EXHIBIT 2:
RATE BASE

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2.2. EXHIBIT 2: RATE BASE

2.2.1 RATE BASE

2.2.1.1 OVERVIEW

The following Exhibit provides details and analysis of the Rate Base for ERHDC.

ERHDC has prepared its Rate Base for the Purpose of calculating the revenue requirement in this Application following Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Applications issued on May 14, 2020 ("Filing Requirements"). In accordance with the Filing Requirements, ERHDC has calculated its Rate Base on the average of 2021 Test Year opening and 2021 Test Year closing balances of gross fixed assets and accumulated depreciation, plus a working capital allowance of 7.5%.

Net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

As per discussions with the OEB and pursuant to its letter dated September 8, 2020[1], ERHDC has prepared this rate application using the appropriate guidelines with some modifications. Modifications to the variance analysis are as follows:

> "Espanola Hydro proposed limiting the variance analysis and information in the Chapter 2 Appendices to only the test year, bridge year and last three historical years. The OEB accepts this approach and will not require Espanola Hydro to file information pertaining to earlier historical years other than information from the last rebasing test year (2012). These details were part of the last rebasing rate application and therefore should be readily available. Espanola Hydro should provide any available information in the

[1] EB-2020-0020 – Letter from OEB re Espanola Regional Hydro Distribution Corporation's 2021 Cost of Service Application – Requested Adjustments and Extension to Filing Deadline dated September 8, 2020.

> Chapter 2 Appendices for 2012 and should provide a variance analysis between the 2012 test year and the current 2021 test year."[2]

As such ERHDC has provided analysis for the historical years 2017, 2018 and 2019 and the 2020 Bridge Year and 2021 Test Year, including variance analysis between 2012 test year and current 2021 test year. In some cases, however ERHDC has provided continuity schedules for all years from 2012 Approved to the 2021 Test Year with no analysis for historical years prior to 2017.

ERHDC has provided a summary of its rate base continuity schedule for the years 2012 Board Approved, 2017 Actual, 2018 Actual, 2019 Actual, 2020 Bridge and 2021 Test in Table 2-1 below.

Table 2 - 1: Rate Base Continuity Schedule Summary

Description	2012 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets, Opening Balance	$ 7,943,875	$ 9,162,297	$ 9,739,113	$ 10,178,247	$ 10,323,016	$ 12,917,237
Gross Fixed Assets, Closing Balance	$ 7,951,715	$ 9,739,113	$ 10,178,247	$ 10,323,016	$ 12,917,237	$ 13,380,666
Average Gross Fixed Assets	**$ 7,947,795**	**$ 9,450,705**	**$ 9,958,680**	**$ 10,250,631**	**$ 11,620,126**	**$ 13,148,952**
Accumulated Depreciation, Opening Balance	$ 4,881,329	$ 5,354,132	$ 5,491,954	$ 5,665,974	$ 5,583,572	$ 6,068,857
Accumulated Depreciation, Closing Balance	$ 4,800,812	$ 5,491,954	$ 5,665,974	$ 5,583,572	$ 6,068,857	$ 6,325,526
Average Accumulated Depreciation	**$ 4,841,071**	**$ 5,423,043**	**$ 5,578,964**	**$ 5,624,773**	**$ 5,826,214**	**$ 6,197,191**
Average Net Book Value	**$ 3,106,725**	**$ 4,027,662**	**$ 4,379,716**	**$ 4,625,858**	**$ 5,793,912**	**$ 6,951,760**
Cost of Power plus OM&A	7,586,740	6,644,238	6,238,076	6,772,826	8,561,425	8,630,518
Working Capital Allowance (%)	15.00%	15.00%	15.00%	15.00%	15.00%	7.50%
Working Capital Allowance	**$ 1,138,011**	**$ 996,636**	**$ 935,711**	**$ 1,015,924**	**$ 1,284,214**	**$ 647,289**
Rate Base	**$ 4,244,735**	**$ 5,024,298**	**$ 5,315,427**	**$ 5,641,782**	**$ 7,078,126**	**$ 7,599,049**

ERHDC's assets fall into two general categories – the first is distribution plant, which includes assets such as distribution substation buildings, poles, conductor, overhead and underground electricity distribution infrastructure, transformers, meters and substation equipment. The second is general plant which includes assets such as the operations/service center building, computer equipment and software and vehicles.

[2] Ibid.

(a) Fixed Asset Continuity Statements

ERHDC has completed the Fixed Asset Continuity Schedules (Board Appendix 2-BA) for the Historical Actuals for 2012 through 2019, the 2020 Bridge Year and the 2021 Test Year.

These schedules are provided in Appendix 2-A of this Exhibit and have also been filed in live excel format.

The above continuity schedules reconcile to the annual recorded depreciation expense. The reconciliation is between net book value balances in Appendix 2-BA and balances in rate base calculation. Table 2-2 below reconciles between annual change in accumulated depreciation and depreciation expense.

Table 2 - 2: Depreciation Continuity Schedule

	2012 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test
Accumulated Depreciation Opening	4,891,084	5,354,132	5,491,954	5,665,974	5,583,573	6,068,857
Accumulated Depreciation Closing	4,983,202	5,491,954	5,665,974	5,583,573	6,068,857	6,325,526
Change in Accumulated Depreciation	**92,118**	**137,822**	**174,020**	**(82,401)**	**485,284**	**256,669**
Add Disposals	274,079	29,672	-	268,437	-	-
Less ICM Sub 4 Adjustment		-	-	-	(240,507)	(39,396)
Depreciation Expense	**366,197**	**167,494**	**174,020**	**186,036**	**244,777**	**217,273**

(b) Rate Base Variance Analysis

ERHDC has prepared the following table (Table 2-3) to illustrate the rate base variances for each required comparator. Comparisons year-over-year follow in Tables 2-4 to 2-9 below.

Table 2 - 3: Rate Base Variance Summary

Description	2012 OEB Approved	2017 Actual	2012 Approved vs 2017 Actual	2018 Actual	2017 Actual vs 2018 Actual	2019 Actual	2018 Actual vs 2019 Actual	2020 Bridge Year	2019 Actual vs 2020 Bridge	2021 Test Year	2020 Bridge vs 2021 Test
Reporting Basis	**MIFRS**	**MIFRS**		**MIFRS**		**MIFRS**		**MIFRS**		**MIFRS**	
Gross Fixed Assets, Opening Balance	$ 7,943,875	$ 9,162,297	$ 1,218,422	$ 9,739,113	$ 576,816	$ 10,178,247	$ 439,133	$ 10,323,016	$ 144,769	$ 12,917,237	$ 2,594,221
Gross Fixed Assets, Closing Balance	$ 7,951,715	$ 9,739,113	$ 1,787,398	$ 10,178,247	$ 439,133	$ 10,323,016	$ 144,769	$ 12,917,237	$ 2,594,221	$ 13,380,666	$ 463,429
Average Gross Fixed Assets	**$ 7,947,795**	**$ 9,450,705**	**$ 1,502,910**	**$ 9,958,680**	**$ 507,975**	**$ 10,250,631**	**$ 291,951**	**$ 11,620,126**	**$ 1,369,495**	**$ 13,148,951**	**$ 1,528,825**
Accumulated Depreciation, Opening Balance	$ 4,881,329	$ 5,354,132	$ 472,803	$ 5,491,954	$ 137,822	$ 5,665,974	$ 174,020	$ 5,583,573	-$ 82,401	$ 6,068,857	$ 485,284
Accumulated Depreciation, Closing Balance	$ 4,800,812	$ 5,491,954	$ 691,142	$ 5,665,974	$ 174,020	$ 5,583,573	-$ 82,401	$ 6,068,857	$ 485,284	$ 6,325,526	$ 256,669
Average Accumulated Depreciation	**$ 4,841,071**	**$ 5,423,043**	**$ 581,973**	**$ 5,578,964**	**$ 155,921**	**$ 5,624,774**	**$ 45,810**	**$ 5,826,215**	**$ 201,441**	**$ 6,197,191**	**$ 370,976**
Average Net Book Value	**$ 3,106,725**	**$ 4,027,662**	**$ 920,938**	**$ 4,379,716**	**$ 352,054**	**$ 4,625,857**	**$ 246,141**	**$ 5,793,911**	**$ 1,168,054**	**$ 6,951,760**	**$ 1,157,849**
Cost of Power plus OM&A	$ 7,586,740	$ 8,487,077	$ 900,337	$ 7,862,889	-$ 624,188	$ 8,584,346	$ 721,458	$ 8,561,675	-$ 22,672	$ 8,630,518	$ 68,844
Working Capital Allowance (%)	15.00%	15.00%		15.00%		15.00%		15.00%		7.50%	
Working Capital Allowance	**$ 1,138,011**	**$ 1,273,062**	**$ 135,051**	**$ 1,179,433**	**-$ 93,628**	**$ 1,287,652**	**$ 108,219**	**$ 1,284,251**	**-$ 3,401**	**$ 647,289**	**-$ 636,962**
Rate Base	**$ 4,244,736**	**$ 5,300,724**	**$ 1,055,988**	**$ 5,559,149**	**$ 258,426**	**$ 5,913,509**	**$ 354,360**	**$ 7,078,162**	**$ 1,164,653**	**$ 7,599,049**	**$ 520,887**

Table 2 - 4: Rate Base Variance 2021 Test vs 2012 Approved

Description	2012 OEB Approved	2021 Test Year	2012 Approved vs 2021 Test	%
Gross Fixed Assets, Opening Balance	$ 7,943,875	$ 12,917,237	$ 4,973,362	62.6%
Gross Fixed Assets, Closing Balance	$ 7,951,715	$ 13,380,666	$ 5,428,951	68.3%
Average Gross Fixed Assets	**$ 7,947,795**	**$ 13,148,951**	**$ 5,201,156**	**65.4%**
Accumulated Depreciation, Opening Balance	$ 4,881,329	$ 6,068,857	$ 1,187,528	24.3%
Accumulated Depreciation, Closing Balance	$ 4,800,812	$ 6,325,526	$ 1,524,714	31.8%
Average Accumulated Depreciation	**$ 4,841,071**	**$ 6,197,191**	**$ 1,356,121**	**28.0%**
Average Net Book Value	**$ 3,106,725**	**$ 6,951,760**	**$ 3,845,036**	**123.8%**
Cost of Power plus OM&A	$ 7,586,740	$ 8,630,518	$ 1,043,778	13.8%
Working Capital Allowance (%)	15.00%	7.50%	-7.50%	-50.0%
Working Capital Allowance	**$ 1,138,011**	**$ 647,289**	**-$ 490,722**	**-43.1%**
Rate Base	**$ 4,244,736**	**$ 7,599,049**	**$ 3,354,313**	**79.0%**

ERHDC's 2021 Test year Rate Base is $7,599,049 which is an increase of $3,354,313 over the 2012 Board Approved Rate Base of $4,244,736. The increase is attributable to an increase in Average Net Value of Capital Assets of $3,845,036 and a decrease in Working Capital Allowance of $490,722. ERHDC has invested annually in fixed assets over the nine year period since its last cost of service application including a significant $1,900,000 investment in a new distribution station. Although OM&A and Cost of Power expenses have increased, the working capital allowance has decreased due to the reduction in the working capital percentage from 15% to 7.5%.

Table 2 - 5: Rate Base Variance 2017 Actual vs 2012 Approved

Description	2012 OEB Approved	2017 Actual	2012 Approved vs 2017 Actual	%
Gross Fixed Assets, Opening Balance	$ 7,943,875	$ 9,162,297	$ 1,218,422	15.3%
Gross Fixed Assets, Closing Balance	$ 7,951,715	$ 9,739,113	$ 1,787,398	22.5%
Average Gross Fixed Assets	**$ 7,947,795**	**$ 9,450,705**	**$ 1,502,910**	**18.9%**
Accumulated Depreciation, Opening Balance	$ 4,881,329	$ 5,354,132	$ 472,803	9.7%
Accumulated Depreciation, Closing Balance	$ 4,800,812	$ 5,491,954	$ 691,142	14.4%
Average Accumulated Depreciation	**$ 4,841,071**	**$ 5,423,043**	**$ 581,973**	**12.0%**
Average Net Book Value	**$ 3,106,725**	**$ 4,027,662**	**$ 920,938**	**29.6%**
Cost of Power plus OM&A	$ 7,586,740	$ 8,487,077	$ 900,337	11.9%
Working Capital Allowance (%)	15.00%	15.00%	0.00%	0.0%
Working Capital Allowance	**$ 1,138,011**	**$ 1,273,062**	**$ 135,051**	**11.9%**
Rate Base	**$ 4,244,736**	**$ 5,300,724**	**$ 1,055,988**	**24.9%**

The 2017 Rate Base is $5,300,724 which is an increase of $1,055,988 over the 2012 Board Approved Rate Base of $4,244,736. 87% of the increase is attributable to an increase in Average Net Value of Capital Assets of $920,938 and 13% is attributable to an increase in Working Capital Allowance of $135,051. ERHDC has invested annually in fixed assets over the period since its last cost of service application. The increase in the cost of power accounts for 98% of the increase in Working Capital Allowance.

Table 2 - 6: Rate Base Variance 2017 Actual vs 2018 Actual

Description	2017 Actual	2018 Actual	2017 Actual vs 2018 Actual	%
Gross Fixed Assets, Opening Balance	$ 9,162,297	$ 9,739,113	$ 576,816	6.3%
Gross Fixed Assets, Closing Balance	$ 9,739,113	$ 10,178,247	$ 439,133	4.5%
Average Gross Fixed Assets	**$ 9,450,705**	**$ 9,958,680**	**$ 507,975**	**5.4%**
Accumulated Depreciation, Opening Balance	$ 5,354,132	$ 5,491,954	$ 137,822	2.6%
Accumulated Depreciation, Closing Balance	$ 5,491,954	$ 5,665,974	$ 174,020	3.2%
Average Accumulated Depreciation	**$ 5,423,043**	**$ 5,578,964**	**$ 155,921**	**2.9%**
Average Net Book Value	**$ 4,027,662**	**$ 4,379,716**	**$ 352,054**	**8.7%**
Cost of Power plus OM&A	$ 8,487,077	$ 7,862,889	-$ 624,188	-7.4%
Working Capital Allowance (%)	15.00%	15.00%	0.00%	0.0%
Working Capital Allowance	**$ 1,273,062**	**$ 1,179,433**	**-$ 93,628**	**-7.4%**
Rate Base	**$ 5,300,724**	**$ 5,559,149**	**$ 258,426**	**4.9%**

The 2018 rate base is $5,559,149 which is an increase of $258,426 over the 2017 Rate Base of $5,300,724. The Average Net Book Value increased due to investments in assets during 2018 as detailed in following sections of this exhibit. The decrease in the cost of power accounts for the decrease in Working Capital Allowance.

Table 2 - 7: Rate Base Variance 2018 Actual vs 2019 Actual

Description	2018 Actual	2019 Actual	2018 Actual vs 2019 Actual	%
Gross Fixed Assets, Opening Balance	$ 9,739,113	$ 10,178,247	$ 439,133	4.5%
Gross Fixed Assets, Closing Balance	$ 10,178,247	$ 10,323,016	$ 144,769	1.4%
Average Gross Fixed Assets	**$ 9,958,680**	**$ 10,250,631**	**$ 291,951**	**2.9%**
Accumulated Depreciation, Opening Balance	$ 5,491,954	$ 5,665,974	$ 174,020	3.2%
Accumulated Depreciation, Closing Balance	$ 5,665,974	$ 5,583,573	-$ 82,401	-1.5%
Average Accumulated Depreciation	**$ 5,578,964**	**$ 5,624,774**	**$ 45,810**	**0.8%**
Average Net Book Value	**$ 4,379,716**	**$ 4,625,857**	**$ 246,141**	**5.6%**
Cost of Power plus OM&A	$ 7,862,889	$ 8,584,346	$ 721,458	9.2%
Working Capital Allowance (%)	15.00%	15.00%	0.00%	0.0%
Working Capital Allowance	**$ 1,179,433**	**$ 1,287,652**	**$ 108,219**	**9.2%**
Rate Base	**$ 5,559,149**	**$ 5,913,509**	**$ 354,360**	**6.4%**

The 2019 Rate Base is $5,913,509 which is an increase of $354,360 over the 2018 Rate Base of $5,559,149. The Average Net Book Value increased due to investments in assets during 2018 as detailed in following sections of this exhibit. The increase in the cost of power accounts for 63% of the increase in Working Capital Allowance. ERHDC also incurred expenses in 2019 associated with the sale of the LDC to North Bay Hydro which increased Working Capital.

Table 2 - 8: Rate Base Variance 2019 Actual vs 2020 Bridge

Description	2019 Actual	2020 Bridge Year	2019 Actual vs 2020 Bridge	%
Gross Fixed Assets, Opening Balance	$ 10,178,247	$ 10,323,016	$ 144,769	1.4%
Gross Fixed Assets, Closing Balance	$ 10,323,016	$ 12,917,237	$ 2,594,221	25.1%
Average Gross Fixed Assets	**$ 10,250,631**	**$ 11,620,126**	**$ 1,369,495**	**13.4%**
Accumulated Depreciation, Opening Balance	$ 5,665,974	$ 5,583,573	-$ 82,401	-1.5%
Accumulated Depreciation, Closing Balance	$ 5,583,573	$ 6,068,857	$ 485,284	8.7%
Average Accumulated Depreciation	**$ 5,624,774**	**$ 5,826,215**	**$ 201,441**	**3.6%**
Average Net Book Value	**$ 4,625,857**	**$ 5,793,911**	**$ 1,168,054**	**25.3%**
Cost of Power plus OM&A	$ 8,584,346	$ 8,561,675	-$ 22,672	-0.3%
Working Capital Allowance (%)	15.00%	15.00%	0.00%	0.0%
Working Capital Allowance	**$ 1,287,652**	**$ 1,284,251**	**-$ 3,401**	**-0.3%**
Rate Base	**$ 5,913,509**	**$ 7,078,162**	**$ 1,164,653**	**19.7%**

The 2020 Bridge Year Rate Base is $7,078,162 which is an increase of $1,164,653 over the 2019 Rate Base of $5,913,509. The Average Net Book Value increased due to investments in assets during 2020 as detailed in following sections of this exhibit. Included in the 2020 asset additions is $1,900,000 for the new distribution station was the subject of a 2014 IRM and previously been recorded in regulatory assets. The expenses for the LDC sale were of a one-time nature in 2019 and therefore resulted in a reduction in Working Capital in 2020.

Table 2 - 9: Rate Base Variance 2020 Bridge vs 2021 Test

Description	2020 Bridge Year	2021 Test Year	2020 Bridge vs 2021 Test	%
Gross Fixed Assets, Opening Balance	$ 10,323,016	$ 12,917,237	$ 2,594,221	25.1%
Gross Fixed Assets, Closing Balance	$ 12,917,237	$ 13,380,666	$ 463,429	3.6%
Average Gross Fixed Assets	**$ 11,620,126**	**$ 13,148,951**	**$ 1,528,825**	**13.2%**
Accumulated Depreciation, Opening Balance	$ 5,583,573	$ 6,068,857	$ 485,284	8.7%
Accumulated Depreciation, Closing Balance	$ 6,068,857	$ 6,325,526	$ 256,669	4.2%
Average Accumulated Depreciation	**$ 5,826,215**	**$ 6,197,191**	**$ 370,976**	**6.4%**
Average Net Book Value	**$ 5,793,911**	**$ 6,951,760**	**$ 1,157,849**	**20.0%**
Cost of Power plus OM&A	$ 8,561,675	$ 8,630,518	$ 68,844	0.8%
Working Capital Allowance (%)	15.00%	7.50%	-7.50%	-50.0%
Working Capital Allowance	**$ 1,284,251**	**$ 647,289**	**-$ 636,962**	**-49.6%**
Rate Base	**$ 7,078,162**	**$ 7,599,049**	**$ 520,887**	**7.4%**

The 2021 Test Year Rate Base is $7,599,049 which is an increase of $520,887 over the 2021 Bridge Year Rate Base of $7,078,162. The Average Net Book Value increased due to investments in assets during 2021 as detailed in following sections of this exhibit. The increase is affected by the inclusion of the new distribution station (previously in regulatory assets) being included in the rate base for a full year. Working Capital in 2021 is consistent with 2020.

2.2.1.2 GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT AND DEPRECIATION

(a) Breakdown By Function

The tables below categorizes ERHDC's assets into three categories; distribution plant, general plant, and contributions and grants. In accordance with the Uniform System of Accounts ("USoA"), ERHDC has included gross assets as follows:

- Distribution Plant Assets – includes USoA accounts 1805-1860, these accounts capture assets such as substation equipment, poles, wires, transformers and meters.

- General Plant Assets – includes USoA account 1905 to 1990, these accounts capture assets such as operation service center buildings, computer hardware and software and system supervisory equipment.
- Contributions and Grants – includes USoA accounts 1995 and 2105, these accounts capture all contributions in aid of capital and amortization that ERHDC has received or forecasted to be received as per the Distribution System Code. Details of Accounts 1995 have been presented in Table 2-10.

Table 2 - 10: Contributions

	OEB Account	Opening Net Balance	Contributions	Amortization of Contributions	Closing Net Balance
2012	1995	$183,689	$ 71,268	$ 12,839	$ 242,118
2013	1995	$242,118	$ 25,549	$ 7,607	$ 260,060
2014	1995	$260,060	$ 3,297	$ 7,689	$ 255,668
2015	1995	$255,668	$ 4,714	$ 7,785	$ 252,597
2016	1995	$252,597	$ 47,332	$ 8,735	$ 291,194
2017	1995	$291,194	$ 3,293	$ 8,103	$ 286,384
2018	1995	$286,384	$ 40,269	$ 9,895	$ 316,758
2019	1995	$316,758	$ 39,290	$ 10,107	$ 345,941
2020	1995	$345,941	$ 63,830	$ 8,532	$ 401,239
2021	1995	$401,239	$ 25,000	$ 9,157	$ 417,082

(b) Variance Analysis on Gross Asset Additions

The following variance analysis has been prepared based on ERHDC's materiality threshold; per the materiality threshold being noted in Exhibit 1, Section 2.1.4.14 of this Application. ERHDC has used $50,000 as its basis for the variance analysis of Gross Asset Additions per the materiality calculation noted in Exhibit 1 of this Application. Details of the variances for 2012 Board Approved vs 2012 Actual, 2017 Actual vs 2018 Actual, 2018 Actual vs 2019 Actual, 2019 Actual vs 2020 Bridge and 2020 Bridge vs 2021 Test Year have been provided below in Tables 2-11 to 2-20. For the purposes of the variance analysis assets are categorized as Distribution Assets and General Plant.

(i) 2012 Board Approved vs. 2012 Actual

Table 2 - 11: 2012 Board Approved vs. 2012 Actual

Description	2012 Board Approved	2012 Actuals	Variance from 2012 Board Approved
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 69,945	$ 88,880	$ 18,935
1806 - Land Rights	$ 3,107	$ -	-$ 3,107
1808 - Buildings and Fixtures	$ 350,789	$ 342,089	-$ 8,700
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 425,406	$ 478,757	$ 53,351
1830 - Poles, Towers and Fixtures	$ 2,157,839	$ 2,204,194	$ 46,355
1835 - Overhead Conductors and Devices	$ 1,282,502	$ 1,311,384	$ 28,882
1840 - Underground Conduit	$ 690,493	$ 697,969	$ 7,476
1845 - Underground Conductors and Devices	$ 128,548	$ 113,841	-$ 14,707
1850 - Line Transformers	$ 870,478	$ 887,911	$ 17,433
1855 - Services	$ 370,863	$ 234,657	-$ 136,206
1860 - Meters	$ 680,726	$ 711,954	$ 31,228
1995 - Contributions and Grants	-$ 269,994	-$ 322,802	-$ 52,808
Sub-Total Distribution Assets	$ 6,760,702	$ 6,748,834	-$ 11,868
General Plant			
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ 0
1920 - Computer Equipment - Hardware	$ 152,100	$ 153,799	$ 1,699
1925 - Computer Software	$ 45,256	$ 45,256	$ 0
1930 - Transportation Equipment	$ 712,537	$ 522,537	-$ 190,000
1935 - Stores Equipment	$ 19,838	$ 10,538	-$ 9,300
1940 - Tools, Shop and Garage Equipment	$ 170,783	$ 143,108	-$ 27,675
1945 - Measurement and Testing Equipment	$ 8,484	$ 8,484	-$ 0
1955 - Communication Equipment	$ 18,015	$ 18,014	-$ 1
1985 - Sentinel Lighting Rentals	$ -	$ 10,121	$ 10,121
Sub-Total General Plant	$ 1,191,013	$ 975,857	-$ 215,156
GROSS ASSET TOTAL	$ 7,951,715	$ 7,724,691	-$ 227,024

ERHDC is showing an overall decrease in gross assets between 2012 Board Approved and 2012 Actual of ($227,024), as can be seen in Table 2-11. The vehicle budgeted for $190,000 in 2012 was not received until 2013 ($75,000 was in CWIP in 2012) and Capital Contributions for an unexpected solar farm project and an unexpected industrial park expansion were over budget. Breakdown as follows:

Vehicle	-$190,000
Contribution- industrial park	-$32,355
Contribution- solar farm	-$26,400
	-$248,755

(ii) 2012 Actual vs. 2013 Actual

Increase in gross assets between 2012 Actual and 2013 Actual of $562,434 (Table 2-12). Pursuant to the OEB letter dated September 8, 2020, detailed variance analyses has not been provided.

Table 2 - 12: 2012 Actual vs. 2013 Actual

Description	2012 Actual	2013 Actual	Variance from 2012 Actual
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 88,880	$ 88,880	$ -
1808 - Buildings and Fixtures	$ 342,089	$ 347,854	$ 5,765
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 478,757	$ 489,375	$ 10,618
1830 - Poles, Towers and Fixtures	$ 2,204,194	$ 2,440,704	$ 236,511
1835 - Overhead Conductors and Devices	$ 1,311,384	$ 1,447,391	$ 136,007
1840 - Underground Conduit	$ 697,969	$ 707,562	$ 9,593
1845 - Underground Conductors and Devices	$ 113,841	$ 117,889	$ 4,048
1850 - Line Transformers	$ 887,911	$ 941,028	$ 53,117
1855 - Services	$ 234,657	$ 278,205	$ 43,548
1860 - Meters	$ 711,954	$ 712,719	$ 765
1995 - Contributions and Grants	-$ 322,802	-$ 348,351	-$ 25,549
Sub-Total Distribution Assets	$ 6,748,834	$ 7,223,256	$ 474,422
General Plant			
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ -
1920 - Computer Equipment - Hardware	$ 153,799	$ 153,799	$ -
1925 - Computer Software	$ 45,256	$ 45,256	$ -
1930 - Transportation Equipment	$ 522,537	$ 609,305	$ 86,768
1935 - Stores Equipment	$ 10,538	$ 10,538	$ -
1940 - Tools, Shop and Garage Equipment	$ 143,108	$ 143,108	$ -
1945 - Measurement and Testing Equipment	$ 8,484	$ 8,484	$ -
1955 - Communication Equipment	$ 18,014	$ 19,257	$ 1,243
1985 - Sentinel Lighting Rentals	$ 10,121	$ 10,121	$ -
Sub-Total General Plant	$ 975,857	$ 1,063,869	$ 88,012
GROSS ASSET TOTAL	$ 7,724,691	$ 8,287,125	$ 562,434

(iii) 2013 Actual vs. 2014 Actual

Increase in gross assets between 2013 Actual and 2014 Actual of $268,824 (Table 2 -13). Pursuant to the OEB letter dated September 8, 2020, detailed variance analyses has not been provided.

Table 2 - 13: 2013 Actual vs. 2014 Actual

Description	2013 Actual	2014 Actual	Variance from 2013 Actual
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 88,880	$ 88,880	$ -
1808 - Buildings and Fixtures	$ 347,854	$ 347,854	$ -
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 489,375	$ 489,375	$ -
1830 - Poles, Towers and Fixtures	$ 2,440,704	$ 2,564,879	$ 124,175
1835 - Overhead Conductors and Devices	$ 1,447,391	$ 1,568,813	$ 121,422
1840 - Underground Conduit	$ 707,562	$ 707,562	$ -
1845 - Underground Conductors and Devices	$ 117,889	$ 117,889	$ -
1850 - Line Transformers	$ 941,028	$ 950,593	$ 9,565
1855 - Services	$ 278,205	$ 284,077	$ 5,872
1860 - Meters	$ 712,719	$ 715,075	$ 2,356
1995 - Contributions and Grants	-$ 348,351	-$ 351,648	-$ 3,297
Sub-Total Distribution Assets	$ 7,223,256	$ 7,483,349	$ 260,093
General Plant			
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ -
1920 - Computer Equipment - Hardware	$ 153,799	$ 154,861	$ 1,063
1925 - Computer Software	$ 45,256	$ 45,256	$ -
1930 - Transportation Equipment	$ 609,305	$ 610,116	$ 811
1935 - Stores Equipment	$ 10,538	$ 10,538	$ -
1940 - Tools, Shop and Garage Equipment	$ 143,108	$ 149,967	$ 6,859
1945 - Measurement and Testing Equipment	$ 8,484	$ 8,484	$ -
1955 - Communication Equipment	$ 19,257	$ 19,257	$ -
1970 - Load Management Controls - Customer Premises	$ -	$ -	$ -
1975 - Load Management Controls - Utility Premises	$ -	$ -	$ -
1980 - System Supervisory Equipment	$ -	$ -	$ -
1985 - Sentinel Lighting Rentals	$ 10,121	$ 10,121	$ -
1990 - Other Tangible Property	$ -	$ -	$ -
Sub-Total General Plant	$ 1,063,869	$ 1,072,600	$ 8,731
GROSS ASSET TOTAL	$ 8,287,125	$ 8,555,949	$ 268,824

(iv) 2014 Actual vs. 2015 Actual

Increase in gross assets between 2014 Actual and 2015 Actual of $227,277 (Table 2-14). Pursuant to the OEB letter dated September 8, 2020, detailed variance analyses has not been provided.

1 **Table 2 - 14: 2014 Actual vs. 2015 Actual**

Description	2014 Actual	2015 Actual	Variance from 2014 Actual
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 88,880	$ 88,880	$ -
1806 - Land Rights	$ -	$ -	$ -
1808 - Buildings and Fixtures	$ 347,854	$ 351,783	$ 3,929
1810 - Leasehold Improvements	$ -	$ -	$ -
1815 - Transformer Station Equipment - Normally Primary above 50 kV	$ -	$ -	$ -
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 489,375	$ 489,375	$ -
1825 - Storage Battery Equipment	$ -	$ -	$ -
1830 - Poles, Towers and Fixtures	$ 2,564,879	$ 2,562,749	-$ 2,130
1835 - Overhead Conductors and Devices	$ 1,568,813	$ 1,768,504	$ 199,691
1840 - Underground Conduit	$ 707,562	$ 710,347	$ 2,785
1845 - Underground Conductors and Devices	$ 117,889	$ 125,040	$ 7,152
1850 - Line Transformers	$ 950,593	$ 970,273	$ 19,680
1855 - Services	$ 284,077	$ 290,773	$ 6,696
1860 - Meters	$ 715,075	$ 717,826	$ 2,751
1865 - Other Installations on Customer's Premises	$ -	$ -	$ -
1995 - Contributions and Grants	-$ 351,648	-$ 356,361	-$ 4,714
Sub-Total Distribution Assets	$ 7,483,349	$ 7,719,190	$ 235,841
General Plant			
1905 - Land	$ -	$ -	$ -
1906 - Land Rights	$ -	$ -	$ -
1908 - Buildings and Fixtures	$ -	$ -	$ -
1910 - Leasehold Improvements	$ -	$ -	$ -
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ -
1920 - Computer Equipment - Hardware	$ 154,861	$ 154,861	$ -
1925 - Computer Software	$ 45,256	$ 45,256	$ -
1930 - Transportation Equipment	$ 610,116	$ 598,088	-$ 12,028
1935 - Stores Equipment	$ 10,538	$ 10,538	$ -
1940 - Tools, Shop and Garage Equipment	$ 149,967	$ 149,967	$ -
1945 - Measurement and Testing Equipment	$ 8,484	$ 11,948	$ 3,464
1950 - Power Operated Equipment	$ -	$ -	$ -
1955 - Communication Equipment	$ 19,257	$ 19,257	$ -
1960 - Miscellaneous Equipment	$ -	$ -	$ -
1970 - Load Management Controls - Customer Premises	$ -	$ -	$ -
1975 - Load Management Controls - Utility Premises	$ -	$ -	$ -
1980 - System Supervisory Equipment	$ -	$ -	$ -
1985 - Sentinel Lighting Rentals	$ 10,121	$ 10,121	$ -
1990 - Other Tangible Property	$ -	$ -	$ -
Sub-Total General Plant	$ 1,072,600	$ 1,064,036	-$ 8,564
GROSS ASSET TOTAL	$ 8,555,949	$ 8,783,226	$ 227,277

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(v) 2015 Actual vs. 2016 Actual

Increase in gross assets between 2015 Actual and 2016 Actual of $379,071 (Table 2-15). Pursuant to the OEB letter dated September 8, 2020, detailed variance analyses has not been provided.

Table 2 - 15: 2015 Actual vs. 2016 Actual

Description	2015 Actual	2016 Actual	Variance from 2015 Actual
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 88,880	$ 88,880	$ -
1806 - Land Rights	$ -	$ -	$ -
1808 - Buildings and Fixtures	$ 351,783	$ 354,801	$ 3,019
1810 - Leasehold Improvements	$ -	$ -	$ -
1815 - Transformer Station Equipment - Normally Primary above 50 kV	$ -	$ -	$ -
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 489,375	$ 489,375	$ -
1825 - Storage Battery Equipment	$ -	$ -	$ -
1830 - Poles, Towers and Fixtures	$ 2,562,749	$ 2,669,814	$ 107,065
1835 - Overhead Conductors and Devices	$ 1,768,504	$ 1,963,232	$ 194,728
1840 - Underground Conduit	$ 710,347	$ 710,347	$ -
1845 - Underground Conductors and Devices	$ 125,040	$ 138,678	$ 13,637
1850 - Line Transformers	$ 970,273	$ 999,038	$ 28,765
1855 - Services	$ 290,773	$ 318,184	$ 27,411
1860 - Meters	$ 717,826	$ 721,330	$ 3,504
1865 - Other Installations on Customer's Premises	$ -	$ -	$ -
1995 - Contributions and Grants	-$ 356,361	-$ 403,693	-$ 47,332
Sub-Total Distribution Assets	$ 7,719,190	$ 8,049,986	$ 330,797
General Plant			
1905 - Land	$ -	$ -	$ -
1906 - Land Rights	$ -	$ -	$ -
1908 - Buildings and Fixtures	$ -	$ -	$ -
1910 - Leasehold Improvements	$ -	$ -	$ -
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ -
1920 - Computer Equipment - Hardware	$ 154,861	$ 154,861	$ -
1925 - Computer Software	$ 45,256	$ 45,256	$ -
1930 - Transportation Equipment	$ 598,088	$ 641,705	$ 43,617
1935 - Stores Equipment	$ 10,538	$ 10,538	$ -
1940 - Tools, Shop and Garage Equipment	$ 149,967	$ 154,625	$ 4,658
1945 - Measurement and Testing Equipment	$ 11,948	$ 11,948	$ -
1950 - Power Operated Equipment	$ -	$ -	$ -
1955 - Communication Equipment	$ 19,257	$ 19,257	$ -
1960 - Miscellaneous Equipment	$ -	$ -	$ -
1970 - Load Management Controls - Customer Premises	$ -	$ -	$ -
1975 - Load Management Controls - Utility Premises	$ -	$ -	$ -
1980 - System Supervisory Equipment	$ -	$ -	$ -
1985 - Sentinel Lighting Rentals	$ 10,121	$ 10,121	$ -
1990 - Other Tangible Property	$ -	$ -	$ -
Sub-Total General Plant	$ 1,064,036	$ 1,112,311	$ 48,275
GROSS ASSET TOTAL	$ 8,783,226	$ 9,162,297	$ 379,071

(vi) 2016 Actual vs. 2017 Actual

Increase in gross assets between 2016 Actual and 2017 Actual of $576,816 (Table 2-16). Pursuant to the OEB letter dated September 8, 2020, detailed variance analyses has not been provided.

Table 2 - 16: 2016 Actual vs. 2017 Actual

Description	2016 Actual	2017 Actual	Variance from 2016 Actual
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 88,880	$ 88,880	$ -
1806 - Land Rights	$ -	$ -	$ -
1808 - Buildings and Fixtures	$ 354,801	$ 354,801	$ -
1810 - Leasehold Improvements	$ -	$ -	$ -
1815 - Transformer Station Equipment - Normally Primary above 50 kV	$ -	$ -	$ -
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 489,375	$ 489,375	$ -
1825 - Storage Battery Equipment	$ -	$ -	$ -
1830 - Poles, Towers and Fixtures	$ 2,669,814	$ 2,854,431	$ 184,617
1835 - Overhead Conductors and Devices	$ 1,963,232	$ 2,290,470	$ 327,238
1840 - Underground Conduit	$ 710,347	$ 710,347	$ -
1845 - Underground Conductors and Devices	$ 138,678	$ 164,846	$ 26,168
1850 - Line Transformers	$ 999,038	$ 1,009,803	$ 10,765
1855 - Services	$ 318,184	$ 333,678	$ 15,494
1860 - Meters	$ 721,330	$ 737,156	$ 15,827
1865 - Other Installations on Customer's Premises	$ -	$ -	$ -
1995 - Contributions and Grants	-$ 403,693	-$ 406,986	-$ 3,293
Sub-Total Distribution Assets	$ 8,049,986	$ 8,626,802	$ 576,816
General Plant			
1905 - Land	$ -	$ -	$ -
1906 - Land Rights	$ -	$ -	$ -
1908 - Buildings and Fixtures	$ -	$ -	$ -
1910 - Leasehold Improvements	$ -	$ -	$ -
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ -
1920 - Computer Equipment - Hardware	$ 154,861	$ 154,861	$ -
1925 - Computer Software	$ 45,256	$ 45,256	$ -
1930 - Transportation Equipment	$ 641,705	$ 641,705	$ -
1935 - Stores Equipment	$ 10,538	$ 10,538	$ -
1940 - Tools, Shop and Garage Equipment	$ 154,625	$ 154,625	$ -
1945 - Measurement and Testing Equipment	$ 11,948	$ 11,948	$ -
1950 - Power Operated Equipment	$ -	$ -	$ -
1955 - Communication Equipment	$ 19,257	$ 19,257	$ -
1960 - Miscellaneous Equipment	$ -	$ -	$ -
1970 - Load Management Controls - Customer Premises	$ -	$ -	$ -
1975 - Load Management Controls - Utility Premises	$ -	$ -	$ -
1980 - System Supervisory Equipment	$ -	$ -	$ -
1985 - Sentinel Lighting Rentals	$ 10,121	$ 10,121	$ -
1990 - Other Tangible Property	$ -	$ -	$ -
Sub-Total General Plant	$ 1,112,311	$ 1,112,311	$ -
GROSS ASSET TOTAL	$ 9,162,297	$ 9,739,113	$ 576,816

Pursuant to the OEB letter dated September 8, 2020, detailed variance analyses are provided for years 2017 to 2021 in the following sections.

(vii) 2017 Actual vs. 2018 Actual

Increase in gross assets between 2017 Actual and 2018 Actual of $439,133 (Table 2 - 17)

Table 2 - 17: 2017 Actual vs. 2018 Actual

Description	2017 Actual	2018 Actual	Variance from 2017 Actual
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 88,880	$ 88,880	$ -
1806 - Land Rights	$ -	$ -	$ -
1808 - Buildings and Fixtures	$ 354,801	$ 354,801	$ -
1810 - Leasehold Improvements	$ -	$ -	$ -
1815 - Transformer Station Equipment - Normally Primary above 50 kV	$ -	$ -	$ -
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 489,375	$ 489,375	$ -
1825 - Storage Battery Equipment	$ -	$ -	$ -
1830 - Poles, Towers and Fixtures	$ 2,854,431	$ 3,012,095	$ 157,664
1835 - Overhead Conductors and Devices	$ 2,290,470	$ 2,347,420	$ 56,950
1840 - Underground Conduit	$ 710,347	$ 710,347	$ -
1845 - Underground Conductors and Devices	$ 164,846	$ 393,051	$ 228,205
1850 - Line Transformers	$ 1,009,803	$ 1,029,706	$ 19,903
1855 - Services	$ 333,678	$ 347,860	$ 14,182
1860 - Meters	$ 737,156	$ 738,036	$ 879
1865 - Other Installations on Customer's Premises	$ -	$ -	$ -
1995 - Contributions and Grants	-$ 406,986	-$ 447,255	-$ 40,269
Sub-Total Distribution Assets	$ 8,626,802	$ 9,064,316	$ 437,513
General Plant			
1905 - Land	$ -	$ -	$ -
1906 - Land Rights	$ -	$ -	$ -
1908 - Buildings and Fixtures	$ -	$ -	$ -
1910 - Leasehold Improvements	$ -	$ -	$ -
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ -
1920 - Computer Equipment - Hardware	$ 154,861	$ 156,481	$ 1,620
1925 - Computer Software	$ 45,256	$ 45,256	$ -
1930 - Transportation Equipment	$ 641,705	$ 641,705	$ -
1935 - Stores Equipment	$ 10,538	$ 10,538	$ -
1940 - Tools, Shop and Garage Equipment	$ 154,625	$ 154,625	$ -
1945 - Measurement and Testing Equipment	$ 11,948	$ 11,948	$ -
1950 - Power Operated Equipment	$ -	$ -	$ -
1955 - Communication Equipment	$ 19,257	$ 19,257	$ -
1960 - Miscellaneous Equipment	$ -	$ -	$ -
1970 - Load Management Controls - Customer Premises	$ -	$ -	$ -
1975 - Load Management Controls - Utility Premises	$ -	$ -	$ -
1980 - System Supervisory Equipment	$ -	$ -	$ -
1985 - Sentinel Lighting Rentals	$ 10,121	$ 10,121	$ -
1990 - Other Tangible Property	$ -	$ -	$ -
Sub-Total General Plant	$ 1,112,311	$ 1,113,931	$ 1,620
GROSS ASSET TOTAL	$ 9,739,113	$ 10,178,247	$ 439,133

The principle drivers of the net increase are: $157,664 in 1830 - Poles, Towers and Fixtures from annual pole replacement program and cross lot relocations; $56,950 in 1835 - Overhead Conductors and Devices related to cross lot relocations, annual pole replacement program, annual overhead cutout renewal; $228,205 in 1845 - Underground Conductors and Devices related to the Queensway Subdivision, submarine cable replacement.

(viii) 2018 Actual vs. 2019 Actual

Increase in gross assets between 2018 Actual and 2019 Actual of $144,769 (Table 2 -18).

