted yearly on each vehicle, or at other intervals determined appropriate by the Committee depending on vehicle type and usage. Assessments will be completed by a third party and Oshawa Power jointly, and will deliver the following information:

- Vehicle Condition
- Appraisal Value
- Photo Records of interior and exterior.

The Committee is also responsible for preparing annual capital investment work plans for the fleet that seek to align planned expenditures with the approved Distribution System Plan ("DSP"). Any deviation from the approved DSP will require a formal change request and justification supported by an updated asset information and condition assessment.

4.2 Vehicle Procurement Criteria

The Committee shall use the criteria listed below to determine if an existing vehicle is eligible for consideration of replacement. All vehicles in service are listed in Appendix A. When replacement criteria have been met and Committee members have been reached consensus on replacement, a Vehicle Replacement Form shall be prepared for review and approval by the Committee Executive Sponsor. The Vehicle Replacement Form – Light Fleet is found in Appendix B, and The Vehicle Replacement Form – Heavy Fleet is found in Appendix C.

Commercial Vehicle classification is determined by the Highway Traffic Act R.S.O 1990, regulation O. Reg. 419/15.

4.2.1 Diesel Engine Heavy Fleet

Heavy Vehicles include Digger Derrick, Single Bucket, and Double Bucket Trucks.

Criteria

- Recorded mileage of 250,00km;
- Recorded engine hours of 10,000 hours;
- Ten (10) years of service;
- Changing departmental needs;
- Maintenance and repair costs over a year exceed the book value;
- Condition assessment finds the vehicle to be unfit for service;
- Changing emissions, weights and safety regulations;
- Usefulness to the company

Replacement of Heavy Vehicles are limited to one per fiscal year to minimize capital expenditures unless an emergency occurs in the fleet. If two vehicles are eligible for replacement in the same year, the vehicle with higher kilometers/hours/age will take precedent and the other will follow in the subsequent year.

If a vehicle with ten (10) years of service has considerably less than 250,000 km and/or 10,000 hours, considerations will be made to postpone the unit's replacement if the estimated remaining service life is estimated to be five (5) years or more.

4.2.2 Light Duty Fleet

These vehicles include all light fleet such as pickup trucks, vans, service vehicles, and sedans and can either be gasoline or diesel powered.

Criteria

- Recorded mileage of 150,000 km;
- Six (6) years of service;
- Changing departmental needs;
- Maintenance and repair costs over a year exceed the book value;
- Condition Assessment finds the vehicle to be unfit for service;
- Changing emissions or safety regulations;
- Usefulness to the company;

If a vehicle with six (6) years of services has considerably less than 150,000 km, considerations will be made to postpone the unit's replacement if the estimated remaining service life is estimated to be three (3) years or more.

4.3 Document Review

This policy shall be reviewed annually and updated as required. As per the procedure found in *AD-0204 Records Management Policy*.

Wade Rowland – Manager, HSSE & Fleet, Facilities

Document release and revision history

Revision #	Date	Purpose of Release: Details of Revisions/Amendments	Prepared By	Approved By
1	July 2020	Original	Z. Vonkalckreuth	M. Strecker
2	August 2024		M. Shaw	W. Rowland

Appendix A – Fleet Inventory

MAKE (CHASSIS)	Model	YEAR	Company Unit #
2016 GMC	LT 3500 DUMP	2016	V-003
2012 FRTL	DOUBLE BUCKET	2012	V-005
2015 FRTL	DOUBLE BUCKET	2015	V-007
2012 FRTL	RADIAL BOOM DERRICK	2012	V-010
2012 FRTL	RADIAL BOOM DERRICK	2012	V-012
2019 FRTL	SINGLE BUCKET	2019	V-015
2016 FRTL	SINGLE BUCKET	2016	V-016
2012 FRTL	SINGLE BUCKET	2012	V-019
2013 CHEV	CHEVY CRUZE	2013	V-020
2016 FORD	1 TON STATION CUBE VAN	2016	V-022
2013 CHEV	1/2 TON EXTCAB PICK-UP	2013	V-024
2014 CHEV	1/2 TON EXTCAB PICK-UP	2014	V-027
2006 CHEV	1/2 EXTCAB TON PICKUP 4X4	2006	V-032
2012 FRTL	CUBEVAN	2012	V-044
2012 CHEV	ELECTRIC CAR CHEVY VOLT E/G	2012	V-048
2014 GMC	3/4 TON Savana CARGOVAN	2014	V-068
2015 CHEV	1/2 EXTCAB TON PICKUP 4X4	2015	V-069
2019 CHEV	LT 3500 DUMP	2019	V-080
2019 FORD	F-350	2019	V-081
2019 CHEV	1/2 TON DOUBLE CAB PICKUP 4X4	2019	V-082
2019 CHEV	1/2 TON DOUBLE CAB PICKUP 4X4	2019	V-083
2019 CHEV	1/2 TON DOUBLE CAB PICKUP 4X4	2019	V-084
2019 CHEV	1/2 TON CREW CAB PICKUP 4X4	2019	V-085
2020 Ford	SRW	2020	V-088
2020 Ford	SRW	2020	V-089
2019 FORD	TRANSIT VAN	2019	V-087
2020 FRTL	2020 Freightliner Single Bucket	2020	V-086
Ford	F-150	2023	V-092
Ford	F-150	2023	V-093
Ford	F-150	2023	V-094
Ford	F-150	2023	V-095
Freightliner	FM2 - Radial Derrick	2021	V-091
Freightliner	FM2 Bucket Truck	2022	V-090

Appendix B – Vehicle Replacement Form – Light Fleet

Fleet Replacement Request Form

Date: ____________ Request Submitted by: ____________

Truck Information:

Vehicle Number:		Department:	
Body:		Year:	
Truck Type:			

Factor	Current LTD	Renewal Threshold
Age		6
Kilometers		150,000
Cumulative Repair Costs		
Change in Organizational Need		Yes
Change in Regulations		Yes
Vehicle Condition Report		Unfit for Service

Additional Replacement Comments:

Renewal Information:

DSP Planned Replacement Year		Current Year		Lead Time	
Budgeted Replacement Cost		Quoted Price		*Lead time in Months	
Replacement Type:	Increased Functionality	Decreased Functionality		Like for Like	

Explain Replacement Requirements that differ from current vehicle:

List of included documentation:

Confirmation

HSEE, Fleet Facilities

Signature: ____________ Date: ____________

Name(Printed):

Approval

Signature: ____________ Date: ____________

Mike Weatherbee, Director of Operations

Finance

Signature: ____________ Date: ____________

Name (Printed): ____________

Appendix C – Vehicle Replacement Form – Heavy Fleet

Fleet Replacement Request Form - Heavy Fleet

Date:		**Request Submitted by:**	

Truck Information:

Vehicle Number:		**Department:**	
Body:		**Year:**	
Truck Type:			

Factor	Current LTD	Renewal Threshold
Age:		10
Engine Hours		10,000
Kilometers		250,000
Cumulative Repair Costs		
Change of Organizational Need		Yes
Change in Regulations		Yes
Vehicle Condition Report		Unfit for service

Additional Replacement Comments:

Renewal Information:

DSP Planned Replacement Year		**Current Year**		**Lead Time**	
Budgeted Replacement Cost		**Quoted Price**		*Lead time in Months	
Replacement Type:	*increased/ decreased/ like for like functionality*				

Explain Replacement Requirements that differ from current vehicle:

List of included documentation:

Confirmation

HSSE, Fleet Facilties

Signature: ______________________ Date: ______________

Name (Printed): ______________________

Approval

Signature: ______________________ Date: ______________

Name: **Mike Weatherbee, Director of Operations**

Finance

Signature: ______________________ Date: ______________

Name (Printed): ______________________

Attachment 2 – 11

PMC July 25, 2024 - DSP Slides

DSP (2026 – 2030)
Operational Discussion and Capital Envelope Recommendation

PMC – July 25, 2024

Foreword

The following analysis takes into account 3 distinct levels of investment:

1. Mandatory Projects -

   Investments and Projects that are mandated by the OEB

2. Critical Projects -

   Investments and Projects that are safety, growth and regulatory driven

3. Vital Equipment Projects -

   Investments and Projects that will continue to provide excellent reliability and keep the business running

Mandatory Projects

ITEM	TOTAL ANTICIPATED COSTS	TOTAL ANNUALIZED COST
City / Region Relocate Projects	$10.710M	$2.142M
Connections to System	$1.720M	$0.344M
Expansions to Connect	$13.530M	$2.706M
Revenue Metering – New Connections	$1.200M	$0.240M
TOTAL	**$27.160M**	**$5.432M**

OSHAWA POWER

Critical Projects - Safety/Growth & Regulatory Requirements

ITEM	TOTAL ANTICIPATED COSTS	TOTAL ANNUALIZED COST	REASON FOR CRITICALITY
System renewal reactive bucket	$9.130M	$1.826M	UNPREDICTABLE – BASED ON HISTORICAL. UNAVOIDABLE COSTS
MS Switchgear replacements	$5.881M	$1.176M	ACA / OPTIONS ANALYSIS / EXISTING CONTRACT
Meter Reverification & Replacement Program	$5.500M	$1.100M	REGULATORY – MEASUREMENT CANADA. IF FAILED REVERIFICATION, PROJECT BECOMES MANDATORY
OH System Rebuild Projects	$3.510M	$0.702M	ACA – POOR / VERY POOR CONDITION & HIGH / EXTREME RISK
UG System Rebuild Projects / Cable Injection	$2.260M	$0.452M	ACA – POOR / VERY POOR CONDITION & HIGH / EXTREME RISK
Pole Replacement Program	$1.400M	$0.280M	ACA – POOR / VERY POOR CONDITION & HIGH / EXTREME RISK
Overloaded Transformer Replacements	$1.100M	$0.220M	SAFETY
New feeders from MS9	$1.000M	$0.200M	CUSTOMER GROWTH / CAPACITY
Porcelain Insulator replacements	$0.600M	$0.120M	SAFETY – ESA
Distribution Switchgear Replacement	$0.270M	$0.054M	ACA – VERY POOR CONDITION, HIGH RISK
TOTAL	**$30.651M**	**$6.130M**	

