EXHIBIT 4:

OPERATING EXPENSES

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2.4 Exhibit 4: Operating Expenses Overview

Espanola Regional Hydro Distribution Corporation (ERHDC) determines its Operating, Maintenance and Administrative (OM&A) costs through an analysis of the costs it incurs to operate and maintain the distribution system while remaining responsive to regulatory changes.

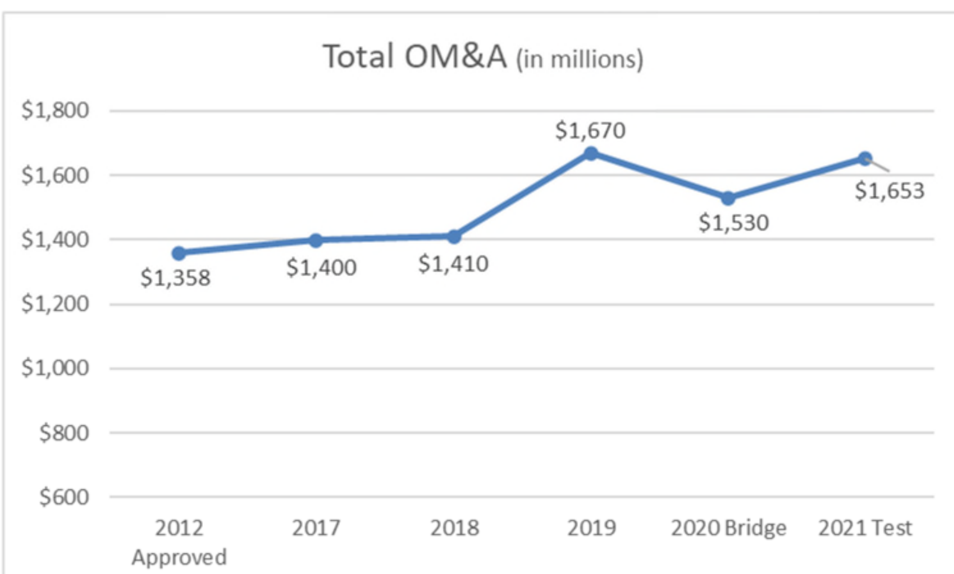
2.4.1.1 OM&A Benchmarking

ERHDC benchmarks its OM&A costs both to internal performance and external sources. Comparisons to budget and year over year analysis are used to control costs internally. In addition, the Yearbook of Electricity Distributors and the Pacific Economics Group (PEG) benchmarking report provide the data to compare ERHDC to its LDC peers.

(a) Year over Year Comparison

As shown in Figure 4-1 below, OM&A expenses have increased $295,304 from the 2012 Approved of $1,358,127 to $1,653,431 in the 2021 test year request for approval. This equates to an average annual increase of 2.42%.

<u>Figure 4-1: OM&A Expenses from 2012 Approved through 2021 Test Year</u>



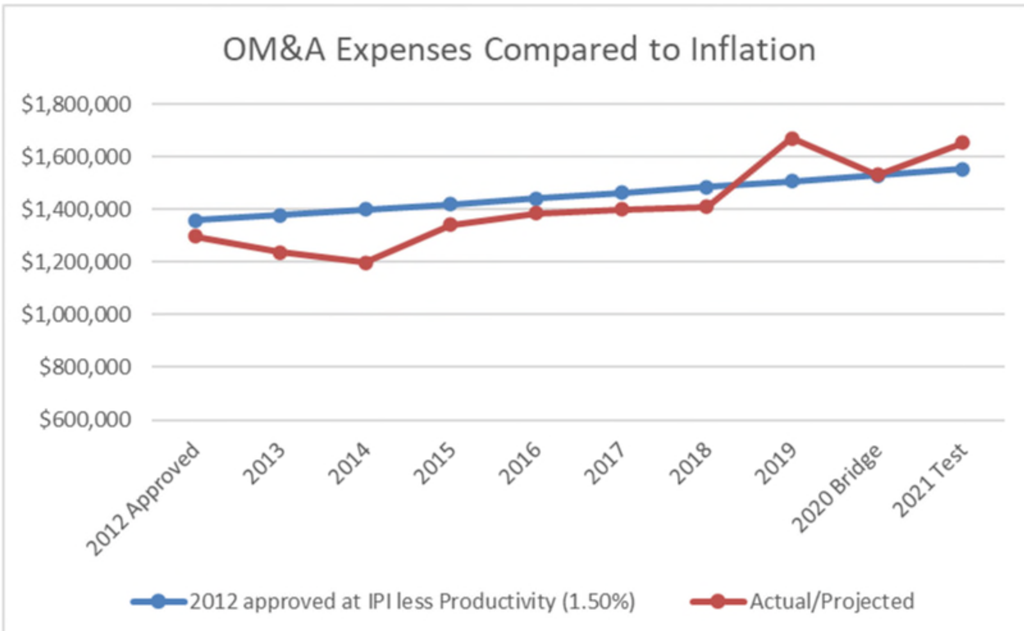
The increase from the 2012 Approved to the 2020 Bridge year amount of $1,530,356 is $172,230, an average annual increase of 1.59%. During the period 2013 to 2020 average annual IPI less the productivity factor has been 1.52% (Table 4-1). ERHDC OM&A expenses have been at IPI less productivity factor for the period 2013 to 2020 (Figure 4-2).

Table 4- 1: Inflation from 2013 to 2021

	Inflation (IPI)	Stretch Factor	IPI less Stretch
2013	1.60%	0.40%	1.20%
2014	1.70%	0.15%	1.55%
2015	1.60%	0.15%	1.45%
2016	2.10%	0.15%	1.95%
2017	1.90%	0.15%	1.75%
2018	1.20%	0.15%	1.05%
2019	1.50%	0.15%	1.35%
2020	2.00%	0.15%	1.85%
2021	1.50%	0.15%	1.35%

Ave. 2013 to 2019	1.66%		1.47%
Ave. 2013 to 2020	1.70%		1.52%
Ave. 2013 to 2021	1.68%		1.50%

Figure 4 - 2 OM&A Expenses Compared to Inflation



As can be seen from Figure 4-2 above, ERDHC's OM&A expenses have had two spikes in the period 2017 to 2021; those being in 2019 and 2021. The 2019 increase in expenses was a result of the costs associated with the sale of the LDC to North Bay Hydro. The costs associated with the sale are not being requested for recovery. Of the $123,074 increase in 2021, the main driver is $99,598 to complete this Cost of Service application. Items included in the 2021 Test Year request which are not currently in expenses being recovered in rates are increased OEB annual fees, Customer Satisfaction and Electrical Safety Surveys, intervenor costs, consultant costs and administrative salary costs due to increased reporting requirements since 2012.

For budgeting purposes, the inflation rate assumed for labour is 1.75% and 1.5% for non-labour. ERHDC recognizes that the Input Price Index ("IPI") effective for a rate application in 2020 is 2.0%.

(b) External Comparators

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 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.

In 2018, for the seventh consecutive year, ERDHC was placed in Group 2. ERHDC's efficiency performance based on the PEG model was below the predicted costs by 24.8% in 2018. In 2019, ERHDC was again placed in Group 2, with actual costs below predicted costs by 17.4%. Based on the 2020 budget, the projected performance for 2020 is 26.9% below predicted costs. Based on the 2021 Test Year request, ERHDC is projecting to again be in Group 2 with actual costs below predicted by 23.84%

(c) Customer Service, Billing, Collections, Network Support and Management Services:

ERHDC has a Services Agreement with PUC Services Inc. A billing and customer service agreement has been in place with PUC Services since December 1, 2001. The agreement includes services such as customer invoice preparation and mailing, scheduling and arranging meter reads, processing of payments, collections, customer service, etc. A management services agreement with PUC Services has been in place since 2006. It includes participation in Board meetings, supervision of all staff, oversight/awareness/monitoring of daily operations, regulatory & legislative requirements, purchasing, human resources, CDM, Engineering services, etc. and the preparation of annual budgets. In 2016 the two agreements were combined and extended to 2021. The 2016 agreement was amended in 2018 to extend the term 9 months (into 2022) to provide for a transition period to the planned amalgamation with North Bay Hydro. Copies of the Service Agreement and amending agreement with PUC Services are in Appendix 4-A.

In August of 2010 ERHDC engaged consultants to provide recommendations and support for the reasonableness of PUC Services's contract to supply services to ERHDC. A copy of the report is in Appendix 4-B.

Although the consultant's report is 10 years old, ERHDC still considers the qualitative information relevant. Data is presented in the report comparing ERHDC's costs to LDC's with less than 6,000 customers and to ERHDC's peers as determined in previous PEG benchmarking reports. ERHDC has updated the comparisons with 2018 and 2019 data from the most recent PEG benchmarking spreadsheet (2020-Benchmarking-Spreadsheet-Forecast-Model).

Table 4-2 below compares ERHDC's 2018 expenses to that of LDC's in the province serving less than 6,000 customers. The chart indicates that ERHDC cost per customer for billing and collecting is at the high end of the group. However, the agreement with PUC Services provides billing, collection and management services, therefore to account for differences in recording similar expenses in different categories by LDCs, the cost per customer for combined billing/collecting and administrative functions is also presented along with the total operations, maintenance and administrative (OM&A) cost per customer. The chart indicates that ERHDC's total administrative type costs (including billing and collecting) are the third best of the group, while total OM&A is also reasonable at 7th best of the group.

Table 4- 2: 2018 Costs per Customer in Comparison to LDCs with Fewer than 6000 Customers

2018 Costs per Customer in Comparison to LDC's with Fewer than 6,000 Customers

LDC	# Customers	Billing/Coll Expense	Admin & Comm Rel	Total OM&A	Billing/Coll Expense per Cust	Admin & Comm Rel per Cust	Bill/Coll/Admin/ Comm Rel per Cust	Total OM&A per Cust
Hydro Hawkesbury Inc.	5,547	$401,290.60	$471,733.30	$1,137,617.47	$72.34	$85.04	$157.39	$205.09
Northern Ontario Wires Inc.	5,903	$677,714.21	$500,403.98	$2,593,340.15	$114.81	$84.77	$199.58	$439.33
Espanola Regional Hydro Distribution Corporation	3,303	$399,207.00	$318,943.25	$1,365,190.96	$120.86	$96.56	$217.42	$413.32
Renfrew Hydro Inc.	4,312	$414,530.34	$525,005.76	$1,410,649.84	$96.13	$121.75	$217.89	$327.15
Hearst Power Distribution Company Limited	2,697	$285,910.74	$334,686.87	$1,117,265.40	$106.01	$124.10	$230.11	$414.26
Rideau St. Lawrence Distribution Inc.	5,909	$500,078.00	$886,208.00	$2,151,628.12	$84.63	$149.98	$234.61	$364.13
Cooperative Hydro Embrun Inc.	2,305	$191,790.41	$393,138.81	$679,958.41	$83.21	$170.56	$253.77	$294.99
Sioux Lookout Hydro Inc.	2,839	$323,679.73	$404,193.74	$1,435,927.04	$114.01	$142.37	$256.38	$505.79
Fort Frances Power Corporation	3,745	$285,024.05	$693,709.38	$1,695,781.33	$76.11	$185.24	$261.34	$452.81
Wellington North Power Inc.	3,805	$339,696.71	$674,534.42	$1,696,666.61	$89.28	$177.28	$266.55	$445.90
Kenora Hydro Electric Corporation Ltd.	5,565	$533,429.00	$1,033,329.00	$2,300,050.00	$95.85	$185.68	$281.54	$413.31
West Coast Huron Energy Inc.	3,869	$425,322.00	$763,247.00	$1,687,483.00	$109.93	$197.27	$307.20	$436.15
Hydro 2000	1,262	$155,371.55	$237,222.48	$442,329.34	$123.12	$187.97	$311.09	$350.50
Atikokan Hydro	1,636	$173,445.33	$400,507.17	$913,651.99	$106.02	$244.81	$350.83	$558.47
Chapleau Hydro	1,208	$113,203.60	$452,493.03	$744,871.70	$93.71	$374.58	$468.29	$616.62
				ERHDC Rank	14	3	3	7

Table 4 - 3 below compares ERHDC's 2019 expenses to that of LDC's in the province serving less than 6,000 customers. The chart indicates that ERHDC's 2019 performace for Bill/Coll/Admin/Comm Rel moved to the middle of he group.

Table 4 - 3: 2019 Costs per Customer in Comparison to LDCs with Fewer than 6,000 Customers

2019 Costs per Customer in Comparison to LDC's with Fewer than 6,000 Customers

LDC	# Customers	Billing/Coll Expense	Admin & Comm Rel	Total OM&A	Billing/Coll Expense per Cust	Admin & Comm Rel per Cust	Bill/Coll/Admin/ Comm Rel per Cust	Total OM&A per Cust
Hydro Hawkesbury Inc.	5,549	$387,098.84	$460,101.70	$1,064,098.36	$69.76	$82.92	$152.68	$191.76
Renfrew Hydro Inc.	4,325	$420,634.98	$488,642.41	$1,331,832.77	$97.26	$112.98	$210.24	$307.94
Northern Ontario Wires Inc.	5,977	$726,572.70	$549,226.60	$2,729,799.33	$121.56	$91.89	$213.45	$456.72
Hearst Power Distribution Company Limited	2,700	$291,689.17	$308,660.74	$1,086,335.37	$108.03	$114.32	$222.35	$402.35
Rideau St. Lawrence Distribution Inc.	5,910	$505,507.05	$883,815.94	$2,210,312.05	$85.53	$149.55	$235.08	$374.00
Cooperative Hydro Embrun Inc.	2,366	$206,395.72	$388,123.72	$683,096.71	$87.23	$164.04	$251.28	$288.71
Fort Frances Power Corporation	3,773	$278,171.62	$688,061.13	$1,856,422.90	$73.73	$182.36	$256.09	$492.03
Espanola Regional Hydro Distribution Corporation	3,309	$394,728.97	$475,749.30	$1,599,451.93	$119.29	$143.77	$263.06	$483.36
Sioux Lookout Hydro Inc.	2,848	$304,822.63	$488,893.74	$1,530,202.25	$107.03	$171.66	$278.69	$537.29
Wellington North Power Inc.	3,830	$388,511.31	$746,881.41	$1,801,471.94	$101.44	$195.01	$296.45	$470.36
Atikokan Hydro	1,629	$173,438.07	$407,782.01	$1,083,377.24	$106.47	$250.33	$356.80	$665.06
Hydro 2000	1,244	$161,986.99	$297,471.52	$506,164.26	$130.21	$239.13	$369.34	$406.88
Chapleau Hydro	1,222	$122,445.26	$505,916.65	$819,047.94	$100.20	$414.01	$514.21	$670.25
				ERHDC Rank	11	5	8	9

However, included in ERHDC's 2019 costs is approximately $100,000 in one-time costs associated with the divestiture to North Bay Hydro. (These costs are not being requested for recovery in the 2021 Test Year.) Excluding these costs from the analysis above results in the comparisons in the following table (Table 4-4). ERHDC's total billing and administrative costs were the fourth lowest of the group in 2019.

Table 4 - 4: 2019 Costs per Customer in Comparison to LDCs with Fewer than 6,000 Customers (Excluding Divestiture Costs)

2019 Costs per Customer in Comparison to LDC's with Fewer than 6,000 Customers
Excluding Divestiture Costs

LDC	# Customers	Billing/Coll Expense	Admin & Comm Rel	Total OM&A	Billing/Coll Expense per Cust	Admin & Comm Rel per Cust	Bill/Coll/Admin/ Comm Rel per Cust	Total OM&A per Cust
Hydro Hawkesbury Inc.	5,549	$387,098.84	$460,101.70	$1,064,098.36	$69.76	$82.92	$152.68	$191.76
Northern Ontario Wires Inc.	5,977	$726,572.70	$549,226.60	$2,729,799.33	$121.56	$91.89	$213.45	$456.72
Renfrew Hydro Inc.	4,325	$420,634.98	$488,642.41	$1,331,832.77	$97.26	$112.98	$210.24	$307.94
Espanola Regional Hydro Distribution Corporation	3,309	$394,728.97	$375,749.30	$1,499,451.93	$119.29	$113.55	$232.84	$453.14
Hearst Power Distribution Company Limited	2,700	$291,689.17	$308,660.74	$1,086,335.37	$108.03	$114.32	$222.35	$402.35
Rideau St. Lawrence Distribution Inc.	5,910	$505,507.05	$883,815.94	$2,210,312.05	$85.53	$149.55	$235.08	$374.00
Cooperative Hydro Embrun Inc.	2,366	$206,395.72	$388,123.72	$683,096.71	$87.23	$164.04	$251.28	$288.71
Sioux Lookout Hydro Inc.	2,848	$304,822.63	$488,893.74	$1,530,202.25	$107.03	$171.66	$278.69	$537.29
Fort Frances Power Corporation	3,773	$278,171.62	$688,061.13	$1,856,422.90	$73.73	$182.36	$256.09	$492.03
Wellington North Power Inc.	3,830	$388,511.31	$746,881.41	$1,801,471.94	$101.44	$195.01	$296.45	$470.36
Hydro 2000	1,244	$161,986.99	$297,471.52	$506,164.26	$130.21	$239.13	$369.34	$406.88
Atikokan Hydro	1,629	$173,438.07	$407,782.01	$1,083,377.24	$106.47	$250.33	$356.80	$665.06
Chapleau Hydro	1,222	$122,445.26	$505,916.65	$819,047.94	$100.20	$414.01	$514.21	$670.25
				ERHDC Rank	11	4	5	7

In addition to the comparison to LDCs with less than 6,000 customers, the consultant's report presents a comparison of LDCs in ERHDC former "PEG" peer group. The PEG peer group comparison is updated in the following table (Table 4-5).