Table 2 - 18: 2018 Actual vs. 2019 Actual

Description	2018 Actual	2019 Actual	Variance from 2018 Actual
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 88,880	$ 88,880	$ -
1806 - Land Rights	$ -	$ -	$ -
1808 - Buildings and Fixtures	$ 354,801	$ 354,801	$ -
1810 - Leasehold Improvements	$ -	$ -	$ -
1815 - Transformer Station Equipment - Normally Primary above 50 kV	$ -	$ -	$ -
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 489,375	$ 489,375	$ -
1825 - Storage Battery Equipment	$ -	$ -	$ -
1830 - Poles, Towers and Fixtures	$ 3,012,095	$ 3,230,231	$ 218,136
1835 - Overhead Conductors and Devices	$ 2,347,420	$ 2,409,296	$ 61,876
1840 - Underground Conduit	$ 710,347	$ 710,347	$ -
1845 - Underground Conductors and Devices	$ 393,051	$ 409,426	$ 16,375
1850 - Line Transformers	$ 1,029,706	$ 1,087,720	$ 58,014
1855 - Services	$ 347,860	$ 360,572	$ 12,712
1860 - Meters	$ 738,036	$ 738,154	$ 119
1865 - Other Installations on Customer's Premises	$ -	$ -	$ -
1995 - Contributions and Grants	-$ 447,255	-$ 486,545	-$ 39,290
Sub-Total Distribution Assets	$ 9,064,316	$ 9,392,258	$ 327,942
General Plant			
1905 - Land	$ -	$ -	$ -
1906 - Land Rights	$ -	$ -	$ -
1908 - Buildings and Fixtures	$ -	$ -	$ -
1910 - Leasehold Improvements	$ -	$ -	$ -
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ -
1920 - Computer Equipment - Hardware	$ 156,481	$ 164,241	$ 7,759
1925 - Computer Software	$ 45,256	$ 45,256	$ -
1930 - Transportation Equipment	$ 641,705	$ 443,607	-$ 198,098
1935 - Stores Equipment	$ 10,538	$ 10,538	$ -
1940 - Tools, Shop and Garage Equipment	$ 154,625	$ 161,791	$ 7,166
1945 - Measurement and Testing Equipment	$ 11,948	$ 11,948	$ -
1950 - Power Operated Equipment	$ -	$ -	$ -
1955 - Communication Equipment	$ 19,257	$ 19,257	$ -
1960 - Miscellaneous Equipment	$ -	$ -	$ -
1970 - Load Management Controls - Customer Premises	$ -	$ -	$ -
1975 - Load Management Controls - Utility Premises	$ -	$ -	$ -
1980 - System Supervisory Equipment	$ -	$ -	$ -
1985 - Sentinel Lighting Rentals	$ 10,121	$ 10,121	$ -
1990 - Other Tangible Property	$ -	$ -	$ -
Sub-Total General Plant	$ 1,113,931	$ 930,758	-$ 183,173
GROSS ASSET TOTAL	$ 10,178,247	$ 10,323,016	$ 144,769

The principle drivers of the net increase are: $218,136 in 1830 - Poles, Towers and Fixtures for annual pole replacement program and cross lot relocations; $61,876 in 1835 - Overhead Conductors and Devices for annual pole replacement program and cross lot relocations; $58,014 in 1850 - Line Transformers for annual transformer renewal, new services and service for new Sacred Heart school; $198,098 in 1930 - Transportation Equipment for disposal of double bucket truck, chipper, trailer and 4 x 4 truck, and addition of used double bucket truck.

(ix) 2019 Actual vs. 2020 Bridge

Increase in gross assets between 2019 Actual and 2020 Bridge of $2,594,220 (Table 2-19).

Table 2 - 19: 2019 Actual vs. 2020 Bridge

Description	2019 Actual	2020 Bridge	Variance from 2019 Actual
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 88,880	$ 88,880	-$ 0
1806 - Land Rights	$ -	$ -	$ -
1808 - Buildings and Fixtures	$ 354,801	$ 389,801	$ 35,000
1810 - Leasehold Improvements	$ -	$ -	$ -
1815 - Transformer Station Equipment - Normally Primary above 50 kV	$ -	$ -	$ -
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 489,375	$ 2,185,331	$ 1,695,956
1825 - Storage Battery Equipment	$ -	$ -	$ -
1830 - Poles, Towers and Fixtures	$ 3,230,231	$ 3,633,597	$ 403,366
1835 - Overhead Conductors and Devices	$ 2,409,296	$ 2,494,971	$ 85,675
1840 - Underground Conduit	$ 710,347	$ 786,919	$ 76,572
1845 - Underground Conductors and Devices	$ 409,426	$ 540,772	$ 131,346
1850 - Line Transformers	$ 1,087,720	$ 1,143,945	$ 56,225
1855 - Services	$ 360,572	$ 441,209	$ 80,637
1860 - Meters	$ 738,154	$ 808,427	$ 70,273
1865 - Other Installations on Customer's Premises	$ -	$ -	$ -
1995 - Contributions and Grants	-$ 486,545	-$ 550,375	-$ 63,830
Sub-Total Distribution Assets	$ 9,392,258	$ 11,963,477	$ 2,571,219
General Plant			
1905 - Land	$ -	$ -	$ -
1906 - Land Rights	$ -	$ -	$ -
1908 - Buildings and Fixtures	$ -	$ -	$ -
1910 - Leasehold Improvements	$ -	$ -	$ -
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ -
1920 - Computer Equipment - Hardware	$ 164,241	$ 169,241	$ 5,000
1925 - Computer Software	$ 45,256	$ 55,256	$ 10,000
1930 - Transportation Equipment	$ 443,607	$ 443,607	$ -
1935 - Stores Equipment	$ 10,538	$ 10,538	$ -
1940 - Tools, Shop and Garage Equipment	$ 161,791	$ 169,791	$ 8,000
1945 - Measurement and Testing Equipment	$ 11,948	$ 11,948	$ -
1950 - Power Operated Equipment	$ -	$ -	$ -
1955 - Communication Equipment	$ 19,257	$ 19,257	$ -
1960 - Miscellaneous Equipment	$ -	$ -	$ -
1970 - Load Management Controls - Customer Premises	$ -	$ -	$ -
1975 - Load Management Controls - Utility Premises	$ -	$ -	$ -
1980 - System Supervisory Equipment	$ -	$ -	$ -
1985 - Sentinel Lighting Rentals	$ 10,121	$ 10,121	$ 0
1990 - Other Tangible Property	$ -	$ -	$ -
Sub-Total General Plant	$ 930,758	$ 953,758	$ 23,001
GROSS ASSET TOTAL	$ 10,323,016	$ 12,917,236	$ 2,594,220

The principle drivers of the net increase include $1,695,956 in 1820 - Distribution Station Equipment - Normally Primary below 50 kV for addition of new Distribution station from account 1508. An ICM was approved in 2014 (EB-2013-0127). For this 2021 rate application, ERHDC is requesting to end the ICM rate rider. As such, it has added the amount of $1,695,956 to rate base in 2020 so that it forms part of opening rate base in 2021.

In addition, other principle drivers are: $403,366 in 1830 - Poles, Towers and Fixtures for annual pole replacement program, cross lot relocations, Duplessis Road line rebuild and addition of new line in conjunction to Distribution station from account 1508 (2014 approved ICM); $85,675 in 1835 - Overhead Conductors and Devices for cross lot relocations, annual overhead cutout renewal; $76,572 in 1840 - Underground Conduit for Spanish River Drive rear lot line replacement; $131,346 in 1845 - Underground Conductors and Devices for Brentwood Subdivision, Spanish River Drive rear lot line replacement, and Kbar replacement; $56,225 in 1850 - Line Transformers for Spanish River Drive rear lot line replacement and overhead transformer renewal; $80,637 in 1855 – Services for Spanish River Drive rear lot line replacement; $70,273 in 1860 – Meters for MIST meter installations and Polyphase meter resealing; $63,830 in 1995 - Contributions and Grants for new services, Brentwood Subdivision.

(x) 2020 Bridge vs. 2021 Test

Increase in gross assets between 2020 Bridge and 2021 Test of $463,4329 (Table 2 - 20)

Table 2 - 20: 2020 Bridge vs. 2021 Test

Description	2020 Bridge	2021 Test	Variance from 2020 Bridge
Reporting Basis	MIFRS	MIFRS	
Distribution Assets			
1805 - Land	$ 88,880	$ 88,880	-$ 0
1806 - Land Rights	$ -	$ -	$ -
1808 - Buildings and Fixtures	$ 389,801	$ 414,801	$ 25,000
1810 - Leasehold Improvements	$ -	$ -	$ -
1815 - Transformer Station Equipment - Normally Primary above 50 kV	$ -	$ -	$ -
1820 - Distribution Station Equipment - Normally Primary below 50 kV	$ 2,185,331	$ 2,188,943	$ 3,612
1825 - Storage Battery Equipment	$ -	$ -	$ -
1830 - Poles, Towers and Fixtures	$ 3,633,597	$ 3,808,792	$ 175,195
1835 - Overhead Conductors and Devices	$ 2,494,971	$ 2,595,050	$ 100,079
1840 - Underground Conduit	$ 786,919	$ 786,919	$ 0
1845 - Underground Conductors and Devices	$ 540,772	$ 594,438	$ 53,666
1850 - Line Transformers	$ 1,143,945	$ 1,200,091	$ 56,146
1855 - Services	$ 441,209	$ 491,521	$ 50,312
1860 - Meters	$ 808,427	$ 824,846	$ 16,419
1865 - Other Installations on Customer's Premises	$ -	$ -	$ -
1995 - Contributions and Grants	-$ 550,375	-$ 575,375	-$ 25,000
Sub-Total Distribution Assets	$ 11,963,477	$ 12,418,907	$ 455,430
General Plant			
1905 - Land	$ -	$ -	$ -
1906 - Land Rights	$ -	$ -	$ -
1908 - Buildings and Fixtures	$ -	$ -	$ -
1910 - Leasehold Improvements	$ -	$ -	$ -
1915 - Office Furniture and Equipment	$ 64,000	$ 64,000	$ -
1920 - Computer Equipment - Hardware	$ 169,241	$ 177,241	$ 8,000
1925 - Computer Software	$ 55,256	$ 55,256	$ -
1930 - Transportation Equipment	$ 443,607	$ 443,607	$ -
1935 - Stores Equipment	$ 10,538	$ 10,538	$ -
1940 - Tools, Shop and Garage Equipment	$ 169,791	$ 169,791	$ -
1945 - Measurement and Testing Equipment	$ 11,948	$ 11,948	$ -
1950 - Power Operated Equipment	$ -	$ -	$ -
1955 - Communication Equipment	$ 19,257	$ 19,257	$ -
1960 - Miscellaneous Equipment	$ -	$ -	$ -
1970 - Load Management Controls - Customer Premises	$ -	$ -	$ -
1975 - Load Management Controls - Utility Premises	$ -	$ -	$ -
1980 - System Supervisory Equipment	$ -	$ -	$ -
1985 - Sentinel Lighting Rentals	$ 10,121	$ 10,121	-$ 0
1990 - Other Tangible Property	$ -	$ -	$ -
Sub-Total General Plant	$ 953,758	$ 961,758	$ 8,000
GROSS ASSET TOTAL	$ 12,917,236	$ 13,380,665	$ 463,429

The principle drivers of the net increase are $175,195 in 1830 - Poles, Towers and Fixtures for annual pole replacement program, Massey 3 phase line replacement, and Clear Lake line replacement; $100,709 in 1835 - Overhead Conductors and Devices for Massey 3 phase line replacement, Clear Lake line replacement and conductor replacement Distribution Station 3; $53,666 in 1845 - Underground Conductors and Devices for Transclosure replacement program, and Kbar replacement at a general service customer; $56,146 in 1850 - Line Transformers for overhead transformer renewal, and Massey 3 phase line replacement; $50,312 in 1855 – Services for Massey 3 phase line replacement.

(c) Incremental Capital Module Adjustments

ERHDC applied for and received an ICM adjustment as part of its 2014 IRM application (EB-2013-0127). In the 2014 ICM application, ERHDC received approval to recover the revenue requirement associated with the incremental capital costs of constructing a fourth distribution station (MS4). In its decision the Board found that the capital costs incurred were prudent and sufficient evidence had been provided that potential alternatives were analyzed and that the completion of the project represented the most cost effective alternative for ratepayers. ERHDC has been recovering costs through an Incremental Capital Module Rate Rider which is in effect until the effective date of the next cost of service based rate order.

The following is an excerpt from the Boards decision (EB-2013-0127):

> "The Board approves combined fixed and variable rate rider to recover a revenue requirement of $168,193 associated with the new municipal substation. For this case, the Board finds that recovery through combined rate riders is consistent with the treatment of the revenue requirement associated with Espanola's overall distribution system. These rate riders will be in effect until Espanola's next cost of service rate order. The approved ICM treatment of the new municipal substation is based on a 2014 in-service date."

In its decision and order the Board approved the forecasted costs of $2,062,500 and the resulting revenue requirement of $168,193. The station was in service in the fall of 2014 and actual costs for the project were $1,967,930 (4.6% under the forecast) due to favourable tending results and the land purchase being under estimate. (Note: The actual land purchase of $18,696, although part of the project costs, was recorded in fixed assets not the 1508 regulatory account – as such it has been included in the revised revenue requirement calculation but not in the requested transfer to fixed assets from 1508). Table 2-21 below is a comparison of the approved ICM costs and the actual amount spent. Table 2-22 below is a recalculation of the revenue requirement based on actual costs of the project.

Table 2 - 21: Comparison of Actual Station 4 Costs to ICM Estimated Costs

	ICM Estimate	Actual
Land	$54,000	$18,696
Building & Equipment	$1,733,500	$1,690,036
Line	$275,000	$259,198
	$2,062,500.00	$1,967,931
		-$94,568.95
		-4.6%

Table 2 - 22: Recalculation of Revenue Requirement Based on Actual Final Costs

Incremental Capital Adjustment 2014 Approved					Incremental Capital Adjustment Adjusted for Actual Costs			
Current Revenue Requirement					**Current Revenue Requirement**			
Current Revenue Requirement - Total			$ 1,647,816	A	Current Revenue Requirement - Total			$ 1,647,816
Return on Rate Base					**Return on Rate Base**			
Incremental Capital CAPEX			$ 2,062,500	B	Incremental Capital CAPEX			$ 1,967,930
Depreciation Expense			$ 50,213	C	Depreciation Expense			$ 39,391
Incremental Capital CAPEX to be included in Rate Base			$ 2,012,287	D = B - C	Incremental Capital CAPEX to be included in Rate Base			$ 1,928,539
Deemed ShortTerm Debt %	4.0%	E	$ 80,491	G = D * E	Deemed ShortTerm Debt %	4.0%	E	$ 77,142
Deemed Long Term Debt %	56.0%	F	$ 1,126,881	H = D * F	Deemed Long Term Debt %	56.0%	F	$ 1,079,982
Short Term Interest	2.08%	I	$ 1,674	K = G * I	Short Term Interest	2.08%	I	$ 1,605
Long Term Interest	4.41%	J	$ 49,695	L = H * J	Long Term Interest	4.41%	J	$ 47,627
Return on Rate Base - Interest			$ 51,370	M = K + L	Return on Rate Base - Interest			$ 49,232
Deemed Equity %	40.0%	N	$ 804,915	P = D * N	Deemed Equity %	40.0%	N	$ 771,416
Return on Rate Base -Equity	9.12%	O	$ 73,408	Q = P * O	Return on Rate Base -Equity	9.12%	O	$ 70,353
Return on Rate Base - Total			$ 124,778	R = M + Q	Return on Rate Base - Total			$ 119,585
Amortization Expense					**Amortization Expense**			
Amortization Expense - Incremental		C	$ 50,213	S	Amortization Expense - Incremental		C	$ 39,391
Grossed up PIL's					**Grossed up PIL's**			
Regulatory Taxable Income		O	$ 73,408	T	Regulatory Taxable Income		O	$ 70,353
Add Back Amortization Expense		S	$ 50,213	U	Add Back Amortization Expense		S	$ 39,391
Deduct CCA			$ 160,680	V	Deduct CCA			$ 155,939
Incremental Taxable Income			-$ 37,059	W = T + U - V	Incremental Taxable Income			-$ 46,195
Current Tax Rate (F1.1 Z-Factor Tax Changes)	15.5%	X			Current Tax Rate (F1.1 Z-Factor Tax Changes)	0.0%	X	
PIL's Before Gross Up			-$ 5,744	Y = W * X	PIL's Before Gross Up			$ -
Incremental Grossed Up PIL's			-$ 6,798	Z = Y / (1 - X)	Incremental Grossed Up PIL's			$ -
Ontario Capital Tax					**Ontario Capital Tax**			
Incremental Capital CAPEX			$ 2,062,500	AA	Incremental Capital CAPEX			$ 1,967,930
Less : Available Capital Exemption (if any)			$ -	AB	Less : Available Capital Exemption (if any)			$ -
Incremental Capital CAPEX subject to OCT			$ 2,062,500	AC = AA - AB	Incremental Capital CAPEX subject to OCT			$ 1,967,930
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	AD			Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	AD	
Incremental Ontario Capital Tax			$ -	AE = AC * AD	Incremental Ontario Capital Tax			$ -
Incremental Revenue Requirement					**Incremental Revenue Requirement**			
Return on Rate Base - Total		Q	$ 124,778	AF	Return on Rate Base - Total		Q	$ 119,585
Amortization Expense - Total		S	$ 50,213	AG	Amortization Expense - Total		S	$ 39,391
Incremental Grossed Up PIL's		Z	-$ 6,798	AH	Incremental Grossed Up PIL's		Z	$ -
Incremental Ontario Capital Tax		AE	$ -	AI	Incremental Ontario Capital Tax		AE	$ -
Incremental Revenue Requirement			$ 168,193	AJ = AF + AG + AH + AI	Incremental Revenue Requirement			$ 158,976

2.2.1.3 ALLOWANCE FOR WORKING CAPITAL

(a) Allowance Factor Overview

In accordance with the Filing Requirements and in a letter dated June 3, 2015, the Board updated its policy for the calculation of the allowance for working capital. As outlined in both documents, distributors may take one of two approaches for the calculation of its allowance for working capital:

1. Use a default allowance approach; or
2. The filing of a lead/lag study.

ERHDC has used the default allowance of 7.5% for the 2021 Test Year in this Application, in accordance with the Filing Requirements.

(b) Working Capital Allowance

ERHDC is proposing a working capital allowance of $647,289 as shown in Table 2-23 below:

Table 2 - 23: Working Capital Allowance

Description	2021 Test
Cost of Power	$7,002,367
Operations	$401,109
Maintenance	$333,727
Billing & Collecting	$428,448
Community Relations	$0
Admin & General Expense	$490,146
Donations - LEAP	$2,000
Less Allocated Depreciation included above	($27,280)
Working Capital	**$8,630,518**
Working Capital Allowance @ 7.5%	**$647,289**

In Table 2-24 below, ERHDC has shown the calculation of the Cost of Power Expense that is included in Table 2-23: Working Capital Allowance above.

ERHDC has calculated cost of power (COP) for the 2020 Bridge Year and 2021 Test Year in support of its rate base calculation, using the load forecast, which is discussed in detail in Exhibit 3 – Operating Revenue.

ERHDC confirms that the Cost of Power (COP) is determined by a split between the Regulated Price Plan (RPP) and non-RPP customers based on actual data, use of most current RPP prices established for the November 1, 2019 to October 31, 2020 period, and use of the most recent approved Uniform Transmission Rates (UTRs), Smart Metering Entity charge and regulatory charges. ERHDC has no Class A customers. The calculation of cost of power includes consideration of the Ontario Electricity Rebate of 33.2% on the total bill.

The total COP expense calculated as per Appendix 2-ZB is shown in Table 2-24 below.

Table 2 - 24: Cost of Power Expense 2021 Test Year (Board Appendix 2-ZB)

		2021 Test Year	RPP		2021 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast				-				
Residential	kWh	34,091,823		4,364,776	744,520		14,957	
-		-		-	-		-	
General Service < 50	kWh	9,732,104		1,246,001	1,144,953		23,002	
General Service > 50	kWh	3,540,928		453,345	12,983,401		260,837	
Streetlight	kWh	-		-	240,056		4,823	
Sentinel Light	kWh	24,855		3,182	1,036		21	
Unmetered Scattered Load	kWh	111,226		14,240	11,708		235	
-		-		-	-		-	
-		-		-	-		-	
SUB-TOTAL		47,500,935		6,081,545	15,125,674		303,875	$ 6,385,419
Global Adjustment non-RPP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential				0			79,619.00	
				0			-	
General Service < 50				0			122,441.31	
General Service > 50				0			1,388,444.89	
Streetlight				0			25,671.54	
Sentinel Light				0			110.75	
Unmetered Scattered Load				0			1,252.06	
				0			-	
				0			-	
SUB-TOTAL		0		0			1,617,540	$ 1,617,540
Transmission - Network	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	34,091,823	0.0067	228,415	744,520	0.0067	4,988	
				-		-	-	
General Service < 50	kWh	9,732,104	0.0063	61,312	1,144,953	0.0063	7,213	
General Service > 50	kW		2.5294	-	38,559	2.5294	97,530	
Streetlight	kW		1.9078	-	660	1.9078	1,259	
Sentinel Light	kW		1.9173	-	67	1.9173	129	
Unmetered Scattered Load	kWh	111,226	0.0063	701	11,708	0.0063	74	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				290,428			111,194	401,622
Transmission - Connection	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	34,091,823	0.0050	170,459	744,520	0.0050	3,723	
				-		-	-	
General Service < 50	kWh	9,732,104	0.0045	43,794	1,144,953	0.0045	5,152	
General Service > 50	kW	-	1.7377	-	38,559	1.7377	67,003	
Streetlight	kW	-	1.3433	-	660	1.3433	887	
Sentinel Light	kW	-	1.3713	-	67	1.3713	92	
Unmetered Scattered Load	kWh	111,226	0.0045	501	11,708	0.0045	53	
				-			-	
				-			-	
SUB-TOTAL				214,754			76,910	291,664
Wholesale Market Service	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	34,091,823	0.0035	119,321	744,520	0.0035	2,606	
				-			-	
General Service < 50	kWh	9,732,104	0.0035	34,062	1,144,953	0.0035	4,007	
General Service > 50	kWh	3,540,928	0.0035	12,393	12,983,401	0.0035	45,442	
Streetlight		-	0.0035	-	240,056	0.0035	840	
Sentinel Light	kWh	24,855	0.0035	87	1,036	0.0035	4	
Unmetered Scattered Load	kWh	111,226	0.0035	389	11,708	0.0035	41	
				-			-	
				-			-	
SUB-TOTAL				166,253			52,940	219,193

RRRP Class per Load Forecast	Units	Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	34,091,823	0.0004	13,637	744,520	0.0004	298	
		-		-	-		-	
General Service < 50	kWh	9,732,104	0.0004	3,893	1,144,953	0.0004	458	
General Service > 50	kWh	3,540,928	0.0004	1,416	12,983,401	0.0004	5,193	
Streetlight	kWh	-	0.0004	-	240,056	0.0004	96	
Sentinel Light	kWh	24,855	0.0004	10	1,036	0.0004	0	
Unmetered Scattered Load	kWh	111,226	0.0004	44	11,708	0.0004	5	
				-			-	
				-			-	
SUB-TOTAL				19,000			6,050	25,051

Low Voltage - No TLF adjustment Class per Load Forecast	Units	Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh**	31,942,118	0.0070	223,595	697,574	0.0070	4,883	
				-		-	-	
General Service < 50	kWh**	9,118,433	0.0063	57,446	1,072,757	0.0063	6,758	
General Service > 50	kW	-	2.4327	-	38,559	2.4327	93,802	
Streetlight	kW	-	1.8805	-	660	1.8805	1,241	
Sentinel Light	kW	-	1.9197	-	67	1.9197	129	
Unmetered Scattered Load	kWh**	104,213	0.0063	657	10,970	0.0063	69	
		-		-			-	
				-			-	
SUB-TOTAL				281,697			106,883	388,580

Smart Meter Entity Charge Class per Load Forecast		Customers	Rate	$	Customers	Rate	$	Total
Residential R1		2,910	0.57	19,904			-	
General Service <50		369	0.57	2,524			-	
GS>50		30	0.57	205			-	
SUB-TOTAL				22,634			-	22,634
SUB- TOTAL				7,076,312			2,275,391	9,351,703
OER CREDIT[3]	33.20%			(2,349,335)			0	(2,349,335)
TOTAL				**4,726,976**			**2,275,391**	**7,002,367**

3.The OER Credit of 31.8% will only apply to RPP proportion of the listed components. Impacts on distribution charges are excluded for the purpose of calculating the cost of power.
4. Class A CBR: use the average CBR per kWh, similar to how the Class A GA cost is calculated. A Class A customer is a customer who participate in the ICI, pays global adjustment (GA) bas

2021 Test Year - Cop		
4705 -Power Purchased	$	6,385,419
4707- Global Adjustment	$	1,617,540
4708-Charges-WMS	$	244,244
4714-Charges-NW	$	401,622
4716-Charges-CN	$	291,664
4750-Charges-LV	$	388,580
4751-IESO SME	$	22,634
Misc A/R or A/P	$	(2,349,335)
TOTAL	**$**	**7,002,367**

2.2.2 CAPITAL EXPENDITURES

2.2.2.1 DISTRIBUTION SYSTEM PLAN

In accordance with the Filing Requirements, ERHDC is required to file its Distribution System Plan ("DSP") as a stand-alone document. ERHDC filed a letter with the Ontario Energy Board (the "OEB") proposing several adjustments to the OEB's Chapter 2 and 5 Filing Requirements applicable to the Application. One of the adjustments approved by the OEB pertains to the filing of the DSP. The DSP will only cover the 2021 forward test year and is attached at Appendix 2-B.

The preparation of the formal Asset Management Plan and Asset Condition Assessment is not being detailed until after the merger with North Bay Hydro. ERHDC's asset management plan is simply a one year forward test year plan which is a continuation of the status quo capital program.

The four categories of system investments have been addressed in ERHDC's capital expenditure plan, including System Access, System Renewal, System Service and General Plant. ERHDC has provided historical spending by material capital projects for the 2017 Actual, 2018 Actual, 2019 Actual, 2020 Bridge and 2021 Test years.

2.2.2.2 CAPITAL EXPENDITURES SUMMARY AND VARIANCE ANALYSIS

Table 2-25 below provides a summary of capital expenditures for 2012 and the historical years, 2017 through 2019. This table can be found in Appendix 2-C and is consistent with Board Appendix 2-AB. Tables 2-26 to 2-29 below show the planned vs actual capital expenditure variances for the historical years. Table 2-30 shows that forecasted capital expenditure summary (net of contributed capital) for 2020 and 2021.

Table 2 - 25: Historical Capital Expenditure Summary

	2012			2017			2018			2019			2020			2021
CATEGORY	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Forecast Period (planned)
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000
System Access	92	87	-5%	242	182	-25%	109	37	-66%	108	38	-65%	148	148	0%	52
System Renewal	736	835	13%	454	467	3%	446	393	-12%	417	338	-19%	502	502	0%	404
System Service			--			--			--			--			--	
General Plant	195	20	-90%	415	-	-100%	13	-	-100%	13	85	582%	58	58	0%	33
TOTAL EXPENDITURE	1,023	942	-8%	1,111	649	-42%	567	430	-24%	537	461	-14%	708	708	0%	488
Capital Contributions	$ 16	$ 71	333%	$ 18	$ 3	-82%	$ 24	$ 40	71%	$ 30	$ 39	33%	$ 64	$ 64	0%	$ 25
Net Capital Expenditures	1,006	871	-13%	1093	646	-41%	544	390	-28%	507	422	-17%	645	645	0%	463
CWIP	-	117		-	107		-	51		-	60		-	-	-	
Total Capital Expenditures including CWIP	1006	988			752	0	544	441		507	481		645	645		463

(a) Planned vs. Actual Variances

Table 2 - 26: 2012 Planned vs. Actual ($80,994 under planned)

System Access	Over (Under Budget)
New and Upgraded Services	$19,326
System Renewal	
Smart Meters	$47,644
Pole, Conductor, Transformer, etc. replacement	$27,037
	$74,681
General Plant	
Vehicle	($190,000)
Software	$19,999
Tools	($5,000)
	($175,001)
	($80,994)

The vehicle budgeted in 2012 was not received until 2013. An amount of $75,000 was included in CWIP.

Table 2 - 27: 2017 Planned vs. Actual ($462,331 under planned)

SYSTEM ACCESS:	Over (Under) Budget
New and Upgraded Services	($51,908)
Purchase of Long Term Load Assets from Hydro One	$22,353
City Projects - Line Relocations	($14,440)
Joint Use, Meter, etc.	($16,526)
	($60,521)
SYSTEM RENEWAL:	
Pole, Conductor, Transformer, etc. replacement	$13,190
GENERAL PLANT:	
Building Upgrades	($45,000)
Budcket Truck	($350,000)
Tools, IT Equipment	($20,000)
	($415,000)
	($462,331)

New and Upgraded Services – customer requests for new services and upgraded services were under budget.

Bucket Truck – the purchase of the budgeted bucket truck was postponed in 2017.

Table 2 - 28: 2018 Planned vs. Actual ($137,121 under planned)

SYSTEM ACCESS:	Over (Under) Budget
New and Upgraded Services	($38,077)
Purchase of Long Term Load Assets from Hydro One	
City Projects - Line Relocations	($15,012)
Joint Use, Meter, etc.	($18,471)
	($71,560)
SYSTEM RENEWAL:	
Pole replacement	$65,539
Spanish River Drive Rebuild	($165,413)
Replace Submarine Cables	$96,478
Cross lot relocations, Transformers, etc.	($49,664)
	($53,060)
GENERAL PLANT:	
Tools, IT Equipment	($12,500)
	($137,121)

The Spanish River Drive project was not undertaken in 2018. The resources were diverted to pole replacements and the replacement of submarine cables.

Table 2 - 29: 2019 Planned vs. Actual ($76,061 under planned)

SYSTEM ACCESS:	Over (Under) Budget
New and Upgraded Services	($40,615)
City Projects - Line Relocations	($10,452)
Joint Use, Meter, etc.	($18,766)
	($69,834)
SYSTEM RENEWAL:	
Pole replacement	$138,376
Spanish River Drive Rebuild	($162,387)
Replace Transclosurers	($52,546)
Cross lot relocations, Transformers, etc.	($2,433)
	($78,991)
GENERAL PLANT:	
Budcket Truck	$70,339
Tools, IT Equipment	$2,425
	$72,764
	($76,061)

The Spanish River Drive project and Transclosures replacement were delayed as the funds were required to replace a failed bucket truck and to increase the pole replacement program.

Table 2 - 30: Forecasted Capital Expenditure Summary (net of contributed capital)

CATEGORY	2020 Plan $ '000	2021 Plan $ '000
System Access	148	52
System Renewal	502	404
System Service		
General Plant	58	33
TOTAL EXPENDITURE	708	488
Capital Contributions	64	25
Net Capital Expenditures	645	463

(b) Variance Analysis By Spending Category

The following variance analysis has been prepared based on ERHDC's materiality threshold of $50,000, per the materiality calculation noted in Exhibit 1 of this Application. Expenditures in the System Access category experience variations – customer growth in ERHDC's service territory is low and there are sporadic variations in the number of requests received for new services from one year to the next, which can result in significant variations in year over year spending in this category. Similarly, the amount of work related to line relocates varies from year to year due to variations in demand for such services. In addition, as a small utility, ERHDC has only one line crew. Availability of employees due to sickness, leaves of absence and other short-term vacancies due to retirements and employees resigning could have a material effect on expenditures in any one year.

(i) 2017 Actual versus 2018 Actual Capital Expenditure Variances

ERHDC experienced an overall decrease in capital expenditures of $219,000 from 2017 Actual results to 2018 Actual results as summarized in Table 2–31 below.

Table 2 - 31: 2017 Actual versus 2018 Actual Capital Expenditure Variances

CATEGORY	2017 $ '000	2018 $ '000	Variance
System Access	182	37	(145)
System Renewal	467	393	(74)
System Service	-	-	-
General Plant	-	-	-
TOTAL EXPENDITURE	649	430	(219)

System Access

- Decrease in System Access in 2018 as a one-time expenditure to acquire Long Term Load Transfer assets occurred in 2017 in the amount of $162,000
- Customer Demand for new Services increased by $24,000

System Renewal

- Replacement of submarine cables increased from $62,000 in 2017 to $184,000 in 2018
- Conductor replacement in 2017 - $273,000 for Tie Feeders F1-F8 and F3-F5
- Increase in pole replacements in 2018 of $36,100
- Increase in cross lot conductor replacements in 2018 of $40,500

(ii) 2018 Actual versus 2019 Actual Capital Expenditure Variances

ERHDC experienced an overall increase in capital expenditures of $30,765 from 2018 Actual results to 2019 Actual results as summarized in Table 2-32 below.

Table 2 - 32: 2018 Actual versus 2019 Actual Capital Expenditure Variances

CATEGORY	2018 $ '000	2019 $ '000	Variance
System Access	37	38	1
System Renewal	393	338	(55)
System Service	-	-	-
General Plant	-	85	85
TOTAL EXPENDITURE	430	461	31

System Renewal

- Submarine cable replacement project was completed in 2018 at a cost of $184,000
- Pole replacement increased by $125,000 over 2018

General Plant

- Used vehicle purchased in 2019 at $70,000
- Miscellaneous tools at $15,000

(iii) 2019 Actual versus 2020 Bridge Year Capital Expenditure Variances

ERHDC is projecting an overall increase in capital expenditures of $247,486 from 2019 Actual results to 2020 Bridge Year results as summarized in Table 2-33 below.

Table 2 - 33: 2019 Actual versus 2020 Bridge Capital Expenditure Variances

CATEGORY	2019 $ '000	2020 $ '000	Variance
System Access	38	148	110
System Renewal	338	502	165
System Service	-	-	-
General Plant	85	58	(27)
TOTAL EXPENDITURE	461	708	247

System Access

- New project for the installation of mandated MIST meters $37,900
- Polyphase meter resealing $24,965
- New subdivision - Brentwood - $26,362
- Sacred Heart School completed in 2019 – ($18,028)
- Miscellaneous – new services, Town road projects, meters - $38,725

System Renewal

- Reduction in Pole replacement program – ($171,704)
- Spanish River Drive – replacement of rear lot poles - $221,504
- Replacement of line on Duplessis Rd. - $55,038
- Increase in O/H Cutout renewal program $48,118
- Reduction in Cross Lot line replacements – program to be completed in 2020 – ($33,726)
- Implementation of Kbar replacement program - $23,793
- Miscellaneous - $21,803

General Plant

- Vehicle purchased in 2019 – ($70,339)
- Building upgrades - $35,000
- Misc IT equipment and tools – $8,075

(iv) 2021 Test Year versus 2020 Bridge Year Capital Expenditure Variances

ERHDC planned capital expenditures for the 2021 Test Year is an overall decrease of $220,001 from the 2020 Bridge Year as summarized in Table 2-34 below.

Table 2 - 34: 2021 Test Year versus 2020 Bridge year Capital Expenditure Variances

CATEGORY	2020 $ '000	2021 $ '000	Variance
System Access	148	52	(96)
System Renewal	502	404	(99)
System Service	-	-	-
General Plant	58	33	(25)
TOTAL EXPENDITURE	708	488	(220)

System Access

- Reduced new subdivisions and service in 2021 – ($38,389)
- MIST meter project completed in 2020 – ($37,900)
- Polyphase meter resealing completed in 2020 – ($24,965)Miscellaneous – Town road projects, meters - $5,064

System Renewal

- Increase in Pole replacement program – $21,898
- Cross lot line replacements completed in 2020 – ($48,038)
- Spanish River Drive – replacement of rear lot poles in 2020 – ($225,210)
- Replacement of line on Duplessis Rd. – ($55,038)
- Increase in O/H transformer renewal - $11,861
- Reduction in O/H cutout renewal – ($43,234)
- Line replacement Clear Lake - $41,821
- Replacement of Massey 3 Phase Line - $126,423
- Replace transclosures - $38,795
- MS 3 conductor replacement - $44,318
- Miscellaneous – ($12,407)

General Plant

- Reduction in Building work – ($10,000)
- Reduction in IT Equipment – ($15,000))

(v) 2021 Forecast Capital Expenditure Variance Analysis

The planned capital expenditure for the Test Year (2021) indicates capital expenditures by ERHDC of $488,429. The capital expenditures during the historic four years (2016 to 2019) amount to an average annual capital expenditure of $ $474,093. The proposed expenditure for the forecasted Test Year, thus, represents an increase of 3.0% from the average annual capital expenditure during the historic four year period (2016 to 2019).

(c) Capital Projects

Table 2-35 below provides a summary of all capital projects for the years 2017 through to the 2020 Bridge Year and 2021 Test Year, which is consistent with Board Appendix 2-AA and is included in Appendix 2-D of this Exhibit. All projects above ERHDC's materiality threshold of $50,000 have been listed with breakdown of account detail. Projects below materiality have been listed under Miscellaneous with no detail.

Table 2 - 35: Capital Project Table

Projects	2017	2018	2019	2020 Bridge Year	2021 Test Year
Reporting Basis					
Pole Replacements					
Distribution Stations					
Poles, Towers, Fixtures	64,088	96,375	190,196	53,717	75,615
O/H Conductors & Devices		3,634	28,677		
Underground Conduit					
U/G Conductors & Devices			6,548		
Line Transformers					
Services - New		158			
Meters					
Sub-Total	64,088	100,167	225,421	53,717	75,615
OH Cutout Renewal	3,689	9,037	4,663		9,547
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices				52,781	
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					
Services - New					
Meters					
Sub-Total	3,689	9,037	4,663	52,781	9,547
Spnaish River Drive			3,706		
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices					
Underground Conduit				76,572	
U/G Conductors & Devices				76,572	
Line Transformers				27,024	
Services - New				45,042	
Meters					
Sub-Total	0	0	3,706	225,210	0
Massey 3 Phase Line Replacement					
Distribution Stations					
Poles, Towers, Fixtures					42,984
O/H Conductors & Devices					42,984
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					15,170
Services - New					25,285
Meters					
Sub-Total	0	0	0	0	126,423
Duplessis road pole Line rebuild					
Distribution Stations					
Poles, Towers, Fixtures				55,038	
O/H Conductors & Devices					
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					
Services - New					
Meters					
Sub-Total	0	0	0	55,038	0
Cross Lot Relocations	39,070			48,038	
Distribution Stations					
Poles, Towers, Fixtures		38,491	42,827		
O/H Conductors & Devices		38,163	34,130		
Underground Conduit		0			
U/G Conductors & Devices		141	4,807		
Line Transformers		2,737			
Services - New					
Meters					
Sub-Total	39,070	79,532	81,764	48,038	0
Double Bucket Truck					
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices					
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					
Services - New					
Meters					
Vehicles			70,339		
Sub-Total	0	0	70,339	0	0

Replace Submarine Cable					
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices					
Underground Conduit					
U/G Conductors & Devices	61,733	184,153			
Line Transformers					
Services - New					
Meters					
Sub-Total	61,733	184,153	0	0	0
Conductor Replacements - Tie Feeders F3-F5					
Distribution Stations					
Poles, Towers, Fixtures	39,389				
O/H Conductors & Devices	128,691				
Underground Conduit	0				
U/G Conductors & Devices	5,056				
Line Transformers	3,367				
Services - New	0				
Meters	0				
Sub-Total	176,503	0	0	0	0
Conductor Replacements - Tie Feeders F1-F8					
Distribution Stations					
Poles, Towers, Fixtures	4,782				
O/H Conductors & Devices	77,844				
Underground Conduit	0				
U/G Conductors & Devices	13,878				
Line Transformers	0				
Services - New	0				
Meters	0				
Sub-Total	96,504	0	0	0	0
Long Term Load Transfer					
Distribution Stations	55,212				
Poles, Towers, Fixtures	77,380				
O/H Conductors & Devices	0				
Underground Conduit	0				
U/G Conductors & Devices	26,666				
Line Transformers	2,404				
Services - New					
Meters					
Sub-Total	161,662	0	0	0	0
Miscellaneous					
Misc. Facilities				35,000	25,000
Tools and Equipment			7,166	8,000	8,000
IT Equipment			7,759	15,000	
New & Upgrade Services	16,460	37,030	18,643	35,595	25,027
Sacred Heart School Service	661	111	18,028		
Joint Use Poles			0	2,521	2,656
City Projects - line relocations			0	11,845	7,762
Meters	3,024		0	32,372	16,419
MIST Meters				37,900	
OH Transformer Renewal	18,468	16,612	21,996	28,793	40,654
Clearlake					41,821
Brentwood Subdivision			1,459	27,821	
OH Forced Outages				5,905	5,587
Kbar Replacement				23,793	12,268
Transclosure Replacement					38,795
UG Forced Outages		3,536		3,161	2,925
MS 3 Conductor Replacement				2,000	46,318
Substation Misc. Projects				3,940	3,612
4kV Feeder at MS 2	6,813				
Miscellaneous Subtotal	45,426	57,289	75,051	273,646	276,844
Total	**648,675**	**430,179**	**460,944**	**708,430**	**488,429**

(d) Non-Distribution Activities

ERHDC has excluded non-distribution activities in its capital expenditures, as such, no reconciliation is required.

(e) Transmitter Capital Contributions

ERHDC has not made any transmitter capital contributions.

2.2.2.3 POLICY OPTIONS FOR THE FUNDING OF CAPITAL

On September 18, 2014, the Board released the *"Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*" and in it provided the option of a funding mechanism that would enable review during a cost of service application for the need and prudence of any incremental capital module funding requests for discrete projects that are part of a distributor's Distribution System Plan, and that are planned to come into service during the IRM period (the Advanced Capital Module or "ACM").

ERHDC has filed a one-year Distribution System Plan that only covers the 2021 forward test year. ERHDC does not foresee the need for an ACM/ICM in this application.

2.2.2.4 ADDITIONS OF PREVIOUSLY APPROVED ACM AND ICM ASSETS TO RATE BASE

As mentioned above in Section 2.2.1.2(c) ERHDC applied for and received an ICM adjustment as part of its 2014 IRM application (EB-2013-0127). An explanation of the variance between actual capital spending and the OEB-approved amount for the ICM is provided in Section 2.2.1.2(c).

Table 2 - 36 below sets out the revenue collected from 2014 to 2019 and the projected for the 2020 Bridge Year and the 2021 Test Year compared to the revised revenue requirement calculated above. The Bridge and Test Year projections are based on the proposed weather-normalized load study and the current approved rates. The difference between the recalculated revenue requirement based on the actual cost of Station 4 and revenue the revenue collected and projected to be collected from customers is an under-collection of $11,784.90.

Table 2 - 36: Revenue Collected vs Revenue Requirement

	2014	2015	2016	2017	2018	2019	2020	2021	Total
Collection from Customers	$86,076	$159,676	$154,509	$152,004	$157,479	$157,397	$159,751	$53,250	$1,080,143
Recalculated ICM Revenue Requirement	$87,971	$158,976	$158,976	$158,976	$158,976	$158,976	$158,976	$50,101	$1,091,928
Over (Under) recovered	-$1,895	$700	-$4,467	-$6,972	-$1,497	-$1,579	$775	$3,149	-$11,785

ERHDC is not requesting disposition of $11,784.90 (recoverable) as the amount is not material. ERHDC will forgo recovery of this amount from customers.