Vital Equipment Projects

ITEM	TOTAL ANTICIPATED COSTS	TOTAL ANNUALIZED COST	REASON FOR INCLUSION
Vehicles	$2.300M	$0.460M	END OF LIFE
Major Tools	$0.650M	$0.130M	END OF LIFE
Facility – General	$0.500M	$0.100M	REPAIRS
Computer Hardware	$2.529M	$0.506M	END OF LIFE
Software	$4.156M	$0.831M	BUSINESS SOFTWARE / AUTOMATION
Firon Switch replacement Program	$1.250M	$0.250M	DEFECTIVE EQUIPMENT – OPERATIONAL RISK MITIGATION
44kV Quick Sleeve replacement Program	$1.000M	$0.200M	DEFECTIVE EQUIPMENT – OPERATIONAL RISK MITIGATION
Distribution Automation – 13.8KV	$0.975M	$0.195M	RELIABILITY RISK MITIGATION AND LOAD ALLEVIATION
Distribution Automation – 44KV	$0.720M	$0.144M	RELIABILITY RISK MITIGATION AND LOAD ALLEVIATION
Miscellaneous – SCADA / Fault Locators	$0.389M	$0.078M	RELIABILITY RISK MITIGATION AND LOAD ALLEVIATION
Distribution system lock replacement	$0.350M	$0.070M	DEFECTIVE EQUIPMENT – SAFETY RISK MITIGATION
OH System rebuild Program - Ritson, Taunton	$1.655M	$0.331M	ACA RECOMMENDATION BASED ON HIGH RISK, FAIR CONDITION
UG System Rebuild Projects / Cable Injection	$2.500M	$0.500M	ACA RECOMMENDATION BASED ON HIGH RISK, FAIR CONDITION
Non-wires solutions	$0.715M	$0.143M	NEW OEB REQUIREMENT & SUPPORTS DEFERRAL OF STATION
TOTAL	**$19.689M**	**$3.938M**	

Summary of Mandatory / Critical / Vital

CATEGORY	TOTAL ANTICIPATED COSTS	TOTAL ANNUALIZED COSTS
MANDATORY	$27.160 M	$5.432 M
CRITICAL	$30.651 M	$6.130 M
VITAL EQUIPMENT	$19.689 M	$3.938 M
TOTAL	**$77.5M**	**$15.5M**

- **MANDATORY** - Projects considered mandatory by the OEB.
- **CRITICAL** - Projects that mitigate safety / regulatory risks and capacity building.
- **VITAL EQUIPMENT** - Projects to replace end of use equipment and mitigate risks related to reliability.

Summary of Options for 2026 Asks: Capital

	Capital	Description	Benefits	Risks
1	$13M annually, including $15M for new station	Cannot complete all mandatory & critical projects identified in the distribution system plan	**Fin**: no additional financing required above building/land; <60% debt by 2030	**Ops**: risk of operational failures due to under investment because critical projects cannot be completed **Reg**: concerns about planning & pacing
2	$13M annually, plus separate $15M for new station (ACM)	Can complete all mandatory & critical projects identified in the distribution system plan, with limited investment in vital equipment projects	**Ops**: mandatory, critical, and station covered; consistent system work for staff **Fin**: no additional financing required above building/land	**Ops**: no vital equipment projects means major constraints for equipment at end of life and no risk mitigation **Fin**: requires additional financing of ~$15M to cover station costs
3	$15.5M, no new station Recommended Ask	Can complete all mandatory, critical & vital equipment projects identified in the distribution system plan No new station before 2030	**Ops**: all mandatory, critical & vital equipment projects included **Reg**: no need to undertake advanced capital module	**Ops**: no room for innovation, plus putting off station risks redundancy if demand spikes **Fin**: similar financing required to option 2 but no ACM so exposure to profitability (~$1.6M cumulative over COS period)
4	$15.5M annually, plus separate $15M for new station (ACM)	Can complete all mandatory, critical & vital equipment projects identified in the distribution system plan New station completed before 2030	**Ops**: can complete all mandatory, critical & vital equipment projects as well as new station	**Ops**: no room for innovation **Fin**: requires significant additional financing above building/land of ~$10M for annual spend and $15M for station; significant impact to profitability **Reg**: concerns customer impact & pacing

OMISSIONS FROM RECOMMENDED ASK

1. City/Region Jobs with uncertainty about the exact year within the specified range of 2029-2033 - Approx. Total Cost of $3.71M.

2. Potential Failure of all meters that are up for reverification in 2028 – Approx. Total Cost of $5.5 M (Additional to the $5.5M included under the meter reverification and replacement Program)

3. Based on the Asset Condition Assessment Recommendations in conjunction with internal expertise, high priority items were included in the recommended ask. The items excluded predominantly consists of assets in a Fair condition but were identified as High Risk, yet ranked lower in priority compared to the items included in the ask. – Approx. Total Cost of $20M

Total Omissions from recommended ask is $29.21M

Attachment 2 – 12

EV Uptake Studies

IR 92 Attachment 2-12

Study / Report / Data / Document Name	**Source**	**Page**
1. EV Adoption by Forward Sortation Area	Ministry of Transportation	1
2. ZVEA 2022 Project Results	Plug N Drive primary research / surveys done in field via MEET Trailer	2
3. ZVEA 2023 Project Results	Scout Environmental	3
4. Grid Innovation Fund Data Disaggregation EV Growth Study	Peak Power and Hatch Engineering	11

1. https://data.ontario.ca/dataset/electric-vehicles-in-ontario-by-forward-sortation-area

2. ZVEA 2022 Project Results

MEET Durham

MEET	# of test driver:	Drop ins	Total
Ajax	42	28	
Clarington/Courtice	33	38	
Durham Region	39	27	
Oshawa	22	29	
Pickering	38	25	
Scugog	37	38	
Whitby	67	20	
Grand Total	**278**	205	483

Survey Completion:	250

	Likelihood of purchasing an EV after the test drive experience			
MEET	**As Likely As Be**	**Less Likely**	**More Likely**	**Grand Total**
Ajax	7		33	40
Clarington/Courtice	6	1	25	32
Durham Region	11		26	37
Oshawa	6		14	20
Pickering	3		32	35
Scugog	8		24	32
Whitby	12		42	54
Grand Total	**53**	**1**	**196**	**250**

	Considered an EV before the experience			
MEET	**No**	**Undecided**	**Yes**	**Grand Total**
Ajax	2	21	17	40
Clarington/Courtice	2	17	13	32
Durham Region	1	14	22	37
Oshawa		12	8	20
Pickering		9	26	35
Scugog	1	11	20	32
Whitby	6	26	22	54
Grand Total	**12**	**110**	**128**	**250**

3. ZVEA Project Results

Final Report

TABLE OF CONTENTS

Section A – Final Narrative

Project Summary

As finalized in Schedule A of your Contribution Agreement:

- ***The Proponent will develop a web-based interactive EV guide for residents in partnership with the Oshawa Power and Utilities Corporation*.**

Project Objective

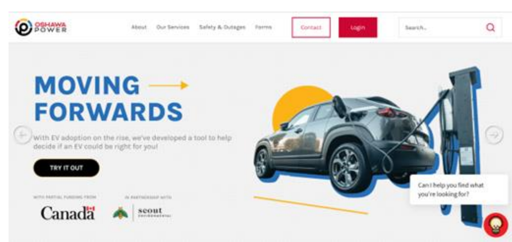
As finalized in Schedule A of your Contribution Agreement:

- ***The objective of this Project is to raise awareness, knowledge and confidence in EVs by developing a measurable, repeatable education and awareness campaign that helps Canadians adopt electric vehicle technology at an unprecedented rate in a sustainable fashion.***

Introduction

In 2023/24, Scout Environmental undertook activities to design, develop and launch an **interactive digital Guide** that would:

- Debunk common myths and promote public confidence in EVs;
- Reduce barriers to EV adoption;
- Help the local utility better profile and predict consumer power demands, plan future infrastructure needs and inform future EV program planning and delivery; and
- Establish a repeatable, best-in-class educational model for utilities (and their customers) across the country.

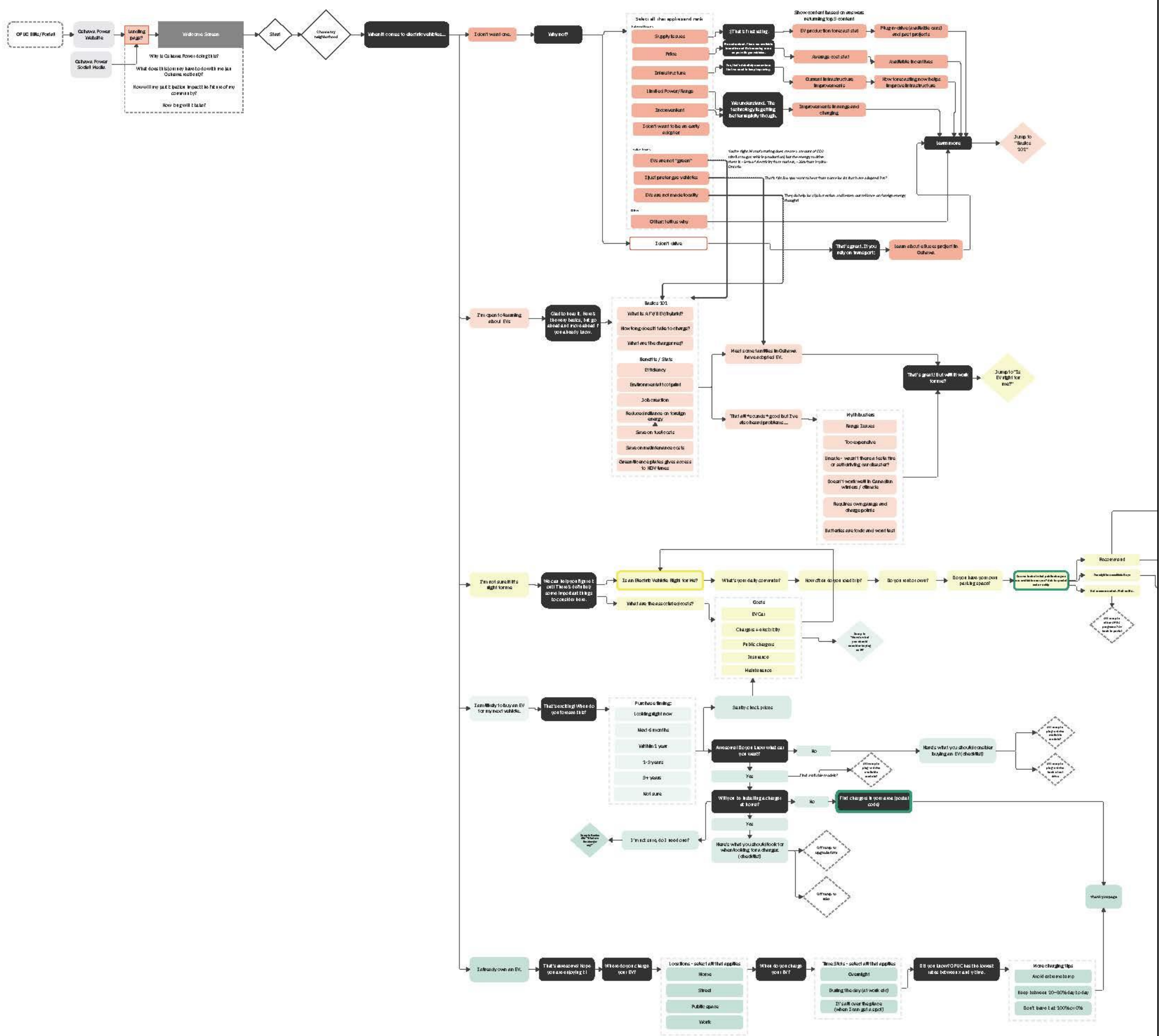


Marketed to Oshawa Power Utility Corporation (OPUC) customers, Moving Forwards: Driving EVs in Oshawa was launched to the public in October 2024.