Table 4 - 5: 2018 Costs per Customer in Comparison to Former PEG Peer Group

2018 Costs per Customer in Comparison to Former PEG Peer Group

LDC	Billing/Coll Expense	Admin Exp	Total Billing/Coll/ Admin	Operating	Maint	O & M	Total
Northern Ontario Wires Inc.	$114.81	$84.77	$199.58	$149.65	$83.13	$232.78	$432.36
Espanola Regional Hydro Distribution Corp	$120.86	$96.56	$217.42	$113.24	$80.86	$194.10	$411.52
Renfrew Hydro Inc.	$96.13	$121.75	$217.89	$74.39	$33.88	$108.27	$326.16
Sioux Lookout Hydro Inc.	$114.01	$142.37	$256.38	$199.39	$44.57	$243.97	$500.35
Fort Frances Power Corporation	$76.11	$185.24	$261.34	$109.14	$78.93	$188.07	$449.42
Atikokan Hydro	$106.02	$244.81	$350.83	$256.56	$53.02	$309.59	$660.41
Algoma Power	$74.77	$377.07	$451.84	$123.59	$438.99	$562.59	$1,014.42
Chapleau Hydro	$93.71	$374.58	$468.29	$140.31	$0.25	$140.56	$608.86
ERHDC Rank	8	2	2	3	6	4	2

Once again the Billing/Collection expense appears to be high, however the total Billing/Collecting/Administrative costs per customer are the second lowest in the group while the overall OM&A cost per customer is also second lowest in the group.

The following Table 4 - 6 presents the 2019 Peer Group comparisons.

Table 4 - 6: 2019 Costs per Customer in Comparison to Former PEG Peer Group

2019 Costs per Customer in Comparison to Former PEG Peer Group

LDC	Billing/Coll Expense	Admin Exp	Total Billing/Coll/ Admin	Operating	Maint	O & M	Total
Renfrew Hydro Inc.	$97.26	$112.98	$210.24	$63.14	$34.56	$97.70	$307.94
Northern Ontario Wires Inc.	$121.56	$91.89	$213.45	$155.40	$81.73	$237.13	$450.58
Fort Frances Power Corporation	$73.73	$182.36	$256.09	$140.10	$62.66	$202.77	$458.86
Espanola Regional Hydro Distribution Corp	$119.29	$143.77	$263.06	$129.39	$88.32	$217.72	$480.78
Sioux Lookout Hydro Inc.	$107.03	$171.66	$278.69	$202.31	$50.64	$252.95	$531.64
Atikokan Hydro	$106.47	$250.33	$356.80	$243.06	$60.99	$304.06	$660.85
Chapleau Hydro	$100.20	$414.01	$514.21	$148.40	$0.00	$148.40	$662.60
Algoma Power	$72.28	$389.22	$461.50	$120.43	$436.11	$556.54	$1,018.05
ERHDC Rank	7	3	4	3	7	4	4

As noted above, the 2019 costs include included in ERHDC's 2019 costs is approximately $100,000 in one-time costs associated with the divestiture to North Bay Hydro. Excluding these costs from the analysis above results in the comparisons in the following Table 4-7. ERHDC;s total billing and administrative costs were the third lowest of the group in 2019 excluding the one-time costs.

Table 4-7: 2019 Costs per Customer in Comparison to Former PEG Peer Group Excluding Divestiture Costs

2019 Costs per Customer in Comparison to Former PEG Peer Group Excluding Divestiture Costs							
LDC	Billing/Coll Expense	Admin Exp	Total Billing/Coll/ Admin	Operating	Maint	O & M	Total
Renfrew Hydro Inc.	$97.26	$112.98	$210.24	$63.14	$34.56	$97.70	$307.94
Northern Ontario Wires Inc.	$121.56	$91.89	$213.45	$155.40	$81.73	$237.13	$450.58
Espanola Regional Hydro Distribution Corp	$119.29	$113.55	$232.84	$129.39	$88.32	$217.72	$450.56
Fort Frances Power Corporation	$73.73	$182.36	$256.09	$140.10	$62.66	$202.77	$458.86
Sioux Lookout Hydro Inc.	$107.03	$171.66	$278.69	$202.31	$50.64	$252.95	$531.64
Atikokan Hydro	$106.47	$250.33	$356.80	$243.06	$60.99	$304.06	$660.85
Algoma Power	$72.28	$389.22	$461.50	$120.43	$436.11	$556.54	$1,018.05
Chapleau Hydro	$100.20	$414.01	$514.21	$148.40	$0.00	$148.40	$662.60
ERHDC Rank	7	3	3	3	7	4	2

ERHDC submits that the tables above demonstrate that the service contracts with PUC Services result in prudent and reasonable costs to its customers while providing a service satisfaction level of 91% as per the 2019 customer satisfaction survey.

2.4.1.2 OM&A Budgeting Process Used by ERHDC

The operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget provides a plan against which actual results may be evaluated. Once approved the budget is only revised if a material change in the plan is required. Capital and operating budgets are formulated to achieve ERHDC's business objectives in a prudent and sustainable manner while considering customer rate impacts.

The following directives are used to prepare the annual budgets:

- Outside expenses for all department budgets are built using previous year actual, current year forecast and current year budgets as the base; for example, when compiling the 2020 budget, the previous year actual (2018), the current year forecast (2019) and the current year budget (2019) would be used;
- Significant variances in spending from prior years must be explained and documented;
- Review the headcount for accuracy and outline any changes;
- Prepare a total labour budget using projected wage and benefit cost. Overtime and account distribution are based on previous years actual plus any identified changes for the future year.
- Senior management reviews the draft budget and makes changes to balance cost control with achieving core objectives. In an effort to contain costs and explore efficiencies and still provide an acceptable level of reliability and customer service, the team looks in detail for discretionary costs and identifies cost areas that can be delayed or addressed with alternative approaches.
- Senior management makes a submission to the Board of Directors on the proposed budget and formal approval is requested.

2.4.1.3 Operating, Maintenance and Administrative ("OM&A") Test Year Levels

ERHDC's Test Year Operating, Maintenance and Administrative ("OM&A") expenses are $1,653,431 excluding expenses relating to the Low Income Energy Assistance Program ("LEAP"). ERHDC follows the Board's Accounting Procedures Handbook ("APH") in distinguishing work performed between operations and maintenance. A summary of ERHDC's OM&A expenses (5005-5695, 6110, 6205), for the 2012 Board Approved, 2017 Actual, 2018 Actual, 2019 Actual, 2020 Bridge and 2021 Test Year is provided in Table 4-8 and Table 4-9 below, which is consistent with the Board's Appendix 2-JA. A copy of the Board's Appendix 2-JA is also included in Appendix 4-C to this Exhibit. ERHDC is proposing to receive the 2021 Test Year costs through distribution rates for the 2021 Test Year.

Table 4 - 8: Summary of Recoverable OM&A Expenses

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Rebasing Year 2012	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 249,347	$ 300,622	$ 374,022	$ 428,161	$ 388,361	$ 401,109
Maintenance	$ 397,159	$ 285,287	$ 267,091	$ 291,771	$ 334,884	$ 333,727
SubTotal	**$ 646,506**	**$ 585,908**	**$ 641,113**	**$ 719,932**	**$ 723,245**	**$ 734,837**
%Change (year over year)		-9.4%	9.4%	12.3%	0.5%	1.6%
%Change (Test Year vs Last Rebasing Year - Actual)						9.7%
Billing and Collecting	$ 371,722	$ 436,238	$ 429,999	$ 452,917	$ 421,987	$ 428,448
Community Relations	$ 1,000	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ 338,898	$ 377,398	$ 339,127	$ 496,779	$ 385,124	$ 490,146
SubTotal	**$ 711,620**	**$ 813,636**	**$ 769,127**	**$ 949,696**	**$ 807,111**	**$ 918,594**
%Change (year over year)		10.4%	-5.5%	23.5%	-15.0%	13.8%
%Change (Test Year vs Last Rebasing Year - Actual)						46.3%
Total	**$ 1,358,127**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,530,356**	**$ 1,653,431**
%Change (year over year)		1.1%	0.8%	18.4%	-8.3%	8.0%

Table 4 - 9: Summary of Recoverable OM&A Expenses Continued

	Last Rebasing Year 2012 OEB Approved	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	Variance 2020 Bridge vs. 2019 Actuals	2021 Test Year	Variance 2021 Test vs. 2020 Bridge
Operations	**$ 249,346**	**$ 300,622**	**$ 374,022**	**$ 428,161**	**$ 388,361**	**-$ 39,800**	**$ 401,109**	**$ 12,748**
Maintenance	**$ 397,158**	**$ 285,287**	**$ 267,091**	**$ 291,771**	**$ 334,884**	**$ 43,114**	**$ 333,727**	**-$ 1,157**
Billing and Collecting	**$ 371,722**	**$ 436,238**	**$ 429,999**	**$ 452,917**	**$ 421,987**	**-$ 30,929**	**$ 428,448**	**$ 6,461**
Community Relations	**$ 1,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Administrative and General	**$ 338,898**	**$ 377,398**	**$ 339,127**	**$ 496,779**	**$ 385,124**	**-$ 111,655**	**$ 490,146**	**$ 105,023**
Total OM&A Expenses	**$ 1,358,124**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,530,356**	**-$ 139,271**	**$ 1,653,431**	**$ 123,074**
Adjustments for Total non-recoverable items[3]								
Total Recoverable OM&A Expenses	**$ 1,358,124**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,530,356**	**-$ 139,271**	**$ 1,653,431**	**$ 123,074**
Variance from previous year		$ 662,311	$ 10,696	$ 259,388	-$ 139,271		$ 123,074	
Percent change (year over year)			1%	18%	-8%		8%	
Percent Change: Test year vs. Most Current Actual							-0.97%	
Simple average of % variance for all years							-2.07%	
Compound Annual Growth Rate for all years								2.7%
Compound Growth Rate (2019 vs. 2012 Actuals)							3.7%	

OM&A expenses reflect costs required to operate, maintain and sustain the electricity distribution operations, including new expenditures to address regulatory changes. ERHDC's OM&A expenditures have increased from $1,358,124 in 2012 to the 2021 rate request amount of

$1,653,431, an average annual increase of 2.7%. The majority of the increase occurred between the 2020 Bridget Year and the 2021 Test Year.

ERHDC is requesting the following items in its Cost of Service rate application which are not currently in expenses being recovered in rates:

- Increased costs to complete the Cost of Service rate application since 2012 approved rates
- Increased OEB annual fees since 2012 approved rates
- Added cost for the mandated Customer Satisfaction Survey since 2012 approved rates
- Added cost for the manadated Electrical Safety Survey since 2012 approved rates
- Costs for intervenors involved in the Cost of Service application process
- Increased administrative salary costs due to increased reporting requirements since 2012 approved rates

2.4.1.4 Associated Cost Drivers and Significant Changes

Table 4-10 below is a summary of cost drivers for 2012 approved to 2021 test year.

Table 4 - 10: Summary of Cost Drivers - 2012 Approved to 2021 Test Year

Description		Amount	
2012 Approved		$1,358,127	
Regulatory Expense (Acct 5655)	$109,598		
Line Clearing - Contract (Acct 5135)	-$101,051		
Administrative Salaries (Acct 5615)	$58,398		
Cost Drivers less than Materiality	$228,358		
Increase - 2012 Approved to 2021 Test		$295,304	21.7%
2021 Test year		$1,653,430	

Regulatory Expense (Acct 5655) – increase of $109,598 from 2012 Approved of $35,000 to 2021 Test of $144,598 – includes increases due to OEB assessment increase, added requirement for customer satisfaction survey every two years, added requirement for safety survey every two years, requirement of Distribution System Plan, and increased costs for the Cost of Service rate approval process (preparation of application, interrogatory responses, settlement conference, intervenor costs, OEB costs).

Line Clearing Contract Work (Acct 5135) – decrease of $101,051 from 2012 Approved of $186,001 to 2021 Test of $84,951. Table 4-11 below shows Account 5135 – Line Clearing Contract Work for 2012 approved vs 2021 test year.

Table 4 - 11: Line Clearing Contract Work (Account 5135)

	2012 Approved	2021 Test	2012 vs 2021
Internal Labour	$45,419	$32,431	-$12,988
Trucking	$14,083	$4,261	-$9,822
Contractor	$126,500	$48,260	-$78,240
	$186,001	$84,951	-$101,051

Due to the increase in capital and other operating and maintenance work, internal resources (labour and trucking) have been reallocated from the 2012 Approved to the 2021 test Year. The 2012 CoS included accelerated tree trimming maintenance to remedy a backlog of areas to trim. The amount of the one-time cost of performing line clearing on Bass Lake Road ($150,000/4 = $37,500) which was included in tree trimming costs has been removed from the 2021 Test Year. In addition the contractor amount has been reduced in the 2021 Test Year. ERHDC has a plan which provides tree trimming in the entire service territory on a three year cycle. Annual contractor costs have been included in Test Year OM&A expenses to complete the program over the three year cycle.

Administrative Salaries (Acct 5615) – increase of $58,398 from 2012 Approved of $0 to 2021 Test of $58,398. Included in ERHDC's rate base is the equivalent of 1.25 office adminstative/financial/regularoty position. Subsequent to the 2012 rate approval the office assistant resource increased to full time due to the increased regulatory workload.

Table 4-12 below is a summary of cost drivers for 2020 bridge year to 2021 test year.

Table 4 -12: Summary of Cost Drivers - 2020 Bridge Year to 2021 Test Year

Description	Amount		
2020 Bridge		$1,530,356	
Regulatory Expense (Acct 5655)	$99,598		
Cost Drivers less than Materiality	$23,476		
Increase - 2012 Approved to 2021 Test		$123,074	8.0%
2021 Test year		$1,653,431	

Regulatory Expense (Acct 5655) – increase of $99,598 from 2020 Bridge Year of $45,000 to 2021 Test of $144,598 – includes increases due the Cost of Service rate approval process.

2.4.1.5 Overall Trends in Costs

ERHDC's OM&A cost per customer increased from the 2012 Approved of $404 to the Test Year amount of $491, an increase of 21.4% over nine years (average of 2.4% per year). The majority of the increase occurred between the 2020 Bridget Year and the 2021 Test Year as a result of the increase in expenses to complete the Cost of Service application. Excluding the $100,000 increase due to the Cost of Service expenses, the average increase is 1.6% per year. These increases factor in improvements in productivity, cost containment measures and account for inflation.

(a) Employee Costs

ERHDC's FTE's have increased from 5.42 in the 2012 Approved to 7.00 in the Test Year as shown in Table 4-13 below.

Table 4 - 13 Table of FTEs

Position	2012 Approved	2021 Test
Chief Financial Officer	1.00	0.00
Chief Financial Officer – Transition	0.17	0.00
Manager of Accounting		1.00
Admin Assistant	0.25	1.00
Lead Hand	1.00	1.00
Power Line Techs	3.00	3.00
Line Supervisor	0.00	1.00
Total	5.42	7.00

In 2013 ERHDC hired a Lines Supervisor, the salary for which was offset by a reduction in the Service Contract expense with PUC Services who had provided the Supervisor prior to 2013. An additional 0.75 FTE is an increase to full time for the office assistant due to the increased regulatory workload. A coop student is also included in the 2021 Test Year at 0.30 of a FTE. Base salaries reflect the cost of living and salary progression increases arising from recent collective bargaining agreements with unionized employees as well as commensurate percentage increases for management staff. See further details in Section 2.4.3.1(g) Succession/Workforce Planning below.

2.4.1.6 Inflation Rate Assumed

The inflation rates assumed in the Test Year for labour is 1.75% and 1.5% for non-labour. While the IPI effective for a rate application in 2020 is 2.0%, ERHDC has reduced the non-labour inflation rate to 1.5% for budgeting purposes. The 1.75% labour rate increase is based on the collection agreement in effect for 2021.

2.4.1.7 Business Environment Changes

Since ERHDC's last rebasing in 2012, there has been a number of significant business environment changes that will impact operating costs – the introduction of Metering Inside the Settlement Timeframe (MIST); the introduction of Ontario One Call; Measurement Canada sampling requirements now that ERHDC's smart meter seals are expiring; overhead transformer PCB testing;

Renewed Regulatory Framework for Electric Distributors and government programs for customers and other mandated programs.