ERHDC is requesting approval from the Board to move the Incremental Capital Expenditures currently recorded in Account 1508 to its capital assets as of the date of the approved rate order using the net book value of these assets at December 31, 2020.

As set out in Table 2-37, the following is recorded in Account 1508 as of December 31, 2019 and has been included in the fixed asset continuity schedule as a 2020 addition with the corresponding accumulated depreciation:

Table 2 - 37 – Amounts recorded in Account 1508 as of December 31, 2019

1508 Other Regulatory Assets, Sub-account Incremental Expenditures Rate Riders Revenues	($884,497.84)
1508 Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues, Carrying Charges	($23,326.89)
1508 Other Regulatory Assets, Sub-account Incremental Capital Expenditures	$1,949,234.64
1508 Other Regulatory Assets, Sub-account Incremental Capital Expenditures, Carrying Charges	$150,677.25
1508 Other Regulatory Assets, Sub-account Depreciation Expense	$240,507.00
1508 Other Regulatory Assets, Sub-account Accumulated Depreciation	($240,507.00)

Table 2-36 provides the recalculation of the revenue requirement based on actual expenditures for the distribution substation. ERHDC confirms that accelerated CCA was not used.

As shown in Table 2-19 and the accompanied explanation, the amount of $1,695,956 has been added to rate base in 2020 so that it forms part of opening rate base in 2021.

2.2.2.5 CAPITALIZATION POLICY

ERHDC follows International Financial Reporting Standards as well as the guidelines as set out in the OEB Accounting Procedure Handbook. ERHDC has not changed its capitalization policy since its last rebasing in 2012.

A capital expenditure is defined as any significant expenditure incurred to acquire or improve land, buildings, plant, engineering structures, machinery and equipment used in providing services to customers. Improvement or "betterment" includes increasing capacity, reliability, efficiency or economy of operation or extending the useful life of a previous capital expenditure. It includes electric plant, vehicles, office furniture, computer equipment and other equipment. A capital expenditure normally provides a benefit lasting beyond one year and results in the acquisition of or extends the life of a fixed asset.

Expenditures for repairs and/or maintenance designed to maintain an asset in its original state is not a capital expenditure but should be charged to an operating account. These definitions and accounting treatment are summarized below in Table 2-38:

Table 2 - 38 – Capital and Operating Expenditure Table

	Definition	Accounting Treatment
Capital Expenditure	An expenditure to acquire or add to a capital asset – an expenditure yielding enduring benefits	Capitalize if above the materiality limit
Improvement	An expenditure made for the purpose of enhancing a fixed asset and which is an addition to the cost of the asset	Capitalize if above the materiality limit
Maintenance	The cost of keeping a property in efficient working condition	Current operations expense
Repair	The cost of replacement of parts or other restoration of plant and machinery, designed to restore normal working efficiency	Current operations expense

The following (Table 2-39) are materiality limits for the listed category of assets. Items with a cost less than the materiality levels as listed below should be charged to operations whether they are of a capital nature or of a repairs/maintenance nature.

Table 2 - 39 –Materiality Limits

Account #	Description	Limit
1705, 1805, 1905	Land	All
1706, 1806, 1906	Land Right	$1,000
1708, 1808, 1908	Buildings	$1,000
1715, 1815	Transformer Station Equipment	$1,000
1820, 1825	Distribution Station Equipment	$1,000
1720, 1725, 1830	Poles, Towers and Fixtures	$1,000
1730, 1835	Lines & Feeders – O/H	$1,000
1735, 1840	Conduit – U/G	$1,000
1740, 1845	Lines & Feeders – U/G	$1,000
1850	Distribution Transformers	$1,000
1850	Distribution Transformers	$1,000
1855	Services	All
90	Meters	All
1915	General Office Equipment	$1,000
1920, 1925	Computer Equipment	$1,000
1935	Stores Warehouse Equipment	$1,000
1930	Rolling Stock	$1,000

1940, 1945	Miscellaneous Equipment	$1,000
1955	Communication Equipment	$1,000
1980	System Supervisory Equipment	$1,000

2.2.2.6 CAPITALIZATION OF OVERHEAD

As noted above, PP&E is recorded at cost – including purchase price, costs to bring the asset to the location and condition necessary to operate, etc. One of the costs explicitly prohibited from being included in the cost of an asset under IFRS is "administrative and other general overhead costs".

ERHDC currently includes the following in PP&E costs: direct labour, direct material from inventory or from a third party vendor, and vehicle costs used to bring the asset to the location and condition necessary to operate. Direct labour costs are based on an hourly rate and the number of hours that an employee works on a specific project. Also, included in direct labour costs are health benefits, CPP, and EI. These costs are allocated to capital and period expenses based on the percentage of total labour dollars directly charged to each. Material from inventory or from a third party is charged directly to the asset that the material is used for. Vehicles are charged to a specific job based on an hourly rate and the number of hours the vehicle is used on the job. The hourly vehicle rate is estimated annually and "trued-up" at year end to account for actual costs. As outlined in Appendix 2-E – Board Appendix 2-D Overhead Expense, ERHDC charges a portion of the Lines Supervisor's time to capital projects in the same proportion as the line crew charges time to the capital projects.

ERHDC will continue to capitalize costs that are directly attributable to bringing the asset to the location and condition necessary to operate. These costs include the direct labour with an allocation for health benefits, CPP and EI, material costs, and vehicle costs. ERHDC will not capitalize any administrative or general overheard costs.

2.2.2.7 COST OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFING GENERATION FACILITIES

ERHDC has not identified any material eligible investments for which rate protection is required. Please see Board Appendices 2-FA through 2-FC which indicate there are no eligible investments for recovery.

2.2.2.8 SERVICE QUALITY

ERHDC follows the Board's Reporting and Record Keeping Requirements Guideline to report its Service Quality Indicators annually. In accordance with the Filing Requirements, Table 2-40 is provided below which is consistent with the Board Appendix 2-G, Service Quality Indicators and is included as Appendix 2-F to this Exhibit. Appendix 2-F is consistent with ERHDC's 2019 Scorecard. The table provides the performance measures for the last five historical years 2015 through 2019. Also included below in Table 2-40 is a summary of ERHDC's Major Events between 2015 and 2019 as reported in the Reporting and Record Keeping Requirements (RRR).

Table 2 - 40: Service Reliability and Quality Indicators

Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
SAIDI	0.900	10.430	9.480	0.280	0.540	0.280	2.130	0.350	0.160	0.350	0.280	0.550	0.350	0.160	0.350
SAIFI	0.180	4.620	4.790	0.070	0.260	0.030	1.890	0.100	0.060	0.170	0.030	1.100	0.100	0.060	0.170

5 Year Historical Average

	Including outages caused by loss of supply	Excluding outages caused by loss of supply	Excluding Major Event Days
SAIDI	4.326	0.654	0.338
SAIFI	1.984	0.450	0.292

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2015	2016	2017	2018	2019
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	n/a	n/a	100.0%	100.0%	100.0%
Telephone Accessibility	65.0%	76.1%	76.2%	72.6%	70.7%	63.0%
Appointments Met	90.0%	100.0%	100.0%	98.2%	100.0%	98.6%
Written Response to Enquires	80.0%	96.2%	98.0%	90.4%	97.0%	100.0%
Emergency Urban Response	80.0%	100.0%	n/a	100.0%	100.0%	n/a
Emergency Rural Response	80.0%	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	10.0%	3.5%	4.0%	4.7%	7.2%	8.4%
Appointment Scheduling	90.0%	98.0%	97.1%	97.9%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	n/a	100.0%	100.0%	n/a	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

ERHDC met all the Service Quality targets in the table for the period 2015 to 2019 except for the 2019 Telephone Calls Answered on Time. The main contributing factor to the missed target was staff turnover which resulted in new staff having longer average talk times with customers. The extra time on the phones with customers then lead to calls waiting in the queue. ERHDC has a fully trained team in place and has seen significant improvement for 2020. ERHDC will continue to monitor this performance measure to identify opportunities for improvement.

In the Service Quality table, for any indicators where there were no activities occurring in that category it is listed as “N/A”.

Further performance discussions regarding Service Quality Indicators can be found in Exhibit 1.

ERHDC has completed Board Appendix 2-BB – Service Life Comparison and has attached a copy at Appendix 2-G of this Exhibit.

APPENDIX 2-A
Fixed Asset Continuity Schedules

Board Appendix 2-BA

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2021

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Adjustment Sub 4 ICM	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Adjustment Sub 4 ICM	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -				$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 55,256				$ 55,256	$ 6,802				$ 6,802	$ 48,454
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 88,881				$ 88,881	$ -				$ -	$ 88,881
47	1808	Buildings	$ 389,801	$ 25,000			$ 414,801	$ 203,474	$ 5,772			$ 209,246	$ 205,555
13	1810	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 2,185,331	$ 3,612			$ 2,188,943	$ 580,618	$ 3,643	$ 33,804		$ 618,065	$ 1,570,878
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,633,597	$ 175,195			$ 3,808,792	$ 1,679,801	$ 56,478	$ 5,592		$ 1,741,871	$ 2,066,921
47	1835	Overhead Conductors & Devices	$ 2,494,971	$ 100,079			$ 2,595,050	$ 957,663	$ 30,176			$ 987,839	$ 1,607,211
47	1840	Underground Conduit	$ 786,919				$ 786,919	$ 629,537	$ 5,538			$ 635,075	$ 151,844
47	1845	Underground Conductors & Devices	$ 540,772	$ 53,666			$ 594,438	$ 79,212	$ 14,329			$ 93,541	$ 500,897
47	1850	Line Transformers	$ 1,143,945	$ 56,146			$ 1,200,091	$ 734,932	$ 13,161			$ 748,093	$ 451,998
47	1855	Services (Overhead & Underground)	$ 441,209	$ 50,312			$ 491,521	$ 88,957	$ 8,507			$ 97,464	$ 394,057
47	1860	Meters	$ 808,427	$ 16,419			$ 824,846	$ 575,683	$ 57,225			$ 632,908	$ 191,938
47	1860	Meters (Smart Meters)	$ -				$ -	$ -				$ -	$ -
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 64,000				$ 64,000	$ 64,000				$ 64,000	-$ 0
10	1920	Computer Equipment - Hardware	$ 169,241	$ 8,000			$ 177,241	$ 198,535	$ 3,000			$ 201,535	-$ 24,294
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 443,607				$ 443,607	$ 218,374	$ 27,280			$ 245,653	$ 197,953
8	1935	Stores Equipment	$ 10,538				$ 10,538	$ 10,538				$ 10,538	$ -
8	1940	Tools, Shop & Garage Equipment	$ 169,791				$ 169,791	$ 153,097	$ 4,146			$ 157,243	$ 12,548
8	1945	Measurement & Testing Equipment	$ 11,948				$ 11,948	$ 10,564	$ 346			$ 10,910	$ 1,038
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 19,257				$ 19,257	$ 19,256				$ 19,256	$ 1
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -				$ -	$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -				$ -	$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -				$ -	$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -				$ -	$ -				$ -	$ -
47	1990	Other Tangible Property	$ 10,121				$ 10,121	$ 10,121				$ 10,121	$ -
47	1995	Contributions & Grants	$ -				$ -	$ -				$ -	$ -
47	2440	Deferred Revenue [5]	-$ 550,375	-$ 25,000			-$ 575,375	-$ 152,307	-$ 12,328			-$ 164,635	-$ 410,740
	2005	Property Under Finance Lease [7]	0				$ -	0				$ -	$ -
		Sub-Total	**$ 12,917,237**	**$ 463,429**			**$ 13,380,666**	**$ 6,068,856**	**$ 217,273**	**$ 39,396**	**$ -**	**$ 6,325,525**	**$ 7,055,141**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 12,917,237**	**$ 463,429**		**$ -**	**$ 13,380,666**	**$ 6,068,856**	**$ 217,273**	**$ 39,396**	**$ -**	**$ 6,325,525**	**$ 7,055,141**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]											
		Total							**$ 217,273**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 27,280
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 189,993

Accounting Standard	MIFRS
Year	**2020**

			Cost					Accumulated Depreciation					
CCA Class [2]	**OEB Account** [3]	**Description** [3]	**Opening Balance**	**Additions** [4]	**Adjustment Sub 4 ICM**	**Disposals** [6]	**Closing Balance**	**Opening Balance**	**Additions**	**Adjustment Sub 4 ICM**	**Disposals** [6]	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -				$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 45,256	$ 10,000			$ 55,256	$ 6,802				$ 6,802	$ 48,454
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 88,881				$ 88,881	$ -				$ -	$ 88,881
47	1808	Buildings	$ 354,801	35,000			$ 389,801	$ 198,202	5,272			$ 203,474	$ 186,327
13	1810	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 489,375	5,920	1,690,036		$ 2,185,331	$ 341,814	37,374	201,430		$ 580,618	$ 1,604,713
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,230,230	144,169	259,198		$ 3,633,597	$ 1,583,034	57,690	39,077		$ 1,679,801	$ 1,953,796
47	1835	Overhead Conductors & Devices	$ 2,409,296	85,675			$ 2,494,971	$ 929,155	28,508			$ 957,663	$ 1,537,308
47	1840	Underground Conduit	$ 710,347	76,572			$ 786,919	$ 623,999	5,538			$ 629,537	$ 157,382
47	1845	Underground Conductors & Devices	$ 409,426	131,346			$ 540,772	$ 66,225	12,988			$ 79,212	$ 461,560
47	1850	Line Transformers	$ 1,087,720	56,225			$ 1,143,945	$ 723,174	11,758			$ 734,932	$ 409,013
47	1855	Services (Overhead & Underground)	$ 360,572	80,637			$ 441,209	$ 81,708	7,249			$ 88,957	$ 352,252
47	1860	Meters	$ 738,154	70,273			$ 808,427	$ 519,552	56,131			$ 575,683	$ 232,744
47	1860	Meters (Smart Meters)	$ -				$ -	$ -				$ -	$ -
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 64,000				$ 64,000	$ 64,000				$ 64,000	-$ 0
10	1920	Computer Equipment - Hardware	$ 164,241	5,000			$ 169,241	$ 195,535	3,000			$ 198,535	-$ 29,294
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 443,607				$ 443,607	$ 191,094	27,280			$ 218,374	$ 225,233
8	1935	Stores Equipment	$ 10,538				$ 10,538	$ 10,538				$ 10,538	$ -
8	1940	Tools, Shop & Garage Equipment	$ 161,791	8,000			$ 169,791	$ 149,751	3,346			$ 153,097	$ 16,694
8	1945	Measurement & Testing Equipment	$ 11,948				$ 11,948	$ 10,218	346			$ 10,564	$ 1,384
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 19,257				$ 19,257	$ 19,256				$ 19,256	$ 1
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -				$ -	$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -				$ -	$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -				$ -	$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 10,121				$ 10,121	$ 10,121				$ 10,121	$ -
47	1990	Other Tangible Property	$ -				$ -	$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 486,545	(63,830)			-$ 550,375	-$ 140,604	(11,703)			-$ 152,307	-$ 398,068
47	2440	Deferred Revenue[5]	$ -				$ -	$ -				$ -	$ -
	2005	Property Under Finance Lease[7]	$ -				$ -	$ -				$ -	$ -
		Sub-Total	**$ 10,323,016**	**$ 644,987**		**$ -**	**$ 12,917,237**	**$ 5,583,572**	**$ 244,777**		**$ -**	**$ 6,068,856**	**$ 6,848,381**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 10,323,016**	**$ 644,987**		**$ -**	**$ 12,917,237**	**$ 5,583,572**	**$ 244,777**		**$ -**	**$ 6,068,856**	**$ 6,848,381**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**$ 244,777**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 27,280
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 217,497

Accounting Standard MIFRS
Year **2019**

			Cost					Accumulated Depreciation					
CCA Class [2]	**OEB Account** [3]	**Description** [3]	**Opening Balance**	**Additions** [4]		**Disposals** [6]	**Closing Balance**	**Opening Balance**	**Additions**		**Disposals** [6]	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -				$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 45,256				$ 45,256	$ 6,702	100			$ 6,802	$ 38,454
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 88,881				$ 88,881	$ -				$ -	$ 88,881
47	1808	Buildings	$ 354,801				$ 354,801	$ 193,630	4,572			$ 198,202	$ 156,599
13	1810	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 489,375				$ 489,375	$ 338,362	3,452			$ 341,814	$ 147,561
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,012,094	218,136			$ 3,230,230	$ 1,534,238	48,796			$ 1,583,034	$ 1,647,196
47	1835	Overhead Conductors & Devices	$ 2,347,420	61,876			$ 2,409,296	$ 902,070	27,085			$ 929,155	$ 1,480,141
47	1840	Underground Conduit	$ 710,347				$ 710,347	$ 620,375	3,624			$ 623,999	$ 86,348
47	1845	Underground Conductors & Devices	$ 393,051	16,375			$ 409,426	$ 56,537	9,688			$ 66,225	$ 343,201
47	1850	Line Transformers	$ 1,029,706	58,014			$ 1,087,720	$ 712,681	10,494			$ 723,174	$ 364,546
47	1855	Services (Overhead & Underground)	$ 347,860	12,712			$ 360,572	$ 76,452	5,256			$ 81,708	$ 278,864
47	1860	Meters	$ 738,036	119			$ 738,154	$ 467,667	51,885			$ 519,552	$ 218,602
47	1860	Meters (Smart Meters)	$ -				$ -	$ -				$ -	$ -
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 64,000				$ 64,000	$ 64,000				$ 64,000	-$ 0
10	1920	Computer Equipment - Hardware	$ 156,482	7,759			$ 164,241	$ 193,747	1,788			$ 195,535	-$ 31,294
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 641,705	70,339		(268,437)	$ 443,607	$ 432,251	27,280		-$ 268,437	$ 191,094	$ 252,513
8	1935	Stores Equipment	$ 10,538				$ 10,538	$ 10,538				$ 10,538	$ -
8	1940	Tools, Shop & Garage Equipment	$ 154,625	7,166			$ 161,791	$ 147,972	1,779			$ 149,751	$ 12,040
8	1945	Measurement & Testing Equipment	$ 11,948				$ 11,948	$ 9,872	346			$ 10,218	$ 1,730
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 19,257				$ 19,257	$ 19,256				$ 19,256	$ 1
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -				$ -	$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -				$ -	$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -				$ -	$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 10,121				$ 10,121	$ 10,121				$ 10,121	$ -
47	1990	Other Tangible Property	$ -				$ -	$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 447,255	(39,290)			-$ 486,545	-$ 130,497	(10,107)			-$ 140,604	-$ 345,941
47	2440	Deferred Revenue[5]	$ -				$ -	$ -				$ -	$ -
	2005	Property Under Finance Lease[7]	$ -				$ -	$ -				$ -	$ -
		Sub-Total	**$ 10,178,247**	**$ 413,205**		**-$ 268,437**	**$ 10,323,016**	**$ 5,665,973**	**$ 186,036**		**-$ 268,437**	**$ 5,583,572**	**$ 4,739,444**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 10,178,247**	**$ 413,205**		**-$ 268,437**	**$ 10,323,016**	**$ 5,665,973**	**$ 186,036**		**-$ 268,437**	**$ 5,583,572**	**$ 4,739,444**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**$ 186,036**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 27,280
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 158,756

Accounting Standard	MIFRS
Year	**2018**

			Cost					**Accumulated Depreciation**					
CCA Class [2]	**OEB Account** [3]	**Description** [3]	**Opening Balance**	**Additions** [4]		**Disposals** [6]	**Closing Balance**	**Opening Balance**	**Additions**		**Disposals** [6]	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -				$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 45,256				$ 45,256	$ 6,702				$ 6,702	$ 38,554
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 88,881				$ 88,881	$ -				$ -	$ 88,881
47	1808	Buildings	$ 354,801				$ 354,801	$ 189,058	4,572			$ 193,630	$ 161,171
13	1810	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 489,375				$ 489,375	$ 334,912	3,450			$ 338,362	$ 151,013
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,854,431	157,664			$ 3,012,094	$ 1,489,990	44,248			$ 1,534,238	$ 1,477,856
47	1835	Overhead Conductors & Devices	$ 2,290,471	56,950			$ 2,347,420	$ 875,998	26,072			$ 902,070	$ 1,445,351
47	1840	Underground Conduit	$ 710,347				$ 710,347	$ 616,745	3,630			$ 620,375	$ 89,972
47	1845	Underground Conductors & Devices	$ 164,846	228,205			$ 393,051	$ 47,237	9,300			$ 56,537	$ 336,514
47	1850	Line Transformers	$ 1,009,803	19,903			$ 1,029,706	$ 703,210	9,471			$ 712,681	$ 317,026
47	1855	Services (Overhead & Underground)	$ 333,678	14,182			$ 347,860	$ 71,343	5,109			$ 76,452	$ 271,408
47	1860	Meters	$ 737,156	879			$ 738,036	$ 415,784	51,883			$ 467,667	$ 270,368
47	1860	Meters (Smart Meters)	$ -				$ -	$ -				$ -	$ -
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 64,000				$ 64,000	$ 64,000				$ 64,000	-$ 0
10	1920	Computer Equipment - Hardware	$ 154,862	1,620			$ 156,482	$ 193,212	535			$ 193,747	-$ 37,265
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 641,705				$ 641,705	$ 409,659	22,592			$ 432,251	$ 209,454
8	1935	Stores Equipment	$ 10,538				$ 10,538	$ 10,538				$ 10,538	$ -
8	1940	Tools, Shop & Garage Equipment	$ 154,625				$ 154,625	$ 145,264	2,707			$ 147,972	$ 6,653
8	1945	Measurement & Testing Equipment	$ 11,948				$ 11,948	$ 9,526	346			$ 9,872	$ 2,076
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 19,257				$ 19,257	$ 19,256				$ 19,256	$ 1
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -				$ -	$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -				$ -	$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -				$ -	$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 10,121				$ 10,121	$ 10,121				$ 10,121	$ -
47	1990	Other Tangible Property	$ -				$ -	$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 406,986	(40,269)			-$ 447,255	-$ 120,602	(9,895)			-$ 130,497	-$ 316,758
47	2440	Deferred Revenue[5]	$ -				$ -	$ -				$ -	$ -
	2005	Property Under Finance Lease[7]	$ -				$ -	$ -				$ -	$ -
		Sub-Total	**$ 9,739,114**	**$ 439,133**		**$ -**	**$ 10,178,247**	**$ 5,491,953**	**$ 174,020**		**$ -**	**$ 5,665,973**	**$ 4,512,274**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 9,739,114**	**$ 439,133**		**$ -**	**$ 10,178,247**	**$ 5,491,953**	**$ 174,020**		**$ -**	**$ 5,665,973**	**$ 4,512,274**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**$ 174,020**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 22,592
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 151,428

Accounting Standard	MIFRS
Year	**2017**

			Cost					Accumulated Depreciation					
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**		**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**		**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -				$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 45,256				$ 45,256	$ 6,702				$ 6,702	$ 38,554
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 88,881				$ 88,881	$ -				$ -	$ 88,881
47	1808	Buildings	$ 354,801				$ 354,801	$ 184,486	4,572			$ 189,058	$ 165,743
13	1810	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 489,375				$ 489,375	$ 331,462	3,450			$ 334,912	$ 154,463
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,669,814	184,617			$ 2,854,431	$ 1,449,953	42,468		(2,431)	$ 1,489,990	$ 1,364,441
47	1835	Overhead Conductors & Devices	$ 1,963,232	327,238			$ 2,290,471	$ 858,349	25,989		(8,340)	$ 875,998	$ 1,414,473
47	1840	Underground Conduit	$ 710,347				$ 710,347	$ 613,121	3,624			$ 616,745	$ 93,602
47	1845	Underground Conductors & Devices	$ 138,678	26,168			$ 164,846	$ 43,659	3,578			$ 47,237	$ 117,609
47	1850	Line Transformers	$ 999,038	48,325		(37,560)	$ 1,009,803	$ 713,018	8,973		(18,781)	$ 703,210	$ 306,594
47	1855	Services (Overhead & Underground)	$ 318,185	15,693		(200)	$ 333,678	$ 66,543	4,920		(120)	$ 71,343	$ 262,335
47	1860	Meters	$ 721,330	15,827			$ 737,156	$ 363,960	51,825			$ 415,784	$ 321,372
47	1860	Meters (Smart Meters)	$ -				$ -	$ -				$ -	$ -
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 64,000				$ 64,000	$ 64,000				$ 64,000	-$ 0
10	1920	Computer Equipment - Hardware	$ 154,862				$ 154,862	$ 192,659	553			$ 193,212	-$ 38,350
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 641,705				$ 641,705	$ 387,067	22,592			$ 409,659	$ 232,046
8	1935	Stores Equipment	$ 10,538				$ 10,538	$ 10,538				$ 10,538	$ -
8	1940	Tools, Shop & Garage Equipment	$ 154,625				$ 154,625	$ 142,557	2,707			$ 145,264	$ 9,361
8	1945	Measurement & Testing Equipment	$ 11,948				$ 11,948	$ 9,180	346			$ 9,526	$ 2,422
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 19,257				$ 19,257	$ 19,256				$ 19,256	$ 1
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -				$ -	$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -				$ -	$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -				$ -	$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 10,121				$ 10,121	$ 10,121				$ 10,121	$ -
47	1990	Other Tangible Property	$ -				$ -	$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 403,693	(3,293)			-$ 406,986	-$ 112,499	(8,103)			-$ 120,602	-$ 286,384
47	2440	Deferred Revenue[5]	$ -				$ -	$ -				$ -	$ -
	2005	Property Under Finance Lease[7]	$ -				$ -	$ -				$ -	$ -
		Sub-Total	**$ 9,162,298**	**$ 614,576**		**-$ 37,760**	**$ 9,739,114**	**$ 5,354,132**	**$ 167,493**		**-$ 29,672**	**$ 5,491,953**	**$ 4,247,161**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 9,162,298**	**$ 614,576**		**-$ 37,760**	**$ 9,739,114**	**$ 5,354,132**	**$ 167,493**		**-$ 29,672**	**$ 5,491,953**	**$ 4,247,161**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**$ 167,493**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 22,592
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 144,901

Accounting Standard	MIFRS
Year	**2016**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]		Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions		Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -				$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 45,256				$ 45,256	$ 6,702				$ 6,702	$ 38,554
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 88,881				$ 88,881	$ -				$ -	$ 88,881
47	1808	Buildings	$ 351,783	3,019			$ 354,801	$ 179,914	4,572			$ 184,486	$ 170,315
13	1810	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 489,375				$ 489,375	$ 328,012	3,450			$ 331,462	$ 157,913
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,562,749	107,065			$ 2,669,814	$ 1,414,101	35,852			$ 1,449,953	$ 1,219,861
47	1835	Overhead Conductors & Devices	$ 1,768,504	194,728			$ 1,963,232	$ 838,441	19,908			$ 858,349	$ 1,104,884
47	1840	Underground Conduit	$ 710,347				$ 710,347	$ 609,497	3,624			$ 613,121	$ 97,226
47	1845	Underground Conductors & Devices	$ 125,040	13,637			$ 138,678	$ 40,735	2,924			$ 43,659	$ 95,019
47	1850	Line Transformers	$ 970,273	28,765			$ 999,038	$ 704,001	9,017			$ 713,018	$ 286,020
47	1855	Services (Overhead & Underground)	$ 290,773	27,411			$ 318,185	$ 61,985	4,558			$ 66,543	$ 251,642
47	1860	Meters	$ 717,826	3,504			$ 721,330	$ 313,184	50,776			$ 363,960	$ 357,370
47	1860	Meters (Smart Meters)	$ -				$ -	$ -				$ -	$ -
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 64,000				$ 64,000	$ 64,000				$ 64,000	-$ 0
10	1920	Computer Equipment - Hardware	$ 154,862				$ 154,862	$ 192,106	553			$ 192,659	-$ 37,798
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 598,088	43,617			$ 641,705	$ 364,475	22,592			$ 387,067	$ 254,638
8	1935	Stores Equipment	$ 10,538				$ 10,538	$ 10,538				$ 10,538	$ -
8	1940	Tools, Shop & Garage Equipment	$ 149,967	4,658			$ 154,625	$ 139,848	2,708			$ 142,557	$ 12,068
8	1945	Measurement & Testing Equipment	$ 11,948				$ 11,948	$ 8,728	452			$ 9,180	$ 2,768
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 19,257				$ 19,257	$ 19,257	(1)			$ 19,256	$ 1
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -				$ -	$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -				$ -	$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -				$ -	$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 10,121				$ 10,121	$ 10,121				$ 10,121	$ -
47	1990	Other Tangible Property	$ -				$ -	$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 356,361	(47,332)			-$ 403,693	-$ 103,764	(8,735)			-$ 112,499	-$ 291,194
47	2440	Deferred Revenue [5]	$ -				$ -	$ -				$ -	$ -
	2005	Property Under Finance Lease [7]	$ -				$ -	$ -				$ -	$ -
		Sub-Total	**$ 8,783,227**	**$ 379,071**		**$ -**	**$ 9,162,298**	**$ 5,201,881**	**$ 152,251**		**$ -**	**$ 5,354,132**	**$ 3,808,167**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 8,783,227**	**$ 379,071**		**$ -**	**$ 9,162,298**	**$ 5,201,881**	**$ 152,251**		**$ -**	**$ 5,354,132**	**$ 3,808,167**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]											
		Total							**$ 152,251**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 22,592
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 129,659

Accounting Standard	MIFRS
Year	**2015**

			Cost					Accumulated Depreciation					
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Adjustments**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**		**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -				$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 45,256				$ 45,256	$ 6,352	350			$ 6,702	$ 38,554
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 88,881				$ 88,881	$ -				$ -	$ 88,881
47	1808	Buildings	$ 347,854	3,929			$ 351,783	$ 175,402	$ 4,512			$ 179,914	$ 171,869
13	1810	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 489,375				$ 489,375	$ 324,561	3,450		$ 1	$ 328,012	$ 161,363
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,564,879	150,342	152,472		$ 2,562,749	$ 1,388,553	36,984		(11,436)	$ 1,414,101	$ 1,148,648
47	1835	Overhead Conductors & Devices	$ 1,568,813	304,465	104,774		$ 1,768,504	$ 825,214	18,372		(5,145)	$ 838,441	$ 930,063
47	1840	Underground Conduit	$ 707,562	2,785			$ 710,347	$ 605,873	3,624			$ 609,497	$ 100,850
47	1845	Underground Conductors & Devices	$ 117,889	7,152			$ 125,040	$ 38,152	2,583			$ 40,735	$ 84,305
47	1850	Line Transformers	$ 950,593	19,680			$ 970,273	$ 695,647	8,354			$ 704,001	$ 266,272
47	1855	Services (Overhead & Underground)	$ 284,077	8,648	1,952		$ 290,773	$ 57,884	4,200		(99)	$ 61,985	$ 228,788
47	1860	Meters	$ 715,075	2,751			$ 717,826	$ 262,649	50,535			$ 313,184	$ 404,642
47	1860	Meters (Smart Meters)	$ -				$ -	$ -				$ -	$ -
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 64,000				$ 64,000	$ 64,038	(38)			$ 64,000	-$ 0
10	1920	Computer Equipment - Hardware	$ 154,862				$ 154,862	$ 191,552	553		$ 1	$ 192,106	-$ 37,245
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 610,116			(12,028)	$ 598,088	$ 349,837	22,337		-$ 7,699	$ 364,475	$ 233,613
8	1935	Stores Equipment	$ 10,538				$ 10,538	$ 8,999	1,539			$ 10,538	$ -
8	1940	Tools, Shop & Garage Equipment	$ 149,967				$ 149,967	$ 137,500	2,348			$ 139,848	$ 10,119
8	1945	Measurement & Testing Equipment	$ 8,484	3,464			$ 11,948	$ 8,330	398			$ 8,728	$ 3,220
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 19,257				$ 19,257	$ 18,013	1,244			$ 19,257	$ -
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -				$ -	$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -				$ -	$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -				$ -	$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 10,121				$ 10,121	$ 10,121				$ 10,121	$ -
47	1990	Other Tangible Property	$ -				$ -	$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 351,648	(4,714)			-$ 356,361	-$ 95,979			-$ 7,785	-$ 103,764	-$ 252,597
47	2440	Deferred Revenue[5]	$ -				$ -	$ -				$ -	$ -
	2005	Property Under Finance Lease[7]	$ -				$ -	$ -				$ -	$ -
		Sub-Total	**$ 8,555,950**	**$ 498,503**	**$ 259,198**	**-$ 12,028**	**$ 8,783,227**	**$ 5,072,698**	**$ 161,344**		**-$ 32,162**	**$ 5,201,881**	**$ 3,581,346**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*					$ -					$ -	$ -
		Total PP&E	**$ 8,555,950**	**$ 498,503**		**-$ 12,028**	**$ 8,783,227**	**$ 5,072,698**	**$ 161,344**		**-$ 32,162**	**$ 5,201,881**	**$ 3,581,346**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**$ 161,344**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 22,337
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 139,007

1575 IFRS-CGAAP Amortization
To 1508 - Adjustments

Accounting Standard	MIFRS
Year	**2014**

			Cost					**Accumulated Depreciation**					
CCA Class [2]	**OEB Account** [3]	**Description** [3]	**Opening Balance**	**Additions** [4]		**Disposals** [6]	**Closing Balance**	**Opening Balance**	**Additions**		**Disposals** [6]	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -				$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 45,256				$ 45,256	$ 4,000	2,352			$ 6,352	$ 38,904
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 88,881				$ 88,881	$ -				$ -	$ 88,881
47	1808	Buildings	$ 347,854				$ 347,854	$ 170,969	4,433			$ 175,402	$ 172,452
13	1810	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 489,375				$ 489,375	$ 321,111	3,450			$ 324,561	$ 164,814
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,440,704	124,175			$ 2,564,879	$ 1,355,321	33,232			$ 1,388,553	$ 1,176,326
47	1835	Overhead Conductors & Devices	$ 1,447,391	121,422			$ 1,568,813	$ 811,879	13,335			$ 825,214	$ 743,599
47	1840	Underground Conduit	$ 707,562				$ 707,562	$ 602,319	3,554			$ 605,873	$ 101,689
47	1845	Underground Conductors & Devices	$ 117,889				$ 117,889	$ 35,748	2,404			$ 38,152	$ 79,737
47	1850	Line Transformers	$ 941,028	9,565			$ 950,593	$ 687,831	7,816			$ 695,647	$ 254,946
47	1855	Services (Overhead & Underground)	$ 278,205	5,872			$ 284,077	$ 54,436	3,448			$ 57,884	$ 226,193
47	1860	Meters	$ 712,719	2,356			$ 715,075	$ 212,297	50,352			$ 262,649	$ 452,426
47	1860	Meters (Smart Meters)	$ -				$ -	$ -				$ -	$ -
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 64,000				$ 64,000	$ 64,038				$ 64,038	-$ 38
10	1920	Computer Equipment - Hardware	$ 153,799	1,063			$ 154,862	$ 190,545	1,007			$ 191,552	-$ 36,691
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 609,305	811			$ 610,116	$ 326,063	23,774			$ 349,837	$ 260,279
8	1935	Stores Equipment	$ 10,538				$ 10,538	$ 8,999				$ 8,999	$ 1,539
8	1940	Tools, Shop & Garage Equipment	$ 143,110	6,857			$ 149,967	$ 135,154	2,346			$ 137,500	$ 12,467
8	1945	Measurement & Testing Equipment	$ 8,484				$ 8,484	$ 8,278	52			$ 8,330	$ 154
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 19,257				$ 19,257	$ 18,013				$ 18,013	$ 1,244
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -				$ -	$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -				$ -	$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -				$ -	$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 10,121				$ 10,121	$ 10,121				$ 10,121	$ -
47	1990	Other Tangible Property	$ -				$ -	$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 348,351	(3,297)			-$ 351,648	-$ 88,290	(7,689)			-$ 95,979	-$ 255,669
47	2440	Deferred Revenue [5]	$ -				$ -	$ -				$ -	$ -
	2005	Property Under Finance Lease [7]	$ -				$ -	$ -				$ -	$ -
		Sub-Total	**$ 8,287,125**	**$ 268,824**		**$ -**	**$ 8,555,950**	**$ 4,928,832**	**$ 143,866**		**$ -**	**$ 5,072,698**	**$ 3,483,251**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 8,287,125**	**$ 268,824**		**$ -**	**$ 8,555,950**	**$ 4,928,832**	**$ 143,866**		**$ -**	**$ 5,072,698**	**$ 3,483,251**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]											
		Total							**$ 143,866**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 23,774
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 120,092

Accounting Standard	MIFRS
Year	**2013**

			Cost					Accumulated Depreciation					
CCA Class [2]	**OEB Account** [3]	**Description** [3]	**Opening Balance**	**Additions** [4]		**Disposals** [6]	**Closing Balance**	**Opening Balance**	**Additions**		**Disposals** [6]	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -				$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 45,256				$ 45,256	$ -	4,000			$ 4,000	$ 41,256
CEC	1612	Land Rights (Formally known as Account 1906)	$ -				$ -	$ -				$ -	$ -
N/A	1805	Land	$ 88,881				$ 88,881	$ -				$ -	$ 88,881
47	1808	Buildings	$ 342,089	5,765			$ 347,854	$ 166,536	4,433			$ 170,969	$ 176,885
13	1810	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -				$ -	$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 478,757	10,618			$ 489,375	$ 317,661	3,450			$ 321,111	$ 168,264
47	1825	Storage Battery Equipment	$ -				$ -	$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,204,194	236,511			$ 2,440,704	$ 1,325,195	30,126.00			$ 1,355,321	$ 1,085,383
47	1835	Overhead Conductors & Devices	$ 1,311,384	136,007			$ 1,447,391	$ 800,569	11,310.00			$ 811,879	$ 635,512
47	1840	Underground Conduit	$ 697,969	9,593			$ 707,562	$ 598,765	3,554			$ 602,319	$ 105,243
47	1845	Underground Conductors & Devices	$ 113,841	4,048			$ 117,889	$ 33,344	2,404			$ 35,748	$ 82,141
47	1850	Line Transformers	$ 887,911	53,117			$ 941,028	$ 680,264	7,567			$ 687,831	$ 253,197
47	1855	Services (Overhead & Underground)	$ 234,657	43,548			$ 278,205	$ 50,478	3,958			$ 54,436	$ 223,769
47	1860	Meters	$ 711,954	765			$ 712,719	$ 162,102	50,195			$ 212,297	$ 500,422
47	1860	Meters (Smart Meters)	$ -				$ -	$ -				$ -	$ -
N/A	1905	Land	$ -				$ -	$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ -				$ -	$ -				$ -	$ -
13	1910	Leasehold Improvements	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -				$ -	$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 64,000				$ 64,000	$ 65,897	(1,859)			$ 64,038	-$ 38
10	1920	Computer Equipment - Hardware	$ 153,799				$ 153,799	$ 185,544	5,001			$ 190,545	-$ 36,746
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -				$ -	$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -				$ -	$ -				$ -	$ -
10	1930	Transportation Equipment	$ 522,537	229,716		(142,948)	$ 609,305	$ 501,719	(32,580)		(143,076)	$ 326,063	$ 283,242
8	1935	Stores Equipment	$ 10,538				$ 10,538	$ 8,434	565			$ 8,999	$ 1,539
8	1940	Tools, Shop & Garage Equipment	$ 143,108	2			$ 143,110	$ 132,683	2,471			$ 135,154	$ 7,956
8	1945	Measurement & Testing Equipment	$ 8,484				$ 8,484	$ 6,632	1,646			$ 8,278	$ 206
8	1950	Power Operated Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communications Equipment	$ 18,014	1,243			$ 19,257	$ 17,941	72			$ 18,013	$ 1,244
8	1955	Communication Equipment (Smart Meters)	$ -				$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -				$ -	$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -				$ -	$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -				$ -	$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -				$ -	$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 10,121				$ 10,121	$ 10,121				$ 10,121	$ -
47	1990	Other Tangible Property	$ -				$ -	$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 322,802	(25,549)			-$ 348,351	-$ 80,683	(7,607)			-$ 88,290	-$ 260,061
47	2440	Deferred Revenue[5]	$ -				$ -	$ -				$ -	$ -
	2005	Property Under Finance Lease[7]	$ -				$ -	$ -				$ -	$ -
		Sub-Total	**$ 7,724,691**	**$ 705,382**		**-$ 142,948**	**$ 8,287,125**	**$ 4,983,202**	**$ 88,706**		**-$ 143,076**	**$ 4,928,832**	**$ 3,358,293**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 7,724,691**	**$ 705,382**		**-$ 142,948**	**$ 8,287,125**	**$ 4,983,202**	**$ 88,706**		**-$ 143,076**	**$ 4,928,832**	**$ 3,358,293**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**$ 88,706**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 32,580
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 121,286

Accounting Standard	MIFRS
Year	**2012**

			Cost					Accumulated Depreciation					
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**		**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**		**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid					$ -					$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 25,257	$ 19,999			$ 45,256					$ -	$ 45,256
CEC	1612	Land Rights (Formally known as Account 1906)					$ -					$ -	$ -
N/A	1805	Land	89,014			-$ 133	$ 88,881					$ -	$ 88,881
47	1808	Buildings	342,089				$ 342,089	154,991	11,545			$ 166,536	$ 175,553
13	1810	Leasehold Improvements					$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV					$ -					$ -	$ -
47	1820	Distribution Station Equipment <50 kV	476,084	2,673			$ 478,757	297,454	20,207			$ 317,661	$ 161,096
47	1825	Storage Battery Equipment					$ -					$ -	$ -
47	1830	Poles, Towers & Fixtures	2,089,342	114,852			$ 2,204,194	1,258,673	66,522			$ 1,325,195	$ 878,999
47	1835	Overhead Conductors & Devices	1,233,685	77,699			$ 1,311,384	760,108	40,461			$ 800,569	$ 510,815
47	1840	Underground Conduit	697,740	229			$ 697,969	581,104	17,661			$ 598,765	$ 99,204
47	1845	Underground Conductors & Devices	104,512	9,328			$ 113,841	28,808	4,536			$ 33,344	$ 80,497
47	1850	Line Transformers	883,975	3,937			$ 887,911	660,558	19,706			$ 680,264	$ 207,648
47	1855	Services (Overhead & Underground)	207,548	27,110			$ 234,657	41,093	9,385			$ 50,478	$ 184,179
47	1860	Meters	389,368	684,432		-$ 361,846	$ 711,954	292,579	143,602		(274,079)	$ 162,102	$ 549,852
47	1860	Meters (Smart Meters)					$ -					$ -	$ -
N/A	1905	Land					$ -					$ -	$ -
47	1908	Buildings & Fixtures					$ -					$ -	$ -
13	1910	Leasehold Improvements					$ -					$ -	$ -
8	1915	Office Furniture & Equipment (10 years)					$ -					$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	64,000				$ 64,000	65,469	428			$ 65,897	-$ 1,897
10	1920	Computer Equipment - Hardware	152,100	$ 1,699			$ 153,799	170,867	14,677			$ 185,544	-$ 31,745
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -					$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -					$ -	$ -
10	1930	Transportation Equipment	522,537				$ 522,537	479,111	22,608			$ 501,719	$ 20,818
8	1935	Stores Equipment	10,538				$ 10,538	7,380	1,054			$ 8,434	$ 2,104
8	1940	Tools, Shop & Garage Equipment	143,108				$ 143,108	126,887	5,796			$ 132,683	$ 10,425
8	1945	Measurement & Testing Equipment	8,484				$ 8,484	5,784	848			$ 6,632	$ 1,852
8	1950	Power Operated Equipment					$ -					$ -	$ -
8	1955	Communications Equipment	18,014				$ 18,014	17,941				$ 17,941	$ 73
8	1955	Communication Equipment (Smart Meters)					$ -					$ -	$ -
8	1960	Miscellaneous Equipment					$ -					$ -	$ -
47	1970	Load Management Controls Customer Premises					$ -					$ -	$ -
47	1975	Load Management Controls Utility Premises					$ -					$ -	$ -
47	1980	System Supervisor Equipment					$ -					$ -	$ -
47	1985	Miscellaneous Fixed Assets	10,121				$ 10,121	10,121				$ 10,121	$ -
47	1990	Other Tangible Property					$ -					$ -	$ -
47	1995	Contributions & Grants	(251,533)	(71,268)			-$ 322,802	(67,844)	(12,839)			-$ 80,683	-$ 242,119
47	2440	Deferred Revenue[5]					$ -					$ -	$ -
	2005	Property Under Finance Lease[7]					$ -					$ -	$ -
		Sub-Total	**$ 7,215,982**	**$ 870,689**		**-$ 361,979**	**$ 7,724,691**	**$ 4,891,084**	**$ 366,197**		**-$ 274,079**	**$ 4,983,202**	**$ 2,741,489**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 7,215,982**	**$ 870,689**		**-$ 361,979**	**$ 7,724,691**	**$ 4,891,084**	**$ 366,197**		**-$ 274,079**	**$ 4,983,202**	**$ 2,741,489**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**$ 366,197**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 22,608
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 343,589

APPENDIX 2-B - Distribution System Plan (DSP)

ERHDC's DSP has been uploaded as a separate file.