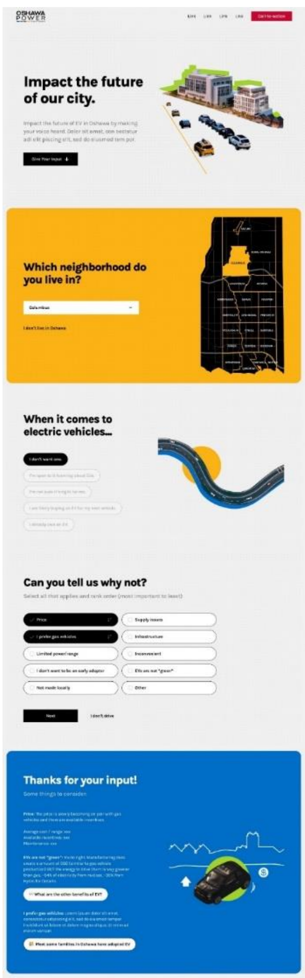
Development and Design

Our goal was to use digital customer experience technology to mimic the actions and logic that an EV subject matter expert would employ in regular conversation, but online. To do this successfully, our digital Guide would need to (a) quickly profile the customer and their knowledge/experience with EVs, (b) tailor questions and educational content to their specific needs, and (c) provide personalized answers and results based on their responses.

Scout worked with the digital development team at **Manyways** to ideate a solution, and fulfill the technical requirements of this project. During the design and production phase of the project, Scout and Manyways developed the required content and technical components, including journey flow (below), wireframes and design recommendations. Extensive quality assurance and user acceptance testing was also conducted, to ensure a positive user experience.



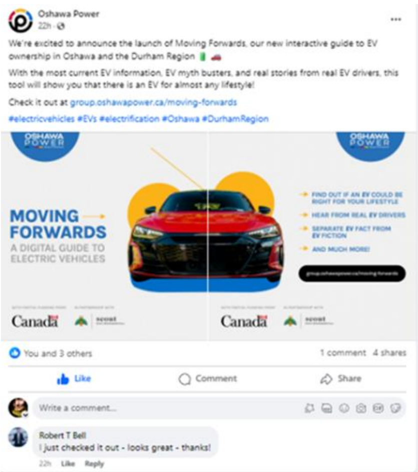
Moving Forwards – user journey flow



Moving Forwards: Sample UX Styling

Promotion

Oshawa Power & Utilities Corporation (OPUC) serves over 60,000 customers from all socioeconomic levels. To efficiently and effectively engage their customers in this project, OPUC's Corporate Communications worked with Scout to define content and audience requirements, and develop a Marketing and Promotion Strategy that included a [press release](), dedicated [project page](), social media and [blog posts]() and email blast.



▿ Moving Forwards - Sample social media posts

Data

Our ability to observe and report on usage data trends and performance analytics is a crucial component to both the success and relevance of this project.

Broken into clear and measurable steps, The *Moving Forwards* Guide is designed to track user participation and collect valuable insights on how users engage with the information provided. This data can then be used to better inform future communication and education priorities, as well as EV programming. *Note: user information is captured safely and securely according to the latest data privacy and security best practices. All data is hosted on Canadian infrastructure, and all sensitive data is secured in transit and at rest.*

Some highlights:

- ➢ From server-side data, we know that the majority of visitors to the Guide were under the age of 45.
- 19-24 year olds: 16.5%
- **25-34 year old: 23.4%**
- 35-44 year olds: 20.7%
- 55-64 year olds: 13.2%
- Over 65: 9%

- ➢ We also know that the **majority are English speakers** (96.6%) and **male** (68.8%)

- ➢ Just over 20% of users state that they already own an EV.

- ➢ Under 8% said that would not switch to EVs.

- 17.8% would be likely purchase an EV as their next vehicle. Of these, over half would be making their purchase within the year, and 71.3% would be installing a charger at home, rather than relying on public charging infrastructure.

- The majority of respondents (54.2%) were on the fence – either interested or unsure, demonstrating the need for further education and promotion of EVs to the general public.

- Of specific interest and relevance to Oshawa Power, data collected shows that the majority of their customers who charge at home do so at off peak hours, with 60% charging overnight between 11pm-7am.

Conclusion

We believe our project was successful in raising public awareness, knowledge and confidence in electric vehicles using curated, interactive digital content.

From the data collected, we know that there were over 2,000 engaged sessions between the months of October 2023 and March 2024.

Oshawa Power has also reported a noticeable uptick in digital engagement on topics surrounding EVs and electrification (both positive and negative). The e-blast promoting the launch of *Moving Forwards* was the most successful marketing piece, reaching over 33k customers. Social media engagement has also been strong, with Facebook posts in particular found to be a good conversation starter – a share of OPUC's Nov. 21 post to the 'Downtown Oshawa' group sparked a 96-comment conversation, mainly driven by detractors (range, ethics of mining, winter performance) and responses from supporters providing factual rebuttals referencing the Guide's "Mythbusting" section.

Additionally, Oshawa Power reports that EV adoption continue to increase in their service territory, up an additional 21% over the life of the project. This increase cannot be directly attributed to the project, but project data does reflect the intention to purchase an EV in the immediate future.

By addressing common myths on EV use, and connecting users to additional resources such as Plug'NDrive's EV car matching tool and Transport Canada's charging station locator tool, the *Moving Forwards* digital Guide provides users with personalized and actionable information – essential to accelerating the adoption of electric vehicles. This model can easily be adapted, replicated and/or scaled to other jurisdictions.

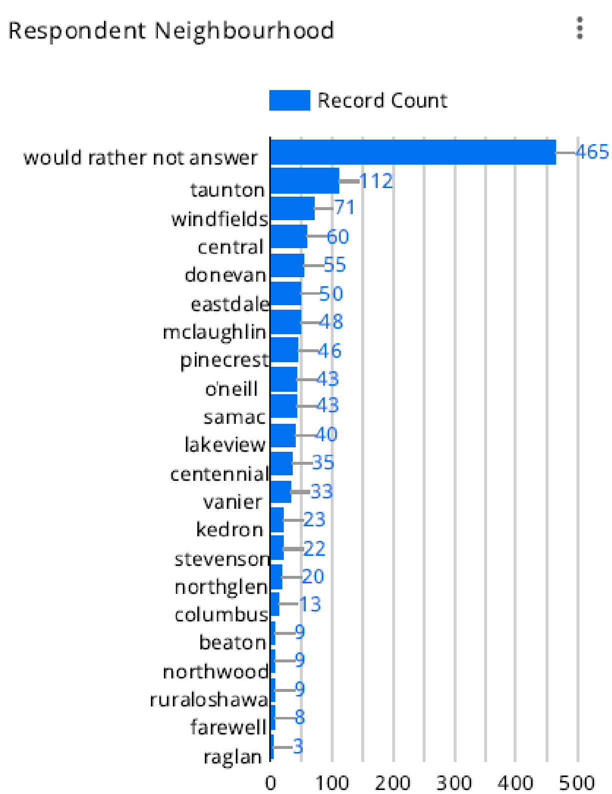
Key Performance Indicators and Final Results

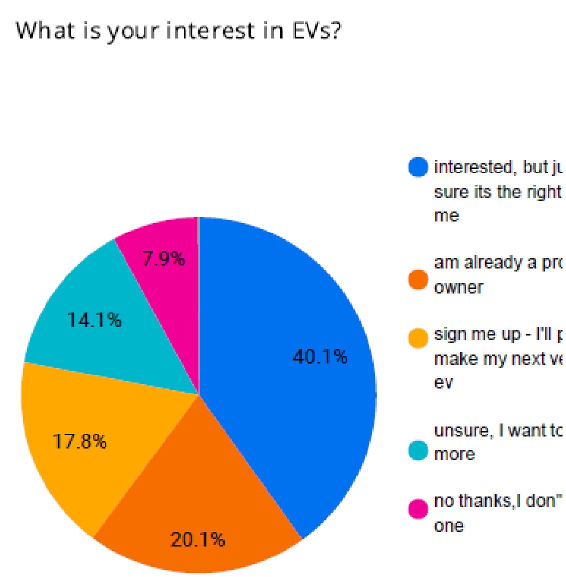
Key Performance Indicators	Final Results
1. Total number of residents affected by this information	The EV Chauffeur Guide reached 48,431 Oshawa residents (and beyond).

Key Performance Indicators	Final Results
2. Total number of visitors to the Digital Guide	We recorded 2,027 sessions between October 2023 and March 2024.
3. Total number of visitors to reach educational milestones	n/a. The Guide was hosted on the OPGOC parent site, which did not allow for analytics reporting at the various educational milestone/"nodes" of the Guide. We were however, able to collect interesting user analytics and response data, which is summarized below.
4. Total number of sessions that did not bounce	We recorded 1,372 engaged sessions between October 2023 and March 2024.