ERHDC's residential customers have decreased from the 2012 approved of 3,359 to the projected test year of 3,357 (-0.1%) (Table 4-14 below). ERHDC's electricity load has decreased by 5.8% from the 2012 approved.

Table 4 - 14: ERHDC's Residential Customers Electricity Load

	2012 Approved	2017	2018	2019	2020 Bridge	2021 Test
Customers	3,359	3,336	3,351	3,357	3,357	3,357
Consumption (kWhs)	62,249,997	54,872,263	57,121,172	57,482,828	58,878,258	58,677,605

2.4.2. OM&A Summary and Cost Driver Tables

Consistent with the Board's Appendix 2-JB, Table 4 - 15 provides a list of the cost drivers that affected year over year OM&A spending or, where the cost driver is common or recurring, expenditures that have impacted multiple years. Commentary has been provided for material variances for the 2017, 2018 and 2019 Historical Years, the 2020 Bridge Year and the 2021 Test Year. A copy of the Board's Appendix 2-JB can also be found in Appendix 4-D to this Exhibit.

<u>Table 4 - 15 Recoverable OM&A Cost Driver Table</u>

OM&A	Last Rebasing Year (2012 Actuals)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Reporting Basis						
Opening Balance²	$ 1,358,127	$ 1,384,120	$ 1,399,544	$ 1,410,239	$ 1,669,627	$ 1,530,357
Regulatory (5655)		$ 37,717	-$ 77,188	$ 12,141		$ 99,598
Metering (5065) Labour				$ 22,469		
Line Clearing (5135) Expense		-$ 14,201		$ 63,850		
Line Clearing (5135) Labour				-$ 21,010		
O/H Lines Lab (5020)				$ 17,686		
O/H Lines Trucking (5020)		$ 15,931	$ 9,657			
O/H Lines Material (5025)		-$ 13,599		$ 23,896		
5005 PUC Supervision		$ 15,503				
5105 PUC Supervision				-$ 19,178		
5016 Sub 1 & 3 Labour			$ 7,885			
5035 O/H transformer labour			$ 8,299			
5040 U/G lines labour			$ 11,837	-$ 19,178		
5045 U/G lines expense			$ 14,126			
5055 U/G transformers labour			$ 9,307			
5070 Customer Premise Labour			$ 8,255			
5125 O/H Conductor Labour		-$ 46,818			$ 23,634	
5130 O/H Services Labour			$ 8,763			
5320 Collecting Labour, S/W, coll agency		$ 16,124	$ 12,578			
5335 Bad Debts		$ 17,435	-$ 27,595	$ 27,395	-$ 35,188	
5610 Management Salaries				$ 11,113		
5615 Admin Labour			$ 9,804	$ 35,204	-$ 22,901	
5630 PUC Supervision				$ 23,854	-$ 12,504	
5630 Audit		-$ 15,751		$ 73,863	-$ 67,616	
5645 Pension			$ 9,573		-$ 20,152	
Misc 2013 to 2016	$ 25,993					
Misc		$ 3,083	$ 5,393	$ 7,283	-$ 4,543	$ 23,476
Closing Balance²	$ 1,384,120	$ 1,399,544	$ 1,410,239	$ 1,669,627	$ 1,530,357	$ 1,653,431

The following explanations detail the primary cost drivers that have influenced the increase in ERHDC's OM&A Expenditures since the last Cost of Service Application, up to and including the 2021 Test Year. Each driver is summarized by its net change year over year. ERHDC has provided comments on those variances greater than its materiality level of $50,000.

2.4.2.1 Regulatory Expenses

(a) 2017 Actual to 2018 Actual – ($77,188)

The 2017 expenses included costs for two surveys, consulting costs concerning rate application matters and consulting costs regarding a Distribution System Plan. These expenses were not incurred again in 2018.

(b) 2020 Bridge to 2021 Test Year - $99,598

The increase in regulatory expenses in 2021 is due to the costs for the cost of service rate application which include preparation of the application, interrogatory responses, settlement conference, intervenor costs and OEB costs. ERHDC does not have the internal resources or experience to prepare the application, therefore external consultants are required.

2.4.2.2 Line Clearing

(a) 2018 Actual to 2019 Actual – ($63,850)

Due to its location and the relatively small volume of work required, periodically it is difficult to hire qualified line clearing contractors in Espanola. This was the case in 2018. No contracted line clearing was done in 2018, however, a contractor was hired in 2019 to complete more than the normal annual plan. ERHDC has a plan which provides tree trimming in the entire service territory on a three year cycle. Annual contractor costs have been included in Test Year OM&A expenses to have the program completed annually by a new tree trimming company formed by the collaboration of Northern Ontario utilities.

2.4.2.3 Audit

(a) 2018 Actual to 2019 Actual – $73,863

During 2019, additional auditing and accounting fees were incurred due to the sale of ERHDC to North Bay Hydro (October 31 and December 31, 2019 audited financial statements were required).

(b) 2019 Actual to 2020 Bridget Year – ($67,616)

The budgeted auditing fees were reduced in the 2020 Bridge year to account for the additional fees incurred in 2019 due to the sale.

2.4.2.4 Recoverable OM&A Cost Per Customer and Per Full Time Equivalent

Table 4 -16 below is a summary of the OM&A cost per customer and per full-time equivalent ("FTE"). This table is consistent with the Board's Appendix 2-L, which is included as Appendix 4-E to this Exhibit. The number of customers is based on an annual average for each metered rate class.

Table 4 - 16: Recoverable OM&A Cost per Customer and per Full Time Equivalent (FTE)

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year 2012 - OEB Approved	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs						
O&M	$ 646,504	$ 585,908	$ 641,113	$ 719,932	$ 723,245	$ 734,837
Admin Expenses	$ 711,620	$ 813,636	$ 769,127	$ 949,696	$ 807,111	$ 918,594
Total Recoverable OM&A from Appendix 2-JB [5]	$ 1,358,124	$ 1,399,544	$ 1,410,240	$ 1,669,628	$ 1,530,356	$ 1,653,431
Number of Customers [2,4]	3,359	3,336	3,351	3,357	3,357	3,357
Number of FTEs [3,4]	5.40	7.00	6.67	7.00	7.07	7.31
Customers/FTEs	622	477	502	480	475	459
OM&A cost per customer						
O&M per customer	$192	$176	$191	$214	$215	$219
Admin per customer	$212	$244	$230	$283	$240	$274
Total OM&A per customer	$404	$420	$421	$497	$456	$493
OM&A cost per FTE						
O&M per FTE	$119,723	$83,701	$96,119	$102,847	$102,298	$100,525
Admin per FTE	$131,781	$116,234	$115,311	$135,671	$114,160	$125,663
Total OM&A per FTE	$251,504	$199,935	$211,430	$238,518	$216,458	$226,188

(a) Variance Analysis for Change in OM&A Expenses

The following Tables 4-17 to 4-21 illustrate the variances in OM&A expenses year over year for the 2012 Approved, 2017 to 2019 Actual, 2020 Bridge and 2021 Test years. ERHDC operates with one line crew (5 staff) and two administrative staff. Depending on the projects undertaken, whether planned or unplanned, variances between expense categories and capital expenditures are not unusual from year to year. Explanations are provided for annual variances greater than the materiality threshold of $50,000.

Table 4 - 17: 2012 Board Approved vs. 2017 Actual

Description	2012 Last Rebasing Year OEB Approved	2017 Actuals	Variance
Operations	$249,346	$300,622	$51,276
Maintenance	$397,158	$285,287	($111,871)
Billing and Collecting	$371,722	$436,238	$64,516
Community Relations	$1,000	$0	($1,000)
Administrative and General	$338,898	$377,398	$38,500
Total	**$1,358,124**	**$1,399,544**	**$41,420**
%Change (year over year)			3.0%

Total increase of $41,420 in OM&A expenditures from 2012 Approved to 2017 is below materiality.

Table 4 - 18: 2017 Actual vs. 2018 Actual

Description	2017 Actuals	2018 Actuals	Variance
Operations	$300,622	$374,022	$73,401
Maintenance	$285,287	$267,091	($18,196)
Billing and Collecting	$436,238	$429,999	($6,238)
Community Relations	$0	$0	$0
Administrative and General	$377,398	$339,127	($38,271)
Total	**$1,399,544**	**$1,410,240**	**$10,696**
%Change (year over year)			0.8%

Total increase of $10,696 in OM&A expenditures from 2017 to 2018 is below materiality.

Table 4 - 19: 2018 Actual vs. 2019 Actual

Description	2018 Actuals	2019 Actuals	Variance
Operations	$374,022	$428,161	$54,139
Maintenance	$267,091	$291,771	$24,680
Billing and Collecting	$429,999	$452,917	$22,917
Community Relations	$0	$0	$0
Administrative and General	$339,127	$496,779	$157,652
Total	**$ 1,410,240**	**$ 1,669,628**	**$ 259,388**
%Change (year over year)			18.4%

Operations – increase of $54,139

The increase over 2018 is the result of increased labour costs in the areas of overhead lines and meter operations partially offset by a reduction in underground lines labour. Costs also increased for Hydro One and Bell pole rentals in 2019.

Administrative and General – increase of $157,652

The 2019 increase in expenses was a result of the costs associated with the sale of the LDC to North Bay Hydro including increased audit fees for two year ends, legal fees and internal and consulting costs to prepare the pre and post request for proposal documents. The costs associated with the sale are not being requested for recovery. In addition the required customer survey was conducted in 2019 which was not in 2018 expenses.

Table 4 - 20: 2019 Actual vs. 2020 Bridge

Description	2019 Actuals	2020 Bridge Year	Variance
Operations	$428,161	$388,361	($39,800)
Maintenance	$291,771	$334,884	$43,114
Billing and Collecting	$452,917	$421,987	($30,929)
Community Relations	$0	$0	$0
Administrative and General	$496,779	$385,124	($111,655)
Total	**$1,669,628**	**$1,530,356**	**($139,271)**
%Change (year over year)			-8.3%

Administrative and General – decrease of $111,655

The reduction in costs associated with the divestiture process were offset by the cost of the required safety survey, regulatory consulting costs and increases to property insurance.

Table 4 21: 2020 Bridge vs. 2021 Test

Description	2020 Bridge Year	2021 Test Year	Variance
Operations	$388,361	$401,109	$12,748
Maintenance	$334,884	$333,727	($1,157)
Billing and Collecting	$421,987	$428,448	$6,461
Community Relations	$0	$0	$0
Administrative and General	$385,124	$490,146	$105,023
Total	**$1,530,356**	**$1,653,431**	**$123,074**
%Change (year over year)			8.0%

General and Administrative – increase of $105,023

The increase is the result of the inclusion of the costs to complete the Cost of Service rate application process in expenses over a five year period.

(b) Overhead Expenses

IAS 16 – Property, Plant & Equipment – Capitalization of Burdens was addressed in ERHDC's 2012 Cost of Service rate application. There are no increases or decreases in the test year relating to capitalized overhead. ERHDC does not capitalize any portion of administrative expenses. Table 4-22 below is consistent with Chapter 2 Appendix 2-D – Overhead Expense. The percentage of capitalized OM&A has been consistent at approximately 3%.

Table 4 - 22: Appendix 2-D Overhead Expense

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	$ 1,703,431
Total OM&A Before Capitalization (B)	$ 1,438,400	$ 1,460,893	$ 1,729,122	$ 1,578,387	$ 1,703,431

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%	2.94%		

2.4.3. OM&A Program Delivery Costs With Variance Analysis

ERHDC has a variety of programs, activities and initiatives that are imperative to provide safe, reliable and affordable service to customers. In Table 4 - 23 below, ERHDC has identified its programs and major functions on a comparative basis for the 2012 Board Approved, 2017 Actual, 2018 Actual, 2019 Actual, 2020 Bridge Year and 2021 Test Year. This table is consistent with the Boards Appendix 2-JC, which can also be found in Appendix 4 - F to this Exhibit. These programs contribute to achieving the new Renewed Regulatory Framework performance outcomes of Customer Focus, Operational Effectiveness and Public Policy Responsiveness. This shows the alignment of ERHDC's direct costs and the management of the costs associated with the outcomes. An analysis is provided below on all material variances that exceed the materiality threshold for the 2021 Test Year versus the 2019 Actuals and the 2021 Test Year versus the 2012 Board Approved amounts.

Table 4 - 23: OM&A Programs Table (Appendix 2-JC)

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2012 OEB-Approved)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year	Variance (Test Year vs. 2019 Actuals)	Variance (Test Year vs. Last Rebasing Year (2012 OEB-
Reporting Basis								
Programs with Variances > Materiality								
5135 Right of Way								
Labour	$45,419	$13,182	$42,994	$21,984	$28,754	$32,431	10,447	-12,988
Expenses	$126,500	$47,566	$2,997	$66,847	$59,056	$48,260	-18,587	-78,240
Trucking	$14,083	$1,457	$5,931	$2,695	$4,198	$4,261	1,566	-9,822
Sub-Total 5135	$186,001	$62,206	$51,922	$91,525	$92,008	$84,951	-$6,575	-$101,051
5615 General Admin Salaries								
Labour	$0	$35,287	$45,092	$80,295	$57,394	$58,398	-21,897	58,398
Expenses	$0	$0	$0	$0	$0	$0	0	0
Sub-Total 5615	$0	$35,287	$45,092	$80,295	$57,394	$58,398	-$21,897	$58,398
5630 Outside Services								
Audit	$35,000	$27,000	$29,253	$103,116	$35,500	$36,033	-$67,084	1,033
Consultant	$2,200	$44	$0	$0	$0	$0	$0	-2,200
Legal	$2,000	$26	$0	$216	$250	$254	$38	-1,746
Negotiations	$1,000	$0	$0	$200	$0	$0	-$200	-1,000
Management, Billing, Collection Contr	$37,742	$28,563	$32,662	$56,517	$44,013	$44,673	-$11,844	6,930
Study Projects			$1,078	$0	$0	$0	$0	0
Sub-Total 5630	$77,942	$55,633	$62,993	$160,049	$79,763	$80,959	-$79,090	$3,017
5655 Regulatory Expenses								
OEB Annual	$8,500	$15,167	$14,006	$14,083	$15,000	$15,415	1,332	6,915
CoS Consulting (BLG, PUC)	$24,375	$18,532		$2,379	$16,000	$87,508	85,129	63,133
Customer Satisfaction Survey		$21,450	$850	$12,000		$12,000	0	12,000
Safety Survey					$12,000			
Training	$1,700			$1,454	$1,500		-1,454	-1,700
Cost Assessments	$425	$384	$299	$413	$500	$675	262	250
CoS Distribution System Plan		$37,650				$13,000		
CoS CDM Consultant						$2,000		
CoS Intervenor Costs						$10,000		
CoS OEB Costs						$4,000		
Software			$840					
Miscellaneous								
Sub-Total 5655	$35,000	$93,183	$15,995	$30,329	$45,000	$144,598	$114,269	$109,598
Programs with Variances < Materiality								
5005 Operations Supervision	$28,199	$67,085	$72,015	$74,847	$68,063	$69,084	-5,763	40,884
5012 Station Buildings	$20,896	$2,792	$2,712	$499	$1,443	$1,467	968	-19,429
5016 Station Equipment - Labour	$8,716	$4,798	$12,683	$7,398	$8,285	$8,428	1,029	-288
5017 Station Equipment - Expenses	$20,100	$20,215	$21,535	$20,048	$19,152	$19,440	-608	-660
5020 O/H Lines Labour	$38,128	$53,407	$63,064	$85,118	$65,856	$66,999	-18,119	28,871
5025 O/H Lines Expenses	$25,750	$45,664	$42,520	$66,416	$59,348	$60,239	-6,178	34,489
5035 O/H Distribution Transformers	$11,657	$10,546	$18,845	$18,675	$18,821	$22,386	3,712	10,729
5040 U/G Lines Labour	$10,969	$29,427	$41,263	$23,334	$28,608	$29,105	5,772	18,136
5045U/g Lines Expenses	$19,000	$9,695	$23,822	$15,624	$15,522	$15,755	131	-3,245
5055 U/G Distributions Transformers	$7,584	$2,188	$11,495	$3,236	$6,847	$10,213	6,977	2,629
5065 Meter Expense	$3,357	$2,160	$6,105	$32,296	$18,638	$18,955	-13,341	15,598
5070 Customer Premise Labour	$12,959	$26,420	$34,674	$37,798	$32,301	$32,860	-4,938	19,901
5075 Customer Premise Expenses	$7,000	$1,589	$1,323	$3,036	$1,578	$1,602	-1,434	-5,398
5085 Misc. Distribution Expenses	$21,631	$10,080	$7,309	$18,421	$22,272	$22,626	4,205	995
5095 O/H Lines - Rental	$13,400	$14,556	$14,658	$21,416	$21,627	$21,951	535	8,551
5105 Maintenance Supervision	$28,199	$71,096	$71,465	$55,280	$64,440	$65,407	10,127	37,208
5110 Maintenance Station Buildings	$35,332	$8,677	$7,368	$14,839	$9,743	$9,912	-4,927	-25,420
5114 Distribution Station Equipment	$9,566	$12,961	$3,263	$2,871	$5,016	$5,097	2,226	-4,469
5120 Maint. Poles/Towers/Fixtures	$18,355	$24,713	$14,127	$16,596	$32,907	$33,406	16,810	15,051
5125 Maint. O/H Conductors	$27,929	$44,197	$47,908	$44,141	$67,774	$68,935	24,794	41,006
5130 Maint. O/H Services	$51,899	$50,210	$58,973	$52,560	$51,261	$52,136	-425	237
5145 Maint. U/G Conduit	$11,473	$0	$0	$1,346	$582	$2,543	1,197	-8,929
5150 Maint. U/G Conductors	$10,162	$2,977	$8,995	$3,905	$5,217	$5,306	1,401	-4,856
5155 Maint. U?G Services	$584	$1,209	$598	$912	$408	$416	-497	-168
5160 Maint. Line Transformers	$16,234	$3,835	$2,306	$4,809	$3,496	$3,555	-1,254	-12,679
5175 Maint. Meters	$1,425	$3,205	$165	$2,986	$2,031	$2,064	-921	639
5310 Meter Reading Expenses	$100,327	$65,821	$70,654	$73,580	$74,105	$75,220	1,640	-25,107
5315 Customer Billing	$175,668	$183,806	$187,750	$186,966	$200,118	$203,144	16,179	27,476
5320 Collecting	$87,727	$128,224	$140,802	$134,184	$124,764	$126,739	-7,445	39,012
5335 Bad Debt Expense	$8,000	$58,387	$30,792	$58,188	$23,000	$23,345	-34,843	15,345
5410 Community Relations	$1,000	$0	$0	$0	$0	$0	0	-1,000
5605 Executive Salaries & Expenses	$19,200	$18,540	$18,540	$15,405	$14,000	$14,210	-1,195	-4,990
5610 Management Salaries	$98,958	$70,935	$75,133	$86,037	$76,213	$77,535	-8,502	-21,423
5620 Office Supplies	$66,998	$74,115	$79,530	$81,227	$77,955	$79,124	-2,103	12,126
5635 Property Insurance	$5,600	$5,815	$5,928	$8,550	$16,000	$16,240	7,690	10,640
5640 Injuries & Damages	$5,000	$10,059	$10,728	$8,088	$12,000	$12,180	4,092	7,180
5645 Employee Pension & Benefits	$20,000	$9,088	$18,661	$22,652	$2,500	$2,538	-20,114	-17,463
5660 General Advertising	$600	$572	$300	$11	$0	$0	-11	-600
5665 Misc. General	$6,800	$1,154	$1,136	$1,212	$1,300	$1,320	108	-5,481
5680 ESA	$2,800	$3,017	$5,090	$2,926	$3,000	$3,045	119	245
Sub-Total Miscellaneous	$1,059,180	$1,153,235	$1,234,238	$1,307,430	$1,256,192	$1,284,525	-$22,905	$225,344
Total	**$1,358,124**	**$1,399,544**	**$1,410,240**	**$1,669,628**	**$1,530,356**	**$1,653,431**	**-$16,197**	**$295,307**