Distribution System Plan

Developed in accordance with:

"Ontario Energy Board – Filing Requirements for Electricity Transmission and Distribution Applications"

Chapter 5

Consolidated System Plan Filing Requirements

Historical Period:

2017 - 2020

Forecast Period:

2021

December 22, 2020

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GLOSSARY

ACA – Asset Condition Assessment

AM – Asset Management

AMP – Asset Management Process

CAIDI – Customer Average Interruption Duration Index

CI – Customers Interrupted

CHI – Customer Hours Interrupted

CSA – Canadian Standard Association

DSC – Distribution System Code

DSP – Distribution System Plan

EOL – End of Life

ESA – Electrical Safety Authority

EHR – Espanola Regional Hydro Distribution Corporation

GIS – Geographic Information System

GS – General Service

GUP – Good Utility Practice

IESO – Independent Electricity System Operator

IST – Information Systems and Technology

IT – Information Technology

KPI – Key Performance Indicator

LDC – Local Distribution Company

LOS – Loss of Supply

MAIFI – Momentary Average Interruption Frequency Index

MED – Major Event Day

MWO – Maintenance Work Order

NBH – North Bay Hydro Distribution Limited

O/H or OH - Overhead

O&M – Operation & Maintenance

OM&A – Operation, Maintenance & Administration

OEB – Ontario Energy Board

REG – Renewable Energy Generation

RTU – Remote Terminal Units

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SCADA – Supervisory Control and Data Acquisition

the Board – Ontario Energy Board

TUL – Typical Useful Life

TS – Transmission Station or Transformer Station

U/G or UG – Underground

ULTC – Under-Load Tap Changing

URD – Underground Residential Distribution

USF – Utilities Standards Forum

XFMR – Transformer

1 INTRODUCTION

Espanola Regional Hydro Distribution Corporation ("ERH") has prepared this Distribution System Plan ("DSP") in accordance with the Ontario Energy Board's ("OEB's") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated 14 May 2020 ("the Filing Requirements") as part of its 2021 Cost of Service Application ("the Application").

On July 24, 2020, ERH submitted correspondence to the OEB requesting certain adjustments to the OEB's Chapters 2 and 5 Filing Requirements applicable to the Application and this DSP. On September 8, 2020, the OEB accepted ERH's proposal subject to certain exceptions as outlined in the OEB's response. In accordance with the OEB's acceptance of ERH's proposed approach, the DSP has been adjusted as follows:

I. ERH limited the forecast period to a one year forward test year plan, rather than the required five-year plan. The historical capital variance analysis is also limited to the last three historical years. Where possible, ERH has identified and leveraged the historical five years of performance and changes to better assess and understand the system needs for developing the single year plan. The primary reason for this request is due to the fact that North Bay Hydro has purchased ERH and ERH will be amalgamated into North Bay Hydro in 2022. Beyond that date, North Bay Hydro will be responsible for creating and managing the service area and assets currently in existence at ERH. Additional information is found in Exhibit 1 of the Application.
II. ERH deferred completing the formal Asset Management Plan and Asset Condition Assessment until after the North Bay Hydro merger. The Espanola Hydro asset management plan would simply be a one year continuation of the status quo capital program. This gives North Bay Hydro time to complete this work in the years after the merger.

1.1 OBJECTIVES & SCOPE OF WORK

The ERH DSP is a stand-alone document and filed in support of ERH's Application. ERH's DSP describes and substantiates ERH's asset management processes and capital expenditure plan for the forecast year of 2021. The DSP documents the practices, policies and processes that are in place to ensure that investment decisions cost-effectively support ERH's desired outcomes and provide value to customers.

ERH's DSP is formulated to support the achievement of the four key OEB established Renewed Regulatory Framework ("RRF") performance outcomes:

1. ***Customer Focus:*** *services are provided in a manner that responds to identified customer preferences.*
2. ***Operational Effectiveness:*** *continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives.*
3. ***Public Policy Responsiveness:*** *utilities deliver on obligations mandated by the government (e.g. in legislation and regulatory requirements imposed further to Ministerial directives to the Board).*
4. ***Financial Performance:*** *financial viability is maintained, and savings from operational effectiveness are sustainable.*

1.2 OUTLINE OF REPORT

This is ERH's first DSP prepared in accordance with OEB's Filing Requirements. This DSP describes how ERH has developed, managed, and maintained its distribution system equipment to provide a safe, secure, reliable, efficient, and cost-effective service to its customers. The DSP identifies major initiatives and projects to be undertaken over the planning period. The DSP spans a historical period between 2017-2020 and a single forecast year of 2021.

The report contains four sections, including this introductory Section 1. Section 2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of ERH's asset management practices. Section 4 provides a summary of ERH's capital expenditure plan, including an overview of the capital expenditure planning process, an assessment of the system capability for Renewable Energy Generation ("REG"), and justification of projects above the materiality threshold.

ERH's DSP is focused on providing the most viable, value-added operating environment possible for its consumers over the long term, with a short-term focus on the continuation of reliable and safe service. ERH intends to execute its capital expenditure plan in full within the timeframe presented. The projects comprising the plan have been prioritized within the context of an overall investment strategy.

Where relevant, the DSP is organized using the same section headings indicated in the OEB's Filing Requirements and addresses the information outlined in each section. Other relevant information is included in separately identified sections and is intended to complement the prescribed data.

1.3 DESCRIPTION OF THE UTILITY COMPANY

ERH is an electricity distributor licensed by the OEB. In accordance with its Distribution License ED-2002-0502, ERH provides electricity distribution services in the Town of Espanola and the former Town of Massey and Webbwood (currently within the Township of Sables-Spanish Rivers), serving over 3,300 customers.

ERH is incorporated under the Ontario Business Corporations Act. ERH is fully owned by North Bay Hydro Holding Ltd., which is an affiliate of North Bay Hydro Distribution Limited ("NBHDL"). NBHDL is a subsidiary of North Bay Hydro Holding Ltd. Which is solely owned by the Corporation of the City of North Bay.

ERH receives power from Hydro One Networks Inc. ("HONI") and delivers electricity to its customers. ERH is responsible for maintaining distribution and infrastructure assets deployed over 83 square kilometres of rural area and 26 square kilometres of urban area within the service areas, as shown in Figure 1-1.

Figure 1-1: Map of Distribution Service Territory

1.3.1 Mission, Vision, and Core Values Statement

ERH aims to be the "best in the class" in energy delivery to its customers who are located within the Towns of Espanola, Massey and Webbwood. Its mission statement is “To provide low-cost reliable service for our electrical customers”. ERH commits to maintaining its distribution services in the best possible condition so that when, within its control, ERH can provide its customers with a safe and reliable source of electricity. ERH is guided by the principles contained in its Code of Business Conduct.

1.3.2 Corporate Strategic Goals

The key objectives of the capital investment program proposed to be implemented during the forecast period include:

- Meeting ERH’s regulatory obligations, including the obligation to serve customers within the service territory and the obligations to relocate lines when requested by the regional and municipal governments, in conjunction with road widening programs.
- Ensuring supply system reliability is maintained at optimal levels by mitigating the risk of in-service equipment failures, through economically efficient investments.
- Mitigating public safety risks from distribution system operations.
- Improving worker safety, productivity and enhancing operating efficiency.
- Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.
- Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations, and ensure regulatory compliance.
- Maintain current staffing requirements, including training and preparing for succession planning.
- To provide a reasonable rate of return to the Shareholder.

1.3.3 Customers Served

In 2019, ERH served 3,309 electricity distribution customers across its service area. The town of Espanola and the former towns of Massey and Webbwood has a combined population of approximately 8500. The service areas are situated on the Spanish River having both urban and rural settings.

Table 1-1 below illustrates the very minor changes in ERH's customer base over a five-year historical period, which includes residential, general service less than 50 kW, and general service greater than or equal to 50 kW. Five years of historical data is presented rather than three years to further understand the changes and trends the system has experienced. Distribution system investments to date have focused on sustaining the existing distribution system infrastructure with a minimal cost impact to customers and servicing the distribution system to meet customer needs.

Table 1-1: ERH's Actual Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Large Use > 5MW	Total
2015 Actual	2,854	406	29	-	3,289
2016 Actual	2,861	393	29	-	3,283
2017 Actual	2,872	388	28	-	3,288
2018 Actual	2,888	388	27	-	3,303
2019 Actual	2,901	380	28	-	3,309

1.3.4 System Demand and Efficiency

Table 1-2 shows the annual peak demand in kilowatt ("kW") for ERH's distribution system.

Table 1-2: Peak System Demand Statistics

Annual Year	*Winter Peak (kW)*	*Summer Peak (kW)*	*Average Peak (kW)*
2015 Actual	13,571	8,554	9,676
2016 Actual	12,316	8,815	9,402
2017 Actual	11,586	8,125	8,908
2018 Actual	15,504	9,882	11,176
2019 Actual	16,594	9,914	11,328

ERH experiences its peak demand mostly during the winter months. Peak data shown includes the net effect of embedded loads and generators. Variances in seasonal peaks are attributable to annual changes in winter weather conditions and loading impacts associated with the number of heating degree days. Table 1-3 indicates the efficiency of the kilowatt-hour purchased by ERH.

Table 1-3: Efficiency of kWh Purchased by ERH

Annual kWh Purchased	Total kWh Delivered (excluding losses)	Total Distribution Losses (kWh)	Total kWh Purchased	Losses as % of Purchased
2015 Actual	58,365,911	1,536,655	60,115,154	2.56%
2016 Actual	56,279,165	2,599,927	59,057,437	4.40%
2017 Actual	54,516,683	3,480,469	58,172,799	5.98%
2018 Actual	56,923,775	2,739,827	59,752,614	4.59%
2019 Actual	57,432,524	2,530,674	59,963,198	4.22%

1.4 Background & Drivers

The Filing Requirements outline four categories of investments into which projects and programs must be grouped. The drivers for each investment category align with those listed in the Filing Requirements. For reporting purposes, a project or program involving two or more drivers associated with different categories is included in the category corresponding to the trigger driver. However, all drivers of a given project or activity were considered in the analysis of capital investment options and are further described in Section 4 of the DSP.

System Access

These investments are modifications to the distribution system ERH is obligated to perform to provide a customer (including generator customers) or group of customers with access to electricity services via ERH's distribution system. This investment group includes asset relocations requested by the Town.

System Renewal

These investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of ERH's distribution system to provide customers with electricity services.

System Service

These investments are modifications to ERH's distribution system to ensure the distribution system continues to meet ERH's operational objectives while addressing anticipated future customer electricity service requirements.

General Plant

These investments are modifications, replacements or additions to ERH's assets that are not part of the distribution system; including land and buildings; tools and equipment; rolling stock; and electronic devices and software used to support day-to-day business and operations activities.

2 DISTRIBUTION SYSTEM PLAN (5.2)

Section 2.1 provides an overview of the DSP. Section 2.2 summarizes coordinated planning activities with third parties. Section 2.3 covers the performance measurement approach to continuously improve asset management and capital expenditure planning processes. Finally, Section 2.4 summarizes the realized efficiencies from smart meters.

2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW (5.2.1)

This section provides the OEB and stakeholders with a high-level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to ERH's asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

2.1.1 Key Elements of the DSP (5.2.1a)

The distribution system is capital-intensive, and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network. ERH's DSP outlines the practices, policies and processes that are in place to ensure that decisions on capital investments and maintenance plans cost-effectively support ERH's desired outcomes and provide value to the customer. Table 2-1 presents the capital expenditures by investment category for both the historical and forecast period.

Table 2-1: Historical and Forecast Capital Expenditures

Category	Historical ($ '000)					Forecast ($ '000)
	2012	2017	2018	2019	2020	2021
System Access (Gross)	87	182	37	38	148	52
System Renewal (Gross)	835	467	393	338	502	404
System Service (Gross)	0	0	0	0	0	0
General Plant (Gross)	20	0	0	85	58	33
Gross Capital Expenses	**942**	**649**	**430**	**461**	**708**	**488**
Capital Contribution	**71**	**3**	**40**	**39**	**64**	**25**
Net Capital Expenditures	**871**	**646**	**390**	**422**	**645**	**463**

Historically, the local economy in ERH's service territory has been dominated by a single pulp and paper plant located in the town of Espanola, which remains the largest employer in the town. However, over recent years, the community invested a significant amount of effort to diversify the local economy and reduce its dependence on a single industry. The diversification efforts include encouraging local professionals and businesses to invest in the local economy and promoting Espanola's strengths as a regional hub to provide services for the surrounding rural communities. The availability of reliable electricity supply at affordable prices is an essential ingredient, needed for the region's diversification efforts to succeed. Therefore, in preparing this distribution plan, ERH has focused on prioritizing the investments into distribution system infrastructure to maintain the required balance between keeping the power supply reliability from degrading and maintaining the electricity distribution rates at affordable levels.

Advanced technology may be incorporated in system design selectively, where benefits outweigh the costs, during the implementation of asset renewal projects, to meet the current and future needs of the customers and to improve operating efficiency. For example, during the renewal of substations, distribution feeder controls would include controls ready for SCADA integration and monitored switchgear and power transformers, with self-monitoring intelligent devices. However, ERH is proposing no investments in the current DSP forecast, either in form of pilot projects or for system-wide implementation, exclusively, for smart grid development to improve operating efficiency or facilitate customer access to real-time consumption data and behind-the-meter services. These considerations can be made once the basic needs to mitigate the prevailing risks to supply system security, reliability and public safety have been addressed.

The capital investments proposed in this distribution plan include investments into three of the four general categories: (1) System Access; (2) System Renewal; and (3) General Plant. Because the existing plant has adequate capacity, without any constraints to allow connection of new loads and generation from renewables during the next five years, this DSP does not include any investments with System Service, although System Service and associated drivers are secondary for several System Renewal investments.

The proposed investments into System Access are intended to facilitate regional growth by allowing connection of new load and generation customers to the grid, meeting requests of existing customers for an increase in service size to allow growth, accommodating telecommunications joint-use requests and meeting ERH's regulatory obligations by relocating distribution lines when requested by the municipality. The indicated investments in the System Access category represent net expenditure by ERH after third party contributions have been subtracted from the total cost.

The proposed investments into System Renewal are intended to mitigate several specific prevailing risks to distribution system reliability and public safety, due to ageing conditions of some key assets, of which the in-service failure would lead to severe consequences. ERH continues to identify a need to proactively manage the replacement of assets that are at or near the end of life. Assets severely deteriorated can begin to affect system service levels through an increase of outages on account of defective equipment. Replacement plans are developed to prioritize assets found to be the end of life. Replacement plans ensure that planning objectives related to service levels, customer satisfaction and operating cost control are achieved.

The proposed investments into General Plant are focussed on providing a safe and productive workplace and to renew the power tools and safety equipment, including motor vehicles, as the existing equipment reaches the end of its service life. The scope and timing of the investments in each category have been determined by considering all information available at the time of preparation of the distribution plan.

Effects of Covid-19

Despite the effects of Covid-19, ERH expects to complete all capital and OM&A projects as budgeted in 2020 and does not anticipate 2021 Test Year plans will be altered. Processes have been adjusted with staff safety at the forefront. However, given the unprecedented nature of the COVID-19 crisis and the potential for staff availability issues, ERH cannot forecast the 2021 impacts of COVID-19 on the OM&A and capital budgets.

An area of concern is the level of bad debts. At this time, it is not possible to predict the level of future bad debts but ERH will monitor customer payment patterns and follow all legislated mandates in this matter.

As noted in the IESO reports over the last several months, a reduction in general service distribution revenue (> 50 kW and < 50 kW) has only been partially offset by increased residential distribution revenue. Due to the uncertainty with the COVID-19 crisis, ERH is unable to predict its effect on future consumption levels, therefore the load forecast (Exhibit 3) has not been modified to account for COVID-19.

After a review of the best information available, ERH has not made any COVID-19 related adjustments to this CoS application.

Key Benefits of Investments:

The capital investments proposed within the forecast period are expected to yield the following benefits:

(i) The investments into the System Access category would allow ERH to meet its obligations to serve new customers, relocate lines in the public right-of-way, upon receipt of requests for such services and have an adequate supply of revenue meters to comply with the requirements of the Distribution System Code ("DSC") and Measurement Canada.

(ii) The investments into System Renewal can reduce the risk of critical assets' failure in service and help sustain the reliability and safety at acceptable levels. These investments can also help avoid an increase in operating costs by eliminating the increase in the extent of emergency repairs upon asset failures.

(iii) Investments into General Plant are aimed at improving employee safety and worker productivity by providing a safe work environment and modern tools and equipment, as well as improvement in customer service through faster response times.

2.1.2 Overview Customer Preferences and Expectations (5.2.1b)

In preparation for the DSP, ERH engaged its customers through an online survey to collect information on customer satisfaction, value, and understanding of ERH as a utility. ERH uses the information derived from customer engagement pieces to ensure its decisions are aligned with customer preferences and that its decisions are valid based on the customer feedback generally. The online survey was marketed through targeted social media ads as well as the traditional ad infrastructure including digital and radio ads.

Overall, customers are satisfied with the system performance delivered by ERH and aside from the expected concerns of delivering reasonable electricity prices, many respondents to the online survey indicated no substantial changes would be required to ERH's proposed capital and maintenance investments. The customer feedback is summarized in the following points:

- The majority of customers prioritize *delivering reasonable electricity prices* followed by *ensuring reliable electrical service*
- Customers have a lower interest in *modernizing the electrical system to support the reduction of greenhouse gases* as this may increase the cost of electricity
- Customers are in alignment with ERH's objective to be proactive in maintaining and upgrading the system equipment to ensure electricity is supplied reliably and safely

- Customers feel ERH can improve and enhance efforts in communicating more updates and information on construction and investment activities
- Most customers feel their electricity bill are accurate however, ERH could improve educating its customers on understanding their bill, specifically what the percentage ERH contributes to the total customer bill
- Furthermore, customers express an interest in learning and understanding the details of the portion ERH contributes to their bill and what those rates are used for by ERH
- The majority of customers expressed no interest in customer service upgrades or expansions such as online customer service, extended hours, or interactive voice response.

Through ERH's customer engagement, certain factors such as safety, reliability and cost have all been identified as concerns. Customers have indicated that they would like reliability maintained and have an obvious and demonstrated preference for maintaining safety. ERH's System Renewal projects address these at a broad level. Through the DSP however, there are no specific projects that address specific customer preferences concerning capital spending and the costs included in the DSP.

2.1.3 Anticipated Sources of Cost Savings (5.2.1c)

The following cost savings have been achieved through good planning and are expected to be achieved through the execution of the proposed distribution plan:

(a) Through careful evaluation of the risks, projects are prioritized for implementation to mitigate higher level risks, while deferring the projects with lower-level risks.

(b) Investments into System Renewal are expected to reduce the number of in-service failure of assets and thus reduce the risk of emergency repair costs from going up. Possible reliability improvements through the renewal of assets may also result in cost savings to customers in the form of avoided costs to business interruptions and/or use of standby generators or fossil fuel energy sources during prolonged outages.

(c) Proposed investments into facilities and IT systems can ensure the efficiency of operations and reduce the risk of operating costs from going up.

2.1.4 Period Covered by DSP (5.2.1d)

For reasons provided in the Introduction , Section 1, The planning horizon for this DSP covers a historical period of 2017 to 2020, and a one-year forecast period of 2021.

2.1.5 Vintage of the Information (5.2.1e)

To document the condition of assets, the DSP leverages information on ERH's asset's condition to a study completed in 2015. The completion of the asset condition assessment and renewal investments completed since 2015, has been taken into consideration while preparing the investment plan for asset renewal proposed in this DSP. Unless otherwise noted, all information contained in the DSP is current as of October 31, 2020.

2.1.6 Important Changes to Asset Management Processes (5.2.1f)

This is ERH's first DSP under the new Filing Requirements and as such, it can not compare it to the last DSP submission.

However, the methodology employed to support the level of investments and prioritize the investments into specific project categories represents an improvement from the methodology used in ERH's previous submission to OEB, in the following ways:

- The methodology used for prioritizing investments employs an objective, risk-based approach, which results in determining the scope and timing of investments to match the level of risk intended to be mitigated through the investment.
- This methodology creates an optimal balance between the service levels provided by the distribution assets and the cost of services, meeting customers' needs for a reliable power supply at affordable prices.
- For evaluation of the risk associated with ageing assets, all available data relevant to the present condition of assets, i.e. demographic information, results of field inspections and in-situ testing has been used.

2.1.7 DSP Contingencies (5.2.1g)

The DSP is based on the following assumptions and constraints:

1. A distribution revenue increase in 2021 of approximately $426,000 as a result of the cost of service rate application to be submitted (rebased recovery of requested OM&A expenses, depreciation expense and PILs expense, plus a return on asset base as prescribed by the OEB). The increase will be effective May 1, 2021; therefore the full effect will not be until 2022.
2. Prudent investment in distribution plant so that ratepayers of ERH can continue to be provided with excellent service and reliability.
3. Continued improvement in customer communication and engagement to best serve our customers.
4. Continuing to seek productivity improvements to provide current and future mandated levels of service to customers at a cost at inflation or less.
5. Managing economic and political uncertainty.
6. Maintaining adequate working capital.

The following business risks, should they materialize, could pressure operations and earnings over the DSP planning horizon:

1. The impact of milder winter and cooler summers (compared to normal weather) on distribution revenue, maintenance costs, and conservation impacts revenue.
2. Weakness in the local economic environment and the associated increase in credit risk. Although not a direct customer of ERH, the status of the Town of Espanola’s largest employer poses a material risk to ERH because of its impact on residents and businesses that are customers of ERH.
3. Equipment failures that affect service to customers.
4. Adverse impacts from lower rates that may arise if the OEB changes the IRM formula parameters. This could result in distribution earnings and cash flow being lower than the rate increases assumed in the ERH’s business plan.
5. Acquisition and retention of human resources to support existing operations and new business requirements.
6. Performance of the company’s information technology systems, especially in the area of cybersecurity attacks.
7. The impact of the current municipal and provincial political environments on LDCs.
8. Other unforeseen events (e.g., storms, pandemics) could adversely impact the electricity distribution system and customers’ ability to pay.

Furthermore, no proposed investments in the planning horizon are contingent upon the outcome of ongoing activities or future events. The level of actual investments for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of customer requests received for services, but such deviations are expected to be minor and the overall expenditure level during the forecast period is not expected to be significantly different from what is proposed in this DSP.

Additionally, since none of the investments involve addressing constraints in the transmission system or upstream distribution system and since there are no embedded distributors served from ERH's distribution system, the regional planning process has no impacts on this distribution plan and proposed investments.

2.1.8 Grid Modernization, Energy Resources & Climate Change Adaptation (5.2.1h)

As the main priority for ERH is to maintain the current performance of its system while managing bill impacts to its customers, ERH is not proposing any major, unique projects related to grid modernization, distributed energy resources and climate change adaptation. However, ERH has ongoing activities that would be in alignment with grid modernization and climate change adaptation, which include:

Storm Hardening – ERH employs proven storm hardening techniques such as installing stainless steel equipment for below-grade applications and designing for CSA Heavy Loading conditions, and utilizing stronger poles in construction.

Replacement of obsolete assets – grid modernization effort to remove assets that no longer meet ERH's design standards. Removing these assets can support reliability performance, resiliency, and operational efficiency, while reducing ERH's procurement and spare inventory costs through standardization of equipment. An example from ERH is transclosure replacements using MiniPad transformers.

2.2 Coordinated Planning with Third Parties (5.2.2)

2.2.1 Summary of Consultations (5.2.2a,5.2.2b, 5.2.2.c)

This DSP has been prepared through a coordinated planning process with all major stakeholders. The stakeholders consulted by ERH during the preparation of the DSP include:

- customers;
- the municipal governments;
- the transmission company- Hydro One; and
- the upstream distributor (into which some of ERH's service territory is embedded) – Hydro One.

2.2.1.1 *Customer Consultations*

Customer engagement is important to the success of ERH. The purpose of these engagements is to focus on addressing issues of concern raised directly by customers. The issues are addressed according to ERH customer preference on how they wish to be served and engaged.

ERH is both proactive and reactive in its customer engagement consultations. The majority of these exercises and discussions provide helpful insight into the day to day operations of ERH. This demonstrates that customer engagement and communication is a continuous priority for ERH and ties directly to ERH's objectives of community and customer focus and safety.

ERH proceeded to complete its formalized customer engagement for its customers through an online survey. The purpose of these activities was to gauge the level of customer satisfaction throughout all aspects of the organization, to determine a benchmark for customer service and reliability for which ERH could strive for continuous improvement and to assist in determining customer preferences. These consultations were used as a way of determining what ERH was doing well, how it could improve and what customers wanted to see from the organization. ERH sought direct input from customers to determine if ERH's operational and capital plans aligned with customer preferences and whether customers would ultimately support the decisions that ERH is making to run an efficient and effective distribution company. The recent customer engagement specific to the DSP is detailed in Section 4.1.3.

In general, customer consultations support the DSP's focus of maintaining existing reliability and service levels through prioritized and paced investment plans that smooth and mitigate impact to rates. No major issues requiring correction were identified through customer engagement activities. Therefore, other than the need to prudently plan investments to maintain utility operations at an optimal level, the customer engagement sessions did not have a material impact on this DSP.

2.2.1.2 ***Municipal Government Consultations***

ERH interacts with the town administrations in its service territory to coordinate infrastructure planning so that new connections to customers can be connected on time. The coordination meetings are generally initiated by the town's administration and ERH along with other service utilities. Although specific details about the town's projects are not always generally available in advance and therefore accurate scheduling and budgeting for the projects are not feasible, it does provide some indication of the projects on the horizon. It provides ERH with a list of projects to monitor and allows for coordination of any infrastructure plans. However, there are no relevant material documents to be presented at this time. Furthermore, there are no significant deliverables forecasted as a result of these consultations in the Test Year. However, ERH will maintain communication channels with the municipal government to coordinate plans.

Because specific information on population/customer growth rates or road relocations was not available from the municipality, the proposed investment level to provide these services is based on historic average costs. The municipal government consultations do not have a direct effect on the investment level proposed in this DSP.

2.2.1.3 ***Transmitter Consultations – Hydro One Networks Inc. (HONI)***

ERH belongs to the "Sudbury/Algoma Region", for which HONI is the lead transmitter. HONI is primarily responsible for steering the regional planning in this region. In April 2020, ERH participated in Hydro One's regional planning meeting. ERH anticipated minor load growth or generator connections and hence had no impact on Hydro One planning. The planning cycle is currently underway with a draft Needs Assessment completed in June 2020. The Needs Assessment reported no additional regional coordination was required for ERH and therefore has no impact on ERH's current DSP leading up to 2021. Currently, there are no additional relevant material documents to be presented at this time. Additionally, there are no significant deliverables forecasted as a result of these consultations in the Test Year.

Furthermore, ERH has frequent communications with Hydro One generally in the form of CIA's for generation connections and proposed generation connection. Other opportunities include an invite to a Bi-Annual large Customer conference to discuss Hydro One's work plan for 2020 outages to discuss how it may impact our facility's operations and updates to ERH's H1 Schedule "D" via H1's Senior Network Management Officer.

2.2.1.4 *Upstream Distributor Consultations – Hydro One Networks Inc. (HONI)*

ERH regularly communicates with the upstream distributor - Hydro One, into whose distribution system the supply feeders for Massey and Webbwood are embedded. The focus of these communications has been ERH's concern about the reliability and capacity issues related to Hydro One's upstream distribution system. Since the upstream distribution system owned by HONI has adequate capacity to meet the forecast load in ERH's service territory, these consultations with the upstream distributor do not have any impact on the capital investments proposed in this DSP. Hence, there are no relevant material documents to be presented at this time. Additionally, there are no significant deliverables forecasted as a result of these consultations in the Test Year.

2.2.2 Regional Planning Process

ERH belongs to the "Sudbury/Algoma Region" and Hydro One Networks Inc. (HONI), the transmitter in the region, is primarily responsible for steering the regional planning in this region. In response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process, the second regional planning cycle is currently underway. A Needs Assessment was completed in June 2020 with no identified actions required from ERH. A copy of the June 2020 Needs Assessment can be found on Hydro One's regional planning website.

If required, ERH will partake in any consultations they are invited to by Hydro One for the Regional Planning process over the forecast period. However, there are no further relevant material documents to be presented at this time. Additionally, there are no significant deliverables forecasted as a result of these consultations in the Test Year.

2.2.3 IESO Comment Letter (5.2.2d)

ERH submitted a Renewable Energy Generation (REG) Investments Plan and a request for a letter of comment to the IESO in October 2020. As the IESO comment letter confirms (attached as Appendix A), there are no investments specific to connecting REG for the plan period. The comment letter also confirms no additional comment from the IESO is required to address the bullet points in the OEB's Filing Requirements. ERH will continue to participate in meetings with the IESO should they be required to co-ordinate with other distributors and the transmitter on implementing elements of the REG investments over the forecast period.

2.3 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT (5.2.3)

ERH's corporate emphasis on continuous improvement is reflected in all areas of its operations. Like most utilities in Ontario, ERH must replace ageing, at risk of failure distribution infrastructure to ensure the safe and reliable supply of electricity. In addition to the strategic replacement of ageing assets, ERH continues to focus on core maintenance activities to reduce the disruption of electricity distribution to customers. ERH focuses on short and long-term planning to ensure sufficient system capacity is available, and contingencies are in place should there be a loss of critical distribution infrastructure.

ERH monitors several performance measures, including those mandated by the OEB, that may assist in the utility's continuous improvement activities and satisfying customer requests. These measures can be divided into three general groups:

1. Customer-oriented performance.
2. Cost efficiency and effectiveness.
3. Asset/system operations performance.

Where applicable, the performance measures included on the scorecard have an established minimum level of performance expected to be achieved. The scorecard is also used to continuously improve ERH's asset management and capital planning process. ERH's current performance state is represented by ERH's official scorecard results for the recent historical year as published by OEB. The scorecard is designed to track and show ERH's performance results over time and helps to benchmark its performance and improvement against other utilities and best practices. The scorecard includes traditional metrics for assessing services, such as frequency of power outages and costs per customer.

Each metric provided in Table 2-2 and the subsections below haved influences on ERH's DSP and daily operations to achieve the best performance for its customers. The following sections address performance metrics as published by the OEB in the performance scorecard and with additional performance metrics identified in OEB's Rate Filing Requirements. Additionally, each performance measure has ERH's target on delivering the target within this DSP. If not identified explicitly, ERH's targets are based on a five-year rolling average and hence the historical period is shown for five years. ERH's recent year scorecard is shown in Appendix B.

Table 2-2: DSP Performance Measures for ERH

<table>
<tr><th>Performance Outcome</th><th>Measure</th><th>Motivation</th><th>Metric</th><th>Target</th></tr>
<tr><td rowspan="6">Customer-oriented performance</td><td rowspan="3">Service Quality</td><td rowspan="3">Regulatory/ Consumer</td><td>New Residential/Small Business Services Connected on Time</td><td>> 90%</td></tr>
<tr><td>Scheduled Appointments Met on Time</td><td>> 90%</td></tr>
<tr><td>Telephone Calls Answered on Time</td><td>> 65%</td></tr>
<tr><td>Customer Satisfaction</td><td>Customer</td><td>Customer Satisfaction Survey</td><td>> 80%</td></tr>
<tr><td rowspan="2">System Reliability</td><td rowspan="2">Regulatory/ Customer</td><td>SAIDI</td><td>0.67</td></tr>
<tr><td>SAIFI</td><td>0.33</td></tr>
<tr><td rowspan="6">Cost efficiency and effectiveness</td><td rowspan="5">Cost Control</td><td rowspan="5">Regulatory/ Customer/ Corporate</td><td>Total Cost per Customer</td><td rowspan="5">Group 2 (between 10% and 25% below predicted costs)</td></tr>
<tr><td>Total Cost per km of Line</td></tr>
<tr><td>O&M Cost per Customer</td></tr>
<tr><td>O&M Cost per km of Line</td></tr>
<tr><td>O&M Cost per MW of Average Peak Capacity</td></tr>
<tr><td>Distribution System Plan Implementation Progress</td><td>Corporate/ Regulatory</td><td>DSP Progress Variance</td><td>In development</td></tr>
<tr><td rowspan="4">Asset/system operations performance</td><td rowspan="3">Safety</td><td rowspan="3">Regulatory/ Corporate</td><td>Level of Public Awareness</td><td>80%</td></tr>
<tr><td>Level of Compliance with Ontario Regulation 22/04</td><td>C</td></tr>
<tr><td>Serious Electrical Incident Index</td><td>0</td></tr>
<tr><td>Distribution Losses</td><td>Corporate</td><td>Line Losses</td><td>< 5%</td></tr>
</table>

If the annual performance variances are not within target ranges or meet minimal performance thresholds, a senior management review of performance cause is completed that may result in changes to immediate or future places to direct performance back to target levels. ERH has been and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers.

2.3.1 Customer-Oriented Performance

2.3.1.1 *Service Quality*

2.3.1.1.1 Methods and Measures (5.2.3a)

ERH measures and reports on an annual basis on each of the service quality requirements set out in the Distribution System Code ("DSC"). Failure to meet minimum service quality targets would result in measures being taken to realign performance with DSC service quality standards. Service Quality measures include the following major measures: New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time, and Telephone Calls Answered on Time. Additional sub-measures are tracked as part of the DSC requirements. All these measures are self-explanatory and all relate to ERH providing connection services as well as quality customer service. ERH is committed to meeting and exceeding all targets found in the Service Quality performance measure group.

2.3.1.1.2 Historical Performance (5.2.3c)

Except for Telephone Accessibility in 2019, ERH has consistently exceeded the OEB targets for its service quality as part of the customer focus efforts. ERH's customer service representatives answer a varying number of phone calls per year within the 30-second window prescribed by the OEB. The overall answer rate is well above the industry targets and is indicative of ERH's dedication to being an organization focused on customer service except for the 2019 Telephone Calls Answered on Time. Table 2-3 presents the measure and sub-measures for tracking ERH's performance in the service quality category.

In 2019, ERH's Customer Care Department received 3,617 calls from its customers. Of those calls, a Customer Care Representative answered the call in 30 seconds or less, 63.04% of the time. This is a decrease from the 2018 results, and ERH just missed the OEB target of 65%. The main contributing factor to the missed target was staff turnover which resulted in new staff having longer average talk times with customers. The extra time on the phones with customers then lead to calls waiting in the queue. ERH has a fully trained team in place and has seen significant improvement for 2020. ERH intends on continuing to monitor the performance measure to identify opportunities for improvement.

Table 2-3: Performance Measures - Service Quality

Measure	Sub-Measure	2015	2016	2017	2018	2019	Minimum Standard	ERH Target
New Residential / Small Business Services Connected on Time	Low Voltage Connections	100%	100%	100%	100%	100%	90%	> 90%
	High Voltage Connections	N/A	N/A	100%	100%	100%	90%	
	Reconnection Performance Standards	100%	100%	100%	100%	100%	85%	
Telephone Calls Answered on Time	Telephone Accessibility	76.1%	76.2%	72.62%	70.67%	63.04%	65%	> 65%
Scheduled Appointments Met on Time	Appointments Met	100%	100%	98.18%	100%	98.55%	90%	> 90%
	Appointment Scheduling	98%	97.1%	97.94%	100%	99.72%	90%	

2.3.1.1.3 Performance Trend into the DSP (5.2.3d)

Other than the one exception noted above in 2.3.1.1.2, ERH has exceeded the industry targets for each service quality measure. ERH's outstanding performance on these measures indicates no substantial additional material projects are required for investments in this area. ERH continues to strive to better serve the customer with the highest excellence. ERH's intended action for these measures is to maintain the performance.

2.3.1.2 *Customer Satisfaction*

2.3.1.2.1 Methods and Measures (5.2.3a)

Customer satisfaction survey results and customer engagements have always been important to the success of ERH. The purpose of the survey has been to focus on addressing issues of concern raised directly by customers. ERH is proactive and reactive in its customer engagement consultations, the majority of which provide helpful insight into the day to day operations of ERH. Historically, ERH has relied on direct, day-to-day, real-time interactions with customers to inform decision making, to advise of issues important to customers and to address communication and customer service needs. ERH's targets for customer satisfaction performance measures are aligned with OEB's targets.

2.3.1.2.2 Historical Performance (5.2.3c)

As seen in Table 2-4, ERH has consistently exceeded the OEB targets for customer satisfaction. When corporate and asset management objectives are aligned with OEB performance outcomes and when ERH involves customers in discussions to understand their preferences and concerns, the result is an increased level of satisfaction.

Table 2-4: Performance Measures – Customer Satisfaction

Measure	2015	2016	2017	2018	2019	ERH Target
Customer Satisfaction Survey Results	89%	87%	87%	87%	91%	>80%

In 2019, ERH engaged the UtilityPulse Division of Simul Corporation to conduct a 2019 customer satisfaction survey. The UtilityPulse Electric Utility Survey has been conducted for over 20 years and is used by a significant number of Ontario distributors. The final report on the customer satisfaction survey was received in late 2019, and ERH received a customer satisfaction score of "A" or 91% (post-survey result) which is above the Ontario benchmark survey that had a grade of "B". The 2019 result is an improvement over the previous result of 87%. The survey asked customers questions on a broad range of topics, including overall satisfaction with reliability, customer service, outages, billing, and corporate image. These customer satisfaction surveys are an important element in our overall customer engagement strategy providing further insight towards planning and supporting customer service improvement at all levels within ERH.

2.3.1.2.3 Performance Trend into the DSP (5.2.3d)

ERH's outstanding performance on these measures indicates no substantial additional material projects are required for investments in this area. ERH continues to strive to better serve the customer with the highest excellence. ERH's intended action for these measures is to maintain the performance.

2.3.1.3 ***System Reliability***

2.3.1.3.1 Methods and Measures (5.2.3a)

System reliability is an indicator of the quality of electricity supply received by the customer. System reliability and performance is monitored via reports prepared manually by operational staff at ERH. The reliability of supply is primarily measured by internationally accepted indices SAIDI and SAIFI as defined in the OEB's *Electricity Reporting & Record Keeping Requirements* dated May 3, 2016. SAIDI, or the System Average Interruption Duration Index, is the length of outage customers experience in the year on average, expressed as hours per customer per year. It is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. SAIFI, or the System Average Interruption Frequency Index, is the number of interruptions each customer experiences in the year on average, expressed as the number of interruptions per year per customer. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An interruption is considered sustained if it lasts for at least one minute.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served}$$

$$SAIFI = \frac{Total\ customer\ interruptions}{Average\ number\ of\ customers\ served}$$

Loss Of Supply (LOS) outages occur due to problems associated with assets owned by another party other than ERH or the bulk electricity supply system. ERH tracks SAIDI and SAIFI including and excluding LOS. Major Event Days (MEDs) are calculated using the fixed percentage approach (i.e. 10% of the customer base experienced an outage with a duration longer than one minute). MEDs are then confirmed by assessing whether interruption was beyond the control of ERH (i.e. force majeure or LOS) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable.

2.3.1.3.2 Historical Performance (5.2.3c)

ERH's reliability indices for 2015-2019 are shown in the figures below (Figure 2-1 to Figure 2-2) to observe the historical trends. In 2019, ERH's average number of hours in which power to a customer was interrupted (excluding LOS) was 0.35 and below the target range of 0.67. Additionally, ERH's average number of customer interruptions (i.e. frequency) was 0.17 and below the target range of 0.33 (excluding LOS). ERH's goal is to have its system reliability trend in an improved or maintained manner over a five-year average; however, it is important to note that in any given year, outage hours correlate with storm occurrences and severity.