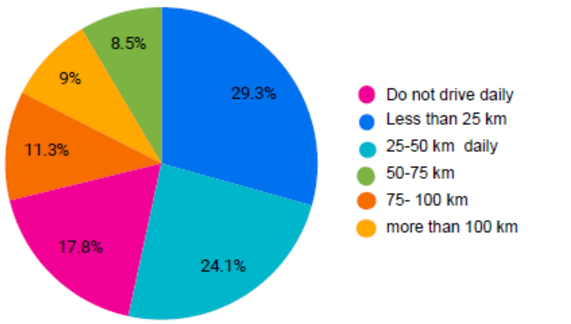
Scout and our delivery partners Oshawa Power believe this project was successful in meeting its goals. Our focus was on educating and engaging Oshawa residents on EVs, which we did, with **direct reach to over 48K OPUC customers between October and March**.

A secondary goal of the project was to generate data for Oshawa Power on customer beliefs and behaviours relating to electric vehicles. The data collected will influence strategy surrounding infrastructure planning and program delivery by the Utility.

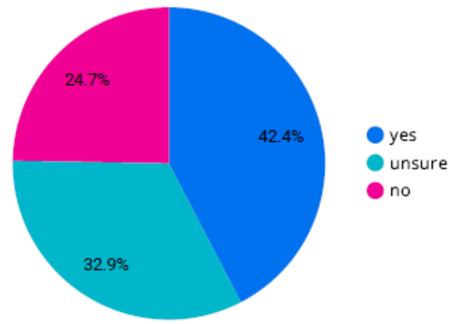




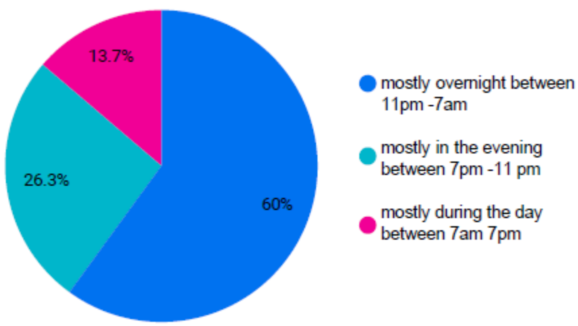
What is your daily commute?



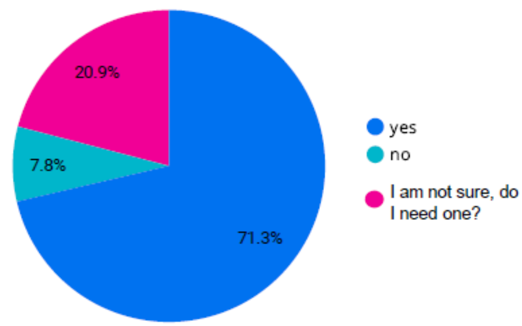
Do you have chargers nearby?



When do you charge?



Will you be installing a charger at home?



If you already have an EV, where do you charge it?

	Where do you charge?	Record
1.	at home	
2.	in a public space, mall, gym, community centre etc	
3.	at work	
4.	on street	

The combination of geographic data and user responses will help OPUC not only plan EV infrastructure upgrades more efficiently, but also target programming and outreach for EV 'hot spots' to further awareness and impact purchase decisions.

Attachment 2 – 13

EV Growth Study

Peak Power
OPUC EV Growth Study

Project Report

2023-06-16	A	Client Review	Kendall Richey/ Rachelle Sarmiento/ Usman Khan/ Xiaoyou Zhang	Kya Weiman	Cheng Lin	
Date	**Rev.**	**Status**	**Prepared By**	**Checked By**	**Approved By**	**Approved By**
HATCH						**Client**

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1. Introduction

The federal government of Canada established a mandate to achieve zero-emissions by 2035 with 100% of new light-duty cars and passenger truck sales.[1] A significant increase in the electrical vehicle (EV) adoption rate is anticipated nation-wide in the near future. In addition, the Ontario Energy Board (OEB) has enabled a new Ultra-Low Overnight Price Plan to encourage customers to adopt EVs and charge their vehicles overnight. Meanwhile, the City of Oshawa has experienced substantial growth with a record-breaking increase in building permit activities. There are multiple major industrial and residential construction projects[2] which could contribute to population growth as well as EV and EV charger growth as a result.

High EV penetration will lead to immense load growth (1750% growth forecasted) in Oshawa. Oshawa Power and Utilities Corporation (OPUC) should closely monitor the impacts of load growth on overall grid performance. Hatch has been engaged through Peak Power to study the future EV and corresponding load growth for the next 5 years in Oshawa. The EV growth is studied with a granularity of Dissemination Area (DA) level, and the load growth is studied at every hour in a year (8760 hours) for the entire city.

This study is based on Peak Power's previous effort on applying data science techniques to identify the locations of EV chargers in OPUC's territory using anonymized meter data. With Peak Power's methodology, the number of EV chargers are identified within each DA. Hatch has studied various socioeconomic factors to forecast the growth rate for each DA in 5 years and used Oshawa's historical charging profiles that were disaggregated from historical smart meter data by Peak Power to forecast the EV loads.

2. Assumptions

- The load forecast was performed for a 5-year horizon, assuming the base year (Year 0) to be 2022 and the corresponding Year 5 to be 2027. Datasets from 2021 are used for the study baseline since it is the latest version available to Hatch.
- The baseline numbers of EV chargers for Year 0 are based on Peak Power's analysis. Peak Power has provided probabilities of the presence of an EV charger for each meter. A charger is assumed to be present if the probability is 90% or higher.
- As per data provided by Peak Power, Level 1 chargers are not included in the scope of this study, and DCFCs are assumed to be only for public use. This study focuses on residential Level 2 chargers.

[1] Building a green economy: Government of Canada to require 100% of car and passenger truck sales be zero-emission by 2035 in Canada - Canada.ca
[2] Oshawa shatters building permit record in 2022 - constructconnect.com

- OPUC's hosting capacity, which may practically limit EV charger installation, is not considered in the scope of this forecast.
- All open-source datasets used for this study are assumed to be valid and accurate. Validating the source data integrity was out of scope for this study.
- Supply chain limitations are not considered for the purpose of forecasting EV and EVSE growth, (i.e., growth rates are focused on the consumer demand side only).
- This study does not account for unforeseeable events such as economic recessions, pandemic re-surges, natural disasters, etc.
- The socioeconomic analysis uses Oshawa's 2021 demographic information where available.
- The utilized income data is based on 2021 Statistics Canada (StatsCan) census total median household income after taxes.
- Findings are based on current government targets for new vehicle sales. If these targets accelerate or stretch out, the results of this study would require reassessment.
- The correlation between EV and EV charger growth is assumed to be linear (i.e., the likelihood to adopt EVs is assumed to be the same as EV chargers).
- The load forecasting assumes no direct or indirect load management (i.e., the load forecast may be overstated if OPUC incorporates additional control measures to manage EV loads).

3. EV Forecast

This section provides an overview of the EV forecast results, communities with forecasted growth, and a description of Hatch's methodologies.

3.1 Results Overview

Figure 1 and Figure 2 provide the overall likelihood to adopt EVs and the projected EV count for each DA in Oshawa in the next 5 years. The composite score indicates the likelihood of EV adoption based on socioeconomic factors including income, residential land uses, current EV ownership, hosing tenure, dwelling type, and education attainment. A high composite score in Figure 1 indicates high likelihood of EV adoptions, and a high projected EV count in Figure 2 is a result of a high likelihood as well as a high EV baseline number. Details for the methodology are provided in Section 3.2.

It can be observed that there are significant variations among DAs and communities which are due to the variations of socioeconomic factors. Insights for three highlighted communicates are provided in Section 3.3 as they have been forecasted with high likelihood of EV growth including Taunton-Pinecrest, Northglen, and Kedron-Windfields. The City of Oshawa community boundaries are provided in Figure 3.

Please refer to the attached Excel document for the forecasted EV per DA in Year 5.

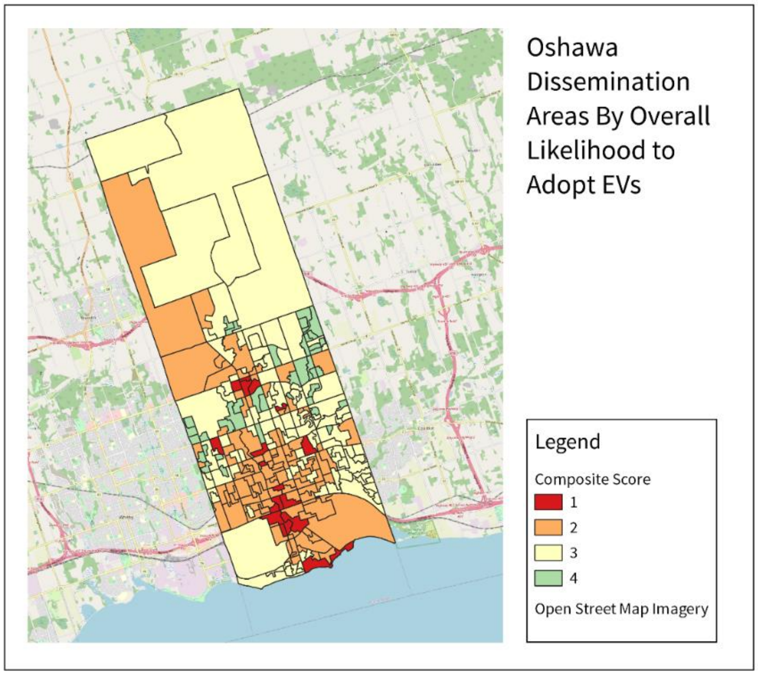

Figure 1: Oshawa Dissemination Areas by Overall Likelihood to Adopt EVs (Not-to-Scale)