(a) Materiality Threshold

In accordance with Chapter 2 Filing Requirements, an applicant must provide justification for changes from year to year to its rate base, capital expenditures and OM&A spending above a materiality threshold. Chapter 2 of the Filing Requirements issued by the Board on July 12, 2018 (Addendum dated July 15, 2019) sets out the materiality levels based on the magnitude of the revenue requirement. ERHDC's revenue requirement is less than $10 million, therefore its materiality level is $50,000.

(b) Program Delivery Variance Analysis

(i) Line Clearing (Right of Way) – Line clearing is a function that LDCs can exercise some degree of control. Although budgeted line clearing is normally completed by contractors, contractor availability in the ERHDC service territory is not controllable. In the years contractors are not available to complete the planned line clearing, decisions are made on allocating the resources to various needs, for example pole replacements versus line clearing based on the current priority.

<u>2021 Test Year vs 2012 Approved – ($101,051)</u>

<u>Table 4 - 24 Line Clearing (Right of Way) 2012 vs 2021</u>

	2012 Approved	2021 Test	2012 vs 2021
Internal Labour	$45,419	$32,431	-$12,988
Trucking	$14,083	$4,261	-$9,822
Contractor	$126,500	$48,260	-$78,240
	$186,001	$84,951	-$101,051

Table 4-24 above shows the Line Clearing (Right of Way) for 2012 approved vs 2021 test year. Due to the increase in capital and other operating and maintenance work, internal resources (labour and trucking) have been reallocated from the 2012 Approved to the 2021 test Year. The 2012 CoS included accelerated tree trimming maintenance to remedy a backlog of areas to trim. The amount of the one-time cost of performing line clearing on Bass Lake Road ($150,000/4 = $37,500) which was included in tree trimming costs has been removed from the 2021 Test Year. In addition the contractor amount has been reduced in the 2021 Test Year. ERHDC has a plan which provides tree trimming in the entire service territory on a three year cycle. Annual contractor costs have been included in Test Year OM&A expenses to complete the program over the three year cycle.

(c) General Admin Salaries – General Admin salaries are a cost controllable by LDCs. ERHDC has attempted to control these expenses and billing and collection expenses through an external contract, however the increase in regulatory requirements has resulted in the need for addition resources.

<u>2021 Test Year vs 2012 Approved - $58,398</u>

Included in ERHDC's rate base is the equivalent of 1.25 office adminstative/financial/regulatory position. In the years subsequent to the 2012 rate approval the office assistant resource increased from 0.25 FTE to full time due to the increased regulatory workload.

(d) Regulatory Expenses – regulatory requirements are outside of ERHDC's control, however ERHDC attempts to minimize these costs through collaborations with other LDCs.

<u>2021 Test Year vs 2019 Actuals – $114,269</u>

Includes increased costs for the Cost of Service rate approval process (preparation of application, interrogatory responses, settlement conference, intervenor costs, OEB costs). ERHDC does not have the internal resources or experience to prepare the application, therefore external consultants are required.

<u>2021 Test Year vs 2012 Approved - $109,598</u>

Includes increases due to OEB assessment increase, added requirement for customer satisfaction survey every two years, added requirement for safety survey every two years, requirement of Distribution System Plan, and increased costs for the Cost of Service rate approval process (preparation of application, interrogatory responses, settlement conference, intervenor costs, OEB costs). ERHDC does not have the internal resources or experience to prepare the application, therefore external consultants are required.

2.4.3.1 Workforce Planning and Employee Compensation

(a) Compensation System

ERHDC's overall compensation for all employees is designed to be competitive and equitable in order to attract and retain qualified personnel. The compensation package includes a base wage and benefits package. ERHDC does not offer any incentive or bonus compensation.

The workforce is comprised of both unionized and non-unionized management employees.

(b) Unionized Workers

ERHDC has 4 unionized employees, all of which are power line technicians. The compensation for unionized employees is negotiated through the collective bargaining process with CUPE Local 4705.

ERHDC's collective agreements provide for annual payroll increases and employee step progressions. Labour rates and benefits are adjusted based on negotiated percentages as per the collective agreement. ERHDC reviews the current settlements of other LDCs before commencing negotiations. The commencement and expiry dates ("Contract Period") of ERHDC's current collective agreement is shown in Table 4 - 25 below:

Table 4 - 25: Current Collective Agreements

Bargaining Unit	Contract Period	Wage Increase
CUPE Local 4705	April 1, 2019 to March 31, 2022	May 1, 2019: 2.0% May 1, 2020: 1.75% May 1, 2021: 1.75%

Each job classification in the collective bargaining agreement has a basic job description and a wage rate progression scale that increases from a minimum to a maximum rate.

(c) Management & Non-Union Employees

ERHDC has 3 non-unionized employees. The Management compensation plan consists of salaries and benefits. Each position within the company has been placed on a pay scale which is reviewed periodically by senior management.

As with unionized employees, compensation for this group of employees provides for annual payroll increases and employee step progressions (for those employees below 100%) upon Board of Director approval. Salary and benefit levels are compared to LDC benehmarks for reasonableness.

(d) Health Benefits

A comprehensive and competitive benefits package exists to address the health and welfare of ERHDC's employees. The plan includes medical insurance, life insurance, vacation and a company-sponsored retirement plan (OMERS). There are separate benefits plans for active Management/Non-Union, CUPE employees and retired employees. The CUPE and retiree benefit plans are subject to change during the collective bargaining process, and the Management/Non-Union plan typically follows suit if improvements are awarded.

The plans are designed to address the health and welfare needs of employees .

(e) Employee Benefit Programs

ERHDC offers the following benefits to PUC equivalent employees:

- Ontario Municipal Employee Retirement Savings ("OMERS")
- Long Term Disability ("LTD")
- Life Insurance Benefits

- Health Care & Dental Benefits
- Employee & Family Assistance Program (EFAP) – assists employees and their immediate family members in assessing and resolving work, health and life issues.

(f) OMERS Pension Plan

ERHDC employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan in which most Ontario LDCs participate. As such, ERHDC's pension benefit costs are consistent with other participating Ontario LDCs. While OMERS is a Defined Benefit plan, for accounting purposes it is effectively treated as a Defined Contribution plan by the participating distributors including ERHDC. This means that the annual employer contributions made to the plan are the same as the accrual accounting expense recorded for financial statement purposes.

(g) Succession/Workforce Planning

ERHDC continually monitors employee retirement eligibility and employee intentions where known, in order to plan for the necessary employee succession.

ERHDC currently has one crew of qualified and experienced Powerline Technicians (PLTs) with 1 of the 4 PLTs that is currently eligible to retire. ERHDC has not recently experienced difficulties in filling PLT positions and therefore will fill any vacancies as they occur.

ERHDC's FTE's have increased from 5.42 in the 2012 Approved to 7.00 in the Test Year as shown in Table 4-13.

ERHDC contemplated succession planning for the retirements of ERHDC's FTEs. The CFO retired at the end of 2019. The CFO's responsibilities were, among other things, day to day accounting operations, review of account reconciliations and journal entries; variance analysis; preparation of annual audit and year end financial statements; regulatory reporting; financial analysis; perform financial analysis; preparation of government returns, remittances and payments; and assist in preparing annual budgets.

Upon review of the CFO's tasks and duties, it was determined that those functions could be performed by an individual with an accounting background. Therefore, the new position being hired was not a CFO, but was instead replaced by a Manager of Accounting.As such, the CFO is replaced by a Manager of Accounting. The title in Table 4-13: "Chief Financial Officer" would become "Manager of Accounting", and this position can undertake the core activities previously performed by the CFO. This work is still required as it is the only financial, administrative, and regulatory FTE available for ERHDC as management oversight is outsourced.

The Line Supervisor is responsible for supervising and coordinating activities of linemen engaged in construction and repair of overhead and underground power lines, and all other aspects of the ERHDC electrical system. The Line Supervisor determines and locates cause of any service interruptions. Overall, he ensures the safety and reliability of the system. He also schedules and monitors the performance of the four linemen who are the field crew and perform technical work in the field. The Line Supervisor can support and aid the line staff in situations where it is necessary (unanticipated leave (extended sick, vacancies), emergencies). This adds to workplace flexibility, which is necessary when so thinly resourced.

Without the Line Supervisor, there would be no backup assistance to linemen if they are absent. This would affect the reliability of the system. Also, no supervision or coordination of work would be performed if there is no Line Supervisor, which would lead to inefficiencies and possible risk of accidents.

As such, hiring a new employee to fill the Line Supervisor position is required for the long-term safe and reliable operations of the ERHDC distribution system.

Base salaries reflect the cost of living and salary progression increases arising from recent collective bargaining agreements with unionized employees as well as commensurate percentage increases for management staff. In the period leading up to collective bargaining ERHDC compares recent provincial agreements in the industry and other agreements in its geographical area to its rates in order to provide for cost effective wage rates that also allow it to attract qualified employees. The collective agreement increase of 1.75% was used to project 2021 Test year labour costs.

(h) FTE & Employee Costs

As required, employee complement by FTE, compensation and benefits are set below in Table 4 - 26. This table is consistent with the Board Appendix 2-K and a copy can also be found in Appendix 4 - G to this Exhibit. As there are only three non-union employees, the information for both Management and Non-Management employees have been aggregated in Non-Management.

Table 4 - 26: FTEs and Employee Costs (Appendix 2-K)

Appendix 2-K
Employee Costs

	Last Rebasing Year (2012 OEB Approved)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
\						
Management (including executive)						
Non-Management (union and non-union)	5.42	7.00	6.67	7.00	7.07	7.31
Total	5.42	7.00	6.67	7.00	7.07	7.31
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)						
Non-Management (union and non-union)	$ 380,771	$ 625,466	$ 600,085	$ 624,367	$ 561,748	$ 571,579
Total	$ 380,771	$ 625,466	$ 600,085	$ 624,367	$ 561,748	$ 571,579
Total Benefits (Current + Accrued)						
Management (including executive)						
Non-Management (union and non-union)	$ 183,948	$ 277,222	$ 208,767	$ 253,584	$ 255,182	$ 259,648
Total	$ 183,948	$ 277,222	$ 208,767	$ 253,584	$ 255,182	$ 259,648
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ -	$ -	$ -	$ -	$ -	$ -
Non-Management (union and non-union)	$ 564,719	$ 902,688	$ 808,852	$ 877,951	$ 816,930	$ 831,227
Total	$ 564,719	$ 902,688	$ 808,852	$ 877,951	$ 816,930	$ 831,227

The number of employees shown above in Table 4 - 26 is based on the computation of the number of full time equivalent (FTE) positions throughout each of the fiscal years. Staff members hired by or resigning from ERHDC are prorated in that year as a portion of an FTE based on the hours worked. The salaries and wages amounts include all salaries and wages paid, inclusive of overtime, sick leave, bereavement leave and other miscellaneous paid leaves.

The benefits amount comprise the employer's portion of statutory benefits, including CPP, EI, EHT, WSIB, vacation and statutory holiday pay. In addition, benefit amounts include the company's cost for providing OMERS and other Employee Benefits as described in Section 2.4.3.1 below.

(i) FTE, Wages & Benefits Variance Analysis

ERHDC completed the Board's Appendix 2-K, which is included above as Table 4 - 26. Table 4 - 27 below details employee costs from 2012 Board Approved and 2017 historical through to the 2021 Test Year. All FTE's with their corresponding wages and benefits are included in the variance analysis below.

Table 4 - 27: FTE and Employee Cost Variances

	Last Rebasing Year (2012 OEB Approved)	2017 Actuals	2012 Board Approved vs 2017 Actual	2018 Actuals	2017 Actual vs 2018 Actual	2019 Actuals	2018 Actual vs 2019 Actual	2020 Bridge Year	2019 Actual vs 2020 Bridge	2021 Test Year	2020 Bridge vs 2021 Test
Number of Employees (FTEs including Part-Time)[1]											
Management (including executive)											
Non-Management (union and non-union)	5.4	7.0	1.6	6.7	- 0.3	7.0	0.3	7.1	0.1	7.3	0.2
Total	5.4	7.0	1.6	6.7	- 0.3	7.0	0.3	7.1	0.1	7.3	0.2
Total Salary and Wages including ovetime and incentive pay											
Management (including executive)											
Non-Management (union and non-union)	$ 380,771	$ 625,466	$ 244,696	$ 600,085	-$ 25,381	$ 624,367	$ 24,281	$ 561,748	-$ 62,619	$ 571,579	$ 9,831
Total	$ 380,771	$ 625,466	$ 244,696	$ 600,085	-$ 25,381	$ 624,367	$ 24,281	$ 561,748	-$ 62,619	$ 571,579	$ 9,831
Total Benefits (Current + Accrued)											
Management (including executive)											
Non-Management (union and non-union)	$ 183,948	$ 277,222	$ 93,274	$ 208,767	-$ 68,455	$ 253,584	$ 44,817	$ 255,182	$ 1,598	$ 259,648	$ 4,466
Total	$ 183,948	$ 277,222		$ 208,767		$ 253,584		$ 255,182	$ 1,598	$ 259,648	$ 4,466
Total Compensation (Salary, Wages, & Benefits)											
Management (including executive)	$ -	$ -		$ -		$ -		$ -		$ -	$ -
Non-Management (union and non-union)	$ 564,718	$ 902,688	$ 337,970	$ 808,852	-$ 93,836	$ 877,951	$ 69,099	$ 816,930	-$ 61,021	$ 831,227	$ 14,297
Total	$ 564,718	$ 902,688	$ 244,696	$ 808,852	-$ 25,381	$ 877,951	$ 24,281	$ 816,930	-$ 61,021	$ 831,227	$ 14,297

Material changes in FTE's, salaries and wages, and benefits are as follows:

(i) <u>2012 Board Approved vs. 2017 Actual:</u>

ERHDC hired a Lines Supervisor, the salary for which was offset by a reduction in the Service Contract expense with PUC Services who had provided the Supervisor prior to 2013. In addition the office assistant was increased to full time due to the increased regulatory workload. Wages and Benefit costs increased as a result of the increase in FTEs. The average compensation per employee also increased due to the addition of the Lines Supervisor.