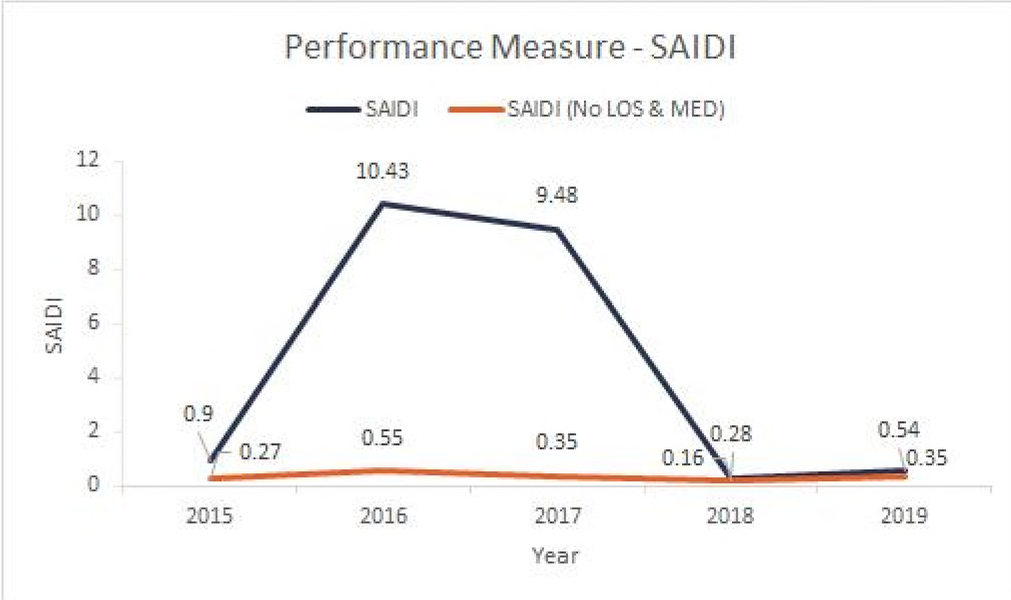

Figure 2-1: Performance Measure – SAIDI

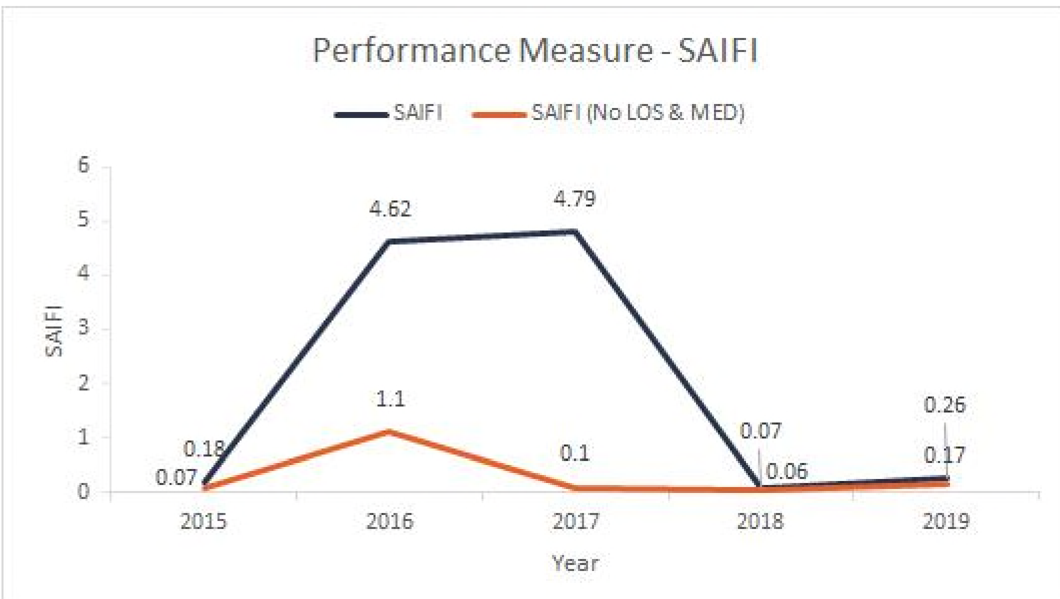

Figure 2-2: Performance Measure – SAIFI

As seen in Table 2-5, ERH has exceeded its targets for both reliability measures demonstrating an improving trend concerning the reliability statistics. ERH's reliability metric values for the historical period, excluding loss of supply and MEDs, are shown in Table 2-6 in addition to ERH's target for each metric.

Table 2-5: 2015-2019 Reliability Metrics (LOS included and excluded)

Metric	2015	2016	2017	2018	2019	Average
Service reliability – Including outages caused by LOS						
SAIDI	0.90	10.43	9.48	0.28	0.54	4.33
SAIFI	0.18	4.62	4.79	0.07	0.26	1.98
Service reliability – excluding outages caused by LOS						
SAIDI	0.28	2.13	0.35	0.16	0.35	0.65
SAIFI	0.03	1.89	0.10	0.06	0.17	0.45

Table 2-6: 2015-2019 Reliability Metrics (LOS and MED Adjusted)

Metric	2015	2016	2017	2018	2019	Average	ERH Target
SAIDI	0.27	0.55	0.35	0.16	0.35	0.34	0.67
SAIFI	0.07	1.1	0.1	0.06	0.17	0.29	0.33

Table 2-7 presents a summary of outages that have occurred within ERH's service territory. The summary provides three different categorizations for the accounting of outages. Further breakdown by cause codes is provided in the subsequent subsections.

Table 2-7: Outage Summation (2015-2019)

Categorization	2015	2016	2017	2018	2019
All interruptions	13	40	21	21	40
All interruptions excluding LOS	12	37	11	20	38
All interruption excluding MED and LOS	12	35	11	20	38

ERH experienced MEDs in 2015, 2016 and 2017. Table 2-8 provides the summary overview of the MEDs contributed by the number of interruptions, the number of customers interrupted and customer hours of interruptions.

Table 2-8: Major Event Details (2015-2019)

Major Events Details	2015	2016	2017	2018	2019
Number of Interruptions					
1-Scheduled Outage	0	0	0	0	0
2-Loss of Supply	1	3	8	0	0
3-Tree Contacts	0	1	0	0	0
4-Lightning	0	0	0	0	0
5-Defective Equipment	0	1	0	0	0
7-Adverse Environment	0	0	0	0	0
9-Foreign Interference	0	0	0	0	0
Number of Customer Interruptions					
1-Scheduled Outage	0	0	0	0	0
2-Loss of Supply	500	9,004	15,898	0	0
3-Tree Contacts	0	2,593	0	0	0
4-Lightning	0	0	0	0	0
5-Defective Equipment	0	2,593	0	0	0
7-Adverse Environment	0	0	0	0	0
9-Foreign Interference	0	0	0	0	0
Number of Customer Hours of Interruptions					
1-Scheduled Outage	0	0	0	0	0
2-Loss of Supply	2000	27,246	29,691	0	0
3-Tree Contacts	0	5,186	0	0	0
4-Lightning	0	0	0	0	0
5-Defective Equipment	0	43.2	0	0	0
7-Adverse Environment	0	0	0	0	0
9-Foreign Interference	0	0	0	0	0

Outage Details for Years 2015-2019

The following sections and figures provide the breakdown of historical outages for years 2015-2019 regarding the number of outages, the number of customers interrupted, and the number of customer hours experienced by the outages. Tracking outage performance by cause code provides valuable information on specific outage causes that need to be addressed to improve negative trending. As with the reliability indices, the five-year historical performance range is used as a target and results outside this range indicate positive or negative trending.

<u>*Outages Experienced*</u>

Table 2-9 presents the count of outages broken down by cause code. The number of outages is an indication of outage frequency and impact customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer fewer outages with longer duration thereby reducing the overall impact on production and business disruption.

Table 2-9: Number of Outages by Cause Codes (2015-2019) - Excluding MEDs

Cause Code	2015	2016	2017	2018	2019	Total Outages	Percent Share
0-Unknown/Other	0	2	0	1	1	4	3%
1-Scheduled Outage	0	8	4	7	15	34	25%
2-Loss of Supply	1	3	10	1	2	17	13%
3-Tree Contacts	2	4	3	2	5	16	12%
4-Lightning	0	0	0	0	2	2	1%
5-Defective Equipment	4	10	3	5	10	32	24%
6-Adverse Weather	4	6	0	1	0	11	8%
7-Adverse Environment	0	0	0	0	0	0	0%
8-Human Element	0	0	0	0	0	0	0%
9-Foreign Interference	2	7	1	4	5	19	14%

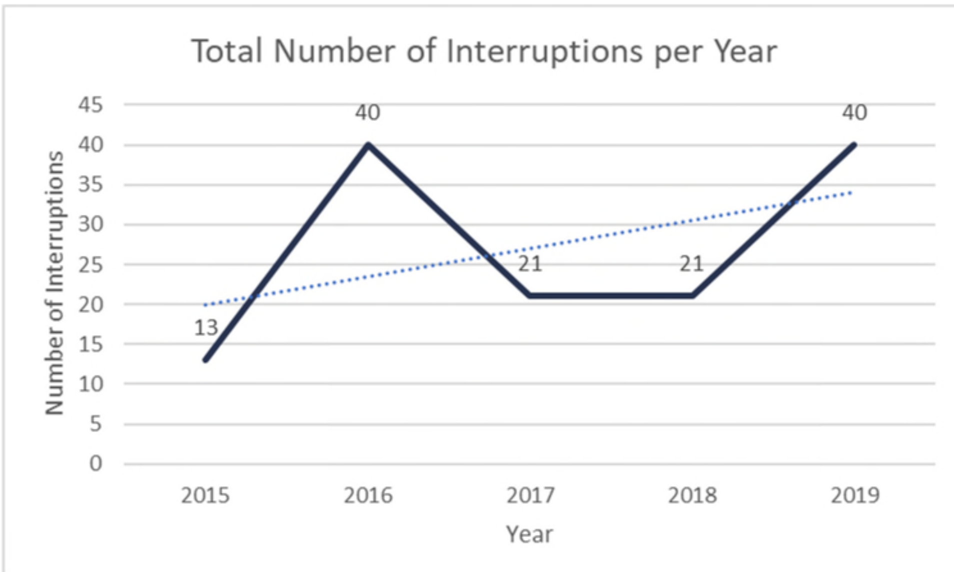

Figure 2-3: Total Number of Outages by Year (2015-2019)

As seen in Figure 2-3, the total number of interruptions over the historical period varies from a low of 13 to a high of 40, with the overall trend increasing in the period. This represents an average of 0.04 to 0.11 interruptions per day. The average is small enough that ERH's customers have not raised concerns that would spark ERH to plan any capital projects to address the deteriorating asset base. However, the observed increasing trend indicates continuous renewal throughout the system in the correct places is needed to allow ERH to manage the number of interruptions it has control of.

The top three cause codes ranked by percentage share over the historical period are *Scheduled Outage, Defective Equipment* and *Foreign Interference*. Despite being leading cause codes for the number of outages, this leading percentage share is not seen in Table 2-10 and Table 2-11 which outlines leading CI and CHI cause codes respectively. Regarding CI and CHI, *Loss of Supply* dominates percentage share with values of 71% and 89% respectively.

Scheduled Outages have experienced an increasing trend over the historical period with a high of 15 outages recorded in 2019. 25% of outages over the historical period can be contributed to scheduled outages. Regarding CI and CHI, *Scheduled Outages* have a low percentage share of 2% and 1% respectively. Capital work and maintenance activities are the main contributors to these outages and with the low percentages for CI and CHI, it is evident that these are being performed in a timely and non-impactful manner. ERH continues to plan capital work and maintenance appropriately in times that would affect minimal customers with short durations.

Defective Equipment shows a slightly increasing trend of outages over the historical period with a high of 10 outages recorded in 2016 and 2019. Over the historical period, this cause code count for 24% of total outages. These outages result from equipment failures due to condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. ERH has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage. ERH utilizes evaluations such as the Asset Condition Assessment to assist in prioritizing investments in asset classes. With regards to CI and CHI, this cause code is responsible for 19% and 3% of the total percent share respectively.

Foreign Interference is the third-highest percentage share of total outages with 14%. Over the historical period, this cause code experiences a steady trend with a high of 7 outages experienced in 2016. The outages contributing to the cause include animal interference, dig-ins, vehicle collisions and/or foreign objects. Some of these contributing factors can be minimized such as educating the public about calling before digging or installing animal guards in areas observed to have a high activity of animals. However, other factors such as vehicle collisions can happen at random and depending on the extent and where the collision happens may result in a large impact. Despite being a leading contributor to total outages, *Foreign Interference* is responsible for only a 2% percentage share of total CI and CHI experienced over the historical period.

Loss of Supply contributed to a smaller share of 13% of total outages throughout the historical period but despite this accounted for 71% and 89% of total CI and CHI respectively. As shown in the following Table 2-10 and Table 2-11, the major factor to this high percentage share is 2016 and 2017 CI and CHI values. Values for both CI and CHI in these years are significantly larger than the next leading cause code and are responsible for the peaks seen in Figure 2-4 and Figure 2-5 in the following subsection.

Customers Interrupted (CI) and Customers Hours Interrupted (CHI)

The number of customers interrupted is a measure of the extent of outages. Customer Hours Interrupted is a measure of outage duration and the number of customers impacted. The tables and figures below provide the historical values and trends for both CI and CHI.

Table 2-10: Customers Interrupted by Cause Codes (2015-2019) - Excluding MEDS

Cause Code	2015	2016	2017	2018	2019	Total CI	Percent Share
0-Unknown/Other	0	7	0	81	81	169	1%
1-Scheduled Outage	39	64	29	60	78	270	2%
2-Loss of Supply	500	5,686	5,541	13	320	12,060	71%
3-Tree Contacts	2	88	181	2	31	304	2%
4-Lightning	0	0	0	0	2	2	0%
5-Defective Equipment	41	2,941	51	20	159	3212	19%
6-Adverse Weather	5	423	0	15	0	443	3%
7-Adverse Environment	0	0	0	0	0	0	0%
8-Human Element	0	0	0	0	0	0	0%
9-Foreign Interference	12	93	79	30	195	409	2%

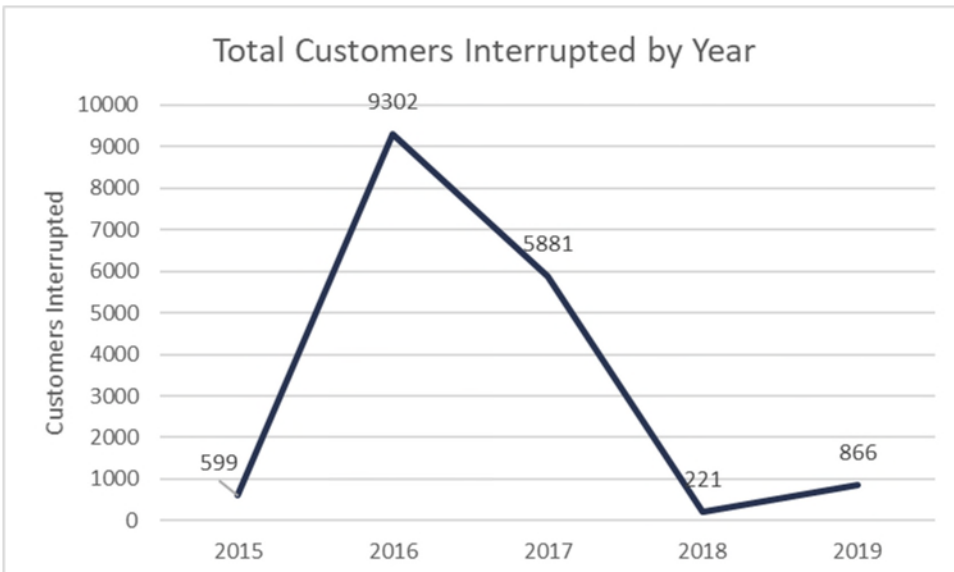

Figure 2-4: Total Number of Customers Interrupted by Year (2015-2019) - Excluding MEDS

Table 2-11: Customer Hours Interrupted by Cause Codes (2015-2019) - Excluding MEDs

Cause Code	2015	2016	2017	2018	2019	Total CHI	Percent Share
0-Unknown/Other	0	9	0	122	122	253	0%
1-Scheduled Outage	51	73	168	228	157	677	1%
2-Loss of Supply	2,000	25,587	16,821	377	635	45420	89%
3-Tree Contacts	2	129	403	4	192	730	1%
4-Lightning	0	0	0	0	3	3	0%
5-Defective Equipment	71	846	52	71	380	1420	3%
6-Adverse Weather	764	568	0	83	0	1415	3%
7-Adverse Environment	0	0	0	0	0	0	0%
8-Human Element	0	0	0	0	0	0	0%
9-Foreign Interference	32	198	521	37	306	1094	2%

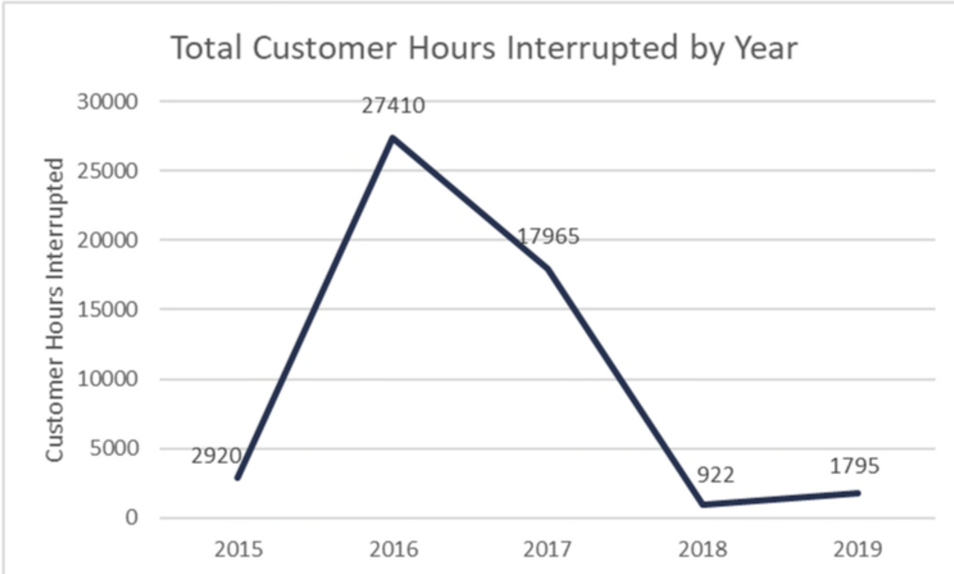

Figure 2-5: Total Number of Customer Hours of Interruption by Year (2015-2019) - Excluding MEDs

As evident through Figure 2-4 and Figure 2-5, CI and CHI share similar trends throughout the historical period, both experiencing extreme peaks in 2016 and 2017. These spikes are a result of the leading cause codes *Loss of Supply* and *Defective Equipment,* but it should be noted that *Loss of Supply* makes up 71% and 89% of total CI and CHI respectively.

2.3.1.3.3 Performance Trend into the DSP (5.2.3d)

ERH uses the SAIDI and SAIFI reliability indexes to gauge the system reliability performance and maintain tight control over capital and maintenance spending. DSP investment priorities are expected to be in alignment with maintaining the historical average reliability performance of specific cause codes that in the control of the utility (i.e. tree contacts and defective equipment cause codes). ERH uses several programs to reduce the number of controllable outages. These programs include:

- Planned renewal of end-of-life assets such as poles and cables.
- Proactive vegetation management.
- Inspection of the plant to identify potential problems.

2.3.2 Cost Efficiency and Effectiveness

2.3.2.1 *Cost Control (5.2.3b)*

2.3.2.1.1 Methods and Measures (5.2.3a)

Cost Metrics

Managing costs is a responsibility taken seriously at ERH. The levels of spending are measured and prudently controlled so that customer rates are minimally affected. Total cost per customer is calculated as the sum of ERH's capital and operating costs and dividing this cost figure by the total number of customers the utility serves:

$$Total\ Cost\ per\ Customer\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Number\ of\ customer\ served}$$

ERH as well collects the trend data on the total cost per kilometre of line. The total cost is calculated as the sum of ERH's capital and operating costs divided by the total kilometres of the line in service at ERH:

$$Total\ Cost\ per\ Kilometre\ of\ Line\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Kilometers\ of\ line}$$

Additionally, ERH tracks the additional metrics introduced in OEB's newest Chapter 5 update: the O&M Cost per customer, O&M Cost per kilometre of line and O&M Cost per MW of Peak Capacity. The metrics are calculated with the total O&M costs divided by the respective number for each metric, defined as follows:

$$O\&M\ \ per\ Customer\ = \frac{\sum O\&M\ Cost}{Number\ of\ customer\ served}$$

$$O\&M\ Cost\ per\ Kilometer\ of\ Line\ = \frac{\sum O\&M\ Cost}{Kilometers\ of\ line}$$

$$O\&M\ Cost\ per\ Average\ Peak\ Capacity\ = \frac{\sum O\&M\ Cost}{Average\ Peak\ Capacity}$$

In addition to calculating the cost metrics, the total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as the number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs.

2.3.2.1.2 Historical Performance (5.2.3c)

In 2019, for the eighth consecutive year, ERH was placed in Group 2. ERH's efficiency performance based on the PEG model was below the predicted costs by an average of 21.68% over the last three years. ERH is projected to remain in Group 2 (between 10% and 25% below predicted costs) based on the 2020 bridge budget and 2021 test year estimates.

Total Cost per Customer is calculated as the sum of ERH's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that ERH serves. The Total Cost per Customer increased on average 4% per annum over a five-year historical period. The cost performance result for 2019 is $758 per customer which is an 11% increase over 2018. ERH had increased costs in 2019 due to higher administrative costs from the sale of ERH to North Bay Hydro. The projected cost per customer for 2020 is $761, a 0.37% increase over 2019. ERH will continue to replace distribution assets proactively in a manner that balances system risks and customer rate impacts. Customer engagement initiatives continue to ensure customers have an opportunity to share their viewpoint on ERH's capital spending plans.

The Total Cost per Kilometer measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometres of the line that the company operates to serve its customers. The Total Cost per Kilometer increased on average 4% per annum over a five-year historical period. ERH's 2019 rate is $17,789 per Km of line, an 11% increase over 2018. As mentioned above, this increase is due to increased administrative expenses related to the sale. ERH continues to experience a low level of growth in its total kilometres of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. The capital cost metrics are visualized below in their respective figures (Figure 2-6 and Figure 2-7).

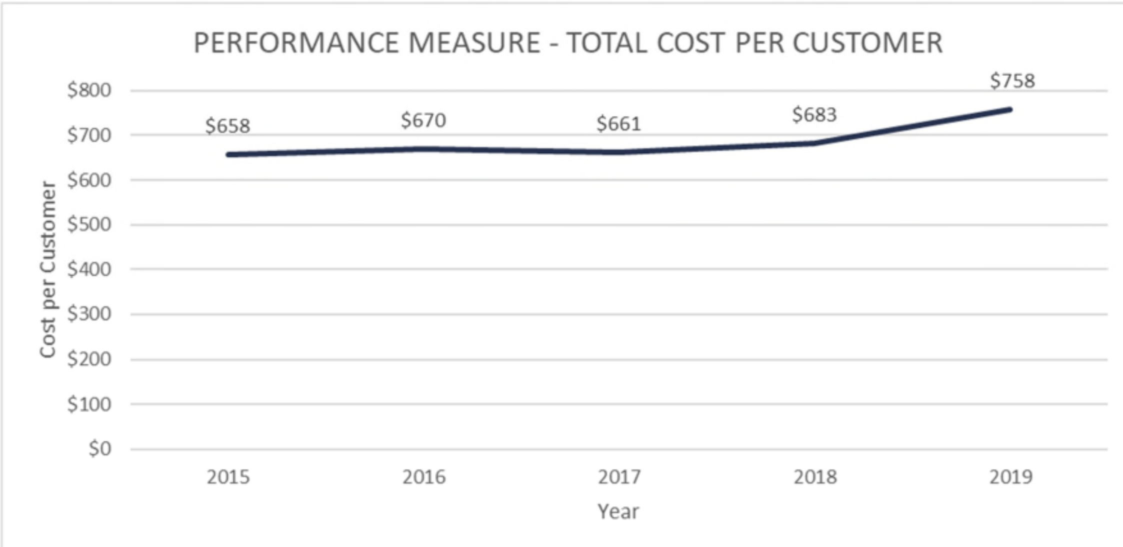

Figure 2-6: Performance Measure - Total Cost per Customer

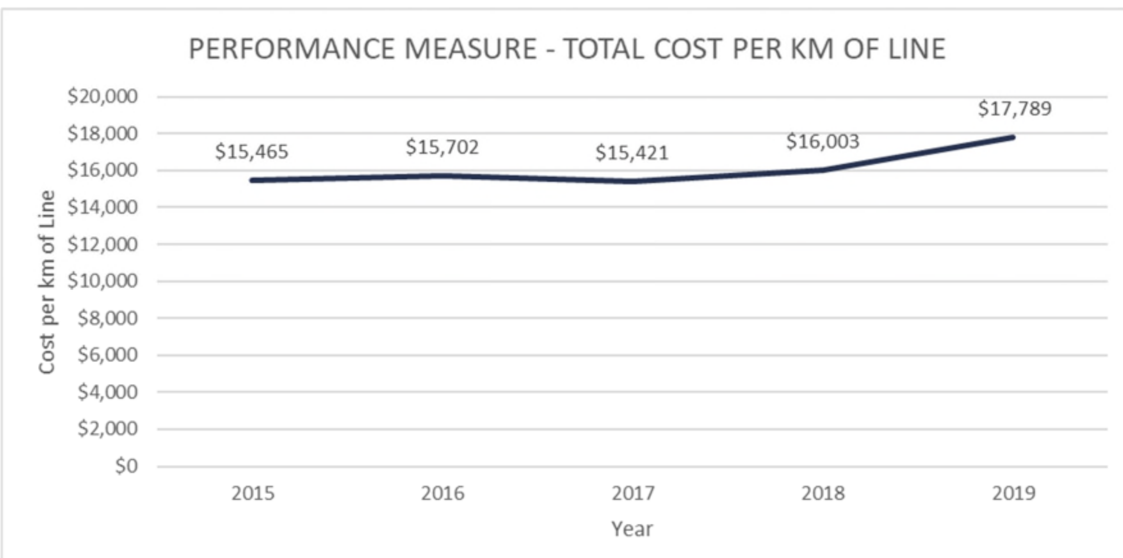

Figure 2-7: Performance Measure - Total Cost per Kilometer of Line

Operating costs are those associated with the maintenance, inspection, and operation of the system and those associated with metering, billing and collections. Specifically, the O&M Cost per Customer increased on average 7% per annum, O&M Cost per Kilometer of Line increased on average 7% per annum and O&M Cost per kilowatt of Average Peak Capacity increased on average 3% per annum. To keep costs low, ERH follows the minimum requirements of the DSC to maintain its assets within the defined intervals for reliable service. The O&M cost metrics are visualized below in their respective figures (Figure 2-8 to Figure 2-10).

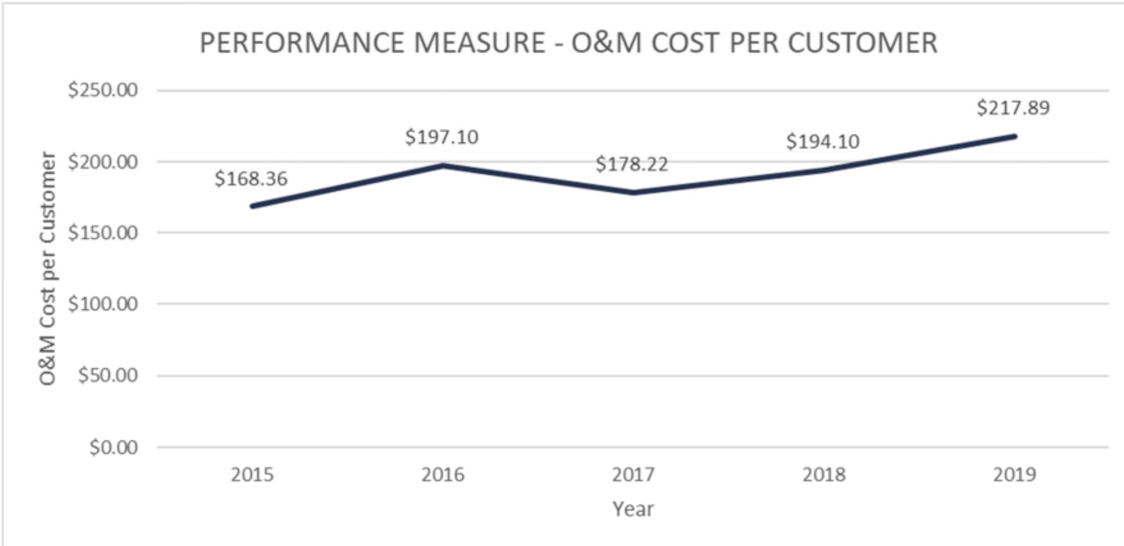

Figure 2-8: Performance Measure - O&M Cost per Customer

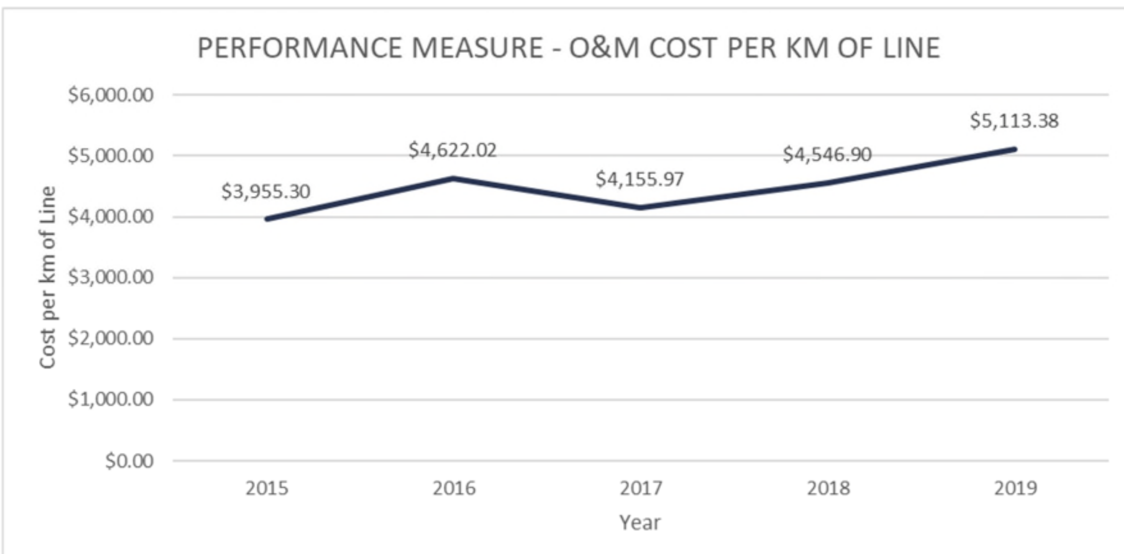

Figure 2-9: Performance Measure - O&M Cost per Kilometer of Line

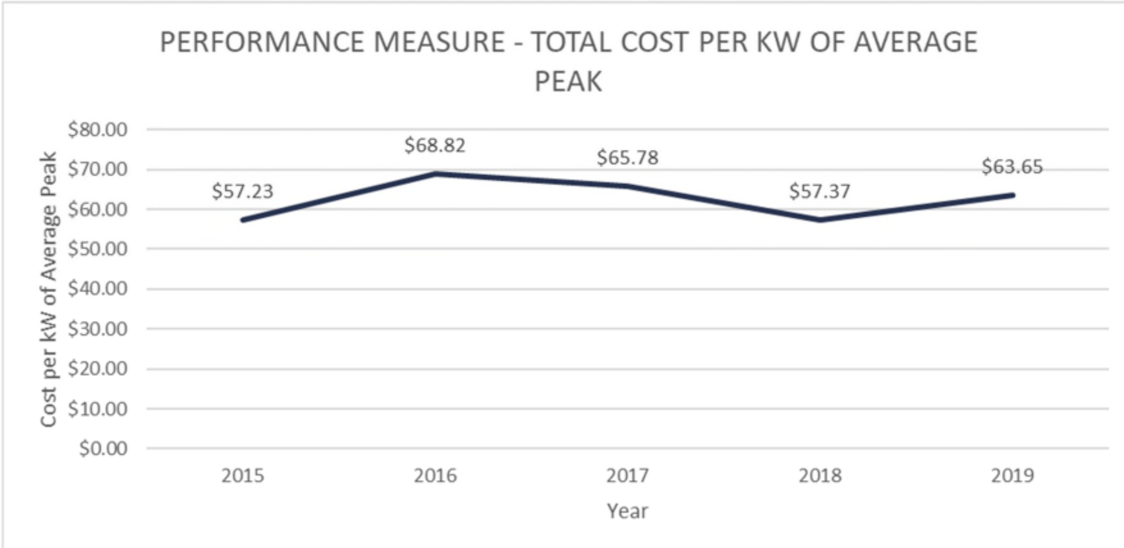

Figure 2-10: Performance Measure - O&M Cost per kW of Average Peak

Table 2-12 outlines the average percentage change for the cost metrics detailed in this section. All metrics experienced on average some increase over the historical period. As seen below, O&M Cost per customer, O&M Cost per Kilometer of line and O&M Cost per Average Peak Capacity experience the greatest yearly variances, ranging up to 20%. All cost metrics experienced a positive average percent change throughout the historical period with O&M Cost per Customer and O&M Cost per Kilometer of Line experiencing the largest change of 7%.

Table 2-12: Average Percent Change for Cost Metrics

Metric	2015	2016	2017	2018	2019	Average % Change	ERH Target
Cost Per Customer	--	2%	-1%	3%	11%	4%	Group 2 (between 10% and 25% below predicted costs)
Total Cost per Kilometer of Line	--	2%	-2%	4%	11%	4%	
O&M Cost per Customer	--	17%	-10%	9%	12%	7%	
O&M Cost per Kilometer of Line	--	17%	-10%	9%	12%	7%	
O&M Cost per Average Peak Capacity	--	20%	-4%	-13%	11%	3%	

2.3.2.1.3 Performance Trend into the DSP (5.2.3d)

ERH continually strives to manage costs without unduly affecting service to customers or creating significant rate increases while addressing increasing customer expectations of an interactive, value-added service. ERH understands that the service it provides is an essential part of daily life for customers and increasing bills are a concern for all. ERH's costs account for a small fraction of a typical residential customer's bill and the company actively monitors costs against prudent budgets set for both capital and operating costs which are aligned with ERH's rate application.

Where possible, ERH will continue to seek cost savings and improve efficiency while maintaining quality customer service and effective AM as detailed in the current rate application that set out the capital and operating investment needs of the business for the forecast period. With limited growth in the ERH service area, the cost metrics are expected to be in alignment with historical values over the DSP period. ERH considers the projects that would have a minimal cost impact on customers but return a benefit to the quality of the service. These trade-offs are considered and communicated with customers to understand their preferences. The projects and programs considered within this DSP period take a proactive approach so that ERH would be able to maintain its distribution system while minimizing the costs to the customers as much as possible. ERH's intended goal for these measures is to maintain costs such that the annual increase does not exceed ERH's target.

2.3.2.2 *Distribution System Plan Implementation Progress*

2.3.2.2.1 Methods and Measures DSP (5.2.3a)

Although ERH has employed some degree of distribution system planning for several years, ERH has historically not tracked a specific metric to measure the accuracy of the plan as this is the first DSP to be submitted.

ERH is committed to continuously improving efficiency and productivity performance to provide better value service for ratepayer money. To work towards the achievement of this objective, ERH seeks to identify and implement measures that can lead to sustainable long-term efficiencies that utilize resources effectively. Ensuring the successful implementation of the DSP as well as continuously improving the planning process is critical to the improvement of efficiency and productivity performance.

2.3.2.2.2 Historical Performance (5.2.3c)

As this is the first DSP filing, there are no historical statistics for benchmarking. In the interim, ERH intends to actively track and monitor its current DSP moving forward.

2.3.2.2.3 Performance Trend into the DSP (5.2.3d)

This metric is still evolving and still in early development. ERH may improve its data collection processes concerning condition data as well as project execution and capturing details of asset replacements to improve capabilities on measuring the execution of the DSP.

2.3.3 Asset/ System Operations Performance

2.3.3.1 *Safety*

2.3.3.1.1 Methods and Measures (5.2.3a)

ERH is committed to protecting its workforce, customers, the public and the environment. In addition to achieving compliance with applicable laws, ERH strives for excellence in our environmental, health and safety performance through adopting good management practices and setting clear objectives and targets for achieving continual improvement.

ERH has adopted the ESA Serious Electrical Incident Index into its performance measure scorecard and is annually reported to the OEB. The safety measures include:

- Component A – Public Awareness of Electrical Safety
- Component B – Compliance with Ontario Regulation 22/04
- Component C – Serious Electrical Incident Index

Component A - Public Awareness of Electrical Safety

This measure is a survey that measures the public's awareness of key electrical safety concepts related to electrical distribution equipment found in a utility's territory. The survey provides a benchmark of the levels of awareness identifying areas where education and awareness efforts may be needed.

Component B – Compliance with Ontario Regulation 22/04

Ontario Regulation 22/04 establishes objective-based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the Regulation requires the approval of equipment, plans, and specifications and the inspection of construction to ensure there are no undue hazards before they are put in service.

Component B is comprised of an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and Compliance Investigations. ESA evaluates all these elements to determine the status of compliance.

As with every other Ontario distributor, ERH's design, construction, inspection, and maintenance practices are audited yearly as required by Ontario Regulation 22/04. The utility can be deemed to be in one of three performance categories:

1. In compliance
2. Needs Improvement
3. Not in compliance

Component C - Serious Electrical Incident Index

This component consists of the number of serious electrical incidents and fatalities, which may occur within a utility's service territory. This measure is intended to address the impacts and needs for improving public electrical safety on the distribution network.

2.3.3.1.2 Historical Performance (5.2.3c)

ERH continues to strive in maintaining its employee safety, health & wellness, and public safety measures and in compliance with Ontario Regulation 22/04. Table 2-13 highlights ERH's historical performance for each of the three components.

Table 2-13: Performance Measure – Safety

Measure	2015	2016	2017	2018	2019	ERH Target
Level of Public Awareness	85%	85%	84%	84%	85%	80%
Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C
Serious Electrical Incident Index	0	0	0	0	0	0

Component A – Public Awareness of Electrical Safety

ERH's third safety awareness survey was conducted in early 2020. A representative sample of ERH's service territory population was surveyed to gauge the public's awareness level of key electrical safety concepts related to distribution assets. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness and identify opportunities where additional education and outreach may be required. ERH's score for 2019 was 85%. ERH's target for this metric is to improve each year the survey is undertaken.

Component B – Compliance with Ontario Regulation 22/04

In each of the past five years of this scorecard period, EHC was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). ERH attributes this continued success to our strong commitment to safety, and adherence to company policies and procedures. ERH's target for this metric is to remain fully compliant with Ontario Regulation 22/04.

Component C – Serious Electrical Incident Index

Section 12 of Ontario Regulation 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. For the reporting period from 2014 to 2019, ERH did not experience any serious electrical incidents. ERH's target for this metric moving forward is to have zero (0) serious electrical incidents reported.

2.3.3.1.3 Performance Trend into the DSP (5.2.3d)

ERH remains strongly committed to both the safety of staff and the public and regularly provides customers with electrical safety information via its website and bill inserts. ERH continues to demonstrate prudent compliance with Ontario Regulation 22/04 and as such ESA compliance continues to play a key role in project prioritization and execution. Ensuring Reg. 22/04 compliance is maintained has been taken into consideration in the development of the DSP and ERH's planning process.

2.3.3.2 *System Losses*

2.3.3.2.1 Methods and Measures (5.2.3a)

ERH system losses are monitored annually. System design and operation are managed such that system losses are maintained within OEB thresholds, as defined in the *OEB Practices Relating to Management of System Losses*. Losses are monitored to ensure that the OEB 5% threshold is not exceeded.

2.3.3.2.2 Historical Performance (5.2.3c)

ERH system losses over the historical period are shown in Table 2-14.

Table 2-14: ERH System Losses

Year	2015	2016	2017	2018	2019	ERH Target
System Losses	2.6%	4.4%	6.0%	4.6%	4.2%	< 5%

Losses over the historical period ranging from a low of 2.6% to a high of 6.0%, with an average loss of 4.3%. This performance record places ERH's average system losses over the historical period within the OEB 5% threshold. It should be noted that in 2017 a system loss of 6.0% was recorded which is well above ERH's target of 5%. According to data from the *2019 OEB Yearbook of Ontario Electricity Distributors*[1], the average annual loss factor in Ontario was 3.95% in that year. The visible green bar in Figure 2-11 is ERH's line loss percentage in comparison to Ontario LDCs. Although ERH is above the 2019 provincial average, ERH's recent years have succeeded in achieving a lower line loss value than the target.

[1] http://www.ontarioenergyboard.ca/

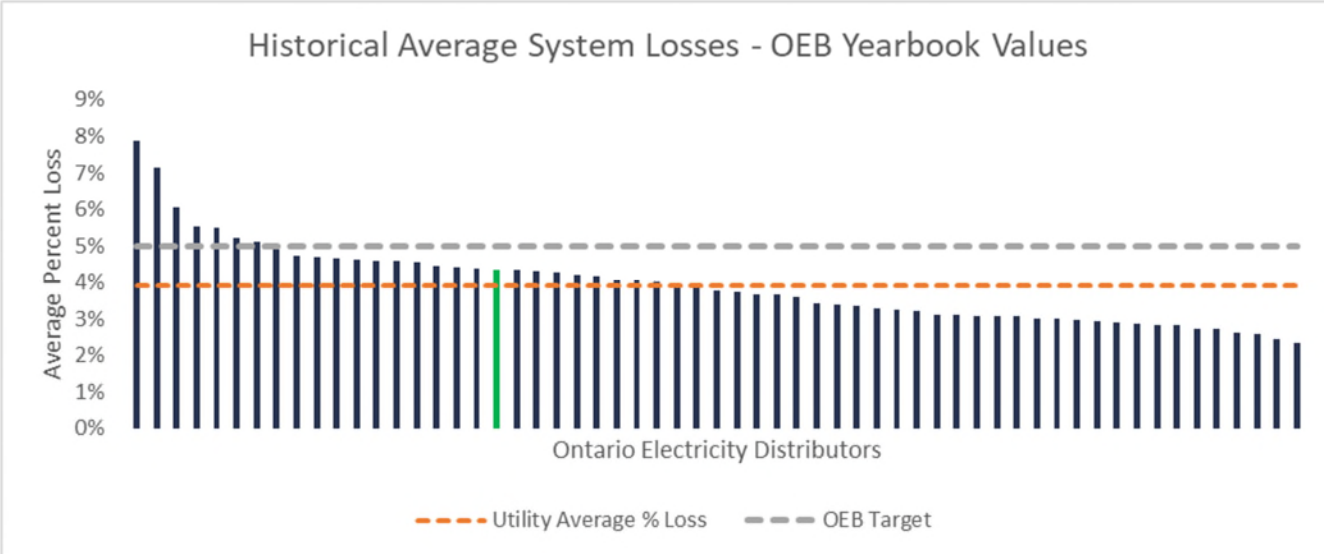

Figure 2-11: 2015-2019 OEB Yearbook of Ontario Electricity Distributors Average Annual Line Loss

2.3.3.2.3 Performance Trend into the DSP (5.2.3d)

The existing performance over the five-year historical period is within performance targets and as such, there is no specific impact on the DSP. For the period of the DSP, ERH has adopted a performance target of a maximum 5% system loss.

2.4 REALIZED EFFICIENCIES DUE TO SMART METERS (5.2.4)

The installation of smart meters provides ERH and its customers an operational advantage in maintaining its service while simultaneously improving upon it. These operational advantages include:

- Smart meters provide more detailed energy use for customers throughout the day. This enables customers to proactively manage their energy consumption. Though this efficiency improvement cannot be directly quantified, customers will have a better understanding of how they may reduce or offset their energy impact.
- The implementation of smart meters has improved the accuracy of billing charged to its customers, with the recent scorecard measure reported to be 99.83% which is above the industry target of 98%. This results in more satisfied customers receiving the correct billing invoice.
- The functionality of the meters is utilized in OMS to identify the extent of outages and devices that operated. This permits ERH to have faster outage detection and restoration of service. Though there were no major instances, the functionality is available for future operations. Additionally, new smart meters possess “last gasp” capabilities which can detect when an outage has occurred. This means that outages can be reported and triangulated automatically without the need for customers to call-in to report the outage.
- Smart meters are used for remote examination of meters (via pinging) to diagnose power-related issues without deploying a crew.