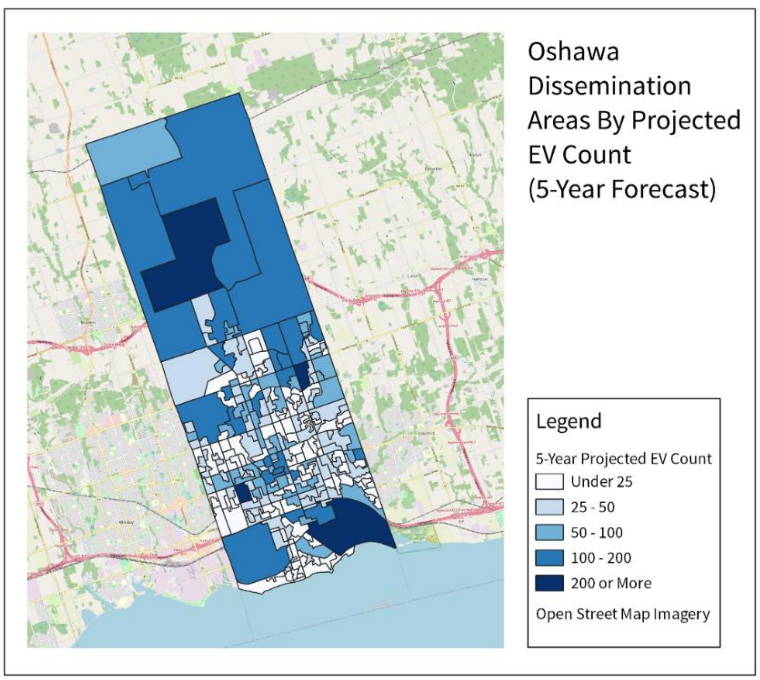

Figure 2: Oshawa Dissemination Areas by Projected EV Count (Not-to-Scale)

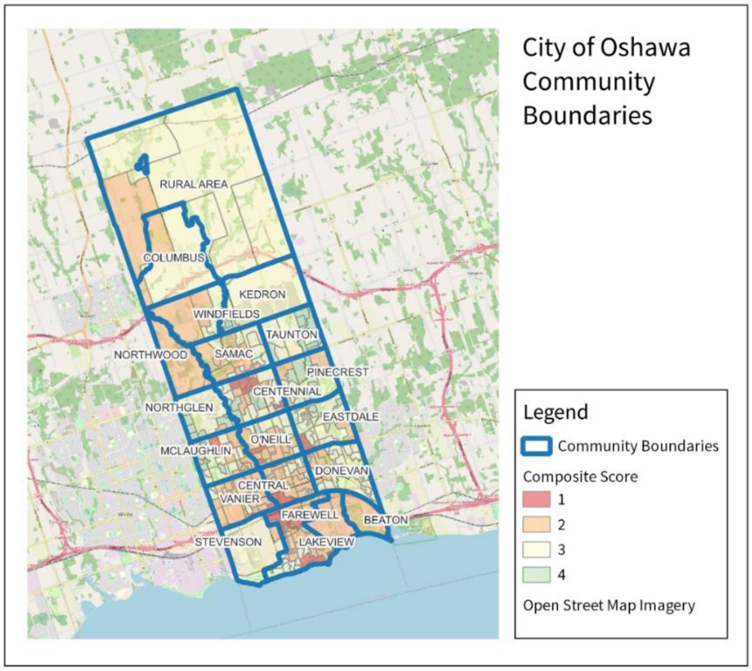

Figure 3: City of Oshawa Community Boundaries

3.2 Methodology

To forecast future EV demand in the Oshawa service area, Hatch selected a set of socioeconomic variables that would influence the likelihood of a particular area to install EV chargers. The following narrative contains the justification for the variables selected to produce the private charging demand analysis at the Census Dissemination Area (DA) level. The factors are organized in descending order based on their assigned weights which reflects the strength of their anticipated influence on overall EV adoption at the DA level.

Data Sources

Socioeconomic data was gathered from StatsCan's 2021 Census estimates and extracted at the DA level.[3] Land use data was collected from the City of Oshawa and was updated as of December 2022.[4] Lastly, Hatch relied on Peak Power's input data to locate EVs. This data was provided with geographical bounds defined by a cluster of 20 or more customers within close proximity to one another to protect individual privacy. Within each cluster, Peak Power incorporated 2021 metering data and into a machine learning model to identify the probability that a dwelling has a level 2 EV charger. With this dataset, Hatch assumes that dwellings with a probability of 0.9 and greater have an EV.[5]

[3] 2021 Census of Population - Statistics Canada
[4] Oshawa Existing Land Use - City of Oshawa Open Data
[5] Peak Power has performed data checks on their pattern recognition model to verify that 0.9 probability reflects the same overall trends as other data sets at their disposal (e.g., customer survey data and overall OPUC % ownership data), all of which support the determination that around 1% of dwellings in Oshawa have an EV.

1. Median Total Income – Median total household income

   Households with higher incomes are more likely to purchase an EV. Due to the necessary charging infrastructure, current EVs typically have a higher upfront cost than a conventional ICE vehicle. The Canadian Government's recognizes that early low- and zero-emission vehicle adoption has been largely concentrated in higher income area thus far.[6, 7, 8]

2. Residential Use – Percent of Dissemination Area devoted to residential uses

   The total area dedicated to residential uses within a DA is used to help focus the analysis on anticipated residential charging access. Research indicates that most early EV adopters have opted to use home chargers rather than fully relying on public charging options.[9] This variable accounts for the sizes and the variety of land uses in Oshawa's DAs including residential developments that are located within or near large DAs that are composed of wetland areas or agricultural uses. Figure 4 provides an example area containing Oshawa Second Marsh.

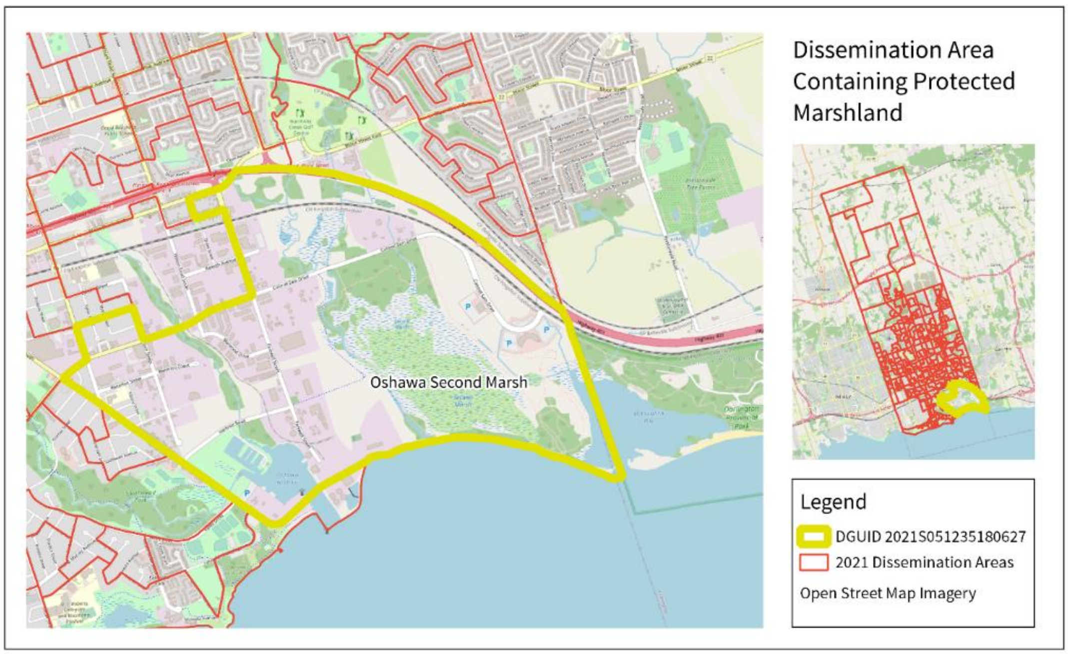

Figure 4: Dissemination Area Containing Oshawa's Second Marsh

[6] Canada's Action Plan for Clean On-Road Transportation - Transport Canada
[7] When might lower-income drivers benefit from electric vehicles? Quantifying the economic equity implications of electric vehicle adoption - The International Council on Clean Transportation
[8] 2021 Census estimates for total household income are in 2020 Canadian dollars.
[9] There's No Place Like Home: Residential parking, electrical access, and implications for the future of electric vehicle charging infrastructure - National Energy Laboratory

3. EV Ownership – Probable Level 2 chargers tied to meters within each Dissemination Area

   A study conducted by the University of California Davis showed that nearly 70% of current plug-in vehicle owners either own or have owned a hybrid or fully electric vehicle in the past. This indicates that current EV owners are very likely to purchase another EV in the future. Based on this trend, current EV ownership is a strong predictor for future EV growth.[10] Similarly, exposure to EVs by a neighbor or co-worker tends to increase the likelihood to adopt an EV. One study in California found that there was a 0.2% increase in BEV sales within a one-mile radius of a Census Block Group's centroid with every additional BEV or PHEV.[11]

4. Housing Tenure – Private households by tenure (home ownership)

   The current literature on the subject indicates that residents who own their home are more likely to purchase an EV than those who rent as home ownership lowers the logistical and financial barriers of installing home charging infrastructure.[12] One study in the US found that homeowners were as much as three times as likely as renters to purchase an EV after controlling for income.[13]

5. Dwelling Type – Single family dwelling equivalents

   This metric includes single-detached houses, semi-detached houses, row houses, and apartments or flats in a duplex. Households in single family developments are typically more likely to adopt EVs as they have greater access to garages and driveways. This makes it more practical to install private charging infrastructure than those who live in multifamily developments. This is increasingly evident in the short-term future as many multifamily developments do not have widespread availability of charging infrastructure.[14]

6. Educational Attainment – Percent of workers with a bachelor's degree or higher

   A study found that there is a significant increase in the likelihood of EV adoption among individuals who hold an undergraduate degree or a greater level of education. The study concluded that those with university degrees place a higher emphasis on the environmental benefits of EVs and have a greater understanding of the development of alternative energy sources.[15]

[10] Plug-in San Diego Electric Vehicle Infrastructure Needs Assessment Methodology Report - San Diego Association of Governments
[11] Plug-in Electric Vehicle Diffusion in California: Role of exposure to new technology at home and work - National Center for Sustainable Transportation
[12] Who will buy electric vehicles? Identifying early adopters in Germany - ScienceDirect
[13] Evidence of a Homeowner-Renter Gap for Electric Vehicles - UC Berkeley
[14] There's No Place Like Home: Residential parking, electrical access, and implications for the future of electric vehicle charging infrastructure - National Energy Laboratory
[15] The Demographics of Decarbonizing Transport: The influence of gender, education, occupation, age, and household size on electric mobility preferences in the Nordic region - ScienceDirect

Geographic Considerations

StatsCan releases their demographic profile data at different geographic levels ranging from nationwide to dissemination blocks. Due to privacy considerations, the Dissemination Area (DA) is the smallest standard geographical unit of data available to the public (slightly smaller than dissemination blocks). The comprehensive 2021 Census of Population releases data at the DA level and above at five-year intervals. The demographic data gathered in this study was based on the census. The selected 265 DAs were determined by a selection query of all Ontario DAs under the Oshawa Census subdivision which aligns with the boundaries of the municipal entity shown in Figure 5 below.