(ii) <u>2017 Actual vs. 2018 Actual:</u>

No material change in FTEs.
No material change in Wages and Benefits.

(iii) <u>2018 Actual vs. 2019 Actual:</u>

No material change in FTEs.
No material change in Wages and Benefits.

(iv) <u>2019 Actual vs. 2020 Bridge:</u>

No material change in FTEs.
No material change in Wages and Benefits.

(v) 2020 Bridge vs. 2021 Test:

No material change in FTEs.
No material change in Wages and Benefits.

(j) Employee Future Benefits

ERHDC provides post-employment benefit life insurance and health care to retirees under the age of 65 through a group defined benefit plan.

The cost of post-employment benefits are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The current service cost for the period is equal to the employee's service rendered in the period. Past service costs from the plan amendments are amortized on a straight line basis over the average remaining service period of the employee's active date of amendment.

ERHDC recovers their OPEB costs based on the accrual method. This method recognizes the cost of OPEBs as an employee's service is rendered and the benefit is earned. The accrued amount is allocated as an overhead on direct labour on an annual basis. As such, ERHDC's obligation for OPEBs is treated similar to pension funding where there is no future obligations.

An actuary report for ERHDC is included as Appendix 4 - H.

Table 4-28 below provides a breakdown of employee benefits charged to OM&A and Capital respectively.

Table 4 - 28: Employee Benefits Charged to OM&A and Capital

Allocation to OM&A						
Benefit	2012 Approved	2017	2018	2019	2020 Bridge	2021 Test
CPP	$10,452	$11,528	$13,461	$13,981	$13,551	$13,788
EI	$5,044	$4,873	$5,676	$5,410	$5,550	$5,647
Employer Health Tax	$6,460	$3,648	$4,344	$4,731	$4,007	$4,078
WSIB	$3,490	$7,891	$8,669	$8,886	$8,201	$8,345
Omers	$29,609	$42,135	$47,535	$46,386	$41,242	$41,963
OPEBs	$20,000	$9,088	$18,661	$22,652	$2,500	$2,538
Corporate Benefits	$50,810	$41,688	$37,889	$39,082	$34,611	$35,217
	$125,864	$120,852	$136,234	$141,126	$109,663	$111,576
Allocation to Capital						
Benefit		2017	2018	2019	2020 Bridge	2021 Test
CPP	$4,480	$5,852	$4,324	$4,693	$7,656	$7,790
EI	$2,162	$2,474	$1,823	$1,816	$3,135	$3,190
Employer Health Tax	$2,768	$1,852	$1,395	$1,588	$2,264	$2,304
WSIB	$1,496	$4,006	$2,785	$2,983	$4,633	$4,714
Omers	$12,689	$21,389	$15,271	$15,570	$23,299	$23,707
Corporate Benefits	$21,776	$21,161	$12,172	$13,118	$19,554	$19,896
	$45,370	$56,733	$37,770	$39,767	$60,541	$61,601
	$171,234	**$177,585**	**$174,005**	**$180,894**	**$170,204**	**$173,177**

2.4.3.2 Shared Services from Affiliates

Shared Services is defined by ERHDC as the concentration of a company's resources performing like activities (typically spread across the organization) in order to service affiliates (and/or a parent company) with the intention of achieving lower costs and higher service levels.

Corporate Cost Allocation is an allocation of costs for corporate and miscellaneous shared services from the parent company to the utility (and vice versa).

ERHDC does not have any shared services with an affiliate and does not allocate costs for corporate and miscellaneous shared service from the parent company.

(a) Affiliate Board Of Director Costs

There are no Board of Director costs from any of ERHDC's affiliates included in ERHDC's costs.

2.4.3.3 Purchases of Non-Affiliate Services

ERHDC purchases services and products from third parties. Table 4-29 below discloses the expenditures by vendor where the annual amount exceeded $50,000 per year, for the years 2017 Actual, 2018 Actual and 2019 Actual. ERHDC anticipates using the same vendors for 2020 and 2021, however new suppliers are continuously being sourced. ERHDC does not have a formal procurement policy. Purchases from non-affiliated parties are approved on a case-by-case basis in accordance with ERHDC's policy and procedures manual as follows:

REQUISITIONS/PURCHASES ORDER/INVOICES

The following authorization guidelines shall apply to purchases identified in the budget or are items of normal recurring business activities that are within the budget but not necessarily specifically identified.

(Requisitions/purchases orders/invoices)

- *Up to $2,000 – the Line Supervisor or Chief Financial Officer*
- *From $2,000 to $25,000 – Chief Financial Officer*
- *From $25,001 to $50,000 – Chief Financial Officer and Treasurer*
- *From $50,000 to $100,000 – President and Treasurer*
- *If a purchases is in excess of $100,000 (excluding the cost of power) the President, Treasurer, and the Chairman or delegate of the Board of Directors.*
- *The monthly invoice for the cost of power will be approved by two of the President, Treasurer, or Chief Financial Officer.*

For purchases that were not in the budget:

- *Up to $250 – the Union Trade Supervisor and Chief Financial Officer*
- *Up to $1,000 – the Line Supervisor and Chief Financial Officer*

- *Exceeding $1,000 – President or Treasurer.*

All invoices for legal services and labour relations matters shall be approved by the President or Treasurer.

Table 4 - 29: Vendor Purchases

Vendor	Product/Service	Procurement Method	2017	2018	2019
ANIXTER POWER SOLUTIONS	conductor, line hardware, meters	Tender through buying consortium	$150,415.57	$41,349.25	$56,179.80
H & C POLELINE CONTRACTOR	submarine cable	Tender		$69,557.28	
PUC Services Inc.	Management , Billing/Collection/Customer Service Contract	Tender	$414,821.88	$456,943.86	$485,205.60
SENSUS CANADA INC. #SENSU	Meter Reading	Tender	$52,055.62	$52,662.50	$59,555.78
THE MEARIE GROUP #BENEFI	Group Health Benefits	Tender	$54,978.33	$41,419.59	$45,986.34
TORONTO AUTO SALES #TORON	Vehicle - Bucket Truck	Quotes			$70,338.50

All material purchasing transactions have been in compliance with ERHDC's policy above.

2.4.3.4 One-Time Costs

ERHDC has included one-time costs of $116,508 in its 2021 test year revenue requirement based on a five year recovery of the $582,539 for the Cost of Service Application as shown in Table 4-30 below. In 2012, the CoS costs totalled $97,500 for an annual cost of $24,375. ERHDC had one-time costs relating to the sale of the LDC to North Bay Hyrdo in 2019. These costs have not been requested for recovery in this application. Details of the one-time cost recovery are in the following section.

Table 4 - 30 – One-Time Costs

One-time Costs	Total Cost	2021 Test
Cost of Service Application	$582,539	$116,508

2.4.3.5 Regulatory Costs

Regulatory costs include on-going expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the Board or other regulatory bodies. Costs include:

- Annual assessment fees paid to the Board;
- Board costs pursuant to Section 30 of the *Ontario Energy Board Act*, 1998;
- Legal and consulting costs for rate applications and other regulatory matters; and
- Intervenor costs.

Regulatory costs in the 2021 Test Year are estimated to be $144,183, an increase of $11,732 from 2019 Actual Year and an increase of $113,854 compared to 2019 Board- Approved. Table 4-31, below identifies the incremental costs of $582,539 expected to be incurred for this Application. This estimate includes special studies, reports, preparation, defence and adjudication costs, as well as Board and intervenor costs. ERHDC proposes to recover these costs evenly over 5 years, as identified in the section on “One Time Costs”.

Table 4-32 below details regulatory costs included within Uniform System of Accounts (“USoA”) account 5655. ERHDC has not included the costs of regulatory staff or other staff working on regulatory applications in Account 5655. These costs are included in Accounts 5605, 5610, and 5615.

ERHDC has included the costs associated with the Cost of Service Rate Application in the revenue requirement. Outside consultants are required to complete the entire application and approval process as due to recent staff turnover, ERHDC finance staff does not have the time or experience to do so. Annual ongoing costs include the OEB assessment ($15,000), section 30 costs ($675), miscellaneous regulatory including training costs and regulated customer survey costs ($12,000). Costs that are not incurred annually totalling $582,539 have been spread over 5 years and have been included in test year expenses at $116,508 per year. One-time costs include costs for legal and consulting assistance from experienced subject matter experts.

Components of the regulatory costs are set out in Table 4 -31 below.

Table 4 - 31 Regulatory Costs

Service	$	Expense Included in Test Year
Legal and rates consulting expenses to complete the application	$100,000	$20,000
Consultant - completion of application, interrogatories, settlement conference, draft settlement and final order	$282,539	$56,508
Services related to the Distribution System Plan and Asset Management Plan	$65,000	$13,000
Legal and rates consulting expenses for the settlement conference	$50,000	$10,000
Intervenor expenses	$50,000	$10,000
OEB Costs	$20,000	$4,000
Settlement conference expenses	$5,000	$1,000
LRAM consulting services	$10,000	$2,000
	$582,539	$116,508

Table 4 - 32: Regulatory Cost Schedule (Appendix 2-M)

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Last Rebasing Year (2012 OEB Approved)	Most Current Actuals Year 2019	2020 Bridge Year	Annual % Change	2021 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(F)	(G)	(H)=[(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
	Regulatory Costs (Ongoing)								
1	OEB Annual Assessment	5655		8,500	14,083	15,000	6.51%	15,000	0.00%
2	OEB Section 30 Costs (OEB-initiated)	5655		300	413	500	21.09%	675	35.00%
3	Expert Witness costs for regulatory matters								
4	Legal costs for regulatory matters								
5	Consultants' costs for regulatory matters	5655			2,379	16,000	572.68%		-100.00%
6	Operating expenses associated with staff resources allocated to regulatory matters								
7	Operating expenses associated with other resources allocated to regulatory matters [1]								
8	Other regulatory agency fees or assessments								
9	Any other costs for regulatory matters (please define)	5655			12,000	12,000	0.00%	12,000	0.00%
10	Intervenor costs								
11	Include other items in green cells, as applicable								
12	Training/Published Notices	5655		1,700	1,454	1,500	3.16%		-100.00%
13									
	Regulatory Costs (One-Time)								
1	Expert Witness costs								
2	Legal costs							150,000	
3	Consultants' costs	5655		62,500				287,539	
4	Incremental operating expenses associated with staff resources allocated to this application.			35,000					
5	Incremental operating expenses associated with other resources allocated to this application. [1]								
6	Intervenor costs	5655						50,000	
7	OEB Section 30 Costs (application-related)							20,000	
8	Include other items in green cells, as applicable	5655						65,000	
9	LRAM Consultant	5655						10,000	
10	Publishing rate application notice								
11									
1	Sub-total - Ongoing Costs [2]		$ -	$ 10,500	$ 30,329	$ 45,000	48.37%	$ 27,675	-38.50%
2	Sub-total - One-time Costs [3]		$ -	$ 97,500	$ -	$ -		$ 582,539	
3	Total		$ -	$ 108,000	$ 30,329	$ 45,000	48.37%	$ 144,183	220.41%

2.4.3.6 Low-Income Energy Assistance Programs ("LEAP")

The delivery of LEAP relies heavily on the cooperation between ERHDC and its lead social agency, the United Way, to administer the program within ERHDC's Service Territory.

In accordance with Filing Guidelines 2.4.3.6, ERDC has included $2,000 of expense in test year expenses. ERHDC understands that the included figure of $2,000 has been used throughout the application. This is $727 less than the calculated amount of $2,727, which is 0.12% of the forecasted service revenue requirement. At the time the final rates are determined, ERHDC will update this figure as calculated in Table 4 - 33 – LEAP. In the table below, this amount is based on 0.12% of the 2021 Test Year forecasted service revenue requirement. This amount has been included in Account 6205 – Donations, to ensure that it is captured appropriately in the Revenue Requirement.

ERHDC's 2021 Test Year Revenue Requirement does not include any legacy low income energy assistance programs.

Table 4 - 33: LEAP

2021 Test Year LEAP	
Service Revenue Requirement	$2,272,419
LEAP %	0.12%
LEAP Amount	$2,727
LEAP Amount included in Test Year	$2,000
	$727

(a) Charitable and Political Donations

Other than the LEAP charitable donations discussed in Section 2.4.3.6 above, ERHDC has not included any other charitable donations in OM&A expenses.

ERHDC also confirms it does not make political contributions; therefore no political contributions have been included for recovery.

2.4.4. Depreciation, Amortization And Depletion

(a) Depreciation Policy

ERHDC has not changed its depreciation policy since the last CoS application. Amortization on capital assets is calculated as follows:

- ERHDC uses the pooling of assets for all fixed assets. Commencing with the 2012 Cost of Service application and continuing in the current application, ERHDC depreciates significant components of fixed assets. Amortization is calculated on a straight line basis over the estimated useful life of the assets commencing when the asset is put in service.
- In 2012, ERHDC modified useful lives of its assets in accordance with the Asset Depreciation Study by Kinetrics as described in the 2012 Cost of Service Application, EB-2012-0162.
- There have been no changes to any amortization periods for capital assets since the last Cost of Service Application
- ERHDC amortizes its capital assets available for use on a straight-line basis over the estimated useful lives of each significant component. Consistent with its historical practices, ERHDC records a full year's worth of amortization on capital additions in the year of acquisition and no amortization is recorded in the year of disposition. This policy has been applied for all historical, Bridge and Test years. The reason that ERHDC has deviated from the half year rule is due to the fact that ERHDC would like to align its OEB ratemaking policy to its financial statement policy. This aligns with Accounting Procedures Handbook Article 410, "In order to maintain symmetry in financial and regulatory reporting for capital assets, the Board expects distributors' capital assets for regulatory reporting to be presented on the same basis as in the general purpose financial statements." Table 4-41 to Table 4-49 below indicate the effect of not utilizing the half-year rule. Table

4-50 which is a summary of Tables 4-41 to 4-49 indicates the effect of not using the half year rule is an average of $6,412 per year.

- Construction in progress assets are not depreciated until the project is complete. Interest is not typically capitalized to the cost of assets constructed as the life cycle of construction projects are usually less than one year.

The tables beginning with Table 4-34 and ending with Table 4-38 provide a summary by year for 2017 Actual, 2018 Actual 2019 Actual, 2020 Bridge Year and 2021 Test Year of depreciation expense including asset amounts and depreciation rates. These tables reflect the Accumulated Depreciation balances in the Fixed Asset Continuity schedule in Exhibit 2 (Appendix 2-A), which are consistent with the Board's Appendix 2-BA. Table 4-39 and Table 4-40 summarize the depreciation and amortization from 2017 to 2021 and provide the variance.