3 ASSET MANAGEMENT PROCESS (5.3)

This section provides an overview of ERH's asset management process, a description of assets managed by ERH, and a presentation of ERH's asset lifecycle optimization policies and practices.

3.1 ASSET MANAGEMENT PROCESS OVERVIEW (5.3.1)

3.1.1 Asset Management Objectives (5.3.1a)

In developing and implementing the DSP, ERH adheres to the following key AM focus areas to achieve its goals presented in Table 3-1. Supporting details are provided for each focus area to further highlight ERH's intended objectives and evaluations on its performance to date. Each core value is used to prioritize investments at ERH which comprise of one or more rankings, which is discussed further in section 4.2.2.

Table 3-1: Espanola Regional Hydro's Asset Management Objectives

RRFE Outcomes	ERH Core Values	Asset Management Objective
Operational Effectiveness	Safety	Both public and staff safety is of paramount importance. ERH's goal is to minimize public and worker safety risks surrounding its system. Additionally, ERH's goal is to maintain the same safety level without incidents by addressing the identified risks.
	Distribution Automation & Smart Grid Development	Modernizing the system grid with a focus on automating the substations has become a goal for ERH over the last few years. The automation initiative is intended to manage reliability and safety performance and remove constraints in the distribution system to accept connections of small and medium-sized generation from renewables for future smart grid development. ERH's goal is to automate its substations over the medium to long-term period as they come due for replacement or renewal.
Customer Focus	Reliability Performance	ERH's objective is to maintain the same level of system performance as it achieved over the last five years. A specific focus is on managing the risk of increased asset failures in service in the future due to ageing assets as well as the common causes of power interruptions such as tree and animal contacts. Furthermore, ERH intends to maintain its system following all applicable standards and guidelines, and in alignment with customers' expectations and needs.
Financial Performance	Optimal Asset Performance – Lifecycle Management	ERH's goal is to implement the least cost life cycle solutions to achieve the optimal balance between equipment renewal and replacement costs on one hand and maintenance and repair costs on the other. In the early stages of the assets' life cycle, it is often economically efficient to invest in preventative maintenance activities, which result in a corresponding increase in the useful service life of assets. However, as the assets approach advanced service age, when they require large investments to restore reliable operating conditions, investments into renewal and replacement rather than maintenance and repair become the optimal option.

RRFE Outcomes	ERH Core Values	Asset Management Objective
Public Policy Responsiveness	Environmental	ERH undertakes regular maintenance practices and has established processes for the disposal, recycling, and containment of materials harmful to the environment, such as PCBs. The goal is to continue to have zero impact on the sensitive northern Ontario environment and wildlife in which the service area resides.

ERH understands decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Optimal operation of the distribution system is achieved when appropriately timed investments into the replacement of assets and asset repair, rehabilitation and preventative maintenance are planned and executed. In summary, ERH's overarching asset management objective is to find the right balance of investments into its infrastructure to maintain and achieve all relevant goals.

3.1.2 Components of the Asset Management Process (5.3.1b)

Before preparing each year's capital plan, ERH's asset management process takes on an effort to estimate the number of assets that require intervention based on the current system operations and needs. Furthermore, the plan builds on the previously completed work and combines the information on assets' operating condition with risk-based frameworks, using all available information, including asset age, asset operating condition determined through inspections and results of asset testing, where available. In addition to these, consequences of risk of asset failure as well as trade-offs between maintenance and replacement are incorporated into the proposed program. The process undertaken is illustrated in Figure 3-1 and further detailed in the section below.

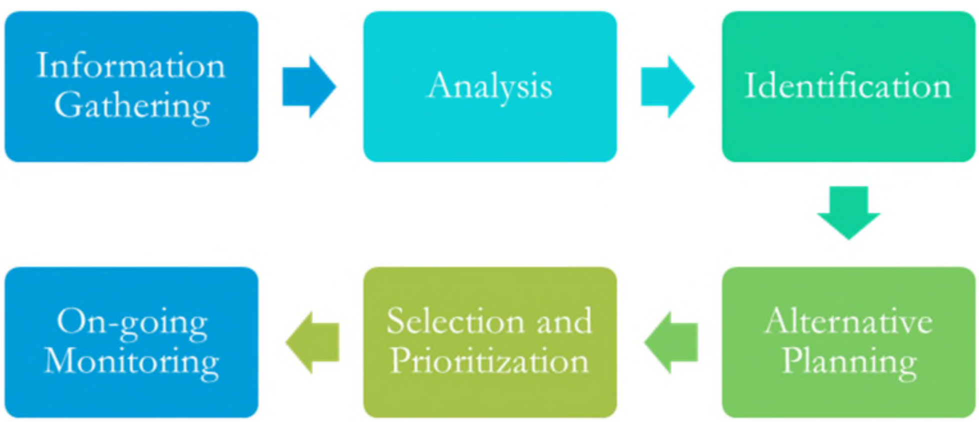

Figure 3-1: ERH Asset Management Process

1. Data and information gathering – To assess the system needs, the first step is to gather all pertinent information such as asset counts, types, conditions, and maintenance information etc. This is done through three mediums:
    a. Review of Records – Though ERH does not have a centralized asset database or GIS system, records which are kept in the form of operating maps, spreadsheets, pole test data and those submitted as a part of OEB reporting functions are key inputs into the asset management planning process
    b. Site visits – The information gathered from the records is augmented through field inspections during site visits through visual inspections, line patrols and substation visits. The site visits allow ERH to confirm data provided by the records as well as gather additional information not available through records

c. Staff Interviews – During site visits information is also gathered directly through staff interviews. This includes gathering customer connection requests for load and generation, and identification of problem areas on the network, which they deal with daily.

2. Analysis of information, application of asset condition assessment, creating the overall system overview and needs – During this step in the planning process, ERH's objective is to sort information gathered to complete asset condition assessments, system constraints and additional relevant system studies.

3. Identification of the specific system needs (target areas) – During this step, targeted areas requiring investments to mitigate capacity constraints or mitigate the risk of in-service failures are identified and detailed analyses are performed to substantiate the required investment levels.

4. This step involves the analysis of alternatives to address the needs and impacts of each alternative – to identify the optimal alternative for implementation. The alternatives analysis work for major investments into stations is extensively explored through the station's condition and planning reports included in the appendices.

5. Selection of optimal alternatives and prioritization of investments are made on the impact assessment completed in the previous steps. Consideration is also given to the practicality of implementation of the proposed plan, by balancing the system needs against available resources to implement the projects.

6. Continuous monitoring of changing operating environment and asset performance as well as being flexible to adapt to changing circumstances where some needs may change in priority and new needs may be brought forward.

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investments not made on time when warranted by the system need to raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when "right-sized" investments into renewal and replacement (capital investments) and asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

Figure 3-2 summarizes the flow chart used to sift through the assets, to objectively identify the assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk.

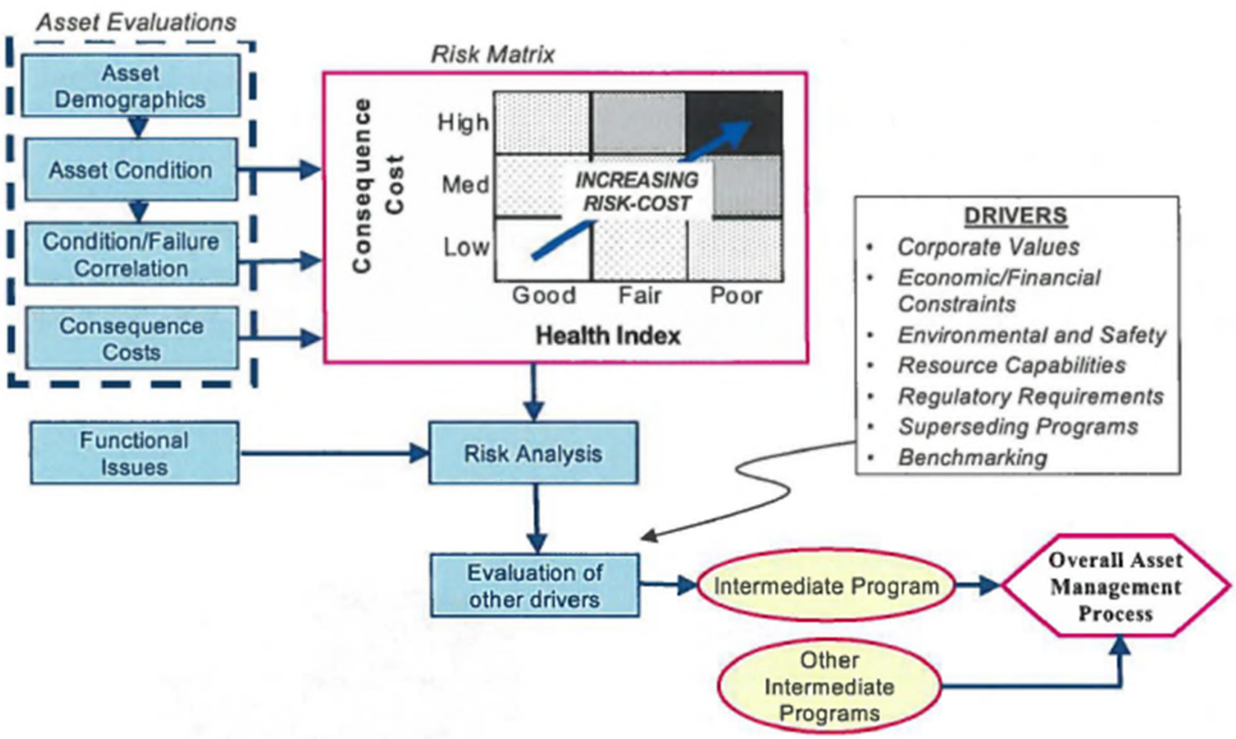

Figure 3-2: Flow Chart for Asset Management Plan

The data sets employed in the prioritization of the investments include:

a) Asset records/demogrpaihc information, station single line diagrams and operating maps, indicating conductor sizes, equipment ratings and service age of assets
b) Station peak loading data, indicating equipment capacities and maximum load
c) Equipment inspection data sets, indicating the operating condition of distribution system assets
d) Substation test result data sets
e) Asset condition assessment report

While data sets listed under a), b) and c) are maintained and updated by ERH's staff, data sets listed under d) and e) are compiled by third-party contractors.

Using asset demographic information from ERH's data sets as an input, service age profiles are developed for all categories of distribution system assets, including distribution stations, the overhead distribution system and the underground distribution system. Anticipated loading levels for distribution stations during the next five years are compared with the station ratings, to identify distribution system constraints. Results of physical inspections of the distribution system performed by ERH staff are reviewed and supplemented by additional inspections of high-risk assets performed by a third-party. By considering asset demographic information, results of physical inspections and in-situ testing, the condition of each major asset in service can be assessed.

Numeric health indices, normalized to a scale of 100, are used to express the health and condition of assets; and this procedure allowed separation of the assets in "very good", "good" and "fair" condition that require minimal risk mitigation from those in "poor" and "very poor" condition. For assets determined to be in “poor” or “very poor” condition, consequences of asset failures are assessed and assets with the highest consequence of failure were identified. For assets with the highest risk, the optimal scope and timing of intervention for risk mitigation are identified, by using the life cycle cost minimization strategy, while constraining the total expenditure at appropriate levels for ERH.

3.2 OVERVIEW OF ASSETS MANAGED (5.3.2)

3.2.1 Description of the Service Area (5.3.2a)

ERH's service territory consists of three non-contiguous land parcels shown in Figure 3-3. ERH serves the towns of Espanola and former towns of Massey and Webbwood (currently within the township of Sables-Spanish Rivers), covering a total service area of approximately 109 sq. km (with 83 sq.km being rural and 26 sq. km being urban). The economic growth in the region is considered to be slow.

The distribution system is predominantly overhead. The climate is typical of most towns in Northern Ontario and reaches temperature extremes of -40°C during winter. The presence of several different soil types, the Canadian Shield, numerous clays, and muskeg make all excavation activities a challenge. The region is vulnerable to strong windstorms, which are a common occurrence.

Due to slow growth in the region, capacity constraints are not anticipated during the next five years. Therefore, minimal to no investments are required in the system service category. Strong winds combined with low temperature expose the overhead distribution system in this region to heavy structural loads during the winter season, making the aged and weakened overhead lines highly vulnerable to failure. Lines with the highest risk of failure consequences are included in the asset renewal program proposed in this DSP.

Figure 3-3: ERH Service Territory

3.2.2 Summary of System Configuration (5.3.2b)

ERH owns and operates systems at two distribution voltages – 4.16 kV and 12.47 kV. The 4.16 kV system primarily services the town of Espanola while the 12.47 kV services the Massey and Webbwood service area.

In Massey and Webbwood, ERH does not own any substations as the 12.47 kV feeders are embedded into the Hydro One distribution system. Massey and Webbwood service areas are supplied via a dedicated HONI 44kV feeder. The 4.16 kV feeders in Espanola are supplied from four municipal substations fed from a single 44 kV overhead feeder. Municipal station ratings and distribution feeder arrangement are indicated in Table 3-2 with their locations visible shown on a map in Figure 3-4. MS4 is the newest station which was built in response to system needs and completed/commissioned in

2014. As a result of only being supplied by one feeder, in instances where HONI experiences an outage, ERH experiences loss of supply to the entire Town of Espanola. This is the major factor affecting reliability performance.

Table 3-2: ERH's Owned Municipal Station Ratings and Distribution Feeder Arrangements

Station	Construction Year	Capacity	4 kV Feeders
MS1	1960	5 MVA	Four Feeders: MS1F1, MS1F2, MS1F3, MS1F4
MS2	1970	5 MVA	Four Feeders: MS2F5, MS2F6, MS2F7, MS2F8
MS3	1958	3 MVA	Two Feeders: MS3F9, MS3F10
MS4	2014	5/6.67MVA	Three Feeders: MS4Fll, MS4F12, MS4F13

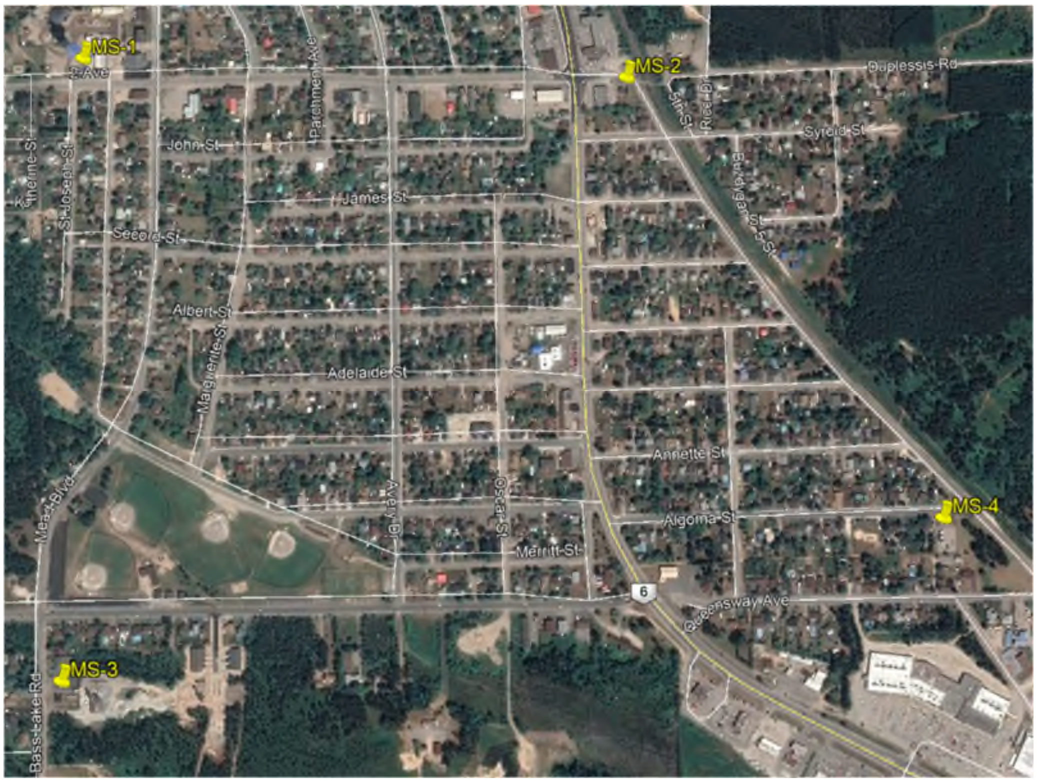

Figure 3-4: ERH's MS locations

Major assets installed on ERH’s distribution system are summarized in Table 3-3. As indicated, the distribution system is predominantly overhead but has a small fraction (approximately 6%) of underground cable circuits, including some submarine cables to service customers located on islands.

Table 3-3: ERH's Distribution System Assets

Asset Type	Count
Overhead lines 3 phase 44 kV (km)	5.8
Overhead lines 3 phase 12.47 kV (km)	9.4
Overhead lines 3 phase 4.16 kV (km)	21.7
Overhead lines 2 phase 12.47 kV (km)	1.1
Overhead lines 2 phase 4.16 kV (km)	1
Overhead lines 1 phase 7.2 kV (km)	35.24
Overhead lines 1 phase 2.4 kV (km)	16
Total of Overhead Lines (km)	90.24
Distribution line poles owned by ERH	1,307
Joint use poles on which distribution lines are attached (owned by Bell)	685
Total distribution system poles	1,992
Underground 3 phase cables 4.16 kV (km)	1.3
Underground 1 phase cables 2.4 kV (km)	7.6
Total of Underground Cables (km)	8.9
Submarine 1 phase cable 7.2Kv (km)	3.0
Pole mounted transformer,1-ph	694
1 phase cut-outs	694
1 phase disconnects	76
3 phase disconnects	68
3 phase load break switches	9
Pad-mount 37.5 kVA, 1-ph	4
Pad-mount 50 kVA, 3-ph	3
Pad-mount 75 kVA, 3-ph	1
Pad-mount 150 kVA, 3-ph	1
Pad-mount 500 kVA, 3-ph	3
Transclosures, 1-ph	49
Revenue Meters	3283
Substations	4

3.2.3 Results of Asset Condition Assessment (5.3.2c)

In the following section, the assets are based on the data obtained in the second quarter of 2015, with appropriate updates for the asset renewal work completed to date. The last condition assessment was completed in 2015 which documented the condition of all major assets and provides a ranking of assets in designations rated "very good", "good", "fair", "poor" and "very poor". In determining the health indices of assets, all available information relevant to the assets' health, including age, results of visual inspections and diagnostic testing has been utilized. For the current application, ERH did not prepare a formal condition assessment. As mentioned in Section 1, OEB has accepted ERH's proposal of deferring a formal Asset Condition Assessment until after the North Bay merger.

STATIONS

Four municipal stations are serving the ERH service area, which steps down 44 kV supply to 4.16 for distribution. MS4 is the newest station which was built in response to system needs and completed/commissioned in 2014.

ERH does not have spare station power transformers available, should a failure take place. Furthermore, during peak winter load periods, stations MS1, MS2 and MS3 had historically been overloaded and although ambient temperature during winter months would permit moderate overloading of transformers beyond the nameplate rating, these overloading conditions over extended durations are expected to have adverse impacts on the lives of the transformers. However, with the addition of MS-4 in 2014, overloading is no longer an issue except in an N-1 contingency situation when one station is out of service.

Based on the existing condition of major assets employed in municipal stations, Table 3-4 summarizes the operating condition of each of the municipal stations. The typical useful service life of station transformers is 45 years. Three of the four station transformers (MS1, MS2 and MS3), have already exceeded the typical useful service life. Each of these three stations will require reconstruction and equipment renewal during the next 10 years to mitigate reliability and supply security risks. Due to its age, condition, peak loading, and impact to failure, ERH proposes the prioritization of the following investments: MS1 to be replaced first, followed by MS2 which has shown extensive signs of insulation deterioration as noted by the 2014 oil testing which concluded that the excessive CO_2 gas in the oil sample is a direct result of deteriorated paper winding insulation. Stations are expected to be rebuilt according to the latest construction and utility standards such as used for MS4.

Table 3-4: Municipal Substation Condition Assessment

Station	Age	Condition
MS1	60	Very Poor
MS2	50	Poor
MS3	62	Fair
MS4	6	Very Good

OVERHEAD DISTRIBUTION

Overhead distribution encompasses all assets downstream of the stations which are configured in a typical overhead design. As egress feeders leave the station, they are either underground to a riser pole or overhead directly to the overhead circuit. Major asset classes of overhead distribution include:

- Lines conductor
- Poles
- Insulators and hardware
- Pole mounted transformers
- Protective devices
    - Switches, and cut-outs (both fused and not fused), arresters etc.

A photograph of an overhead line is shown in Figure 3-5.

Figure 3-5: ERH Overhead Distribution

The overhead primary distribution lines at ERH employ 1/0 ACSR, 2/0 ACSR, 3/0 ACSR, and 336 ACSR conductors. Typical useful service life for these conductors is of the order of 60 years. However, ERH has not experienced a significant increase in conductor failures on overhead lines. Conductors, if loaded below its thermal rating, can last much longer than the remaining useful life indicated by the service age. Therefore, the DSP does not propose direct investments into replacing overhead conductors. However, distribution line sections can also have capacity constraints due to undersized conductors on trunk portions of feeders or present a risk to public safety that are prioritized appropriately within ERH's investment plan.

ERH's overhead pole lines comprise approximately 1,900 wood poles. Failures of poles have the potential to take down lines along with the transformers resulting in prolonged outages, creating public safety risks, and potentially impacting the environment if a transformer were to leak or if the overhead conductor were to land on a tree and catch fire. ERH employs the services of a pole testing contractor annually to complete non-destructive testing and identifies the remaining useful life of these assets. This serves as an input into decisions as to where to focus asset renewal dollars. Those in the worst condition take priority in the program. ERH intends to replace the most at-risk, deteriorated poles within the forecast period.

ERH contains approximately 694 overhead pole-mounted distribution transformers. ERH's DSP does not target proactive replacement of transformers, but rather a reactive approach, meaning transformers are replaced after they have experienced a failure in service. Similarly, the renewal of disconnects and cut-outs are also managed in a reactive mode, i.e. replace upon failure.

UNDERGROUND DISTRIBUTION

Underground distribution encompasses all assets downstream of the stations which are configured in a typical underground design (cables in underground ducts or direct buried). As egress feeders leave the station, they are underground to a riser pole or overhead directly to the overhead circuit, at some point downstream the circuit re-enters the ground and runs throughout serving customers and businesses. Major asset classes of underground distribution include:

- Cable
- Padmount Transformers

- Transclosures

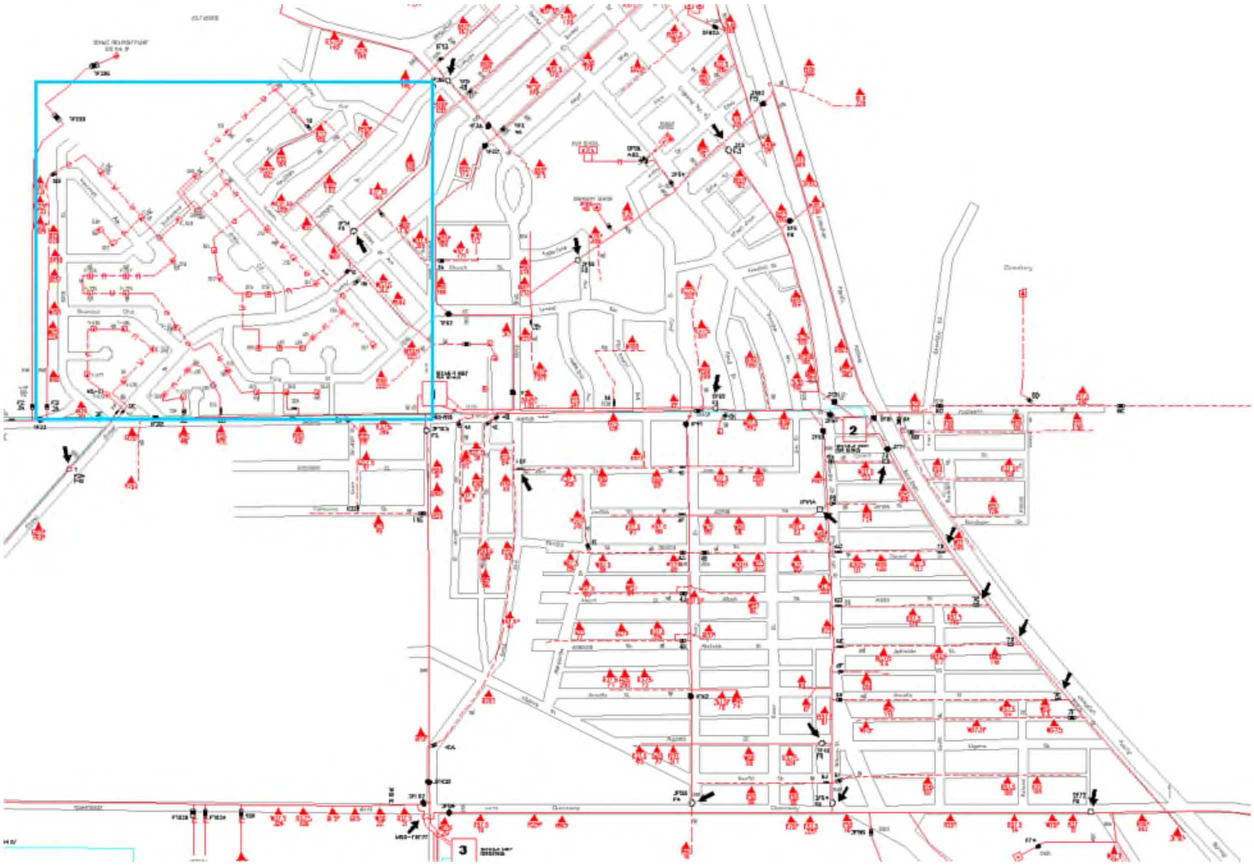

Figure 3-6: Espanola Main Underground Service Area (Enclosed in blue)

Unlike the overhead distribution, underground service is fairly concentrated in a small pocket in the North West corner of Espanola, shown in Figure 3-6. Following the OEB depreciation study, the average useful life of an underground cable is 30 years for direct buried XLPE. Based on this age, a significantly large portion of the cable population in service has exceeded its useful life. It is important to note that the cable is rated for 15kV however and is being operated at 4kV. It is therefore expected that the cable insulation has not been stressed to its design rating and is therefore expected to provide a longer mean service life than 30 years.

In addition to the above described underground cables, ERH inherited some sections of submarine cable from HONI. Submarine cable spans are located near the southern rural region of Espanola with a total line length of approximately 3 km (shown in Figure 3-7 and Figure 3-8). All runs of submarine cable are dedicated to serving customers in remote locations on islands in lakes. Much of this cable was replaced in the past five years due to significant deterioration of the steel wound armour, which also serves as the system neutral conductor.

Figure 3-7: Anderson Lake Submarine Cable Run Area

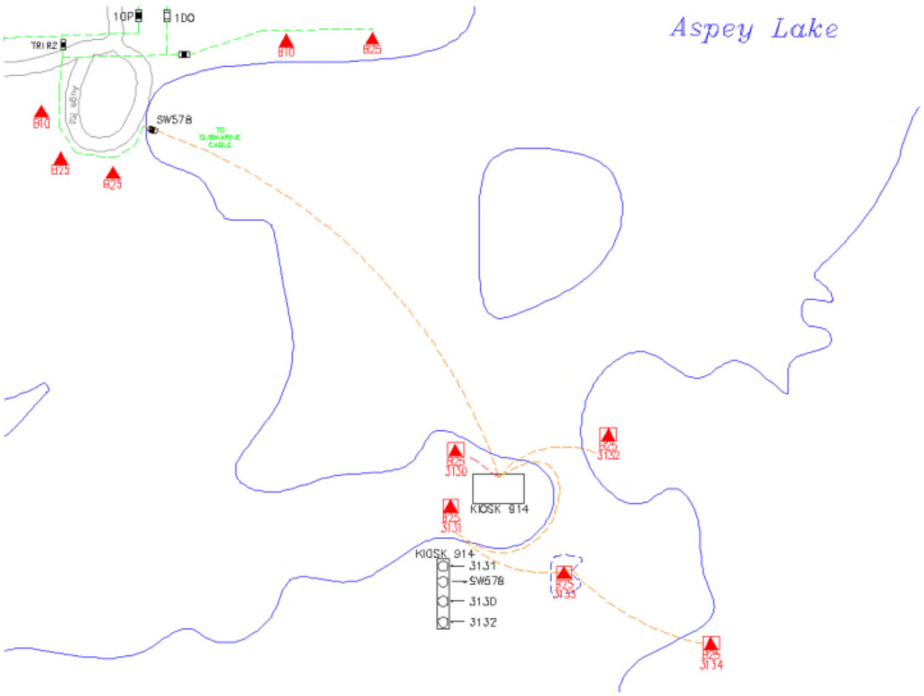

Figure 3-8: Submarine Cable Runs on Apsey Lake

3.2.4 System Utilization (5.3.2d)

Figure 3-9 shows the seasonal variations in total load served from the 44kV circuit supplying the municipal stations serving customers in Espanola. Data shown in the graph is for the period 2009-2015 and is taken from the ACA completed in 2015. A newer ACA is not yet available; however, the general character of the load profile has not changed in any material way since that time and the graph still provides a meaningful illustration of the current loading profile. As shown, the supply system peaks in the winter months. Due to the extreme winters in the remote area of northern Ontario coupled with the fact that much of the heating is electrical in the town, the peak loading period occurs in the winter months. As such it is advantageous because the ambient temperature reduces the impact of the extreme loading on transformers but also poses a greater safety risk in case of failure where the result would be exposure of the public to extreme sub-zero temperatures with loss of heat.

Table 3-2 in Section 3.2.2 highlights ERH's station and feeder configurations with the design capacity. Table 3-5 highlights the peak load experienced by each station as well as the average annual peak load over the last five years. In summary, ERH's distribution stations have sufficient capacity to serve current and future loads while still maintaining a high degree of redundancy.

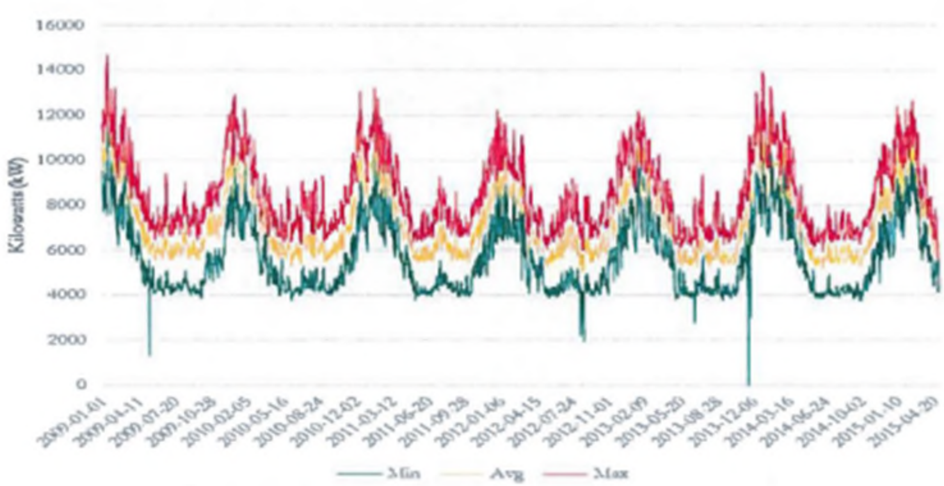

Figure 3-9: ERH Service Territory – Five Year System 2009-2015

Table 3-5: Station Historical 5-Yr Loading 2015-2019

Distribution Station	MVA Rating		Peak Load Experienced Past 5 Years (% of ONAN)	Average Annual Peak Load Experienced Past 5 Years (% of ONAN)
	ONAN	ONAF		
MS1	5	-	81%	64%
MS2	5	-	82%	59%
MS3	3	-	85%	65%
MS4	5	6.667	62%	46%

3.3 Asset Lifecycle Optimization Policies and Practices (5.3.3)

The lifecycle optimization policies and procedures in use at ERH, including the optimization of the capital investment plan as well as optimization of the preventative maintenance practices, are described in the following sections.

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

ERH's overarching objective is to develop a capital and preventative maintenance investment plan, which would result in optimal operating performance to meet stakeholder needs and regulatory compliance while minimizing life cycle costs as shown in Figure 3-10.

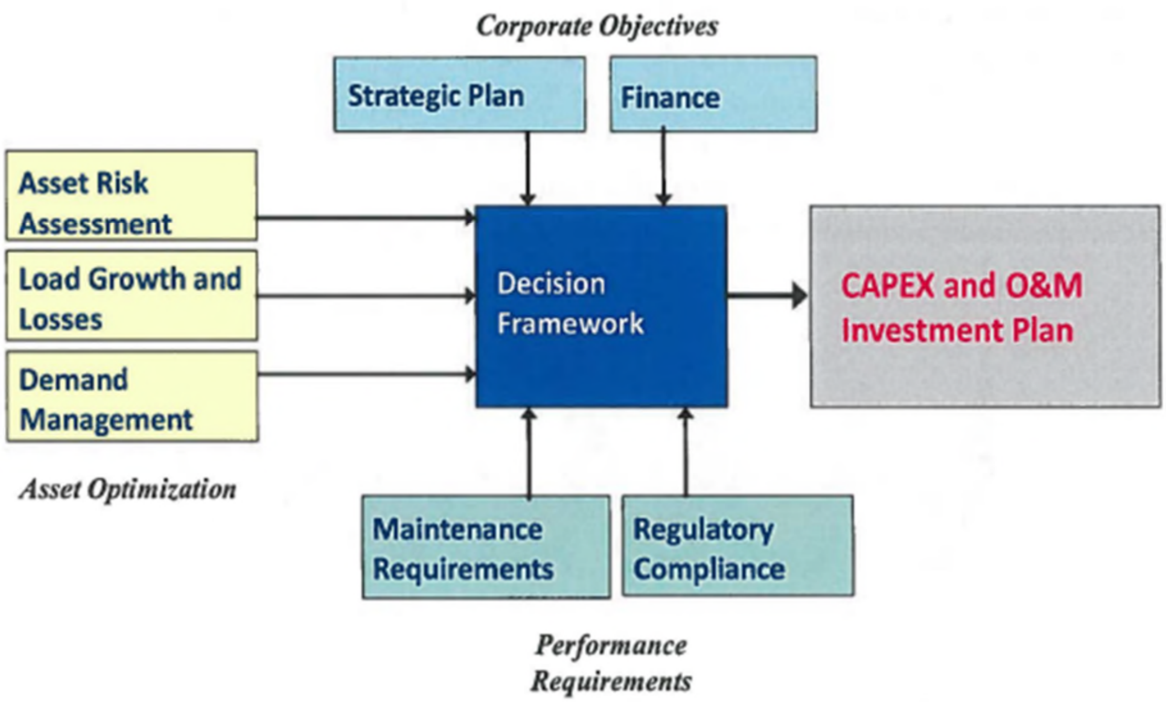

Figure 3-10: Multi-Prong Decision Framework

The life cycle optimization policies and procedures at ERH include determining the optimal time and scope of the most effective risk mitigation option, through trade-offs between capital expenditure, preventative maintenance, and reactive maintenance. Figure 3-11 shows the basic decision support model employed by ERH in preparing this DSP to determine the scope and the timing of the investments. With an increase in service age, an asset's condition degrades, thus increasing the risk of the asset failing in service. In the absence of any intervention in the forms of asset renewal or asset refurbishment or repair, the consequential risk cost would continue to increase. When a risk mitigation intervention is implemented through investment, the risk cost curve resets, triggering a benefit in the form of reduced risk. In preparing the DSP, the timing and the size of the investments have been selected to minimize the "Total Cost" of assets in consideration.

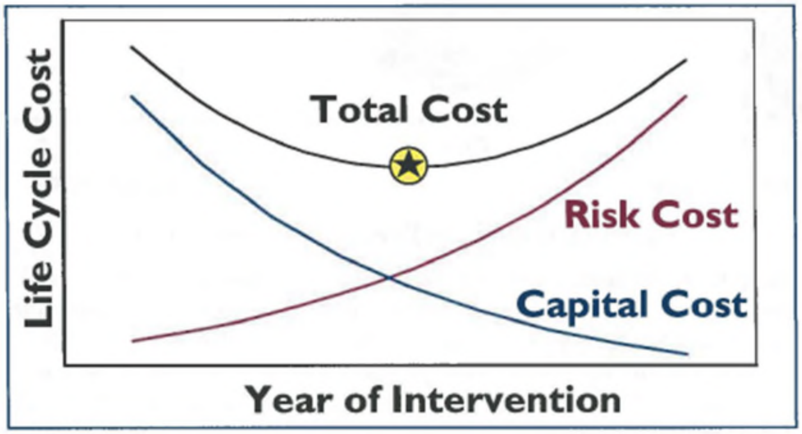

Figure 3-11: Risk-Based Decision Support System

Figure 3-12 illustrates the impact of maintenance activities in extending the service life of an asset[2]. Optimization is carried out to minimize overall life cycle costs of assets, while meeting the required performance levels, by taking all available information relevant to the condition of assets into account. Periodic asset inspections and testing provide valuable information on assets' health and the probability of assets' failures, allowing appropriate risk management initiatives to be implemented over the lifecycle of each asset.

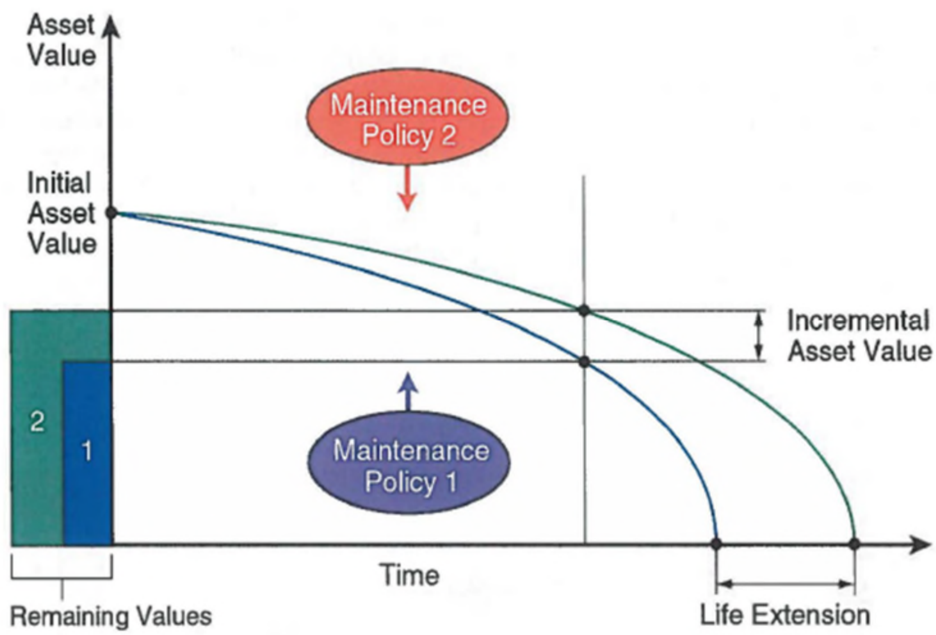

Figure 3-12: Risk-Based Decision Support System

ERH's Operations & Maintenance ("O&M") programs are designed to follow the guidelines set out in the OEB's Appendix-C Distribution System Code ("DSC") for the inspection and maintenance of all

[2] "Predicting Future Asset Condition Based on Current Health Index and Maintenance Level" Thor Hjartarson, Shawn Otal, IEEE 11th International Conference on Transmission & Distribution Construction, Operation and Live-Line Maintenance, 2006, ESMO, Oct. 20

key distribution system assets. ERH reviews its O&M programs annually to best align with its capital programs and the best industry practices and standards. Inspection and testing of assets are critical for the prioritization of O&M spending and optimization of the assets' total life cycle cost. The results of inspections and testing are used to identify and prioritize system rehabilitation projects, resulting in the selection of the optimal decision to either replace, repair or do-nothing. Assets for which replacement is identified as the optimal solution are included in the capital plan for replacement. For assets where replacement is not determined to be the optimal solution, ERH's O&M programs include minor repairs and maintenance work designed to economically extend the life of the assets. In both cases, planned replacement projects and planned O&M activities are selected to align with the budget envelopes by optimizing the scope and the timing of work during project prioritization and selection processes.

ERH utilizes the results of visual inspections, in-situ testing, and service age of assets to evaluate the condition of assets by deriving a Health Index ("HI") for each asset, which is related to the probability of failure for an asset by relating the health of the asset. In addition to assessing the health of the asset, the risk is factored into the selection and prioritization of capital expenditures during the prioritization process. Assets with unacceptably high-risk scores are monitored closely and project plans are developed to either maintain, refurbish, or replace the assets to reduce the risk to an acceptable level. It is noteworthy that some assets carry an inherently higher risk than others, for example, power transformers at stations have a higher associated nominal risk level versus pole-mount transformers. For assets with low health indices, a higher priority for replacement is given to assets with a higher degree of failure consequences. The highly prioritized projects in each investment category are scrutinized with detailed investigation and inputs from subject matter experts to eliminate data inconsistencies and determine the appropriate scopes of work.

3.3.2 Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

Proper maintenance is essential to prolong asset lifecycles and maintain system reliability. ERH's maintenance program employs equipment manufacturers' recommendations as well as best industry practices in determining the scope and the frequency of maintenance activities on assets. The maintenance programs also comply with the regulated requirements for maintenance established by the Electrical Safety Authority ("ESA").

3.3.2.1 *Preventative Maintenance of Critical Equipment in Substations*

ERH's planned substation maintenance schedule is summarized in Table 3-6.

Table 3-6: Municipal Station Preventative Maintenance

Maintenance Activity	Frequency
Visual Inspection of Assets	Monthly
Testing of Insulating Oil Samples	Annually
Full Off-line Substation Maintenance	Once Every Four Years

Monthly inspections at substations include the following tasks:

- Inspect substation security (gates locked, fence condition, warning signs and emergency contact information posted).
- Inspect substation yard and building conditions, including vegetation growth, snowbank accumulation, garbage, vandalism, etc.
- Inspect substation electrical safety, including fence grounds, bonds, equipment grounds, insulators, foundations, ancillary equipment, metal-clad fastenings and corrosion-related impairment of assets.

- Inspect power transformers, including checking and recording oil level, oil temperature, equipment grounds, feeder load readings.
- Inspect access and egress riser poles.
- Verify the voltage level of battery banks (only applicable to MS4).
- Inspect batteries (only applicable to MS4).
- Inspect and record relay voltage, Amps etc. (only applicable to MS4).