Existing Level-2 EV charging probabilities from Peak Power and land uses from the City of Oshawa were all standardized at the DA level for ease of comparison. A mapping of Peak Power's clusters to DAs is provided in the attached Excel file.

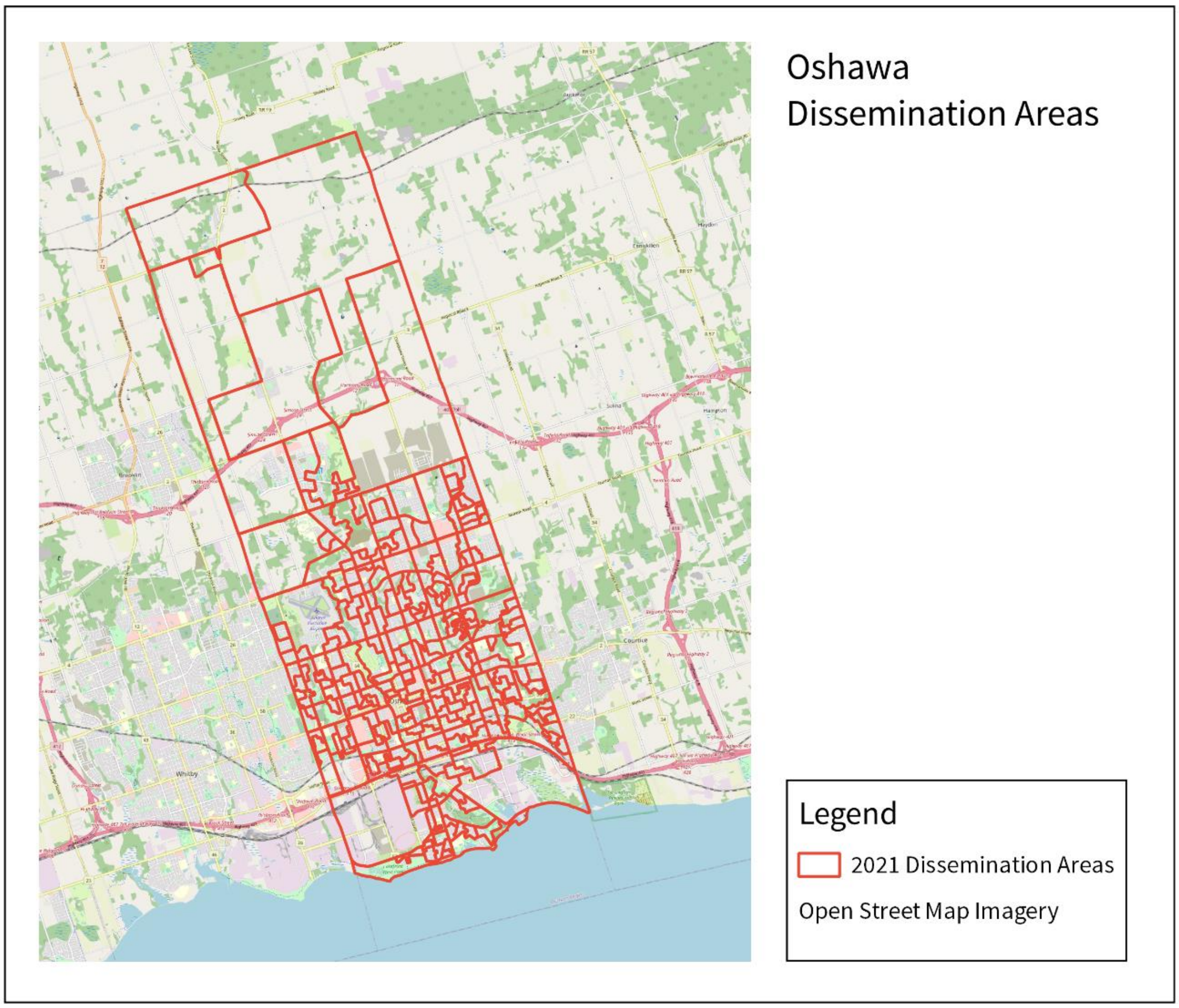

Figure 5: 2021 Dissemination Area Boundaries Within Oshawa (Not-to-Scale)

Percentiles for Data Scoring

Raw data was converted into a standardized score from one to five to ensure granular levels are consistent across different input data sources for comparison when producing overall composite scores. It is important to note that smaller ranges produce more meaningful results since equally sized bands obscure differentiations and trends between groupings as those within each grouping are more likely to be statistically similar. Scoring was based on a Hatch standard percentile range as shown in Table 1. Some variables proved incompatible with this system as variation amongst the 265 DAs was too limited to recognize meaningful trends.

Table 1: Standard Percentile Breaks for Socioeconomic Factors

Standard Percentile Breaks		
Scoring	Percentile	Demand
1	0 – 40%	Low
2	40 – 60%	Low / Medium
3	60 – 80%	Medium
4	80 – 95%	Medium / High
5	95 – 100%	High

1. Median Total Income

Standard percentile breaks were used for Median total household income scoring. The breaks for the scores of 1 ($85,600 or below) and 2 ($85,601 to $96,000) reflect the Canadian average of $84,000 and the Ontario average of $91,000.

Table 2: Median Total Income Breaks

Median Total Income Breaks			
Scoring	Percentile	Median Household Income	Demand
1	0 – 40%	$26,800 - $85,600	Low
2	40 – 60%	$85,600 – $96,000	Low / Medium
3	60 – 80%	$96,000 - $112,000	Medium
4	80 – 95%	$112,000 - $135,800	Medium / High
5	95 – 100%	$135,800 - $176,000	High

2. Residential Use

The ratio of residential area to DA within Oshawa varies, therefore, percentile breaks are kept at the standard values.

Table 3: Residential Land Use Score Breaks

Residential Land Use Score Breaks			
Scoring	Percentile	Percent Land Used for Residential	Demand
1	0 – 20%	1.17% - 29.68%	Low
2	20 – 40%	29.69% - 44.04%	Low / Medium
3	40 – 60%	44.05% - 56.43%	Medium

4	60 – 80%	56.44% - 68.7%	Medium / High
5	80 – 100%	68.71% - 79.13%	High

3. EV Ownership

EV ownership percentiles were held to the standard breaks. As a result, a score of 5 represents eight or more identified EVs within the DA based on Peak Power's methodology. A score of 1 typically means that one or zero EVs were identified in a given DA. According to StatsCan, approximately 7% of new vehicles sold in Ontario in 2022 were zero emissions models.[16]

Table 4: EV Ownership Percentile Breaks

EV Ownership Percentile Breaks			
Scoring	Percentile	Percent Meters with Probable EVs	Demand
1	0 – 40%	0% - 0.59%	Low
2	40 – 60%	0.6% - 0.99%	Low / Medium
3	60 – 80%	1.0% - 1.78%	Medium
4	80 – 95%	1.79% - 3.83%	Medium / High
5	95 – 100%	3.84% - 11.94%	High

4. Housing Tenure

Scores for Housing Tenure were maintained at the standard percentile breaks. The ownership rate between 70% and 82% reflects the Canadian average of 66% and Ontario average of 80% owner-occupied housing. The averages help reference which DAs deviate from these trends.

Table 5: Housing Tenure Percentile Breaks

Housing Tenure Percentile Breaks			
Scoring	Percentile	Percent Owner Occupied	Demand
1	0 – 40%	0 - 45.45%	Low
2	40 – 60%	45.46% - 70.92%	Low / Medium
3	60 – 80%	70.93% - 82.62%	Medium
4	80 – 95%	82.62% - 97.48%	Medium / High
5	95 – 100%	97.48% - 100%	High

5. Dwelling Type

Breaks for Dwelling Types were adjusted to the 25th, 50th, 75th, and 95th percentiles. This helps to accurately demonstrates the variation in residential building types across the city. The majority of DAs have either nearly all or very few single-family housing units which skews the standard percentile breaks.

[16] Let It Roll: The government of Canada moves to increase the supply of electric vehicles for Canadians - Environment and Climate Change Canada

Table 6: Dwelling Type Percentile Breaks

Dwelling Type Percentile Breaks			
Scoring	Percentile	Percent Single Family Dwellings	Demand
1	0 – 25%	0% - 76.34%	Low
2	25 – 50%	76.35% - 92.59%	Low / Medium
3	50 – 75%	92.6% - 96.97%	Medium
4	75 – 95%	96.98% - 99.99%	Medium / High
5	95 – 100%	100%	High

6. Educational Attainment

Bachelor's degree attainment percentiles were kept at the standard breaks. The 95th percentile was approximately 32%, meaning any DA with a score of 5 had a greater educational attainment than the national average of 33% indicating a strong divergence.

Table 7: Educational Attainment Percentile Breaks

Educational Attainment Percentile Breaks			
Scoring	Percentile	Percent Bachelor's Degree or Above	Demand
1	0 – 40%	0% - 14.29%	Low
2	40 – 60%	14.3% - 18.07%	Low / Medium
3	60 – 80%	18.08% - 24.45%	Medium
4	80 – 95%	24.46% - 32.43%	Medium / High
5	95 – 100%	32.44% - 48.08%	High

Horizon Considerations

Macro factors such as government policies and jurisdictional EV targets are considered through EV growth rate. Hatch assumes the following growth rates correspond to each composite score for the next 5 years as shown in Table 8.