Table 4 - 34: Depreciation 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

Table 4 - 35: Depreciation 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

Table 4 - 36: Depreciation 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

Table 4 - 37: Depreciation 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

Table 4 - 38:Depreciation 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					$ -					$ -	$ -
8	1935	Stores Equipment	$ 443,607				$ 443,607	$ 218,374	$ 27,280			$ 245,653	$ 197,953
8	1940	Tools, Shop & Garage Equipment	$ 10,538				$ 10,538	$ 10,538				$ 10,538	$ -
8	1945	Measurement & Testing Equipment	$ 169,791				$ 169,791	$ 153,097	$ 4,146			$ 157,243	$ 12,548
8	1950	Power Operated Equipment	$ 11,948				$ 11,948	$ 10,564	$ 346			$ 10,910	$ 1,038
8	1955	Communications Equipment	$ -				$ -	$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ 19,257				$ 19,257	$ 19,256				$ 19,256	$ 1
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**	**$ 6,068,857**	**$ 217,273**	**$ 39,396**	**$ -**	**$ 6,325,526**	**$ 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**	**$ 6,068,857**	**$ 217,273**	**$ 39,396**	**$ -**	**$ 6,325,526**	**$ 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

Table 4 - 39: Depreciation and Amortization Summary

Annual Depreciation and Amortization

OEB	Description	2017	2018	2019	2020	2021
1611	Computer Software (Formally known as Account 1925)			$100		
1808	Buildings	$4,572	$4,572	$4,572	$5,272	$5,772
1820	Distribution Station Equipment <50 kV	$3,450	$3,450	$3,452	$238,804	$37,447
1830	Poles, Towers & Fixtures	$42,468	$44,248	$48,796	$96,767	$62,070
1835	Overhead Conductors & Devices	$25,989	$26,072	$27,085	$28,508	$30,176
1840	Underground Conduit	$3,624	$3,630	$3,624	$5,538	$5,538
1845	Underground Conductors & Devices	$3,578	$9,300	$9,688	$12,988	$14,329
1850	Line Transformers	$8,973	$9,471	$10,494	$11,758	$13,161
1855	Services (Overhead & Underground)	$4,920	$5,109	$5,256	$7,249	$8,507
1860	Meters	$51,825	$51,883	$51,885	$56,131	$57,225
1920	Computer Equipment - Hardware	$553	$535	$1,788	$3,000	$3,000
1930	Transportation Equipment	$22,592	$22,592	$27,280	$27,280	$27,280
1940	Tools, Shop & Garage Equipment	$2,707	$2,707	$1,779	$3,346	$4,146
1945	Measurement & Testing Equipment	$346	$346	$346	$346	$346
1995	Contributions & Grants	-$8,103	-$9,895	-$10,107	-$11,703	-$12,328
	Total	**$167,493**	**$174,020**	**$186,036**	**$485,284**	**$256,669**

Table 4 - 40 - Depreciation and Amortization Variance Summary

Annual Depreciation and Amortization Variance

OEB	Description	2018	2019	2020	2021
1611	Computer Software (Formally known as Account 1925)	$0	$100	-$100	$0
1808	Buildings	$0	$0	$700	$500
1820	Distribution Station Equipment <50 kV	$0	$2	$235,353	-$201,357
1830	Poles, Towers & Fixtures	$1,780	$4,548	$47,971	-$34,697
1835	Overhead Conductors & Devices	$83	$1,013	$1,423	$1,668
1840	Underground Conduit	$6	-$6	$1,914	$0
1845	Underground Conductors & Devices	$5,722	$388	$3,300	$1,341
1850	Line Transformers	$498	$1,023	$1,264	$1,403
1855	Services (Overhead & Underground)	$189	$147	$1,993	$1,258
1860	Meters	$59	$2	$4,246	$1,094
1920	Computer Equipment - Hardware	-$18	$1,253	$1,212	$0
1930	Transportation Equipment	$0	$4,688	$0	$0
1940	Tools, Shop & Garage Equipment	$0	-$929	$1,567	$800
1945	Measurement & Testing Equipment	$0	$0	$0	$0
1995	Contributions & Grants	-$1,792	-$212	-$1,596	-$625
	Total	**$6,527**	**$12,016**	**$299,248**	**-$228,615**

The depreciation in accounts 1820 and 1830 increased significantly in 2020. The distribution station and related line work that were subject to the 2014 ICM discussed above have been included in capital assets in 2020. In addition the depreciation that has accumulated in account 1508 since 2014 has been cleared to capital assets in 2020. The large reduction in 2021 is the result of the one-time entry that occurred in 2020 to clear account 1508.

Below are Tables 4-41 to 4-49 which are from Chapter 2 Filing Requirements Appendix 2-C. The tables indicate annual variance in the depreciation calculations that are below materiality. The differences relate to ERHDC using a full years depreciation for assets in the year of acquisition. A summary of the differences is in Table 2-50 below.

Table 4 - 41 – 2013 Appendix 2-C

		Book Values								Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	IFRS Adjustments	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b		c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = (g*.5)/j	o = l+m+n	p	q = p-o
1706	Land Rights	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1725	Poles and Fixtures	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1730	Overhead Conductors & Devices	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1735	Underground Conduit	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1740	Underground Conductors & Devices	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1611	Computer Software (Formally known as Account 1925)	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1612	Land Rights (Formally known as Account 1906)	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1805	Land	$88,881		$0	$88,881			$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1808	Buildings	$175,553		$5,765	$181,318			$0	$0	41	2%	50	2%	$4,433	$0	$0	$4,433	$4,433	$0
1810	Leasehold Improvements	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$161,096		$10,618	$171,714			$0	$0	50	2%	50	2%	$3,450	$0	$0	$3,450	$3,450	$0
1825	Storage Battery Equipment	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1830	Poles, Towers & Fixtures	$878,999		$37,482	$916,481			$0	$199,030	36	3%	40	3%	$25,150	$0	$2,488	$27,638	$30,126	$2,488
1835	Overhead Conductors & Devices	$510,815		$25,105	$535,920			$0	$110,902	57	2%	60	2%	$9,462	$0	$924	$10,386	$11,310	$924
1840	Underground Conduit	$99,204		$9,593	$108,797			$0	$0	31	3%	40	3%	$3,554	$0	$0	$3,554	$3,554	$0
1845	Underground Conductors & Devices	$80,497		$1,088	$81,585			$0	$2,959	35	3%	40	3%	$2,330	$0	$37	$2,367	$2,404	$37
1850	Line Transformers	$207,648		$13,023	$220,671			$0	$40,093	34	3%	40	3%	$6,565	$0	$501	$7,066	$7,567	$501
1855	Services (Overhead & Underground)	$184,179		$7,070	$191,249			$0	$36,478	57	2%	60	2%	$3,350	$0	$304	$3,654	$3,958	$304
1860	Meters	$549,852		$0	$549,852			$0	$765	11	9%	15	7%	$50,146	$0	$25	$50,171	$50,195	$24
1860	Meters (Smart Meters)			$0	$0			$0			0%		0%	$0	$0	$0	$0		$0
1905	Land	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)			$0	$0			$0	$0		0%		0%	$0	$0	$0	$0		$0
1915	Office Furniture & Equipment (5 years)	($1,897)		$0	($1,897)			$0	$0	1	98%	10	10%	($1,859)	$0	$0	($1,859)	($1,859)	($0)
1920	Computer Equipment - Hardware	$13,511		$0	$13,511			$0	$0	2	67%	5	20%	$9,001	$0	$0	$9,001	$9,001	$0
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$0	$0			$0	$0		0%		0%	$0	$0	$0	$0		$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$0	$0			$0	$0		0%		0%	$0	$0	$0	$0		$0
1925	Computer Software	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$20,818	($59,095)	$12,766	$92,679			$0	$216,949	8	13%	15	7%	$11,924	$0	$7,232	$19,155	$26,387	$7,232
1935	Stores Equipment	$2,104		$0	$2,104			$0	$0	4	27%	10	10%	$565	$0	$0	$565	$565	$0
1940	Tools, Shop & Garage Equipment	$10,425		$2	$10,427			$0	$0	4	24%	10	10%	$2,471	$0	$0	$2,471	$2,471	($0)
1945	Measurement & Testing Equipment	$1,852		$0	$1,852			$0	$0	1	89%	10	10%	$1,646	$0	$0	$1,646	$1,646	$0
1950	Power Operated Equipment	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$73		$0	$73			$0	$1,243	1	100%	0	0%	$73	$0	$0	$73	$72	($1)
1955	Communication Equipment (Smart Meters)	$0		$0	$0			$0			0%		0%	$0	$0	$0	$0		$0
1960	Miscellaneous Equipment	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0		$0	$0			$0	$0		0%		0%	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	($242,119)		($4,581)	($246,700)	$0		$0	($20,968)	35	3%	40	3%	($7,083)	$0	($262)	($7,345)	($7,607)	($262)
	Total	$2,741,489	($59,095)	$117,931	$2,918,515	$0	$0	$0	$587,450					$125,178	$0	$11,249	$136,427	$147,673	$11,246

Table 4 - 42 – 2014 Appendix 2-C

		Book Values								Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	IFRS Adjustments	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b		c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = (g*.5)/j	o = l+m+n	p	q = p-o
1706	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1725	Poles and Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1730	Overhead Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1735	Underground Conduit	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1740	Underground Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1611	Computer Software (Formally known as Account 1925)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1805	Land	$88,881	$0	$0	$88,881	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1808	Buildings	$175,553	$0	$5,765	$181,318	$0		$0	$0	41	2%	50	2%	$4,433	$0	$0	$4,433	$4,433	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$161,096	$0	$10,618	$171,714	$0		$0	$0	50	2%	50	2%	$3,450	$0	$0	$3,450	$3,450	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1830	Poles, Towers & Fixtures	$878,999	$0	$37,482	$916,481	$199,030		$199,030	$124,175	36	3%	40	3%	$25,150	$4,976	$1,552	$31,678	$33,232	$1,554
1835	Overhead Conductors & Devices	$510,815	$0	$25,105	$535,920	$110,902		$110,902	$121,422	57	2%	60	2%	$9,462	$1,848	$1,012	$12,322	$13,335	$1,013
1840	Underground Conduit	$99,204	$0	$9,593	$108,797	$0		$0	$0	31	3%	40	3%	$3,554	$0	$0	$3,554	$3,554	$0
1845	Underground Conductors & Devices	$80,497	$0	$1,088	$81,585	$2,959		$2,959	$0	35	3%	40	3%	$2,330	$74	$0	$2,404	$2,404	$0
1850	Line Transformers	$207,648	$0	$13,023	$220,671	$40,093		$40,093	$9,565	34	3%	40	3%	$6,565	$1,002	$120	$7,687	$7,816	$129
1855	Services (Overhead & Underground)	$184,179	$0	$7,070	$191,249	$36,478		$36,478	$5,872	70	1%	60	2%	$2,742	$608	$49	$3,399	$3,448	$49
1860	Meters	$549,852	$0	$0	$549,852	$765		$765	$2,356	11	9%	15	7%	$50,146	$51	$79	$50,276	$50,352	$76
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1905	Land	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (5 years)	($1,897)	$0	$0	($1,897)	$0		$0	$0	0	0%	10	10%	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$13,511	$0	$0	$13,511	$0		$0	$1,063	4	23%	5	20%	$3,146	$0	$106	$3,253	$3,359	$106
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1925	Computer Software	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$20,818	($59,095)	$12,766	$92,679	$216,949		$216,949	$811	10	10%	15	7%	$9,257	$14,463	$27	$23,747	$23,774	$27
1935	Stores Equipment	$2,104	$0	$0	$2,104	$0		$0	$0	0	0%	10	10%	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$10,425	$0	$2	$10,427	$0		$0	$6,857	6	16%	10	10%	$1,660	$0	$343	$2,003	$2,346	$343
1945	Measurement & Testing Equipment	$1,852	$0	$0	$1,852	$0		$0	$0	36	3%	10	10%	$52	$0	$0	$52	$52	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$73	$0	$0	$73	$1,243		$1,243	$0	0	0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	($242,119)	$0	($4,581)	($246,700)	($20,968)		($20,968)	($3,297)	35	3%	40	3%	($7,082)	($524)	($41)	($7,648)	($7,689)	($41)
	Total	**$2,741,489**	**($59,095)**	**$117,931**	**$2,918,515**	**$587,450**	**$0**	**$587,450**	**$268,824**					**$114,865**	**$22,498**	**$3,246**	**$140,609**	**$143,866**	**$3,257**

Table 4 - 43 – 2015 Appendix 2-C

		Book Values								Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	IFRS Adjustments	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b		c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = (g*.5)/j	o = l+m+n	p	q = p-o
1706	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1725	Poles and Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1730	Overhead Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1735	Underground Conduit	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1740	Underground Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1611	Computer Software (Formally known as Account 1925)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1805	Land	$88,881	$0	$0	$88,881	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1808	Buildings	$175,553	$0	$5,765	$181,318	$0		$0	$3,929	41	2%	50	2%	$4,433	$0	$39	$4,473	$4,512	$39
1810	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$161,096	$0	$10,618	$171,714	$0		$0	$0	50	2%	50	2%	$3,450	$0	$0	$3,450	$3,450	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1830	Poles, Towers & Fixtures	$878,999	$0	$37,482	$916,481	$323,205		$323,205	$150,342	36	3%	40	3%	$25,145	$8,080	$1,879	$35,105	$36,984	$1,879
1835	Overhead Conductors & Devices	$510,815	$0	$25,105	$535,920	$232,324		$232,324	$304,465	57	2%	60	2%	$9,426	$3,872	$2,537	$15,835	$18,372	$2,537
1840	Underground Conduit	$99,204	$0	$9,593	$108,797	$0		$0	$2,785	31	3%	40	3%	$3,554	$0	$35	$3,589	$3,624	$35
1845	Underground Conductors & Devices	$80,497	$0	$1,088	$81,585	$2,959		$2,959	$7,152	35	3%	40	3%	$2,330	$74	$89	$2,494	$2,583	$89
1850	Line Transformers	$207,648	$0	$13,023	$220,671	$49,658		$49,658	$19,680	33	3%	40	3%	$6,621	$1,241	$246	$8,108	$8,354	$246
1855	Services (Overhead & Underground)	$184,179	$0	$7,070	$191,249	$42,350		$42,350	$8,648	57	2%	60	2%	$3,350	$706	$72	$4,128	$4,200	$72
1860	Meters	$549,852	$0	$0	$549,852	$3,121		$3,121	$2,751	11	9%	15	7%	$50,144	$208	$92	$50,443	$50,535	$92
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1905	Land	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1915	Office Furniture & Equipment (5 years)	($1,897)	$0	$0	($1,897)	$0		$0	$0	50	2%	10	10%	($38)	$0	$0	($38)	($38)	$0
1920	Computer Equipment - Hardware	$13,511	$0	$0	$13,511	$1,063		$1,063	$0	20	5%	5	20%	$690	$213	$0	$903	$903	$0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1925	Computer Software	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$20,818	($59,095)	$12,766	$92,679	$217,760		$217,760	$0	12	8%	15	7%	$7,820	$14,517	$0	$22,337	$22,337	$0
1935	Stores Equipment	$2,104	$0	$0	$2,104	$0		$0	$0	1	73%	10	10%	$1,539	$0	$0	$1,539	$1,539	$0
1940	Tools, Shop & Garage Equipment	$10,425	$0	$2	$10,427	$6,857		$6,857	$0	6	16%	10	10%	$1,662	$686	$0	$2,348	$2,348	$0
1945	Measurement & Testing Equipment	$1,852	$0	$0	$1,852	$0		$0	$3,464	36	3%	10	10%	$52	$0	$173	$225	$398	$173
1950	Power Operated Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$73	$0	$0	$73	$1,243		$1,243	$0	0	1670%	50	2%	$1,219	$25	$0	$1,244	$1,244	($0)
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	($242,119)	$0	($4,581)	($246,700)	($24,265)		($24,265)	($4,714)	0	0%	40	3%	$0	$0	($59)	($59)	$0	$59
	Total	**$2,741,489**	**($59,095)**	**$117,931**	**$2,918,515**	**$856,275**	**$0**	**$856,275**	**$498,503**					**$121,396**	**$29,622**	**$5,104**	**$156,122**	**$161,344**	**$5,222**

Table 4 - 44 – 2016 Appendix 2-C

Account	Description	Book Values: Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	IFRS Adjustments	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Service Lives: Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense: Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b		c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = (g*.5)/j	o = l+m+n	p	q = p-o
1706	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1725	Poles and Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1730	Overhead Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1735	Underground Conduit	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1740	Underground Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1611	Computer Software (Formally known as Account 1925)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1805	Land	$88,881	$0	$0	$88,881	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1806	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1808	Buildings	$175,553	$0	$5,765	$181,318	$3,929		$3,929	$3,019	41	2%	50	2%	**$4,433**	**$79**	**$30**	**$4,542**	$4,572	**$30**
1810	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1820	Distribution Station Equipment <50 kV	$161,096	$0	$10,618	$171,714	$0		$0	$0	50	2%	50	2%	**$3,450**	**$0**	**$0**	**$3,450**	$3,450	**$0**
1825	Storage Battery Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1830	Poles, Towers & Fixtures	$878,999	$0	$37,482	$916,481	$473,547		$473,547	$107,065	43	2%	40	3%	**$21,337**	**$11,839**	**$1,338**	**$34,514**	$35,852	**$1,338**
1835	Overhead Conductors & Devices	$510,815	$0	$25,105	$535,920	$536,790		$536,790	$194,728	69	1%	60	2%	**$7,716**	**$8,946**	**$1,623**	**$18,285**	$19,908	**$1,623**
1840	Underground Conduit	$99,204	$0	$9,593	$108,797	$2,785		$2,785	$0	31	3%	40	3%	**$3,554**	**$70**	**$0**	**$3,624**	$3,624	**$0**
1845	Underground Conductors & Devices	$80,497	$0	$1,088	$81,585	$10,111		$10,111	$13,637	35	3%	40	3%	**$2,330**	**$253**	**$170**	**$2,754**	$2,924	**$170**
1850	Line Transformers	$207,648	$0	$13,023	$220,671	$69,338		$69,338	$28,765	34	3%	40	3%	**$6,564**	**$1,733**	**$360**	**$8,657**	$9,017	**$360**
1855	Services (Overhead & Underground)	$184,179	$0	$7,070	$191,249	$50,998		$50,998	$27,411	59	2%	60	2%	**$3,251**	**$850**	**$228**	**$4,330**	$4,558	**$228**
1860	Meters	$549,852	$0	$0	$549,852	$5,872		$5,872	$3,504	11	9%	15	7%	**$50,151**	**$391**	**$117**	**$50,659**	$50,776	**$117**
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0		$0			0%	0	0%	**$0**	**$0**	**$0**	**$0**		**$0**
1905	Land	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1908	Buildings & Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1910	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1915	Office Furniture & Equipment (10 years)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1915	Office Furniture & Equipment (5 years)	($1,897)	$0	$0	($1,897)	$0		$0	$0	0	0%	10	10%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1920	Computer Equipment - Hardware	$13,511	$0	$0	$13,511	$1,063		$1,063	$0	40	3%	5	20%	**$340**	**$213**	**$0**	**$553**	$553	**$0**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**		**$0**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**		**$0**
1925	Computer Software	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1930	Transportation Equipment	$20,818	($59,095)	$12,766	$92,679	$217,760		$217,760	$43,617	18	6%	15	7%	**$5,167**	**$14,517**	**$1,454**	**$21,138**	$22,592	**$1,454**
1935	Stores Equipment	$2,104	$0	$0	$2,104	$0		$0	$0	0	0%	10	10%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1940	Tools, Shop & Garage Equipment	$10,425	$0	$2	$10,427	$6,857		$6,857	$4,658	7	15%	10	10%	**$1,557**	**$686**	**$233**	**$2,476**	$2,708	**$233**
1945	Measurement & Testing Equipment	$1,852	$0	$0	$1,852	$3,464		$3,464	$0	18	6%	10	10%	**$105**	**$346**	**$0**	**$452**	$452	**$0**
1950	Power Operated Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1955	Communications Equipment	$73	$0	$0	$73	$1,243		$1,243	$0	0	0%	0	0%	**$0**	**$0**	**$0**	**$0**	($1)	**($1)**
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**		**$0**
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1980	System Supervisor Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1990	Other Tangible Property	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	**$0**	**$0**	**$0**	**$0**	$0	**$0**
1995	Contributions & Grants	($242,119)	$0	($4,581)	($246,700)	($28,979)		($28,979)	($47,332)	36	3%	40	3%	**($6,827)**	**($724)**	**($592)**	**($8,143)**	($8,735)	**($592)**
	Total	**$2,741,489**	**($59,095)**	**$117,931**	**$2,918,515**	**$1,354,778**	**$0**	**$1,354,778**	**$379,071**					**$103,130**	**$39,199**	**$4,962**	**$147,290**	**$152,251**	**$4,961**