Full off-line substation maintenance takes place every four years to conduct the inspection, testing and maintenance of all power equipment installed at substations. The substation is taken out of service typically for a day to perform maintenance. The station maintenance work is commonly outsourced, and the scope of work includes:

- Take oil samples from power transformers for testing (standard five-part ASTM and DGA).
- Clean and lubricate switches and fusing.
- Conduct insulation resistance testing on power switches, fuses, 44kV and 4kV riser pole cables.
- Clean and lubricate switchgear, ensure proper operation.
- Inspect power switches and fuses.
- Perform transformer testing, including measuring insulation resistance, turns ratio, capacitance and dissipation factor, and windings resistance.
- Conduct infrared scan (“IR”) scans of all high voltage electrical equipment (insulators, switches, cables, connections, and riser poles).

3.3.2.2 *Line Clearing Program*

ERH's Line Clearing Program is conducted on a three-year cycle. ERH's service territory is divided into three partitions to delineate the scope for plant inspections and vegetation management over each inspection period.

ERH leverages its relationship with PUC Distribution Inc., the LDC for the City of Sault Ste. Marie (“SSM PUC”). Under a management services contract, ERH takes advantage of SSM PUC's larger contracts for line clearing and pole testing. The contractor conduct work for ERH for the same terms and conditions as set out in the contract with SSM PUC and bill ERH directly. The work typically spans six to eight weeks during late summer or early fall. The contractors are responsible for the removal of dangerous trees, vegetation growth within three metres of primary conductors, 1.5 metres of the secondary conductor, as well as brushing and herbicide treatment and substation herbicide treatment, as required.

For vegetation management outside of the contracted scope of work, ERH line crews identify dangerous trees for removal during plant inspections. These danger trees are then removed by ERH line crews as required unless the work can be coordinated with contractors during the contract period. ERH line crews also respond to customer requests on vegetation issues throughout the year. All customer requests for tree-related issues are tracked as Customer Service Orders through the CIS.

3.3.2.3 *Safety Inspections of Overhead and Underground Lines*

Overhead lines and underground distribution system plants are inspected on a three-year cycle, to comply with the DSC requirements. One-third of the distribution assets employed on the overhead distribution system are inspected each year. In addition to the inspection of the overhead system, ERH comples non-destructitve wood pole testing to ideitnfy any critical and at-risk of failure poles to be replaced. Structural defects, clearance issues and electrical problems and hazards are identified through visual inspections and where problems are revealed, either repair work is scheduled or capital work is planned, as needed. Where the inspections determine an immediate hazard to the public, immediate follow-up action is taken to mitigate the problem.

3.4 System Capability Assessment for Renewable Energy Generation (5.3.4)

3.4.1 Applications Over 10 kW (5.3.4a)

As of October 1, 2020, there are no current applications from renewable generators over 10kW for connection in the ERH's service area.

3.4.2 Forecast of REG Connections (5.3.4b)

There is a total of 13 renewable energy generation installations presently connected to ERH's distribution system under the province's Feed-in-Tariff ("FIT") and micro FIT programs:

- 2 FIT installations with a generating capacity of 750 kW.
- 10 micro FIT installations with 86 kW installed capacity.
- 1 solar net-metering installations with 1.72 kW installed capacity.

There are currently no additional applications in the queue. ERH expects an equal or less amount of applications from REG's over the rate filing period to what has been connected to date due to the reduced incentives and the limited participation to date.

3.4.3 Capacity Available (5.3.4c)

ERH's distribution system has adequate capacity to connect all anticipated REG customers during the next five years without any additional investment above what is already accounted for in infrastructure renewal. Currently, there are no applications in the queue from generation connections <10kW and under the micro-FIT program. All requests for micro-Fit generation received to date have been successfully connected to the system.

Distribution system capacity for accepting renewable generation is indicated in Table 3-7 and based on prior experience it far exceeds the capacity likely to be requested by renewable energy generation customers.

Table 3-7: REG Connection Capacity

Station	ONAN Transformer Rating (MVA)	Feeder	REG Connection Capacity (MW)
MS-1	5	F1	3
		F2	
		F3	
		F4	
MS-2	5	F5	3
		F6	
		F7	
		F8	
MS-3	3	F9	1.8
		F10	
MS-4	5	F11	3
		F12	
		F13	

3.4.4 Constraints – Distribution and Upstream (5.3.4d)

There are no constraints on the ERH system related to the connection of REG.

3.4.5 Constraints – Embedded Distributor (5.3.4e)

There are no constraints for an embedded distributor that may result from connections of REGs.

4 CAPITAL EXPENDITURE PLAN (5.4)

This section describes ERH's capital expenditure plan over the forecast period, including a summary of the plan, an overview of ERH's capital expenditure planning process, an assessment of ERH's system development over the forecast period, a summary of capital expenditures, and a justification of capital expenditures.

4.1 SUMMARY

ERH's DSP details the programme of system investment decisions developed based on information derived from ERH's asset management and capital expenditure planning process. Investments, whether identified by category or by a specific project, are justified in whole or in part by reference to specific aspects of ERH's asset management and capital expenditure planning process.

4.1.1 Capital Expenditures over the Forecast Period

The DSP and the underlying capital investments conform to ERH's objectives and high-level goals as illustrated in Figure 4-1 and further detailed.

Figure 4-1: Distribution System Plan Goals

1. Reliability Performance – Over the past five years, apart from interruptions resulting from the loss of 44kV and 12kV supplies from Hydro One, system performance has been good and in line with the customer's expectations and needs. The most common causes of power interruptions on power lines in the past have been equipment failures and adverse weather impacts, and more specifically attributable to associated tree and animal contacts. The objective is to maintain the same level of system performance, which presents the risk of increased asset failures in service in the future due to ageing assets.

2. Life Cycle Management – Life cycle management decisions involve implementing the least cost life cycle solutions to achieve the optimal balance between equipment renewal and replacement costs on one hand and maintenance and repair costs on the other. In the early stages of the assets' life cycle, it is often economically efficient to invest in preventative maintenance activities, which result in a corresponding increase in the useful service life of assets. However, as the assets approach advanced service age, when they require large investments to restore reliable operating conditions, investments into renewal and replacement rather than maintenance and repair become the optimal option.

3. Safety – Both public and staff safety is of paramount importance. ERH has had no serious injuries or safety-related incidents in the past and ERH's goal is to maintain the same safety level without incidents by addressing the identified risks.

4. Environmental – ERH undertakes regular maintenance practices and has established processes for the disposal, recycling, and containment of materials harmful to the environment. To date, there have been no hazardous materials released into the environment through the operation and renewal of system assets. The goal is to continue to have zero impact on the sensitive northern Ontario environment and wildlife in which the service area resides.

5. Distribution Automation and Smart Grid Development – Aside from the implementation of the provincially mandated smart metering program in 2009, there have been virtually no automation at three of the existing distribution stations MS1, MS-2 and MS-3. In 2014, ERH constructed a new distribution station, MS4, and this station is equipped with automatic feeder reclosers, controlled through SEL protection relays. The remaining three existing stations are planned to receive the same degree of automation, i.e. equipped with automated feeder reclosers when they are reconstructed. This automation initiative is expected to not only help improve reliability and safety but would also better support the connections of small and medium-sized generation from renewables by allowing for the expansion of the existing available connection capacity.

Table 4-1 summarizes the planned capital expenditures, by investment category, for the DSP forecast period:

Table 4-1: Planned Gross Capital Expenditures

Category	2021($)
System Access	$ 51,864
System Renewal	$ 403,565
System Service	$ -
General Plant	$ 33,000
Gross Capital Expenses	$ 488,429

The capital expenditure proposed in this DSP is in response to the following categories:

- System Access
- System Renewal
- General Plant

Proposed investments in the System Access category are included to connect new generation and load customers, permit service upgrades requested by customers, allow line relocates in response to requests from the municipality and investments into revenue metering. The investment level in the System Access category is based on the historical average number of service requests. Proposed investments into System Renewal are based on optimizing the risk associated with asset failures which are based on ERH's inspection and lifecycle processes. Investments in the General Plant category are based on historical average expenditures in this category and include the cost of replacing tools, fleet, and safety work equipment at the end of their service life.

The distribution infrastructure and particularly the assets employed in substations at ERH have reached an advanced service age, where the probability of asset failure in service is very high. Hence, the major focus of ERH's DSP is on the renewal of aged and deteriorated assets that present the largest risks to ERH's operations and reliability to minimize customer impacts.

4.1.2 Capital Planning for 2020

The following briefly describes the outputs of the asset management and capital expenditure planning processes for each of the four investment categories.

4.1.2.1 *System Access*

The proposed investments in the System Access category include expenditure required by ERH to meet its regulatory obligations. These investments consist of three main components:

(i) line extensions to permit new customer connections.
(ii) line relocations are required in conjunction with the municipal road widening programs.
(iii) joint use "make-ready work", related to joint-use applications where third-party upgrades require make-ready work by LDCs.

Although ERH has used all available information obtained through consultations with the municipal government, local developers and major customers to estimate the expenditure requirements in this category, these investment requirements are potentially subject to change due to changing plans in the community. ERH does not typically get significant advance notice for such services. The capital investment level for this category, is, therefore, based on known information about specific projects in this category as well as the average expenditure in this category during the last five years.

There has not been a significant change in the number of customers served by ERH during the past several years, but there continue to be activity in-service upgrade requests from existing customers. Currently, there is no backlog of customers requiring new services within ERH service areas. ERH receives about 10 requests for new services and approximately 15 requests for service upgrades, annually, and this trend is expected to continue. The size of future investments to serve customer requests for new load or generation connections and upgrade of existing services is based on the average of the past five historic years.

Road widening projects undertaken in the municipality require relocation of some power distribution lines, requiring capital investments by ERH, from time to time. There are no known projects requiring line relocations at present, but such projects are anticipated to be performed when requested by the municipal authorities. Such requests are often received with relatively short notice.

The System Access category investments also include an allowance for the net contribution required from ERH for "make-ready work" on joint use pole lines, when third party upgrades require make-ready work to be completed by ERH.

4.1.2.2 *System Renewal*

The scope of capital investments proposed in the "System Renewal" category has been determined with the objective of keeping power supply reliability from deteriorating. Investment required for renewal of the assets found in "poor" or "very poor" condition presents the highest risk of failure in service and have been prioritized for renewal. Prioritized investments into asset renewal included in this DSP are summarized below:

(i) Lines determined to be in "very poor" condition present the highest risk of failure as well as they may present capacity constraints for load transfer among adjacent stations during "N-1" operating conditions.

(ii) Poles that are in very poor condition present a high risk of failure in service when exposed to a windstorm, particularly when conductors are loaded with ice. The proposed plan targets the replacement of these poles.

(iii) For distribution transformers and cut-outs, ERH follows the "run-to-failure" strategy. Based on the condition assessment of these assets, funds have been included in the budget to replace these assets upon failure

(iv) Although the asset renewal initiatives described above, through mitigation of the highest consequence asset risks, are expected to go a long way to mitigate risks to the distribution system reliability, they do not eliminate all risks. Considering the advanced service age and poor condition of many assets on ERH's distribution system, some assets are bound to fail in service, even after implementation of the proposed renewal projects. Therefore, the investment plan includes an allowance for unplanned renewal of unidentified assets when they fail in service and require immediate replacement to restore power.

4.1.2.3 *System Service*
As described previously, projects proposed under asset renewal may contribute to the removal of capacity constraints during “N-1” operating conditions and the implementation of targeted smart grid initiatives. However, no investments are proposed in this DSP within the System Service category.

4.1.2.4 *General Plant*
Capital investments under the General Plant category include investments into improving buildings and facilities, motor vehicle fleet, tools and equipment and IT hardware and software. These investments are aimed at improving worker productivity, operating efficiency, and employee safety.

4.1.3 Customer Engagement and Preferences (5.4a)

4.1.3.1 *Customer Engagement*
ERH undertakes several ongoing customer engagement activities, including:

I. Direct Engagement
  - Telephone calls, emails, written notices, in-person interactions at offices

II. Online Engagement
  - Corporate website
  - Online bill portal for residential and commercial customers

III. Customer Survey Program
  - Customer Satisfaction Surveys

In addition to the required customer satisfaction surveys, bill inserts, and on-bill messaging is included each month, communicating topics of interest and relevance to customers. Furthermore, customers are contacted each year to discuss vegetation management activities that are to be performed on their property and customers are contacted and engaged on pole-line rebuilds or major construction projects.

ERH customer service also receives calls related to power outages, vegetation management and construction which are transferred directly to the responsible department, who then continues to manage the customer service and request. These informal measures allow for ERH to engage customers by each case and respond accordingly. Whether responding to a residential concern or a meeting with an industrial customer, ERH can establish the needs of the customer and leverage that information against its O&M procedures and future decisions as warranted.

In preparation for ERH’s upcoming rate file application, ERH engaged its customers to gather information on their preferences and to inform ERH of the priority of investments in the forecast period. The engagement was delivered through an online survey which was communicated through targeted ads on social media, radio, and other digital mediums. The feedback received from the customer engagement was used to ensure that the DSP was aligned with the customer preference and validate the decision-making protocols of ERH.

4.1.3.2 *Customer Preference*

Overall, customers are satisfied with ERH and aside from issues with the cost of services, there were little to no additional concerns, with many of the respondents to the online survey citing no major changes needed to the DSP capital plan whatsoever.

The survey indicates that customers are generally satisfied with the existing reliability levels provided by the distribution system. Furthermore, while customers would prefer to avoid a rate increase on their electricity bills, they understand the reasoning and purpose of the proposed infrastructure investments that will result in a rate increase. Given this customer feedback, to keep the investments into asset renewal at reasonably low levels, this DSP targets only those assets for renewal that present extreme risk of failure in service; while accepting the risk and adopting a reactive strategy (respond upon failure) for assets presenting a moderate risk of failure in service. The capital investments proposed in this DSP are focused on keeping the existing reliability levels from deteriorating, by proactively replacing only the very high-risk infrastructure assets when they reach the end of their economic life.

4.1.3.3 *Projects in Response to Customer Preference, Technology, and Innovation*

Through ERH's customer engagement, certain factors such as safety, reliability and cost have all been identified as concerns. Customers have indicated that they would like reliability maintained and have an obvious and demonstrated preference for maintaining safety. ERH's System Renewal projects address these at a broad level. ERH uses the information derived from customer engagement pieces to ensure its decisions are aligned with customer preferences and that its decisions are valid based on the customer feedback generally, but no specific projects are implemented as a direct and/or sole result of any particular feedback or customer engagement as part of this DSP. This makes up most projects identified by ERH for the current DSP capital expenditures.

4.1.4 System Development over the Forecast Period (5.4b)

4.1.4.1 *Ability to Connect New Load/Generation*

ERH's system services small towns that have seen low customer growth over the historical period. With low growth and development in the towns, ERH is capable of handling all new and/or upgraded connections quickly. ERH can do this through the implementation of efficient internal processes, appropriate resourcing requirements, and a system that has excess capacity and is in a state, for the most part, that does not inhibit service requests.

Due to the flat growth trend and excess capacity in the system, very minimal expenditures have been planned over the planning horizon to address the capability to connect the new load. The costs that are included are based on historical information and are relatively minor.

4.1.4.2 *Load and Customer Growth*

ERH expects growth of the system regarding both the customers and the loading perspective, to follow a near-flat trend, which is consistent with the historical period.

4.1.4.3 *Grid Modernization*

All renewal projects planned by ERH follow the latest planning and design standards which can be identified as best practices. The best practices continue to evolve and incorporate the latest grid modernization policies.

Regarding smart grid development, there are no smart grid initiatives planned over the forecast period.

4.1.4.4 *REG Accommodation*

ERH's distribution system has adequate capacity to connect all anticipated loads and generation customers in the forecast period. Currently, there are no applications in the queue for generation connections <10kW, under the micro-FIT program and all requests for micro-Fit generation received to date have been successfully connected to the system. The expected number of connections in the planning period should be equivalent to the number of connections over the historical period.

4.1.4.5 *Climate Change Adaptation*

Where economical and applicable, ERH employs proven storm hardening techniques such as installing stainless steel equipment for below-grade applications, designing the system to Canadian Standard Association ("CSA") Heavy Loading conditions and utilizing stronger, treated poles in new constructions.

4.2 CAPITAL EXPENDITURE PLANNING PROCESS OVERVIEW (5.4.1)

4.2.1 Tool and Methods for Risk Management (5.4.1a)

ERH prepares its capital plans with consideration to business risks discussed throughout the DSP. These include consultations with key parties, incorporating historical performances into actionable items for the forecast plan, tailoring asset management goals, processes and practices and adopting the latest industry standards to achieve the best value out of its system while managing the risk categories such as safety, cybersecurity, and changing environments. ERH relies on a set of tools to assist in achieving the desired goals with consideration to corporate business risk. These are explained further in sections 3.1, 3.3 and 4.2.2. To support the tools and methodologies, a set of planning objectives, assumptions and criteria are applied to reflect ERH's system. The supporting items are explained in the description below.

Planning Objectives, Assumptions, and Criteria for Risk Management

The capital expenditure plan is developed using the conclusions of ERH's asset management processes as input, which supports the alignment of the overall corporate objectives and goals with the proposed investment plan.

ERH's investment planning objectives into each investment categories are:

1. Ensure appropriate level of investment allocation to meet the regulatory obligations of System Access investments such as metering, system relocations for municipal road work, and future system requirements for residential, commercial, and industrial load customers as well as generation customers.

2. Ensure adequate level of investment into distribution renewal to maintain optimal risk levels related to asset failures in service, particularly those impacting safety, reliability, and environment, as determined through the continued condition assessment of assets.

3. Determine the acceptable level of expenditures required to maintain sufficient system capacity to meet existing and future capacity demand levels, including adequate capacity to allow the connection of renewable generation.

4. Ensure proper allocation of investments into general plant assets to maintain employee safety and productivity.

5. Review overall expenditures to ensure retail rate impacts and adjust spending as required to ensure retail rates remain affordable.

Because the distribution system has adequate capacity to allow connection of anticipated load and generation customers, no REG investments are proposed for system capacity upgrades to accept new generation or load customers. Also, because customers have indicated a preference for lower electricity prices no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level. As mentioned earlier, ERH is proactively participating in the province's CDM program for load management.

ERH has determined that there are several important inputs required to support investment decisions, to ensure the investment level is appropriate, and the investment is targeted into the appropriate areas. As such, planning criteria inputs are utilized to support investments into each of the four categories, as indicated below:

- Consultation, with municipal officials to understand future projects requiring relocation of distribution lines in support of System Access investments.
- Incorporating customer growth forecasting into capital expenditures for anticipated residential and commercial developments in support of System Access investments.
- Consultation with existing general service customers, specifically customers with >50 kW load, to gain perspective on any changes in their electrical demand in support of System Access investments.
- System condition assessments to support expenditures related to asset renewal to maintain the system as designed in support of System Renewal investments.
- System capacity assessments to identify requirements for System Service investments.
- Individual assessments on key areas such as building, IT and Fleet required to support expenditures in General Plant.

The investment requirements to facilitate customer connections and service upgrades as well as for line relocation in response to municipal requests are difficult to predict accurately, so the expenditure requirements in these categories have been estimated based on average annual expenditure during the past five years.

The overarching objective of ERH's asset management is to identify and implement the optimal time and scope of investments into asset maintenance, refurbishment, and replacement. All of the asset management objectives are considered during the prioritization of the investments into system renewal, with appropriate weights assigned to each objective.

As part of the DSP and the plans outlined, the following assumptions are applicable:

- Equipment maintenance, refurbishment and replacement programs are in place to ensure that the capacity and capability of the distribution system are maintained at a reasonable level of risk of disruption due to lifecycle related equipment failure.
- Incidences of extreme weather continue to be manageable under existing standards of design and construction.

4.2.2 Processes, Tools, and Methods (5.4.1b)

In developing and implementing the DSP, ERH has aligned its key asset management objectives with its corporate vision and goals. ERH's corporate goals include delivery of electricity to its customers in a safe, reliable, and efficient manner, minimizing increases in distribution rates, while maximizing return on equity for its shareholders. The key asset management objectives on which the DSP is based, complete with their ranking on a scale of 5 to 1 (5 being the highest) in prioritizing investments is indicated below:

Objective	Ranking	ERH Core Value
✓ Maintaining public and employee safety	Ranking 5	Safety
✓ Maintaining reliability commensurate with customer needs	Ranking 5	Reliability Performance
✓ Providing customer service quality to satisfy customer needs	Ranking 5	
✓ Controlling costs - minimizing asset life cycle costs	Ranking 4	Lifecycle Management
✓ Minimizing the risk of in-service failures	Ranking 4	
✓ Minimizing environmental risks	Ranking 4	Environmental
✓ Aligning the DSP with regional planning objectives	Ranking 3	Distribution Automation & Smart Grid Development
✓ Facilitating new renewable generation connections	Ranking 3	
✓ Facilitating the smart grid development	Ranking 2	

Because there are no pending applications for connecting renewable generation, a lower-ranking for investments into smart grid development and facilitating renewable generation connections have no significant adverse impact. Similarly, none of the investments proposed in this DSP conflict with the regional planning objectives and therefore lower ranking of the regional planning objectives have no adverse impact.

The following tools and methods were used to identify, select, prioritize, and pace execution of projects in each investment category, excluding System Service which ERH has not had any investments in the past nor is proposing in the forecast period.

<u>System Access</u>

System Access projects are non-discretionary. Projects are identified through contact with customers wishing to connect new or upgrade existing services or requests from municipal landowners to relocate assets to accommodate road construction. Prioritization of projects is based on the expected date when all service requirements are fulfilled by the customer, as identified through regular contact between both parties. Projects are planned and executed to ensure that low voltage connections are completed within five days of the fulfillment of all service conditions and high voltage services are connected within 10 days of the fulfillment of all service conditions.

<u>System Renewal</u>

ERH identifies asset repair, refurbishment, and replacement requirements through condition assessments and internal maintenance processes to identify high-risk assets. Projects are identified, selected, prioritized, and paced through the following process:

1. Asset nameplate and inspection data are converted to a composite health index which indicates the probability of failure.

2. Risk consequences for each project area with assets found in poor or very poor condition are evaluated. Costs for the scope of work to mitigate risk in each project area are determined, using a distribution system estimating data. Projects are sorted and prioritized based on the risk of asset failure and risk mitigation cost.

3. The selected projects are initially paced based on the type of work predominantly involved (overhead or underground) and the estimated resource requirements. Considering these factors allows adequate resources to be assigned to the work.

General Plant

General Plant projects are identified and assessed using a combination of inspections, policies, and expert knowledge. Projects related to the fleet are prioritized to keep the vehicles properly maintained and replaced for safe operation while minimizing life cycle costs. This requires balancing vehicle purchase costs against excessive repair bills and operational downtime. Decisions requiring the selection and prioritization of investments into live-line work tools and equipment is made using expert knowledge and observing changes to industry best practices. Investments into building repairs are based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security systems and building mechanical systems.

4.2.3 REG Investment Prioritization (5.4.1c)

ERH does not use a separate prioritization for REG investments. In addition, due to sufficient capacity in the system and minimal forecasted connections, the analysis does not indicate a requirement for material capital expenditures over the rate filing period. ERH does not have plans over the forecast period to connect distributor-owned renewable generation projects.

4.2.4 Non-Distribution System Alternatives to Relieving System Capacity (5.4.1d)

ERH's implementation of Conservation and Demand Management ("CDM") projects is an example of a non-distribution system alternative to scaling the system to meet new system demand. However, ERH does not have capacity-related constraints and therefore currently does not have a formal policy to relieving system capacity constraints with distribution system alternatives.

ERH continues to support CDM initiatives following regulatory requirements, monitor results of CDM projects and accommodate REG connections because of the inherent benefits to both ERH and its partners. Currently, no CDM initiatives are relied upon to address system capacity, as there are no system capacity limitations. Should any unanticipated system capacity issues arise beyond the forecast period, ERH intends to actively address these constraints to ensure continued reliability in the system.

4.2.5 System Modernization (5.4.1e)

ERH plans to modernize its grid by replacing assets that no longer meet ERH's design standards with assets that may contribute to operational efficiencies. Additionally, through system renewal investments, ERH may investigate options and act where it can modernize its system to alleviate feeder capacity constraints in specific areas forecasted to experience growth beyond the DSP forecast period. However, system modernization depends on multiple factors and limits and should be evaluated on a project by project basis.

Customers recently indicated their preferred level of priority of modernizing the system to be at the bottom of their list as this would avoid the potential bill increases. Therefore, ERH is listening and responding to its customer engagement to prioritize investments into maintaining the system performance and addressing identified concerns promptly. In the interim, ERH intends to take each opportunity provided and assess the benefit and impact it may have on the business.

4.2.6 Rate-Funded Activities to Defer Distribution Infrastructure (5.4.1f & 5.4.1.1)

ERH does not have any activities proposed within the current forecast period that may defer distribution infrastructure. Though, ERH notes that in a case-by-case scenario alternative solutions may be considered that may result in deferring infrastructure capital. However, this is and has not been typically observed at ERH to date.

4.3 Capital Expenditure Planning Summary (5.4.2)

The Capital Expenditure Summary provides a ‘snapshot’ of ERH’s capital expenditures over a multi-year period. The costs of projects or activities are allocated to one of four investment categories based on the primary (i.e. initial or ‘trigger’) driver of the investment. ERH does not have a previously filed or approved DSP and as a result variance explanation of actual expenditures is compared to ERH’s internally approved budget plan. ERH’s historical and forecast capital expenditures by OEB category are presented in Table 4-2. Additionally, the table includes the planned and actual values and identifies the variances in each year. Furthermore, the table identifies capital contributions and system O&M as separate line items, for both historical and forecast years with planned and actual values reported.

A completed *Chapter 2 Appendix 2-AA* is submitted as part of ERH’s application. No capital projects have a project life cycle greater than one year. Additionally, there are no expenditures for non-distribution activities in ERH’s budget.

Table 4-2: Historical and Forecast Capital Expenditures and System O&M

Category	Historical												Bridge	Forecast
	2012			2017			2018			2019			2020	2021
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000
System Access	92	87	*-5.0*	242	182	*-25.0*	109	37	*-65.8*	108	38	*-64.7*	148	52
System Renewal	736	835	*13.4*	454	467	*2.9*	446	393	*-11.9*	417	338	*-19.0*	502	404
System Service	0	0	*0*	0	0	*0*	0	0	*0*	0	0	*0*	0	0
General Plant	195	20	*-89.7*	415	0	*-100*	13	0	*-100*	13	85	*582.1*	58	33
Total	1023	942	*-7.9*	1111	649	*-41.6*	567	430	*-24.2*	537	461	*-14.2*	708	488
Capital Contributions	16	71	*330.9*	18	3	*-82.1*	24	40	*70.8*	30	39	*32.7*	64	25
Net Capital Expenditures	1006	871	*-13.5*	1093	646	*-40.9*	544	390	*-28.3*	507	442	*-16.9*	645	463
System O&M	647	670	*3.6*	647	586	*-9.4*	649	641	*-1.3*	688	720	*4.7*	723	735

4.3.1 Variances in Capital Expenditures

The below sections summarize the variances between planned and actual capital expenditures for each OEB investment category over the last three years. Additional detail with specific cost values by line items is presented in Exhibit 2 of ERH's rate application. With consideration of the actual expenditures and the variances experienced in each year, ERH has adjusted its 2021 Test Year to be aligned with the historical actuals observed.

<u>System Access</u>

Expenditures in the System Access category experience variations – customer growth in ERH's service territory is low and there are sporadic variations in the number of requests received for new services from one year to the next, which can result in significant variations in year over year spending in this category. Similarly, the amount of work-related to line relocates varies from year to year due to variations in demand for such services. Also, as a small utility, ERH has only one line crew. Availability of employees due to sickness, leaves of absence and other short-term vacancies due to retirements and employees resigning could have a material effect on expenditures in any one year.

<u>System Renewal</u>

The expenditures in System Renewal resulted in project deferrals due to internal resource constraints. Additional variation explanations comprise of changes in identified assets requiring replacement (either a decrease or increase of assets in scope). Furthermore, the progression of detailed costing analysis contributed to the annual variations (i.e. projects initially scoped were further designed resulting in project estimate changes).

<u>System Service</u>

No budget has been allocated in this investment category in 2015-2019. However, a major capital project, involving the construction of a new substation (MS4), was completed in 2015/16 to alleviate capacity constraints, which resulted in a large increase in expenditure in this category during 2015/16.

<u>General Plant</u>

In the General Plant category, expenditure fluctuations become high during those calendar years when a large motor vehicle (a bucket or derrick truck) is purchased to replace an old vehicle of a similar type. Additional variations were largely contributed by deferral of planned investments in a given year to manage budget constraints.

4.4 Justifying Capital Expenditures (5.4.3)

This section provides the necessary data, information, and analyses to support the capital expenditure levels proposed in this DSP.

4.4.1 Overall Plan (5.4.3.1)

The investment drivers considered in the forecast period include System Access, System Renewal and General Plant upgrades. Because a large fraction of the proposed investments is aimed at the renewal of assets presenting the highest risk, this reduction in planned expenditure level is not expected to result in the worsening of the power supply reliability. Furthermore, sufficient system capacity is available to meet existing and future capacity demand levels, including adequate capacity to allow connection of renewable generation, hence, no new investments are required in the System Service category.

Expenditure in System Access is a regulatory obligation. The proposed expenditure level is based on the average historic spending levels and the specific information available at the time of preparation of this DSP, related to new requests for services, line relocates, and requirements for revenue meter replacement.

Proposed investments into System Renewal are based on objective, risk-based criteria, and the methodology employed for prioritization of the investments is aligned to ERH's corporate strategy. The investment level in this category has been determined to maintain asset risk related to asset failures in service, particularly those impacting safety, reliability, and the environment.

The proposed investment level into General Plant has been determined partly based on historic spending level to maintain the general plant in safe operating conditions as well as renewing tools, equipment and facilities.

4.4.1.1 *Comparative Expenditures by Category over the Historical Period*

ERH's planned capital expenditure for the Test Year (2021) is a total sum of $488,429. The capital expenditures over the historical period (2017 to 2020) amount to an average annual capital expenditure of $561, 250. The proposed expenditure for the forecasted Test Year, thus, represents a 13% decrease from the historical average annual capital expenditure.

System Access

The historical trend with System Access was variable year over year due to customer connection service requests and line relocates. As shown in Figure 4-2, the forecast average is approximately 49% less than the historical average. In 2017, a one-time expenditure to acquire Long Term Load Transfer assets occurred for $162,000. The proposed forecast is lower than historical since there are fewer investments planned for meter assets. Aside from the decreased investment in meters, the forecast expenditures are expected to be similar to those completed in the past. Detailed information on ERH's historical actuals and their variances can be found in Exhibit 2 of the application.

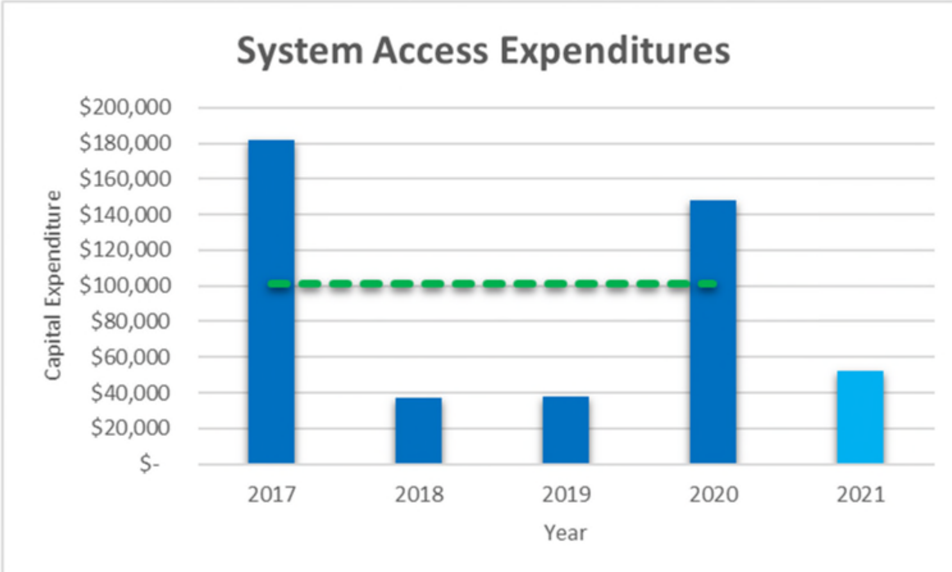

Figure 4-2: Comparative expenditure of System Access

System Renewal

ERH's forecast average is approximately 5% less than the historical average, shown in Figure 4-3. The forecast expenditures are in alignment with historical efforts and projects planned by ERH by continuing to service older and at-risk of failure assets to maintain system performance levels. Detailed information on ERH's historical actuals and their variances can be found in Exhibit 2 of the application.

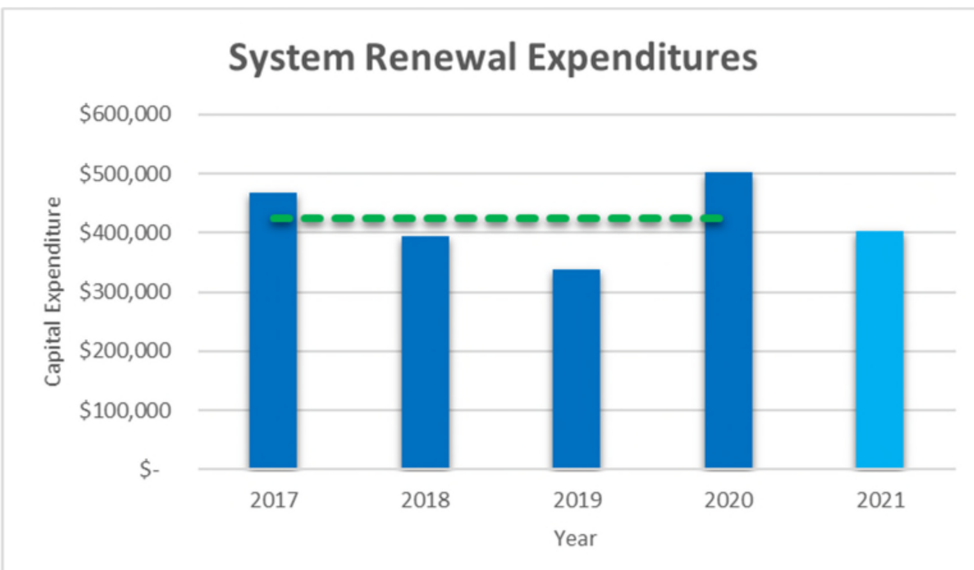

Figure 4-3: Comparative expenditure of System Renewal

<u>General Plant</u>

As shown in Figure 4-4, the forecast average is approximately 8% less than the historical average. The historical expenditures included investments to maintain ERH's operations and functionality to service its customers and system safely and efficiently. The forecast expenditures are lower than historical since there are no significant investments in purchasing vehicles nor IT renewals/upgrades, which both items can contribute to significant costs. ERH continues to use the same framework as it had used in the past which is to address only the critical issues needed promptly to maintain the existing facilities, fleet, and IT assets functionality. Detailed information on ERH's historical actuals and their variances can be found in Exhibit 2 of the application.

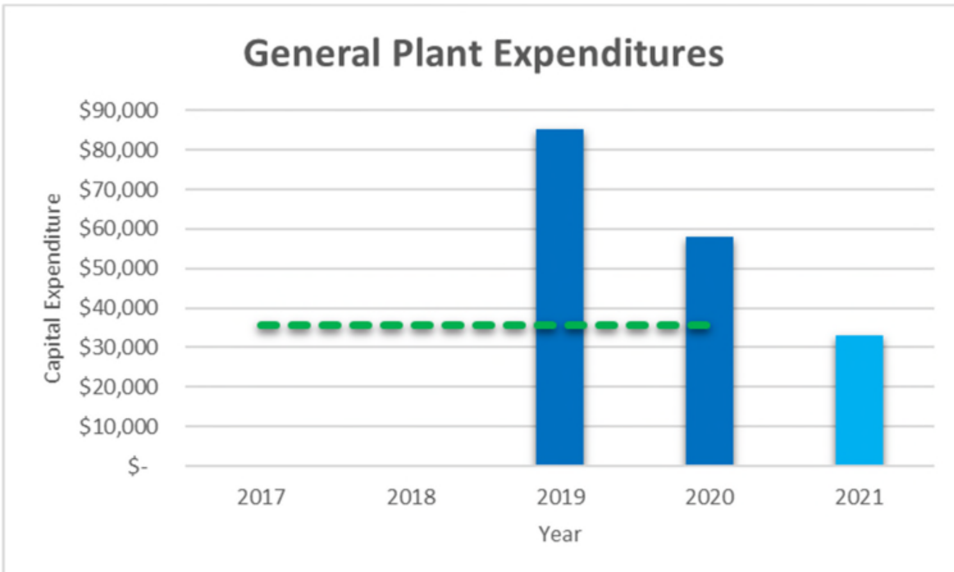

Figure 4-4: Comparative expenditure of General Plant

4.4.1.2 *Forecast Impact of System Investment on System O&M Costs*

<u>System Access</u>

These investments include capital investments to implement customer service requests, line relocates to facilitate municipal infrastructure developments, such as road widening projects and investments into revenue metering. Although the impact of these investments on future O&M expenses has not been quantified, investments into System Access generally increase the number of assets in service and therefore result in increases in future O&M expenditure.

<u>System Renewal</u>

The proposed investments into System Renewal include both reactive expenditures for replacement of the assets that have failed in service, as well as proactive replacement of assets where the risk of an assets' failure in service is unacceptable. It is not possible to quantitatively determine the impact of capital investments on future O&M expenditure, but qualitatively, investments into System Renewal generally reduce the risk of an increase in O&M expenditure because replacement of old vintage assets with new assets results in fewer equipment failures and lower expenditure into emergency repairs. Alternatively, limited or no investments into System Renewal generally increase O&M expenditures as remaining assets continue to age and increase the probability of failing.

System Service

ERH is not proposing any investments into this category, hence there is no impact on future O&M expenditures.

General Plant

These investments are generally focussed on asset renewal in the General Plant category and replacement of older plant with new is expected to result in a possible reduction in O&M expenditure.

4.4.1.3 *Investment Drivers by Category*

System Access

System Access investments include the following drivers:

- Customer Service Requests - The continued requirement for new customer connections. Forecasts assume relatively consistent connections year over year. Connections often include pole replacement, reframing, or other upgrades to meet the requirements of Ontario Reg. 22/04.

System Renewal

System Renewal investments include the following drivers:

- Failure Risk - Multiyear planned asset replacement programs that address assets at the end of life condition. Includes priority replacement of one-off items because of high-risk issues identified during inspection and maintenance programs.
- Failure - Emergency reactive replacement of distribution system assets (poles, transformers, switches, switchgear, cable, conductor, insulators, guys, anchors, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.

General Plant

General Plant investments include the following drivers:

- System Maintenance Support – Replacement of items ensuring that adequate tools, equipment, and systems are in place to support the day to day operations of ERH's business. The replacement of major fleet units is also included.

4.4.2 Material Investments (5.4.3.2)

The focus of this section is on 2021 projects that meet the materiality threshold set out in Chapter 2 of the Filing Requirements. Table 4-3 presents a consolidated list of applicable project that are above the material threshold categorized accordingly.

Table 4-3: ERH capital projects above material threshold

Category	Project Name/Description	Test Year Value ($)
System Renewal	Overhead Renewal – Poles (Job #70)	$ 75,615
	Massy Line Rebuild (Job #71)	$ 126,423

Detailed descriptions for these projects .are presented in Appendix C - Projects Above the Materiality Threshold.

Appendix A – IESO Comment Letter

IESO response to ERH Regional Hydro Distribution Corporation's REG Investment Plan 2021 – 2025

In accordance with the Ontario Energy Board's (OEB) Chapter 5 filing requirements to submit a Distribution System Plan (DSP) with its Cost of Service application, on October 27, 2020, Espanola Regional Hydro Distribution Corporation (ERH) sent its Renewable Energy Generation (REG) Plan as part of its DSP, to the Independent Electricity System Operator (IESO) for comment. The IESO has reviewed ERH's REG Plan and notes that it contains no investments specific to connecting REG for the Plan period 2021 - 2025.

The IESO notes that ERH's service territory is within the Sudbury/Algoma Region where ERH's distribution system is embedded into the Hydro One distribution system. The IESO confirms that ERH participated with the Study Team[1] indirectly through their Hydro One account representative in the recent planning activities. The IESO reports that regional planning is complete in the Sudbury/Algoma Region, as the recent Needs Assessment published by Hydro One Networks Inc. did not identify a need for further regional coordination.[2]

ERH's REG Plan states: "ERH currently has no planned connections. ERH is well positioned to support a broad range of REG and smart grid initiatives without any additional investment above what is already accounted for in infrastructure renewal (i.e.: in the OEB category System Renewal). ERH can also say with confidence that past investments along with currently available capacity will allow the connection of all forecast REG projects for the next five years with no need for additional system investments."

The IESO submits that as ERH has no REG investments during the 5-year Distribution System Plan period, no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties.[3]

The IESO appreciates the opportunity provided to review the REG Plan of ERH and looks forward to working together during the next regional planning processes.

[1] **Sudbury/Algoma Region** Study Team members included the IESO and Hydro One Networks Inc. (Distribution and Lead Transmitter), and North Bay Hydro (includes former ERH as an embedded LDC).

[2] Hydro One Networks Inc., Needs Assessment, August 6, 2020: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/sudburyalgoma/Documents/Sudbury%20-%20Algoma%20Region%20Needs%20Assessment%20Report%20-%20June%2029%202020.pdf

[3] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

Appendix B – ERH 2019 Scorecard

Scorecard - Espanola Regional Hydro Distribution Corporation

9/23/2020

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%	→	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	98.18%	100.00%	98.55%	↓	90.00%	
		Telephone Calls Answered On Time		76.10%	76.20%	72.62%	70.67%	63.04%	↓	65.00%	
	Customer Satisfaction	First Contact Resolution		99.8%	99.17 %	99.60%	99.73%	99.23%			
		Billing Accuracy		99.93%	99.95%	99.95%	99.89%	99.98%	↑	98.00%	
		Customer Satisfaction Survey Results		89%	87 %	87 %	87%	91.00			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		85.00%	85.00%	84.00%	84.00%	85.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.27	0.55	0.35	0.16	0.35	↓		0.67
		Average Number of Times that Power to a Customer is Interrupted [2]		0.07	1.10	0.10	0.06	0.17	↓		0.33
	Asset Management	Distribution System Plan Implementation Progress		On Track	On Track	On Track	On Track	On Track			
	Cost Control	Efficiency Assessment		2	2	2	2	2			
		Total Cost per Customer [3]		$658	$670	$661	$683	$758			
		Total Cost per Km of Line [3]		$15,465	$15,702	$15,421	$16,003	$17,789			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]		20.83%	35.54%	80.32%	99.00%	131.00%			2.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		0.00%	0.00%						
		New Micro-embedded Generation Facilities Connected On Time			100.00%	100.00%			→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.47	1.34	1.17	1.22	0.83			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.30	1.22	1.17	1.12	-22.35			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.12%	9.12%	9.12%	9.12%	9.12%			
			Achieved	15.91%	6.29%	2.45%	4.12%	-9.46%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the now discontinued 2015-2020 Conservation First Framework. 2019 results include savings reported to the IESO up until the end of February 2020.