Table 8: Average Growth Rate Assumption

Composite Score	Growth Rate Each Year
5	105%
4	95%
3	85%
2	75%
1	65%

The growth rate assumed for this study was defined to be the mid-point between the slow (80.8% in 2020 – 2021) and fast rate (130.5% in 2017 – 2018). The growth from 2017 to 2018 in Ontario corresponds to the fast rate which was during the last year with the provincial

EV subsidies in Ontario.[17] The slow growth rate from 2020 to 2021 represents a more stable growth rate since sales were stabilized after the removal of subsidies and the impacts of the COVID-19 pandemic diminished. This rate of 105% was assumed to correspond to DAs with the highest composite scores and were further adjusted to determine the growth rates for the rest of the scores. This represents how a rate of growth is associated with the composite scores derived from the previous step for each DA. For instance, a DA with a composite score of 4 is assumed to have an EV growth rate of 95% year-over-year for the next 5 years.

It is worth noting that for 2027 and beyond, which is out of the scope of this study, the growth rate may increase since the Government of Canada mandated that 100% of new vehicle sales must be zero-emission by 2035, accelerating their previous deadline of 2040.[18] The government has also established goals starting in 2026 when 20% of vehicles sold must be zero emissions, and 60% by 2030.[19] These new purchases are projected to bring the total proportion of zero-emissions light-duty vehicles on the road to 5% by 2026 and to 40% by 2035.[20] It is assumed that due to the rapid increase of EV adoption mandates from the federal government, the socioeconomic factors will have less impact on the likelihood of a particular household purchasing an EV in every subsequent year. This is inevitable as the federal and provincial governments are heavily investing in public charging infrastructure including $900 million Canadian dollars through the national 2030 Emissions Reduction Plan which aims to add 50,000 new public chargers. Additionally, the federal budget from 2022 contained $1.7 billion CAD in ZEV purchasing and leasing incentives.[21]

3.3 Highlighted Communities

This section provides additional insights for the top three communities that are forecasted with high likelihood of EV growth in the next 5 years.

3.3.1 Taunton-Pinecrest

As shown in Figure 6, this area in northeast Oshawa contains a higher concentration of DAs that have high likelihood of forecasted EV ownership (composite scores of 3 and 4). At its center, the Oshawa North II SmartCentres shopping area serves as a commercial anchor for the low-density neighborhood. The predominant dwelling type is single-family detached homes (97.7%). These homes were built in the early 2010s and households have moderate to high incomes (average median income of over $126,000 compared to the Oshawa median household income of $86,000).[22,23] The Harmony Valley Conservation Area is directly south of this area which renders a low likelihood in EV ownership probability (composite score of 2).

[17] I. Bickis, "End of Ontario electric vehicle rebate program expected to hit sales," The Canadian Press, 13 July 2018. [Online]. Available: End of Ontario electric vehicle rebate program expected to hit sales | CTV News.
[18] Building a Green Economy: Government of Canada to require 100% of car and passenger truck sales be zero-emission by 2035 in Canada - Transport Canada
[19] Canada moves to make one-fifth of all vehicle sales electric starting in 2026 - CBC News
[20] Canada's Zero-Emission Vehicle (ZEV) Sales Targets - Transport Canada
[21] Let It Roll: The Government of Canada moves to increase the supply of electric vehicles for Canadians - Transport Canada
[22] Taunton - Neighbourhood Guide
[23] Pinecrest - Neighbourhood Guide

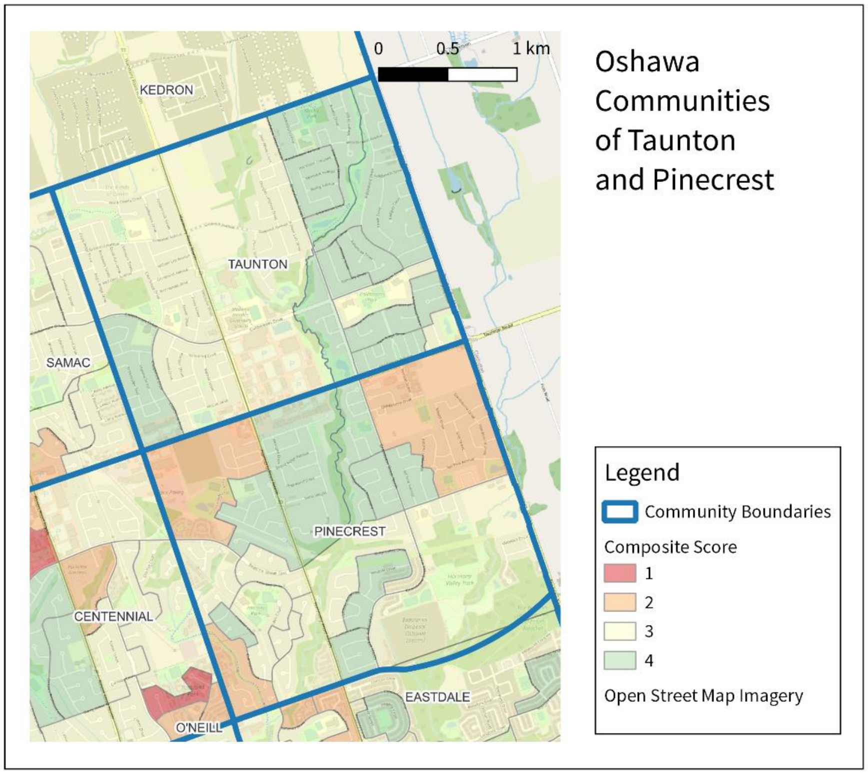

Figure 6: Taunton-Pinecrest Area Likelihood to Adopt EVs

3.3.2 Northglen

Established in the 1970s, the Northglen community in southwest Oshawa historically had an agricultural focus. Previously, the area was predominantly rural, and the neighborhood began to grow around the Oshawa Executive Airport and the Oshawa Golf and Curling Club during the 1960s. Most of this growth was in the form of owner-occupied (85.8%) single family homes (93.6%). These residents have relatively high incomes and high education attainment (26.7% of adults in the area have a bachelor's degree or higher compared with Oshawa's 19.1%). As shown in Figure 7, many of the DAs immediately adjacent to the airport have a composite score of 4 indicating that they are very likely to purchase an EV.

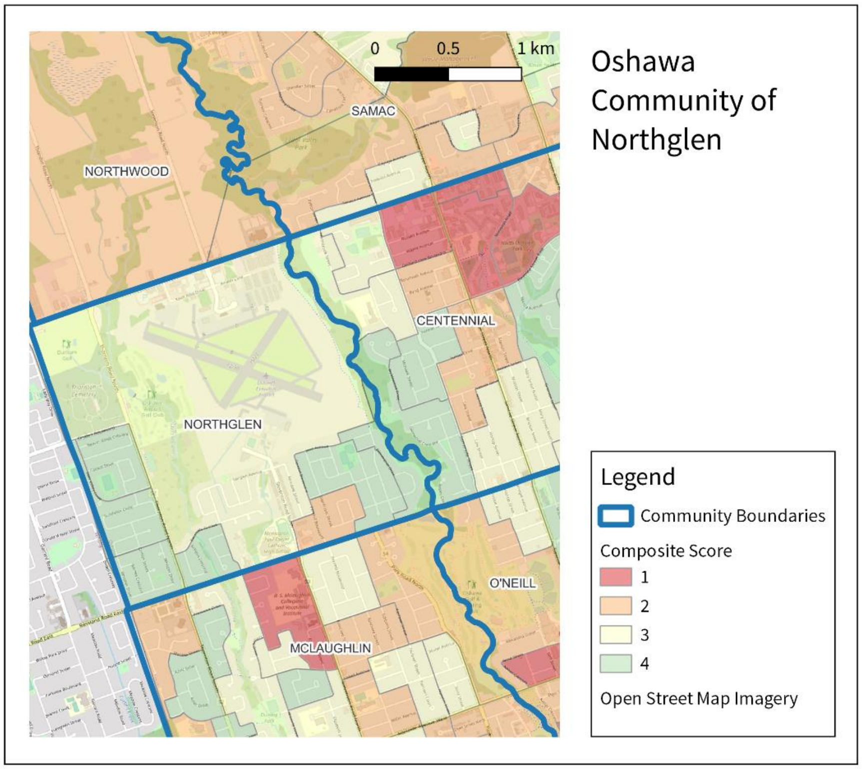

Figure 7: Northglen Area Likelihood to Adopt EVs

3.3.3 *Kedron-Windfields*

The communities of Kedron and Windfields, located in northern Oshawa, was constructed on former agricultural land. Nearby, Ontario Tech University and Durham College both have campuses that are home to over 30,000 students in total.[24,25] The Kedron-Windfields area contains a high concentration of single-family homes at a rate of 94.6% with high incomes (average of over $124,000 per year). The residents of the area are mostly young families. Many of the existing homes were constructed in the 2010s including the Kedron Park development. There are around 1,500 more planned homes in the coming years across several developments which is projected to bring over 20,000 new residents to the area.[26] In 2020, construction began at the corner of Winchester Road East and Simcoe Street North for a large mixed-use development which includes over 500 condos and over 83,000 square feet of retail space which is now near completion.[27] Figure 8 illustrates the likelihood of residents to adopt EVs in the area.

[24] University facts | Ontario Tech University
[25] Fact sheet | Durham College
[26] Kedron - Neighbourhood Guide
[27] RioCan REIT - RioCan Windfields

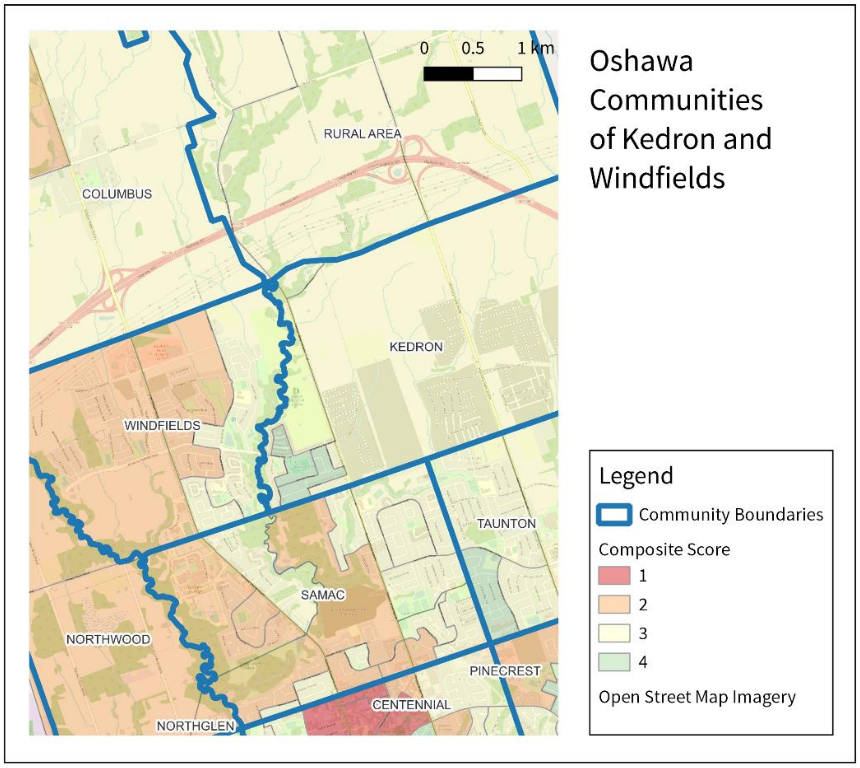

Figure 8: Kedron-Windfields Area Likelihood to Adopt EVs

4. Load Forecast

With the forecasted EV growth for Oshawa, an hourly load forecast was performed to study the EV load growth for 8760 hours in Year 5. OPUC's 2021 smart meter data was analyzed for residential Level 2 chargers. Peak Power disaggregated EV loads from residential loads using anonymized meter data within each cluster. By analyzing historical EV loading patterns along with Hatch's forecasted EV growth, a future EV loading pattern can be forecasted for Year 5.