Table 4 - 45 – 2017 Appendix 2-C

		Book Values								Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	IFRS Adjustments	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b		c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = (g*.5)/j	o = l+m+n	p	q = p-o
1706	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1725	Poles and Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1730	Overhead Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1735	Underground Conduit	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1740	Underground Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1611	Computer Software (Formally known as Account 1925)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1805	Land	$88,881	$0	$0	$88,881	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1808	Buildings	$175,553	$0	$5,765	$181,318	$6,948		$6,948	$0	41	2%	50	2%	$4,433	$139	$0	$4,572	$4,572	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$161,096	$0	$10,618	$171,714	$0		$0	$0	50	2%	50	2%	$3,450	$0	$0	$3,450	$3,450	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1830	Poles, Towers & Fixtures	$878,999	$0	$37,482	$916,481	$580,611		$580,611	$184,617	39	3%	40	3%	$23,337	$14,515	$2,308	$40,160	$42,468	$2,308
1835	Overhead Conductors & Devices	$510,815	$0	$25,105	$535,920	$731,518		$731,518	$327,238	64	2%	60	2%	$8,343	$12,192	$2,727	$23,262	$25,989	$2,727
1840	Underground Conduit	$99,204	$0	$9,593	$108,797	$2,785		$2,785	$0	31	3%	40	3%	$3,554	$70	$0	$3,624	$3,624	$0
1845	Underground Conductors & Devices	$80,497	$0	$1,088	$81,585	$23,748		$23,748	$26,168	35	3%	40	3%	$2,330	$594	$327	$3,251	$3,578	$327
1850	Line Transformers	$207,648	$0	$13,023	$220,671	$98,103		$98,103	$48,325	42	2%	40	3%	$5,312	$2,453	$604	$8,369	$8,973	$604
1855	Services (Overhead & Underground)	$184,179	$0	$7,070	$191,249	$78,410		$78,410	$15,693	57	2%	60	2%	$3,352	$1,307	$131	$4,789	$4,920	$131
1860	Meters	$549,852	$0	$0	$549,852	$9,376		$9,376	$15,827	11	9%	15	7%	$50,144	$625	$528	$51,297	$51,825	$528
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1905	Land	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (5 years)	($1,897)	$0	$0	($1,897)	$0		$0	$0	0	0%	10	10%	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$13,511	$0	$0	$13,511	$1,063		$1,063	$0	40	3%	5	20%	$340	$213	$0	$553	$553	$0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1925	Computer Software	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$20,818	($59,095)	$12,766	$92,679	$261,377		$261,377	$0	18	6%	15	7%	$5,167	$17,425	$0	$22,592	$22,592	$0
1935	Stores Equipment	$2,104	$0	$0	$2,104	$0		$0	$0		0%	10	10%	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$10,425	$0	$2	$10,427	$11,515		$11,515	$0	7	15%	10	10%	$1,556	$1,151	$0	$2,707	$2,707	$0
1945	Measurement & Testing Equipment	$1,852	$0	$0	$1,852	$3,464		$3,464	$0	0	0%	10	10%	$0	$346	$0	$346	$346	($0)
1950	Power Operated Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$73	$0	$0	$73	$1,243		$1,243	$0	0	0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	($242,119)	$0	($4,581)	($246,700)	($76,311)		($76,311)	($3,293)	40	2%	40	3%	($6,113)	($1,908)	($41)	($8,062)	($8,103)	($41)
	Total	**$2,741,489**	**($59,095)**	**$117,931**	**$2,918,515**	**$1,733,849**	**$0**	**$1,733,849**	**$614,576**					**$105,206**	**$49,122**	**$6,583**	**$160,911**	**$167,493**	**$6,583**

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Table 4 - 46 – 2018 Appendix 2-C

		Book Values								Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	IFRS Adjustments	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b		c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = (g*.5)/j	o = l+m+n	p	q = p-o
1706	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1725	Poles and Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1730	Overhead Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1735	Underground Conduit	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1740	Underground Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1611	Computer Software (Formally known as Account 1925)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1805	Land	$88,881	$0	$0	$88,881	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1808	Buildings	$175,553	$0	$5,765	$181,318	$6,948		$6,948	$0	41	2%	50	2%	$4,433	$139	$0	$4,572	$4,572	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$161,096	$0	$10,618	$171,714	$0		$0	$0	50	2%	50	2%	$3,450	$0	$0	$3,450	$3,450	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1830	Poles, Towers & Fixtures	$878,999	$0	$37,482	$916,481	$765,228		$765,228	$157,664	43	2%	40	3%	$21,176	$19,131	$1,971	$42,277	$44,248	$1,971
1835	Overhead Conductors & Devices	$510,815	$0	$25,105	$535,920	$1,058,756		$1,058,756	$56,950	72	1%	60	2%	$7,477	$17,646	$475	$25,597	$26,072	$475
1840	Underground Conduit	$99,204	$0	$9,593	$108,797	$2,785		$2,785	$0	31	3%	40	3%	$3,560	$70	$0	$3,630	$3,630	$0
1845	Underground Conductors & Devices	$80,497	$0	$1,088	$81,585	$49,916		$49,916	$228,205	35	3%	40	3%	$2,347	$1,248	$2,853	$6,447	$9,300	$2,853
1850	Line Transformers	$207,648	$0	$13,023	$220,671	$146,429		$146,429	$19,903	42	2%	40	3%	$5,313	$3,661	$249	$9,222	$9,471	$249
1855	Services (Overhead & Underground)	$184,179	$0	$7,070	$191,249	$94,103		$94,103	$14,182	58	2%	60	2%	$3,304	$1,568	$118	$4,991	$5,109	$118
1860	Meters	$549,852	$0	$0	$549,852	$25,203		$25,203	$879	11	9%	15	7%	$50,144	$1,680	$29	$51,854	$51,883	$29
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1905	Land	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (5 years)	($1,897)	$0	$0	($1,897)	$0		$0	$0		0%	10	10%	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$13,511	$0	$0	$13,511	$1,063		$1,063	$1,620	0	0%	5	20%	$0	$213	$162	$375	$535	$160
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1925	Computer Software	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$20,818	($59,095)	$12,766	$92,679	$261,377		$261,377	$0	18	6%	15	7%	$5,167	$17,425	$0	$22,592	$22,592	$0
1935	Stores Equipment	$2,104	$0	$0	$2,104	$0		$0	$0	0	0%	10	10%	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$10,425	$0	$2	$10,427	$11,515		$11,515	$0	7	15%	10	10%	$1,556	$1,151	$0	$2,707	$2,707	$0
1945	Measurement & Testing Equipment	$1,852	$0	$0	$1,852	$3,464		$3,464	$0	0	0%	10	10%	$0	$346	$0	$346	$346	($0)
1950	Power Operated Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$73	$0	$0	$73	$1,243		$1,243	$0	0	0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	($242,119)	$0	($4,581)	($246,700)	($79,604)		($79,604)	($40,269)	36	3%	40	3%	($6,899)	($1,990)	($503)	($9,392)	($9,895)	($503)
	Total	**$2,741,489**	**($59,095)**	**$117,931**	**$2,918,515**	**$2,348,425**	**$0**	**$2,348,425**	**$439,133**					**$101,028**	**$62,288**	**$5,353**	**$168,669**	**$174,020**	**$5,351**

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Table 4 - 47 – 2019 Appendix 2-C

		Book Values								Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	IFRS Adjustments	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b		c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = (g*.5)/j	o = l+m+n	p	q = p-o
1706	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1725	Poles and Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1730	Overhead Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1735	Underground Conduit	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1740	Underground Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1611	Computer Software (Formally known as Account 1925)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1805	Land	$88,881	$0	$0	$88,881	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1808	Buildings	$175,553	$0	$5,765	$181,318	$6,948		$6,948	$0	41	2%	50	2%	$4,433	$139	$0	$4,572	$4,572	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$161,096	$0	$10,618	$171,714	$0		$0	$0	50	2%	50	2%	$3,452	$0	$0	$3,452	$3,452	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1830	Poles, Towers & Fixtures	$878,999	$0	$37,482	$916,481	$922,892		$922,892	$218,136	45	2%	40	3%	$20,270	$23,072	$2,727	$46,069	$48,796	$2,727
1835	Overhead Conductors & Devices	$510,815	$0	$25,105	$535,920	$1,115,706		$1,115,706	$61,876	72	1%	60	2%	$7,459	$18,595	$516	$26,569	$27,085	$516
1840	Underground Conduit	$99,204	$0	$9,593	$108,797	$2,785		$2,785	$0	31	3%	40	3%	$3,554	$70	$0	$3,624	$3,624	$0
1845	Underground Conductors & Devices	$80,497	$0	$1,088	$81,585	$278,121		$278,121	$16,375	35	3%	40	3%	$2,325	$6,953	$205	$9,483	$9,688	$205
1850	Line Transformers	$207,648	$0	$13,023	$220,671	$166,331		$166,331	$58,014	45	2%	40	3%	$4,885	$4,158	$725	$9,768	$10,494	$725
1855	Services (Overhead & Underground)	$184,179	$0	$7,070	$191,249	$108,285		$108,285	$12,712	59	2%	60	2%	$3,239	$1,805	$106	$5,150	$5,256	$106
1860	Meters	$549,852	$0	$0	$549,852	$26,082		$26,082	$119	11	9%	15	7%	$50,138	$1,739	$4	$51,881	$51,885	$4
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1905	Land	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (5 years)	($1,897)	$0	$0	($1,897)	$0		$0	$0	0	0%		0%	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$13,511	$0	$0	$13,511	$2,683		$2,683	$7,759	0	0%	5	20%	$0	$537	$776	$1,312	$1,888	$576
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1925	Computer Software	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$20,818	($59,095)	$12,766	$92,679	$261,377		$261,377	$70,339	18	6%	15	7%	$5,165	$17,425	$2,345	$24,935	$27,280	$2,345
1935	Stores Equipment	$2,104	$0	$0	$2,104	$0		$0	$0	0	0%	10	10%	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$10,425	$0	$2	$10,427	$11,515		$11,515	$7,166	0	0%	10	10%	$0	$1,151	$358	$1,510	$1,779	$269
1945	Measurement & Testing Equipment	$1,852	$0	$0	$1,852	$3,464		$3,464	$0	0	0%	10	10%	$0	$346	$0	$346	$346	($0)
1950	Power Operated Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$73	$0	$0	$73	$1,243		$1,243	$0	0	0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	($242,119)	$0	($4,581)	($246,700)	($119,873)		($119,873)	($39,290)	40	2%	40	3%	($6,128)	($2,997)	($491)	($9,616)	($10,107)	($491)
	Total	**$2,741,489**	**($59,095)**	**$117,931**	**$2,918,515**	**$2,787,558**	**$0**	**$2,787,558**	**$413,205**					**$98,792**	**$72,994**	**$7,270**	**$179,056**	**$186,036**	**$6,980**

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Table 4 - 48 – 2020 Appendix 2-C

		Book Values								Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	IFRS Adjustments	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b		c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = (g*.5)/j	o = l+m+n	p	q = p-o
1706	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1725	Poles and Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1730	Overhead Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1735	Underground Conduit	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1740	Underground Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1611	Computer Software (Formally known as Account 1925)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1805	Land	$88,881	$0	$0	$88,881	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1808	Buildings	$175,553	$0	$5,765	$181,318	$6,948		$6,948	$35,000	41	2%	50	2%	$4,433	$139	$350	$4,922	$5,272	$350
1810	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$161,096	$0	$10,618	$171,714	$0		$0	$5,920	5	22%	50	2%	$37,256	$0	$59	$37,315	$37,374	$59
1825	Storage Battery Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1830	Poles, Towers & Fixtures	$878,999	$0	$37,482	$916,481	$1,141,028		$1,141,028	$144,169	36	3%	40	3%	$25,560	$28,526	$1,802	$55,888	$57,690	$1,802
1835	Overhead Conductors & Devices	$510,815	$0	$25,105	$535,920	$1,177,582		$1,177,582	$85,675	72	1%	60	2%	$7,454	$19,626	$714	$27,794	$28,508	$714
1840	Underground Conduit	$99,204	$0	$9,593	$108,797	$2,785		$2,785	$76,572	31	3%	40	3%	$3,554	$70	$957	$4,581	$5,538	$957
1845	Underground Conductors & Devices	$80,497	$0	$1,088	$81,585	$294,496		$294,496	$131,346	35	3%	40	3%	$2,342	$7,362	$1,642	$11,346	$12,988	$1,642
1850	Line Transformers	$207,648	$0	$13,023	$220,671	$224,345		$224,345	$56,225	47	2%	40	3%	$4,743	$5,609	$703	$11,055	$11,758	$703
1855	Services (Overhead & Underground)	$184,179	$0	$7,070	$191,249	$120,997		$120,997	$80,637	49	2%	60	2%	$3,888	$2,017	$672	$6,577	$7,249	$672
1860	Meters	$549,852	$0	$0	$549,852	$26,201		$26,201	$70,273	11	9%	15	7%	$49,699	$1,747	$2,342	$53,788	$56,131	$2,342
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1905	Land	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (5 years)	($1,897)	$0	$0	($1,897)	$0		$0	$0	0	0%	0	0%	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$13,511	$0	$0	$13,511	$10,442		$10,442	$15,000	0	0%	6	17%	$0	$1,740	$1,250	$2,990	$3,000	$10
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0		$0
1925	Computer Software	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$20,818	($59,095)	$12,766	$92,679	$331,716		$331,716	$0	18	6%	15	7%	$5,167	$22,114	$0	$27,281	$27,280	($1)
1935	Stores Equipment	$2,104	$0	$0	$2,104	$0		$0	$0	0	0%	10	10%	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$10,425	$0	$2	$10,427	$18,680		$18,680	$8,000	6	15%	15	7%	$1,611	$1,215	$260	$3,086	$3,346	$260
1945	Measurement & Testing Equipment	$1,852	$0	$0	$1,852	$3,464		$3,464	$0	0	0%	10	10%	$0	$346	$0	$346	$346	($0)
1950	Power Operated Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$73	$0	$0	$73	$1,243		$1,243	$0	0	0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1995	Contributions & Grants	($242,119)	$0	($4,581)	($246,700)	($159,163)		($159,163)	($63,830)	40	2%	40	3%	($6,128)	($3,979)	($798)	($10,905)	($11,703)	($798)
	Total	**$2,741,489**	**($59,095)**	**$117,931**	**$2,918,515**	**$3,200,763**	**$0**	**$3,200,763**	**$644,987**					**$139,580**	**$86,532**	**$9,954**	**$236,065**	**$244,777**	**$8,712**

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Table 4 - 49 – 2021 Appendix 2-C