Legend:

5-year trend: ↑ up ↓ down → flat

Current year: target met / target not met

2019 Scorecard Management Discussion and Analysis ("2019 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2019 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2019, North Bay (Espanola) Acquisition Inc. acquired Espanola Regional Hydro Distribution Corporation and amalgamated under the name Espanola Regional Hydro Distribution Corporation ("ERHDC").

ERHDC exceeded all performance targets in 2019, with the exception of telephone calls answered on time and financial targets.

ERHDC had a strong performance in Operational Effectiveness in 2019. Not only has ERHDC exceeded the 5-year rolling average distributor target in both reliability performance metrics, for a sixth year in a row, ERHDC had zero public incidents in relation to safety. For the eighth consecutive year, ERHDC has maintained an efficiency assessment rating of Group 2 which is defined as having actual costs between 10% and 25% below predicted costs under the Pacific Economics Group LLC (PEG) model.

In 2019, due to the acquisition being fully financed, ERHDC incurred significant increases in its debt to equity ratios and reduced ratios tied to liquidity. With the proposed future amalgamation with North Bay Hydro Distribution Inc. (North Bay Hydro) in 2022 this situation will be temporary, but until the amalgamation is approved and completed, ERHDC will continue to operate as an independent LDC. Once amalgamated, the New North Bay Hydro will have strong liquidity and debt service ratios as well as more optimal debt to equity ratios with financial capacity for any necessary borrowing.

ERHDC will continue working towards maintaining its high-level of customer satisfaction and operational effectiveness. The details provided in this report on service quality, customer satisfaction, safety, system reliability, asset management, cost control, CDM results, and financial rations confirm ERHDC's continued strong performance in 2019.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  In 2019, ERHDC connected 12 eligible low-voltage residential and small business customers (connections under 750 volts) to its distribution system, with 100% of these connections completed within the five-day timeline prescribed by the Ontario Energy Board (OEB). This score exceeds the OEB mandated threshold of 90%.

- **Scheduled Appointments Met on Time**
  In 2019, ERHDC scheduled 69 appointments with customers to complete customer requested work (e.g. meter installs/removals, service disconnects/reconnects, meter locates etc.) ERHDC achieved 98.55% which exceeded the OEB target of 90%.

- **Telephone Calls Answered on Time**
  In 2019, ERHDC's Customer Care Department received 3,617 calls from its customers. Of those calls, a Customer Care Representative answered the call in 30 seconds or less, 63.04% of the time. This is a decrease from the 2018 results, and ERHDC just missed the OEB target of 65%. The main contributing factor to the missed target was staff turnover which resulted in new staff having longer average talk times with customers. The extra time on the phones with customers then lead to calls waiting in the queue. ERHDC has a fully trained team in place and has seen significant improvement for 2020. ERHDC will continue to monitor this performance measure to identify opportunities for improvement.

Customer Satisfaction

- **First Contact Resolution**
  ERHDC's First Contact Resolution was measured by tracking the number of electric related calls that were escalated to a Senior Customer Care Representative, Supervisor, or Manager. This was accomplished by tracking two specific call types in our Customer Information System (CIS), which are queried to provide the number of customer concerns that were escalated.

  In 2019, ERHDC had 3,617 calls, of which 21 contacts were escalated to a higher level of management. This resulted in a First Contact Resolution percentage of 99.23%. However, it should be noted that First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

- **Billing Accuracy**
  ERHDC issued 39,559 bills for the period from January 1, 2019 – December 31, 2019 and achieved an accuracy of 99.98%. This compares favorably to the prescribed OEB target of 98%. ERHDC continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**
  In 2019, ERHDC used a leading market research organization, UtilityPULSE, to conduct a bi-annual customer satisfaction survey. The survey included questions focused on the key areas of: power quality and reliability; price; billing and payment; communication; customer service experience; and corporate image. The survey result yielded an 91% satisfaction level. The next survey will be conducted in 2021.

Safety

The Public Safety measure was introduced by the OEB in 2015 and focuses on the safety of the distribution system from a customer's point of view. The Electrical Safety Authority (ESA) provides an assessment as it pertains to Component B – Compliance with Ontario Regulation 22/04 and Component C – Serious Electrical Incident Index.

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**

The Public Awareness of Electrical Safety measure is determined by public survey. The purpose of the survey is to monitor the effort and impact LDC's are having on improving public electrical safety for the Distribution Network. This public safety survey is intended to be conducted every two years. The questions on the survey are standardized across the province.

ERHDC's third safety awareness survey was conducted in early 2020 and resulted in a score of 85%. This was a 1% improvement over the previous Safety survey.

  - **Component B – Compliance with Ontario Regulation 22/04**

Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, and specifications, and the inspection of construction before they are put in service.

Component B is comprised of an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and Compliance Investigations. All these elements are evaluated as a whole to determine the status of compliance. Over the past nine years, ERHDC was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). ERHDC attributes this continued success to our strong commitment to safety, and adherence to company policies and procedures. ERHDC's target for this metric is to remain fully compliant with Ontario Regulation 22/04.

- **Component C – Serious Electrical Incident Index**

Section 12 of Ontario Regulation 22/04 specifies the requirement to report to the ESA any serious electrical incidents of which they become aware within 48 hours after the occurrence. ERHDC had no serious electrical incidents to report for the period January 1 through December 31, 2019. The utility has not had a serious electrical incident to report in the last six years. For 2019, the results are zero incidents with a rate of 0.0 per 100 km of line.

ERHDC remains strongly committed to both the safety of staff and the general public. ERHDC regularly provides its customers with electrical safety information via its website and bill inserts. Additionally, ERHDC has made significant maintenance and capital infrastructure investments in the past several years to enhance system safety and reliability.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**
  The System Average Interruption Duration Index (SAIDI) of 0.35 in 2019 was below the target of 0.67. There are ongoing efforts to maintain reliability including vegetation management practices and the proactive replacement of aging infrastructure.
- **Average Number of Times that Power to a Customer is Interrupted**

  The System Average Interruption Frequency Index (SAIFI) of .17 in 2019 was below the target of 0.33. Consistent with SAIDI, there are ongoing efforts to maintain reliability including vegetation management practices and the proactive replacement of aging infrastructure.

Asset Management

- **Distribution System Plan Implementation Progress**
  Although ERHDC has employed some degree of distribution system planning for several years, it began drafting its first formal DSP in 2015-2016 with the intention of filing the DSP with the OEB as part of a 2017 Cost of Service Application. Activity was halted however in 2017 with the announcement of the pending sale of ERHDC to North Bay Hydro.

Now that the sale is complete, ERHDC will be updating its DSP in preparation for its 2021 Cost of Service Application. Due to future amalgamation in 2022, the OEB has accepted that the DSP will only cover 2021, rather than a full five-year DSP. The DSP will outline how ERHDC will develop, manage, and maintain its distribution system equipment to provide a safe, reliable, efficient, and cost-effective distribution system.

Cost Control

- **Efficiency Assessment**
  The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as the number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. The following table summarizes the distribution of all distributors across the 5 groupings for 2019:

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDC's in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	7
2	Actual costs are 10% to 25% below predicted costs	More Efficient	17
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	29
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	4
5	Actual costs are 25% or more above predicted costs	Least Efficient	2

  In 2019, for the eighth consecutive year, ERHDC was placed in Group 2, attesting to its ability to keep costs in line with predictions. efficiency performance based on the PEG model was under the predicted costs by 21.7% between 2017 and 2019.

- **Total Cost per Customer**
  Total cost per customer is calculated as the sum of ERHDC's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model) and dividing this cost figure by the total number of customers that ERHDC serves. The cost performance result for 2019 is $758 per customer which is a 11% increase over 2018. ERHDC had increased costs in 2019 due to higher administrative costs from the sale of ERHDC to North Bay Hydro.

Overall, ERHDC's Total Cost per Customer has increased on average by 3.80% per annum over the period 2015 through 2019. ERHDC will continue to replace distribution assets proactively in a manner that balances system risks and customer rate impacts. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on ERHDC's capital spending plans.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. ERHDC's 2019 rate is $17,789 per Km of line, a 11% increase over 2018. As mentioned above, this increase is due to increased administration expenses related to the sale.

  ERHDC continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per Km of line has increased an average of 3.76% since 2015 with the increase in capital and operating costs.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

  In the early part of the 2019 year the Provincial government transitioned away from the local delivery of conservation program to a central delivery system. While we continued to deliver the program above the program targets, these targets were now not part of the program for local utilities and became a single provincial target. During this transition we have continued to support customers through program knowledge and conservation awareness, while closing out any applications that were still in process during this transition. We continuously work closely with the town and local school board on applications for new school that is going to be built in the area and facility improvements throughout the town.

  For our residential customers we have seen significant uptake in the provincially funded Affordability Fund program. This program helps customers reduce their consumption of electricity through the use of energy efficient appliances and in some instances heating/cooling. ERHDC is committed to helping its customers understand their energy usage by offering programs that enable them to become more energy efficient.

  ERHDC had a conservation target of 2.41 Gigawatt hours. Results for 2019 show progress of 131.00% towards that target.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**
  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority.

  For the year 2019, no CIA requests were received. However, ERHDC maintains its internal processes to ensure all applications are processed within the prescribed timelines when they are received.

- **New Micro-embedded Generation Facilities Connected on Time**
  In 2019, ERHDC did not receive any requests to connect any new micro-embedded generation facilities.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**
  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  ERHDC's current ratio went from 1.22 in 2019 to 0.83 in 2019. Until ERHDC amalgamates with North Bay Hydro, it will continue to see increases in its debt to equity ratios and reduced ratios tied to liquidity due to financing structure. However, with the proposed amalgamation in 2022 this situation will be temporary, and the liquidity ratio will continue to be low until the amalgamation occurs.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**
  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt to equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

ERHDC has a debt to equity ratio of negative -22.35 in 2019 which is below the deemed capital structure. As noted above, the financing structure is temporary and the leverage ratio tied to liquidity will continue to be low until the amalgamation occurs.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  ERHDC's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.12%. The OEB allows a distributor to earn within +/- 3 percentage points of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**
  ERHDC's ROE is a negative -9.46% for the year end as a result of the net and comprehensive loss realized in 2019. ERHDC's last Cost of Service approval for a rate increase was in 2012. For the past few years, the ROE has been below the OEB deemed 9.12% primarily due to unfavourable distribution revenue as ERHDC has not rebased its rates since 2012 and not had an IRM increase since May 1, 2015. In addition, consumption volumes are below those projected in the 2012 Cost of Service rate application. For 2019, ERHDC additionally experienced higher administrative costs associated with the sale of ERHDC and additional audit and financing expenses.

  ERHDC expects the financial targets to remain low for the next few years until approval of the 2021 Cost of Service Rate Application for an increase in rates and the future amalgamation with North Bay Hydro in 2022.

Note to Readers of 2019 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Appendix C – Projects Above the Materiality Threshold

A. General Information						
Project/Activity	Overhead Renewal - Poles					
Project Number	Job #70					
Investment Category	System Renewal					
	2021					
Capital Cost (5.4.3.2 A.1)	$ 75,615					
Capital Contribution	$ -					
Net Cost	$ 75,615					
O&M Cost (5.4.3.2 A.1)	**2021**					
Capital Contributions to Transmitters (5.4.3.2 A.2)	NA					

Customer Attachments and Load (5.4.3.2 A.3)

Customer attachments and load vary year to year dependent on identified deteriorated poles, pole locations and which circuit poles are located on.

Start Date (5.4.3.2 A.4)	01-Jan-21			**In Service Date (5.4.3.2 A.4)**	31-Dec-21
Expenditure Timing for the Test Year (5.4.3.2 A.4)	**2021 Q1**	**2021 Q2**	**2021 Q3**	**2021 Q4**	
	$ 18,904	$ 18,904	$ 18,904	$ 18,904	

Project Summary

Within ERH's overhead distribution system, ERH owns approximately 1900 poles and are currently joint use on a quantity of communications and Hydro One owned poles throughout our system. Since 2009, ERH has been obtaining a third party to perform pole testing on an annual basis and has a plan to retest all poles on a 7 year cycle. We are currently part way through the second cycle, testing all which are beyond 10 years of age to identify those requiring immediate attention, replacement in the short term and poles to continue to monitor. In addition to third party testing field identification by staff and response to public concerns constitute the identification process. This results in the scope of work for the deteriorated pole project for a given year. It is estimated that 10 poles will be identified annually for replacement.

Risk Identification & Mitigation (5.4.3.2 A.5)

This project is based on deteriorated pole identification and level of risk of failure identified in the field through visual inspection and non-destructive testing. Dependent on the level of risk for the poles identified, they may be considered emergency replacements, short term replacements (<1year) or long term replacements (<5years). Dependent on the risk identified, each task will be given a relative priority in an effort to mitigate risks. Resources play a factor in designing and replacing the identified poles. **Individual deteriorated pole projects are generally issued in small packages that can be handled easily by the in-house ERH line crew. These projects can be started and stopped as required to intersperse with any higher priority emergency work when it arises to ensuring all work for the year is completed.**

Comparative information on expenditures for equivalent projects/activities (5.4.3.2 A.6)

Pole replacement costs over the historical period are used to estimate the average cost of a single pole replacement as well as projecting the quantity of poles that are anticipated to be identified as deteriorated. Estimated expenditure may require revision from year to year due to the actual quantity identified, the complexity of identified poles and to ensure our system is not aging faster than replacements can occur. Ensuring pole testing is included in O&M budget to effectively gather pole condition results should minimize risks of quantity of poles significantly increasing.

REG Investment Details including Capital and OM&A costs (5.4.3.2 A.7)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.3.2 A.8)

Not applicable.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.3.2 B.1.a)

Power supply reliability is the primary driver for this project. Proactively identifying poles that are close to failure and proactively replacing them minimizes the risk of a failure occurring. This reduces the risk of prolonged, uncontrolled power outages. Without this project ERH's reliability statistics would be negatively affected.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.3.2 B.1.a)

Public safety is the secondary driver for this project. Proactively replacing identified poles mitigates the risk of the pole failing in service and controls the hazards to a reasonable level.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.3.2 B.1.a)

One investment objective is to continue the operation of a safe electrical distribution through the timely replacement of assets. Additionally, the project is intended to aid in the improvement of ERH's reliability statistics by controlling hazards and outages through proactively replacing poles nearing the end of their life.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.3.2 B.1.a)

Using the age distribution of ERH's poles in conjunction with previous pole testing data and historical quantities of deteriorated poles identified in the field, ERH attempts to accurately predict the quantity of poles that will require replacement. Using historical average costs per pole replacement with the estimated quantity of poles, ERH estimates the expenditures required. Cost vary depending on the quantity of the poles identified and the nature of the poles (ex. 35ft pole vs 65 ft. pole).

Demonstrate Good Utility Practice in Reliability Planning (5.4.3.2 B.1.b)

Pole replacement designs are prepared in accordance with USF design standards and industry best practice design practices. This ensures these investments are constructed for current acceptable levels of reliability with consideration to anticipated future impact of climate change such as potentially more severe wind and ice loading conditions.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.3.2 B.1.c) Priority relative to other investments

This project generally receives the highest priority in relation to ERH's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a pole failing in service. The risk level is based upon the nature of the pole and the potential reliability and safety concerns that would arise if the pole fails. ERH reviews identified deteriorated poles and prioritizes each pole within the project.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.3.2 B.1.d.i)

The project has minimal effect on system operation efficiency. The project is considered with other projects in an attempt to coordinate projects for cost effectiveness. If this is not practical, the single pole replacements occur. There are no practical alternatives to this project as not replacing the poles will result in asset failures, system reliability concerns and potential public safety concerns. Each pole replacement is reviewed on a case by case basis to identify any available alternatives. Some alternatives may include the replacement of two poles with one, additional coordination with adjacent pole owners, etc that lead to more cost effective alternative than a simple 'like-for-like' repacement approach.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.3.2 B.1.d.ii)

Proactive pole replacements provide system reliability benefits to customers. Additionally, proactive pole replacements reduce the cost in comparison to reactive replacements upon failure, reducing ERH's overall costs and minimizing impacts to customer's monthly bill.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2 B.1.d.iii)
Proactive replacement of poles identified as deteriorated reduces the unplanned frequency of outages and significantly reduces the duration of outages. Proactive replacements allow for limited, planned outages to transfer infrastructure in lieu of the unplanned outage. This allows ERH to advise effected customers to allow them to plan for the outage versus react to an outage. Proactive replacements positively impacts reliability statistics.
Safety (5.4.3.2 B2)
Public safety is a secondary driver for this project. Proactively replacing deteriorated poles reduces the risk of in service failures and the risk of poles and/or live conductors falling to the ground. No health benifits are expected to be derived from this investment.
Cyber-Security, privacy (5.4.3.2 B.3) (where applicable)
This project has no adverse impact on cyber security or privacy issues.
Co-Ordination, Interoperability (5.4.3.2 B.4.a) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)
Pole replacements will be constructed to USF and/or ERH specific standards which are in line with industry standards allowing third parties reasonable access.
Co-Ordination, Interoperability (5.4.3.2 B.4.b) Future technological functionality and/or future operational requirements (where applicable)
Pole replacements are typically constructed to USF and/or ERH standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.
Environmental Benefits (5.4.3.2 B.5) (where applicable)
Not applicable.
Conservation and Demand Management (5.4.3.2 B.6) (where applicable)
Not applicable.

C. Category-Specific Requirements - System Renewal
Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.3.2 SR-C1.1)
This project generally receives the highest priority in relation to ERH's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a pole failing in service. The risk level is based upon the nature of the pole and the potential reliability and safety concerns that would arise if the pole fails. ERH reviews identified deteriorated poles and prioritizes each pole within the project. The need is then further prioritized according to the asset lifecycle optimization policies in decribed in Section 3.3 of the DSP where risk costs and capital costs are optimized for the lowest overall life cycle cost.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.3.2 SR-C1.2)
Conditions of pole to be replaced are all below acceptable, sustainable condition. The condition is based on visual inspections and third party pole testing. Asset life relative to the typical life cycle is on a case by case basis. Generally, deteriorated poles are beyond the 45 years old, but some poles are identified as deteriorated prior to this due to ground line rot, infestation, woodpecker damage, etc.
The number of customers in each class potential affected by failure of the assets (5.4.3.2 SR-C1.3)
The quantity and class of customers is unknown at this time and is dependent on the poles that are identified as requiring replacement. The quantity and class is variable if the poles are secondary cross over poles versus supporting sub transmission lines (44kV)
Quantitative customer impacts (5.4.3.2 SR-C1.4)
It is not feasible to determine quantitative customer impacts for this project ahead of time.
Qualitative customer impacts (5.4.3.2 SR-C1.5)
Customers located in the area of the deteriorated poles identified will benefit from increased system reliability dependent on the nature of the pole.
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 (5.4.3.2 SR-C1.6)
Impacts to customers vary on a case to case basis. Some examples are the reduction of the number and duration of extended outages to residential homes heated using electrical heat, to commercial properties' business operations and to critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, ERH reviews each identified pole on a case by case basis relating to reliability and safety risks and place poles within replacement schedule.
Timing and Priority of Project (5.4.3.2 SR-C2)
This project generally receives the highest priority in relation to ERH's system renewal project, after emergency forced renewal (e.g. emergency restoration work after a major storm).
Consequences for system O&M costs (5.4.3.2 SR-C3)
Replacement of deteriorated poles that are beyond 10 years old, reduces O&M costs as ERH tests poles only that are over 10 years old. Treatment of poles has an increased O&M cost which extends the life of certain poles minimizing the required cost within this project.
Impact on reliability performance and/or safety (5.4.3.2 SR-C4)
Reliability performance is directly benefited from replacement of deteriorated poles. This reduces the quantity of unplanned outages which typically result in longer duration outages. This project increases safety by minimizing the risk of pole failures causing potential maintenance and electrical hazards.
Analysis of Project Benefits and Timing (5.4.3.2 SR-C5)
Project timing is generally immediately after emergency replacements and customer demand. System benefits from reducing the quantity of unplanned outages resulting from pole failures.
Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.3.2 SR-C6)
ERH attempts to have all poles replaced within this project designed to USF and/or ERH specific standards. Alternatives are reviewed on a case by case basis to maximize benefits and minimize costs.

A. General Information						
Project/Activity	Massy Line Rebuild					
Project Number	Job #71					
Investment Category	System Renewal					
	2021					
Capital Cost (5.4.3.2 A.1)	$ 126,423					
Capital Contribution	$ -					
Net Cost	$ 126,423					
O&M Cost (5.4.3.2 A.1)	**2021**					
Capital Contributions to Transmitters (5.4.3.2 A.2)	NA					

Customer Attachments and Load (5.4.3.2 A.3)

Number of Residential Customers: 104
Number of General Service Customers (<50kW): 3
Load Impacted (Tx Ratings):1330kVA

Start Date (5.4.3.2 A.4)	01-Mar-21		**In Service Date (5.4.3.2 A.3)**	30-Jun-21
Expenditure Timing for the Test Year (5.4.3.2 A.4)	**2021 Q1**	**2021 Q2**	**2021 Q3**	**2021 Q4**
	$ -	$ 126,423	$ -	$ -

Project Summary

This system improvement / enhancement will replace 3 phase primary voltage feed to approximately 25% of our customers in the Town of Massey. The existing circuit is constructed on 1960 to 1980 vintage poles across the top of a high rock feature in the center of town creating significant difficulty with respect to pole replacements, maintenance of the system and restoration in the event of a failure during an unplanned event.
This upgrade to the distribution system will address asset replacement needs, operational needs, improve customer service and prepare for demand generated by existing or new customer connection requests. These upgrades are necessary to ensure that ERH's distribution system continues to meet its operational objectives related to safety, reliability, power quality and system efficiency, while addressing future customer requirements for electricity service and reducing operation/response costs for individual failed equipment.
The need for this investment has been identified based on third party testing of distribution poles identiying the short term need for replacement and and response to concerns from ERH's Field Staff.

Risk Identification & Mitigation (5.4.3.2 A.5)

This project will include many different aspects that are not typical for ERH including a new line build in a more accesible location, revision to electrical service connection points and removal of the existing pole line in a less accesible location. With ERH's experience with other projects and support from an engineering firm, this project should be efficient and achievable. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises.

Comparative information on expenditures for equivalent projects/activities (5.4.3.2 A.6)

The estimated expenditure for this project is based on information provided by experienced, qualified staff with respect to labour, materials and miscellanious internal and external costs anticipated to complete the project. Espanola Hydro has completed a number of similar projects in recent years that are used to provide comparative costing models including 'Cross-Lot' projects in 2018 and 2019 as identified in Appendix 2-AA of this Cost of Service application.

REG Investment Details including Capital and OM&A costs (5.4.3.2 A.7)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.3.2 A.8)

Not applicable.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.3.2 B.1.a)

Power supply reliability is the primary driver for this project. Proactively identifying inadequacy in legacy system designs and correcting it minimizes the risk of a failure occurring and reduces outage times in the event of a failure. This project will reduces the risk of prolonged, uncontrolled power outages. Without this project ERH's reliability statistics may be negatively affected.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.3.2 B.1.a)

Improved level of service is the secondary driver for this project. Proactively constructing this feed along an alternate route mitigates the risk of loss of electric service to the connected customers and will provide 3 phase connectivity to a larger section of the commercial district along Hwy 17 in Massey.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.3.2 B.1.a)

One investment objective is to continue the operation of a safe electrical distribution through the timely replacement of assets. Additionally, the project is intended to aid in the maintenance of ERH's reliability statistics by controlling hazards and outages through proactively replacing poles nearing the end of their life that are along the proposed route.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.3.2 B.1.a)

Using the age of the existing circuits' poles and the age of poles that exist in the planned, new, route in conjunction with maintenance concerns identified in the field, ERH has deemed these expenditures required.

Demonstrate Good Utility Practice in Reliability Planning (5.4.3.2 B.1.b)

This line rebuild project employs designsthat are prepared in accordance with USF design standards and industry best practice design practices. This ensures these investments are constructed for current acceptable levels of reliability with consideration to anticipated future impact of climate change such as potentially more severe wind and ice loading conditions.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.3.2 B.1.c) Priority relative to other investments

In priority this project comes behind asset renewals such as our deteriorated pole replacements that may be deemed to require immediate attenttion, emergency forced renewal and customer demand requirements. This prioritization is based upon the risk level of a pole or other system component failing in service and the potential reliability and safety concerns that would arise in such an event.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.3.2 B.1.d.i)

The project has significant effect on system operation efficiency within the community of Massey. The project is being considered with other projects such as annual pole replacements in an attempt to coordinate projects for cost effectiveness. There are no practical alternatives to this project as this is the shortest available route around the geological formation and provides the added benefit of enhanced 3 phase connectivity within the Town's business district.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.3.2 B.1.d.ii)

This project will provide system reliability benefits to customers. The proposed design will provide for an alternate (loop) during the construction phase and allow for sectionalization to reduce the number of customers impacted during the planned work.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2 B.1.d.iii)

Proactively constructing this new feed will minimize the frequency of unplanned outages and significantly reduce duration should they occur. Proactive replacements allow for limited, planned outages to transfer infrastructure in lieu of the unplanned outage. Proactive replacement of poles within the project scope that are nearing end of life allows ERH to advise effected customers to allow them to plan for the outage versus react to an outage.

Safety (5.4.3.2 B2)

Public safety is a secondary driver for this project. Proactively replacing assets which are components within the project scope that are near end of life reduces the risk of in service failures and the risk of poles and/or live conductors falling to the ground. The new line route is easily accessible with conventional bucket trucks and dericks for maintenance and repair and will result in reduced response and restoration times. No health benifits are expected to be derived from this investment.

Cyber-Security, privacy (5.4.3.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.3.2 B.4.a) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

The line will be constructed to USF and/or ERH specific standards which are in line with industry standards allowing third parties good access.

Co-Ordination, Interoperability (5.4.3.2 B.4.b) Future technological functionality and/or future operational requirements (where applicable)

This project will be constructed to USF and/or ERH standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Environmental Benefits (5.4.3.2 B.5) (where applicable)

Not Applicable.

Conservation and Demand Management (5.4.3.2 B.6) (where applicable)

Not Applicable.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.3.2 SR-C1.1)

This project is seen as lower in priority in relation to ERH's overall system renewal requirements; after immediate attention pole replacements and emergency forced renewal. This prioritization is based upon the risk level of a pole or other system component failing in service. The risk level is based upon the nature of the pole and the potential reliability and safety concerns that would arise if the pole or other system component fails. The poles within the scope of this project are near end of life vs those within the pole replacement program that may be designated as in need of immediate replacement. The need hs been prioritized according to the asset lifecycle optimization policies in decribed in Section 3.3 of the DSP where risk costs and capital costs are optimized for the lowest overall life cycle cost.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.3.2 SR-C1.2)

The poles within the existing line construction planned to be replaced as well as most of those that will become part of the newly constructed line are between 40 and 60 years old. Generally, poles are those which are beyond 45 years old are considered near end of life, but some poles have been identified via thirdparty testing as deteriorated prior to this due to ground line rot, infestation, treatment and species type, woodpecker damage, etc.

The number of customers in each class potential affected by failure of the assets (5.4.3.2 SR-C1.3)

Number of Residential Customers: 104
Number of General Service Customers (<50kW): 3
Load Impacted (Tx Ratings): 1330 kVA

Quantitative customer impacts (5.4.3.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.3.2 SR-C1.5)

Customers located in the area serviced by the new line will benefit via ongoing favourable system reliability.

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 (5.4.3.2 SR-C1.6)

Impacts to customers vary on a case to case basis. Some examples are the reduction of the number and duration of extended outages to residential homes heated using electrical heat, to commercial properties' business operations and to critical customers who rely on electricity for emergency services.

Timing and Priority of Project (5.4.3.2 SR-C2)

This project is seen as lower in priority in relation to ERH's overall system renewal requirements; after immediate attention pole replacements and emergency forced renewal. **The timing of the proposed project could be impacted by emergency activities such as restoration work after a major storm, requiring the reallocation of your crews away from this project. However adequate resources are available to complete all anticipated normal and emergency work for the year within the year and the project is expected to be complete as planned.**

Consequences for system O&M costs (5.4.3.2 SR-C3)

The existing line will soon become a burden from both a maintenance and operational perspective due to the age of the assets and the inability for Espanola Hydro staff to acccess it with readily available equipment. The O&M costs associated with accessing the existing line in its location over a rockcut are expected to outweigh the capital costs to relocate it as the existing line as it continues to take additional time and effort to access and as it continues to deteriorate.

Impact on reliability performance and/or safety (5.4.3.2 SR-C4)

Future reliability performance is positively impacted from replacement of the line. Replacement reduces the quantity of unplanned outages which typically result in longer duration outages vs. planned work. This project increases safety by minimizing the risk of pole or other asset failures causing potential maintenance and electrical hazards.

Analysis of Project Benefits and Timing (5.4.3.2 SR-C5)

Project timing is generally immediately after emergency replacements and customer demand. System benefits from reducing the quantity of unplanned outages resulting from asset failures.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.3.2 SR-C6)

ERH will have all construction within the scope of this project designed to USF and/or ERH specific standards. Design and project execution alternatives are considered for all aspects of the project to maximize benefits and minimize costs.

Appendix D – OEB Chapter 2-AA

Appendix 2-AA
Capital Projects Table

Projects	2017	2018	2019	2020 Bridge Year	2021 Test Year
Reporting Basis					
Pole Replacements					
Distribution Stations					
Poles, Towers, Fixtures	64,088	96,375	190,196	53,717	75,615
O/H Conductors & Devices		3,634	28,677		
Underground Conduit					
U/G Conductors & Devices			6,548		
Line Transformers					
Services - New		158			
Meters					
Sub-Total	64,088	100,167	225,421	53,717	75,615
OH Cutout Renewal	3,689	9,037	4,663		9,547
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices				52,781	
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					
Services - New					
Meters					
Sub-Total	3,689	9,037	4,663	52,781	9,547
Spnaish River Drive			3,706		
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices					
Underground Conduit				76,572	
U/G Conductors & Devices				76,572	
Line Transformers				27,024	
Services - New				45,042	
Meters					
Sub-Total	0	0	3,706	225,210	0
Massey 3 Phase Line Replacement					
Distribution Stations					
Poles, Towers, Fixtures					42,984
O/H Conductors & Devices					42,984
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					15,170
Services - New					25,285
Meters					
Sub-Total	0	0	0	0	126,423
Duplessis road pole Line rebuild					
Distribution Stations					
Poles, Towers, Fixtures				55,038	
O/H Conductors & Devices					
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					
Services - New					
Meters					
Sub-Total	0	0	0	55,038	0

Cross Lot Relocations	39,070			48,038	
Distribution Stations					
Poles, Towers, Fixtures		38,491	42,827		
O/H Conductors & Devices		38,163	34,130		
Underground Conduit					
U/G Conductors & Devices		141	4,807		
Line Transformers		2,737			
Services - New					
Meters					
Sub-Total	39,070	79,532	81,764	48,038	0
Double Bucklet Truck					
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices					
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					
Services - New					
Meters					
Vehicles			70,339		
Sub-Total	0	0	70,339	0	0
Replace Submarine Cable					
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices					
Underground Conduit					
U/G Conductors & Devices	61,733	184,153			
Line Transformers					
Services - New					
Meters					
Sub-Total	61,733	184,153	0	0	0
Conductor Replacements - Tie Feeders F3-F5					
Distribution Stations					
Poles, Towers, Fixtures	39,389				
O/H Conductors & Devices	128,691				
Underground Conduit	0				
U/G Conductors & Devices	5,056				
Line Transformers	3,367				
Services - New	0				
Meters	0				
Sub-total	176,503	0	0	0	0
Conductor Replacements - Tie Feeders F1-F8					
Distribution Stations					
Poles, Towers, Fixtures	4,782				
O/H Conductors & Devices	77,844				
Underground Conduit	0				
U/G Conductors & Devices	13,878				
Line Transformers	0				
Services - New	0				
Meters	0				
Sub-Total	96,504	0	0	0	0

Long Term Load Transfer					
Distribution Stations	55,212				
Poles, Towers, Fixtures	77,380				
O/H Conductors & Devices	0				
Underground Conduit	0				
U/G Conductors & Devices	26,666				
Line Transformers	2,404				
Services - New					
Meters					
Sub-Total	161,662	0	0	0	0
Miscellaneous					
Misc. Facilities				35,000	25,000
Tools and Equipment			7,166	8,000	8,000
IT Equipment			7,759	15,000	
New & Upgrade Services	16,460	37,030	18,643	35,595	25,027
Sacred Heart School Service	661	111	18,028		
Joint Use Poles			0	2,521	2,656
City Projects - line relocations			0	11,845	7,762
Meters	3,024		0	32,372	16,419
MIST Meters				37,900	
OH Transformer Renewal	18,468	16,612	21,996	28,793	40,654
Clearlake					41,821
Brentwood Subdivision			1,459	27,821	
OH Forced Outages				5,905	5,587
Kbar Replacement				23,793	12,268
Transclosure Replacement					38,795
UG Forced Outages		3,536		3,161	2,925
MS 3 Conductor Replacement				2,000	46,318
Substation Misc. Projects				3,940	3,612
4kV Feeder at MS 2	6,813				
Miscellaneous Subtotal	45,426	57,289	75,051	273,646	276,844
Total	**648,675**	**430,178**	**460,944**	**708,430**	**488,429**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***					
Total	**648,675**	**430,178**	**460,944**	**708,430**	**488,429**

APPENDIX 2-C - Capital Expenditure Summary

Board Appendix 2-AB

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2021*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2012			2017			2018			2019			2020			2021	2022	2023	2024	2025
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	92	87	-5.0%	242	182	-25.0%	109	37	-65.8%	108	38	-64.7%	148	148	0.0%	52				
System Renewal	736	835	13.4%	454	467	2.9%	446	393	-11.9%	417	338	-19.0%	502	502	0.0%	404				
System Service			--			--			--			--			--					
General Plant	195	20	-89.7%	415	-	-100.0%	13	-	-100.0%	13	85	582.1%	58	58	0.0%	33				
TOTAL EXPENDITURE	1,023	942	-7.9%	1,111	649	-41.6%	567	430	-24.2%	537	461	-14.2%	708	708	0.0%	488	-	-	-	-
Capital Contributions	16	71	330.9%	18	3	-82.1%	24	40	70.8%	30	39	32.7%	64	64	0.0%	25				
Net Capital Expenditures	1,006	871	-13.5%	1,093	646	-40.9%	544	390	-28.3%	507	422	-16.9%	645	645	0.0%	463				
System O&M	$ 647	$ 670	3.6%	$ 647	$ 586	-9.4%	$ 649	$ 641	-1.3%	$ 688	$ 720	4.7%	$ 723	$ 723	0.0%	$ 735				

APPENDIX 2-D - Capital Projects Table

Board Appendix 2-AA

Appendix 2-AA
Capital Projects Table

Projects	2017	2018	2019	2020 Bridge Year	2021 Test Year
Reporting Basis					
Pole Replacements					
Distribution Stations					
Poles, Towers, Fixtures	64,088	96,375	190,196	53,717	75,615
O/H Conductors & Devices		3,634	28,677		
Underground Conduit					
U/G Conductors & Devices			6,548		
Line Transformers					
Services - New		158			
Meters					
Sub-Total	64,088	100,167	225,421	53,717	75,615
OH Cutout Renewal	3,689	9,037	4,663		9,547
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices				52,781	
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					
Services - New					
Meters					
Sub-Total	3,689	9,037	4,663	52,781	9,547
Spnaish River Drive			3,706		
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices					
Underground Conduit				76,572	
U/G Conductors & Devices				76,572	
Line Transformers				27,024	
Services - New				45,042	
Meters					
Sub-Total	0	0	3,706	225,210	0
Massey 3 Phase Line Replacement					
Distribution Stations					
Poles, Towers, Fixtures					42,984
O/H Conductors & Devices					42,984
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					15,170
Services - New					25,285
Meters					
Sub-Total	0	0	0	0	126,423
Duplessis road pole Line rebuild					
Distribution Stations					
Poles, Towers, Fixtures				55,038	
O/H Conductors & Devices					
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					
Services - New					
Meters					
Sub-Total	0	0	0	55,038	0
Cross Lot Relocations	39,070			48,038	
Distribution Stations					
Poles, Towers, Fixtures		38,491	42,827		
O/H Conductors & Devices		38,163	34,130		
Underground Conduit					
U/G Conductors & Devices		141	4,807		
Line Transformers		2,737			
Services - New					
Meters					
Sub-Total	39,070	79,532	81,764	48,038	0
Double Bucklet Truck					
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices					
Underground Conduit					
U/G Conductors & Devices					
Line Transformers					
Services - New					
Meters					
Vehicles			70,339		
Sub-Total	0	0	70,339	0	0
Replace Submarine Cable					
Distribution Stations					
Poles, Towers, Fixtures					
O/H Conductors & Devices					
Underground Conduit					
U/G Conductors & Devices	61,733	184,153			
Line Transformers					
Services - New					
Meters					
Sub-Total	61,733	184,153	0	0	0

Conductor Replacements - Tie Feeders F3-F5					
Distribution Stations					
Poles, Towers, Fixtures	39,389				
O/H Conductors & Devices	128,691				
Underground Conduit	0				
U/G Conductors & Devices	5,056				
Line Transformers	3,367				
Services - New	0				
Meters	0				
Sub-total	176,503	0	0	0	0
Conductor Replacements - Tie Feeders F1-F8					
Distribution Stations					
Poles, Towers, Fixtures	4,782				
O/H Conductors & Devices	77,844				
Underground Conduit	0				
U/G Conductors & Devices	13,878				
Line Transformers	0				
Services - New	0				
Meters	0				
Sub-Total	96,504	0	0	0	0
Long Term Load Transfer					
Distribution Stations	55,212				
Poles, Towers, Fixtures	77,380				
O/H Conductors & Devices	0				
Underground Conduit	0				
U/G Conductors & Devices	26,666				
Line Transformers	2,404				
Services - New					
Meters					
Sub-Total	161,662	0	0	0	0
Miscellaneous					
Misc. Facilities				35,000	25,000
Tools and Equipment			7,166	8,000	8,000
IT Equipment			7,759	15,000	
New & Upgrade Services	16,460	37,030	18,643	35,595	25,027
Sacred Heart School Service	661	111	18,028		
Joint Use Poles			0	2,521	2,656
City Projects - line relocations			0	11,845	7,762
Meters	3,024		0	32,372	16,419
MIST Meters				37,900	
OH Transformer Renewal	18,468	16,612	21,996	28,793	40,654
Clearlake					41,821
Brentwood Subdivision			1,459	27,821	
OH Forced Outages				5,905	5,587
Kbar Replacement				23,793	12,268
Transclosure Replacement					38,795
UG Forced Outages		3,536		3,161	2,925
MS 3 Conductor Replacement				2,000	46,318
Substation Misc. Projects				3,940	3,612
4kV Feeder at MS 2	6,813				
Miscellaneous Subtotal	45,426	57,289	75,051	273,646	276,844
Total	**648,675**	**430,178**	**460,944**	**708,430**	**488,429**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*					
Total	**648,675**	**430,178**	**460,944**	**708,430**	**488,429**

APPENDIX 2-E - Overhead Expense

Board Appendix 2-D

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Bridge Year	2021 Test Year
Total OM&A	$ 1,438,400	$ 1,460,893	$ 1,729,122	$ 1,578,387	$ 1,705,431
Total OM&A Before Capitalization (B)	$ 1,438,400	$ 1,460,893	$ 1,729,122	$ 1,578,387	$ 1,705,431

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Bridge Year	2021 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
Supervisory Salaries & Benefits	$ 38,856	$ 50,653	$ 59,495	$ 48,031	$ 50,000	Yes	
Insert description of additional item(s) and new rows if needed							
Total Capitalized OM&A (A)	$ 38,856	$ 50,653	$ 59,495	$ 48,031	$ 50,000		

% of Capitalized OM&A (=A/B)	2.70%	3.47%	3.44%	3.04%	2.93%		

APPENDIX 2-F - Service Reliability Indicators

Board Appendix 2-G

Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
SAIDI	0.900	10.430	9.480	0.280	0.540	0.280	2.130	0.350	0.160	0.350	0.280	0.550	0.350	0.160	0.350
SAIFI	0.180	4.620	4.790	0.070	0.260	0.030	1.890	0.100	0.060	0.170	0.030	1.100	0.100	0.060	0.170

5 Year Historical Average

	Including outages caused by loss of supply	Excluding outages caused by loss of supply	Excluding Major Event Days
SAIDI	4.326	0.654	0.338
SAIFI	1.984	0.450	0.292

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2015	2016	2017	2018	2019
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	n/a	n/a	100.0%	100.0%	100.0%
Telephone Accessibility	65.0%	76.1%	76.2%	72.6%	70.7%	63.0%
Appointments Met	90.0%	100.0%	100.0%	98.2%	100.0%	98.6%
Written Response to Enquires	80.0%	96.2%	98.0%	90.4%	97.0%	100.0%
Emergency Urban Response	80.0%	100.0%	n/a	100.0%	100.0%	n/a
Emergency Rural Response	80.0%	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	10.0%	3.5%	4.0%	4.7%	7.2%	8.4%
Appointment Scheduling	90.0%	98.0%	97.1%	97.9%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	n/a	100.0%	100.0%	n/a	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

APPENDIX 2-G - Service Life Comparison

Board Appendix 2-BB

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

Parent*	#	Asset Details: Category| Component | Type			Useful Life: MIN UL	TUL	MAX UL	USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL?: Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	40	3%	40	3%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55								
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	60	2%	60	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	40	3%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment <50kV	50	2%	50	2%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment<50kV	50	2%	50	2%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment<50kV	50	2%	50	2%	No	No
	18	Station Switch			30	50	60	1820	Distribution Station Equipment<50kV	50	2%	50	2%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	32	Secondary Cables in Duct			35	40	60								
	33	Network Tranformers	Overall		20	35	50	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45								
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	40	3%	40	3%	No	No
	36	UG Foundation			35	55	70								
	37	UG Vaults	Overall		40	60	80	1840	Underground Conduit	40	3%	40	3%	No	No
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45								
	40	Ducts			30	50	85								
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30								

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category| Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current: Years	Current: Rate	Proposed: Years	Proposed: Rate	Outside Range of Min, Max TUL?: Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture/Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipments	15	7%	15	7%	No	No
		Trailers	5	20	1930	Transportation Equipments	15	7%	15	7%	No	No
		Vans	5	10								
3	Administrative Buildings		50	75	1808		50	2%	50	2%	No	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75	1808	Buildings & Fixtures	50	2%	50	2%	No	No
		Parking	25	30								
		Fence	25	60	1808	Buildings & Fixtures	50	2%	50	2%	No	No
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardward	5	20%	5	20%	No	No
		Software	2	5	1611	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10								
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement and Testing Equipment	10	10%	10	10%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10								
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35								
11	Wholesale Energy Meters		15	30								
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								