4.1 Results Overview

- In the base year, the maximum combined EV load for all EVs in OPUC's territory is approximately 1.2 MW, while OPUC's total maximum combined residential load in 2022 is 132 MW.
- In year 5, the maximum combined EV load for all EVs forecasted in OPUC's territory is approximately 22.2 MW.
- The detailed hourly EV load forecast is provided in the attached Excel document.

4.2 OPUC EV Charging Patterns

Figure 9, Figure 10, and Figure 11 provide various comparisons of daily EV loading profiles for different seasons on weekdays and weekends. It can be observed that residential customers generally charge their EVs in the afternoons and at nights with slight variations between weekdays and weekends, and among four seasons. These trends align with observations from other jurisdictions. A study performed by PG&E concludes that most of their study participants charged during the overnight window. The proportion of participants that charged during the day was small relative to the magnitude of off-peak charging which corresponds with PG&E EV rate and TOU rate price signals[28]. A similar charging pattern is observed in South Carolina that shows that EV charging behaviour can be impacted by the price signal.[29] Additionally, managed charging will impact the EV loading profiles which is discussed in the section below.

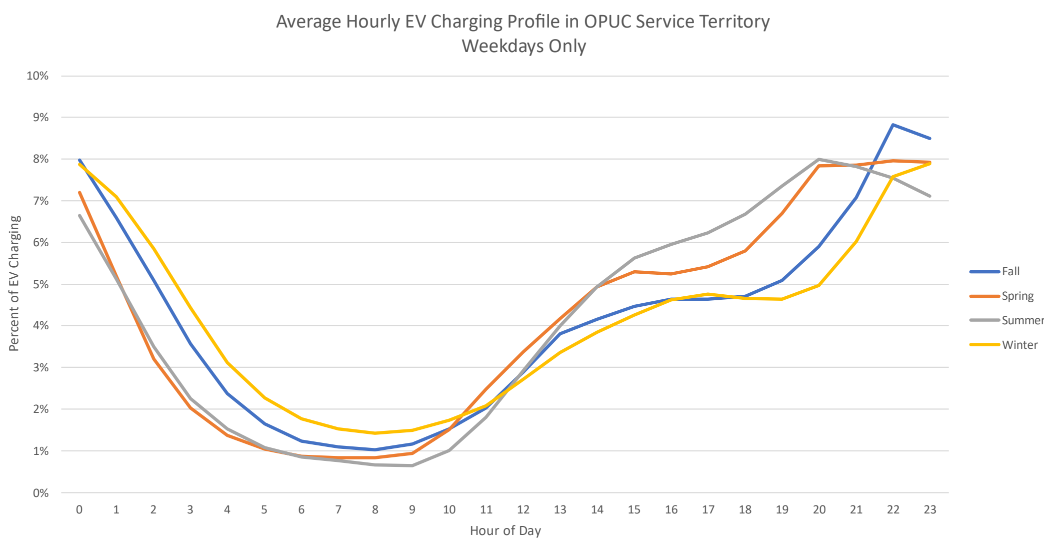

Figure 9: Seasonal Variations of EV Loads – Weekdays

[28] PG&E Electric Vehicle Automated Demand Response Study Report | ETCC (etcc-ca.com)
[29] The State of Managed Charging in 2021

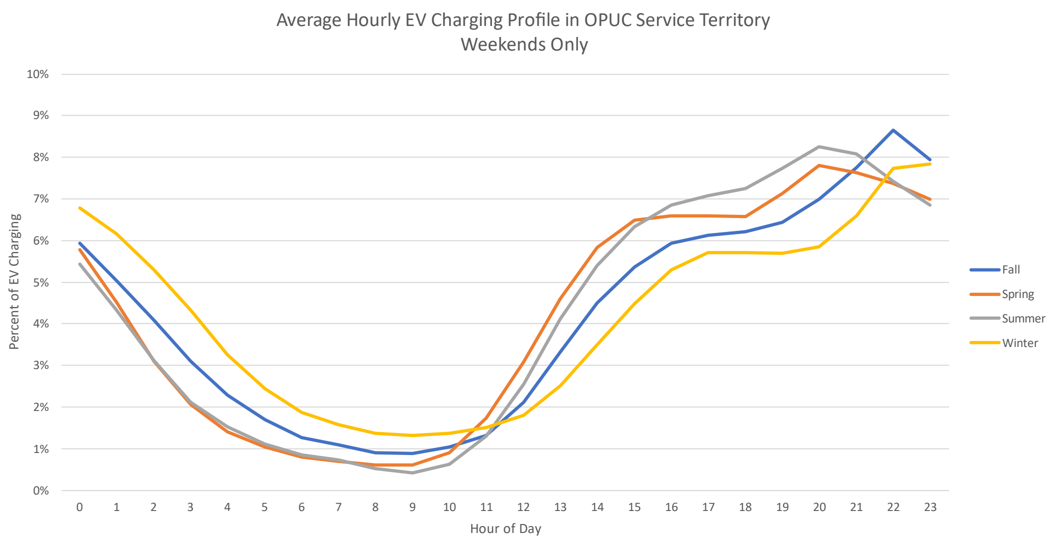

Figure 10: Seasonal Variations of EV Loads – Weekends

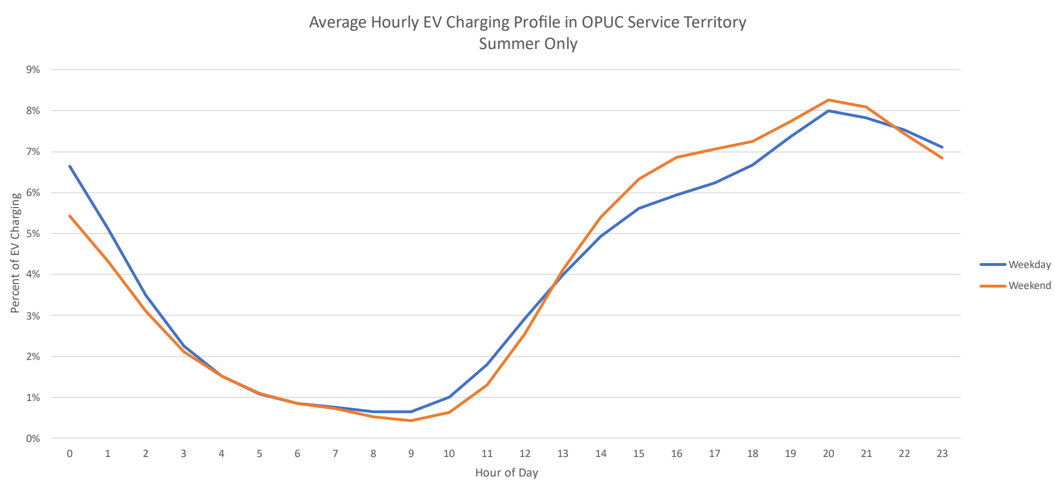

Figure 11: Weekday vs Weekend Variations of EV Loads

4.3 Comparison with Existing Methodology

OPUC is currently performing load forecasts based on a conventional top-down approach which currently do not account for load growth due to electrification. It is recommended to perform dedicated EV forecasts to facilitate load forecasting to accommodate for EV growth in the future.

4.4 Additional Considerations and Recommendations

This section provides some additional considerations that may impact future EV load growth and recommendations for further improvements.

- **Managed charging**: EV energy management system (EVEMS) is included in the recent version of Ontario Electrical Safety Code (OESC 2021) as: "*a means used to control electric vehicle supply equipment loads through the process of connecting, disconnecting, increasing, or reducing electric power to the loads and consisting of any of the following: a monitor(s), communications equipment, a controller(s), a timer(s), and other applicable device(s).*" If an EVEMS is installed at a customer's site, EV loads will be smaller with managed charging. However, it is recommended that OPUC considers monitoring and control capabilities for several EVEMS downstream of a service transformer, in addition to visibility into the transformer's load.
- **Ultra low overnight rate in Ontario**[30]: This new and optional Ultra-Low Overnight price plan, launched on May 1, 2023, for electricity consumers on the Regulated Price Plan, in addition to the existing Time-of-Use (TOU) and Tiered plans. This price plan will encourage more nighttime electricity use such as electric heating and EV charging overnight. It will benefit both customers and utilities by saving electricity cost and shifting some loads to the nighttime, respectively. With such price signal, more EV users may choose to charge their vehicles overnight, further shifting the loading curve to nighttime. It is recommended that OPUC closely monitor customers' loading patterns under this new price plan for future study purposes.
- **Vehicle-to-Grid (V2G) Considerations:** V2G refers to a system in which EVs can be used as a source of power for the electric grid. With V2G technology, in addition to ordinary EV charging behaviour, EVs can feed electricity back into the grid when the grid requires additional power. One use case is to use parked and plugged-in EVs during peak hours to help relieve the burden on the grid. It is recommended that OPUC monitors V2G policy updates and studies the potential impact to the grid.

[30] Enabling the Implementation of an Ultra-Low Overnight Price Plan | Ontario Energy Board (oeb.ca)