Account	Description	Book Values: Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1)[1]	Less Fully Depreciated[7]	IFRS Adjustments	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change[2]	Less Fully Depreciated[5]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Service Lives: Average Remaining Life of Assets Existing Before Policy Change[3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change[4]	Depreciation Rate on New Additions	Depreciation Expense: Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions[5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance[6]
		a	b		c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = (g*.5)/j	o = l+m+n	p	q = p-o
1706	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1725	Poles and Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1730	Overhead Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1735	Underground Conduit	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1740	Underground Conductors & Devices	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1611	Computer Software (Formally known as Account 1925)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1805	Land	$88,881	$0	$0	$88,881	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1808	Buildings	$175,553	$0	$5,765	$181,318	$41,948		$41,948	$25,000	41	2%	50	2%	$4,433	$839	$250	$5,522	$5,772	$250
1810	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment <50 kV	$161,096	$0	$10,618	$171,714	$5,920		$5,920	$3,612	50	2%	50	2%	$3,450	$118	$36	$3,605	$3,643	$38
1825	Storage Battery Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1830	Poles, Towers & Fixtures	$878,999	$0	$37,482	$916,481	$1,285,197		$1,285,197	$175,195	46	2%	40	3%	$19,968	$32,130	$2,190	$54,288	$56,478	$2,190
1835	Overhead Conductors & Devices	$510,815	$0	$25,105	$535,920	$1,263,257		$1,263,257	$100,079	72	1%	60	2%	$7,454	$21,054	$834	$29,342	$30,176	$834
1840	Underground Conduit	$99,204	$0	$9,593	$108,797	$79,357		$79,357	$0	31	3%	40	3%	$3,654	$1,984	$0	$5,638	$5,538	$0
1845	Underground Conductors & Devices	$80,497	$0	$1,088	$81,585	$425,842		$425,842	$53,666	35	3%	40	3%	$2,341	$10,646	$671	$13,658	$14,329	$671
1850	Line Transformers	$207,648	$0	$13,023	$220,671	$280,570		$280,570	$56,146	47	2%	40	3%	$4,743	$7,014	$702	$12,459	$13,161	$702
1855	Services (Overhead & Underground)	$184,179	$0	$7,070	$191,249	$201,634		$201,634	$50,312	44	2%	60	2%	$4,308	$3,361	$419	$8,088	$8,507	$419
1860	Meters	$549,852	$0	$0	$549,852	$96,474		$96,474	$16,419	11	9%	15	7%	$49,699	$6,432	$547	$56,678	$57,225	$547
1860	Meters (Smart Meters)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1905	Land	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1908	Buildings & Fixtures	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (5 years)	($1,897)	$0	$0	($1,897)	$0		$0	$0	0	0%	0	0%	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$13,511	$0	$0	$13,511	$25,442		$25,442	$8,000	0	0%	10	10%	$0	$2,544	$400	$2,944	$3,000	$56
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0	$0	$0	$0	$0		$0			0%	0	0%	$0	$0	$0	$0		$0
1925	Computer Software	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$20,818	($59,096)	$12,766	$92,679	$331,716		$331,716	$0	18	6%	15	7%	$5,165	$22,114	$0	$27,280	$27,280	$0
1935	Stores Equipment	$2,104	$0	$0	$2,104	$0		$0	$0	0	0%	10	10%	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$10,425	$0	$2	$10,427	$26,680		$26,680	$0	3	40%	0	0%	$4,146	$0	$0	$4,146	$4,146	$0
1945	Measurement & Testing Equipment	$1,852	$0	$0	$1,852	$3,464		$3,464	$0	0	0%	10	10%	$0	$346	$0	$346	$346	($0)
1950	Power Operated Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communications Equipment	$73	$0	$0	$73	$1,243		$1,243	$0	0	0%	0	0%	$0	$0	$0	$0	$0	$0
1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1980	System Supervisor Equipment	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0	$0	$0	$0	$0		$0	$0		0%	0	0%	$0	$0	$0	$0	$0	$0
2440	Deferred Revenue[5]	($242,119)	$0	($4,581)	($246,700)	($222,993)		($222,993)	($25,000)	40	2%	40	3%	($6,128)	($5,575)	($313)	($12,016)	($12,328)	($313)
	Total	$2,741,489	($59,096)	$117,931	$2,918,515	$3,845,750	$0	$3,845,750	$463,429	437	78%	480	63%	$103,133	$103,008	$5,737	$211,878	$217,273	$5,395
									$4,309,179									$0	$5,395
																		$1,594,735	
																			$87,705

General: Appli[illegible]s are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.

Table 4-50 below is the summary of the annual differences in depreciation between Appendix 2-BA and Appendix 2-C. As noted above the differences are not material.

Table 4 - 50 – Variance in Annual Depreciation Appendix 2-BA and 2-C

Varinace Expense per App. 2-BA vs App. 2-C

	Variance Appendices 2-BA vs 2-C
2013	$11,246
2014	$3,257
2015	$5,222
2016	$4,961
2017	$6,583
2018	$5,351
2019	$6,980
2020	$8,712
2021	$5,395
	$57,707
Annual Average	$6,412

(b) Asset Retirement Obligations (“AROs”)

ERHDC has not recorded any Asset Retirement Obligations in fixed assets.

(c) Typical Service Life Comparison

In its 2012 Cost of Service application ERHDC adopted for asset depreciation purposes the typical useful lives recommended by Kinectrics in its Asset Depreciation Study prepared for the OEB. The useful lives used by ERHDC for depreciation purposes is consistent with the Kinectrics report as detailed Chapter 2 Appendix 2-BB included below as Table 4-51.

Table 4 - 51 – Appendix 2-BB – Service Life Comparison

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

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	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		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	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								

2.4.5. Taxes Or Payments In Lieu Of Taxes (Pils) And Property Taxes

2.4.5.1 Income Taxes or PILS

ERHDC is subject to Payment in Lieu ("PILS") under Section 93 of the Electricity Act, 1998, as amended. ERHDC does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. A copy of the 2019 Federal T2 and Ontario C23 tax return has been provide in Appendix 4-I to this Exhibit.

ERHDC confirms that the financial statements filed with its 2019 corporate income tax returns are the same as the 2019 audited financial statements filed with this application.

In accordance with the filing instructions, ERHDC has completed the Board's Tax/PILS Work Form for 2021 Filers, Version 1.20 and has filed this model in live excel format and as Appendix 4-J.

(a) PILS for the 2021 Test Year

The 2021 Test Year's PILS have been calculated at zero. The details of the calculations are in the Income Tax/ PILS Work Form in Appendix 4-J.

The 2021 Test Year PILS have been determined by applying substantively enacted 2021 tax rates against Taxable Income. The 2021 Taxable Income amount has been determined by taking Utility Income before Taxes and applying Schedule 1 corporate tax adjustments to this number.

(i) <u>Utility Income Before Taxes</u>

This is calculated based on the 2021 expected total revenues less the 2021 expected cost and expenses. The utility income before taxes in 2021 is $253,504. The details of this calculation are in Table 4-52 below and can also be found in Exhibit 6, Table 6-1.

Table 4 - 52 – Calculation of Utility Net Income

Operating Revenues:	
Distribution Revenue (at Proposed Rates)	$2,071,003
Other Revenue (1)	$201,416
Total Operating Revenues	$2,272,419
Operating Expenses:	
OM+A Expenses	$1,653,431
Depreciation/Amortization	$229,389
Property taxes	$ -
Capital taxes	$ -
Other expense	$2,000
Subtotal (lines 4 to 8)	$1,884,820
Deemed Interest Expense	$134,095
Total Expenses (lines 9 to 10)	$2,018,915
Utility income before income taxes	$253,504
Income taxes (grossed-up)	$ -
Utility net income	$253,504

(ii) Tax Adjustments

Tax adjustments are made for both temporary and permanent differences and reserves. Significant temporary differences included are the differences between depreciation for accounting purposes versus capital cost allowance (CCA) for tax purposes.

The tax provision for the 2021 Test Year is detailed in Table 4-53 as follows:

Table 4 - 53 : PILS Tax Provision 2021 Test Year

PILs Tax Provision - Test Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate					Wires Only		
Regulatory Taxable Income								T1	-$ 156,074	A	
Ontario (Max 11.5%)	11.5%	3.2%	-$ 4,994	3.2%	B						
Federal (Max 15%)	15.0%	9.0%	-$ 14,047	9.0%	C						
Combined effective tax rate (Max 26.5%)									12.20%	D = B + C	
Total Income Taxes									-$ 19,041	E = A * D	
Investment Tax Credits										F	
Miscellaneous Tax Credits										G	
Total Tax Credits									$ -	H = F + G	
Corporate PILs/Income Tax Provision for Test Year									$ -	I = E - H	S. Su
Corporate PILs/Income Tax Provision Gross Up [1]						87.80%	J = 1-D		$ -	K = I/J-I	
Income Tax (grossed-up)									$ -	L = K + I	S. Su

Due to the fact that CCA is in excess of depreciaton in the test year, ERHDC has a loss for tax purposes. With the loss carry forwards available and CCA projected to be in access of depreciaton, ERHDC does not expect to pay taxes during this Cost of Service term. Therefore, no income taxes have been included in the revenue requirement.

(b) Expected 2021 Tax Rates

ERHDC does not have taxable income in the 2021 Test Year.

(i) <u>Tax Calculation</u>

The following Table 4-54 presents the tax calculation for the 2021 Test Year.

Table 4 - 54 : Tax Calculation 2021 Test Year

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	253,504
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		229,389
Recapture of capital cost allowance from Schedule 8	107	T8	0
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	0
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
	295		
	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			**229,389**

1

Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	638,968
Terminal loss from Schedule 8	404	T8	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	0
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions			
Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		
Non-taxable imputed interest income on deferral and variance accounts	395		
	395		
	395		
	395		
	395		
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**638,968**
NET INCOME FOR TAX PURPOSES		calculated	**-156,074**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	T4	0
Net capital losses of previous tax years from Schedule 4	332	T4	0
Limited partnership losses of previous tax years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**-156,074**

(c) Tax Calculations and PILs

(i) Capital Cost Allowance

Details of the Capital Cost Allowance continuity schedules for the 2020 Bridge Year and the 2021 Test Year are provided in Table 4-55 and Table 4-56 as follows:

Table 4 - 55 : CCA Continuity Schedule 2020

Schedule 8 CCA - Bridge Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the bridge year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)
1	Buildings, Distribution System (acq'd post 1987)	H8	$ 1,234,094							$ 1,234,094
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	H8	$ -							$ -
2	Distribution System (acq'd pre 1988)	H8	$ -							$ -
3	Buildings (acq'd pre 1988)	H8	$ -							$ -
6	Certain Buildings; Fences	H8	$ -							$ -
8	General Office Equipment, Furniture, Fixtures	H8	$ 18,375	$ 8,000	$ 8,000					$ 26,375
10	Motor Vehicles, Fleet	H8	$ 82,561	$ 5,000	$ 5,000					$ 87,561
10.1	Certain Automobiles	H8	$ -							$ -
12	Computer Application Software (Non-Systems)	H8	$ -	$ 10,000						$ 10,000
13_1	Lease # 1	H8	$ -							$ -
13_2	Lease # 2	H8	$ -							$ -
13_3	Lease # 3	H8	$ -							$ -
13_4	Lease # 4	H8	$ -							$ -
14	Limited Period Patents, Franchises, Concessions or Licences	H8	$ -							$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	H8	$ -							$ -
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	H8	$ -							$ -
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	H8	$ -							$ -
42	Fibre Optic Cable	H8	$ -							$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	H8	$ 5							$ 5
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8	$ -							$ -
47	Distribution System (acq'd post Feb 22/05)	H8	$ 4,219,025	$ 685,817	$ 685,817	$ 1,949,234				$ 6,854,076
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	H8	$ 3,384							$ 3,384
95	CWIP	H8	$ -							$ -
		H8	$ -							$ -
		H8	$ -							$ -
		H8	$ -							$ -
		H8	$ -							$ -
		H8	$ -							$ -
		H8	$ -							$ -
		H8	$ -							$ -
		H8	$ -							$ -
	TOTALS		$ 5,557,444	$ 708,817	$ 698,817	$ 1,949,234	$ -	$ -	$ -	$ 8,215,495

(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the bridge year (column 9 minus column 17)
$ -	$ -	0.50	$ -	$ -	4%			$ 49,364		$ 1,184,730
$ -	$ -	0.50	$ -	$ -	6%			$ -		$ -
$ -	$ -		$ -	$ -	6%			$ -		$ -
$ -	$ -		$ -	$ -	5%			$ -		$ -
$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -
$ -	$ 8,000	0.50	$ 4,000	$ -	20%			$ 6,075		$ 20,300
$ -	$ 5,000	0.50	$ 2,500	$ -	30%			$ 27,018		$ 60,543
$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
$ -	$ -	0.00	$ -	$ 5,000	100%			$ 5,000		$ 5,000
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -		$ -	$ -	7%			$ -		$ -
$ -	$ -	0.50	$ -	$ -	5%			$ -		$ -
$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -
$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -
$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -
$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -
$ -	$ -		$ -	$ -	45%			$ 2		$ 3
$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
$ -	$ 685,817	0.50	$ 342,909	$ -	8%			$ 575,759		$ 6,278,317
$ -	$ -	0.50	$ -	$ -	55%			$ 1,861		$ 1,523
$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	**$ 698,817**		**$ 349,409**	**$ 5,000**		**$ -**	**$ -**	**$ 665,079**	B1	**$ 7,550,416**

Table 4 - 56 : CCA Continuity Schedule 2021

Schedule 8 CCA - Test Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the test year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)
1	Buildings, Distribution System (acq'd post 1987) Only if election under ONTARIO REGULATION 162/01 ss. 5 or 7 filed in	B8	$ 1,184,730							$ 1,184,730
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	B8	$ -							$ -
2	Distribution System (acq'd pre 1988)	B8	$ -							$ -
3	Buildings (acq'd pre 1988)	B8	$ -							$ -
6	Certain Buildings; Fences	B8	$ -							$ -
8	General Office Equipment, Furniture, Fixtures	B8	$ 20,300							$ 20,300
10	Motor Vehicles, Fleet	B8	$ 60,543	8,000	8,000					$ 68,543
10.1	Certain Automobiles	B8	$ -							$ -
12	Computer Application Software (Non-Systems)	B8	$ 5,000							$ 5,000
13 ₁	Lease # 1	B8	$ -							$ -
13 ₂	Lease # 2	B8	$ -							$ -
13 ₃	Lease # 3	B8	$ -							$ -
13 ₄	Lease # 4	B8	$ -							$ -
14	Limited Period Patents, Franchises, Concessions or Licences	B8	$ -							$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	B8	$ -							$ -
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	B8	$ -							$ -
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	B8	$ -							$ -
42	Fibre Optic Cable	B8	$ -							$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	B8	$ 3							$ 3
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -							$ -
47	Distribution System (acq'd post Feb 22/05)	B8	$ 6,278,317	480,429	480,429					$ 6,758,746
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	B8	$ 1,523							$ 1,523
95	CWIP	B8	$ -							$ -
		B8	$ -							$ -
		B8	$ -							$ -
		B8	$ -							$ -
		B8	$ -							$ -
		B8	$ -							$ -
		B8	$ -							$ -
		B8	$ -							$ -
		B8	$ -							$ -
	TOTALS		$ 7,550,416	$ 488,429	$ 488,429	$ -	$ -	$ -	$ -	$ 8,038,845

(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the test year (column 9 minus column 17)
$ -	$ -	0.50	$ -	$ -	4%			$ 47,389		$ 1,137,341
$ -	$ -	0.50	$ -	$ -	6%			$ -		$ -
$ -	$ -		$ -	$ -	6%			$ -		$ -
$ -	$ -		$ -	$ -	5%			$ -		$ -
$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -
$ -	$ -	0.50	$ -	$ -	20%			$ 4,060		$ 16,240
$ -	$ 8,000	0.50	$ 4,000	$ -	30%			$ 21,763		$ 46,780
$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
$ -	$ -	0.00	$ -	$ -	100%			$ 5,000		$ -
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -	0.00	$ -	$ -	NA					$ -
$ -	$ -		$ -	$ -	7%			$ -		$ -
$ -	$ -	0.50	$ -	$ -	5%			$ -		$ -
$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -
$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -
$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -
$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -
$ -	$ -		$ -	$ -	45%			$ 1		$ 2
$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
$ -	$ 480,429	0.50	$ 240,215	$ -	8%			$ 559,917		$ 6,198,829
$ -	$ -	0.50	$ -	$ -	55%			$ 838		$ 685
$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	$ -		$ -	$ -						$ -
$ -	**$ 488,429**		**$ 244,215**	**$ -**		**$ -**	**$ -**	**$ 638,968**	T1	**$ 7,399,877**

A reconciliation between ERHDC's December 31, 2019 UCC balance per the filed tax return and the balance used for the opening UCC balance for the 2020 Bridge Year is provided in Table 4-57 as follows:

Table 4 - 57 : Reconciliation of the 2019 UCC Balance

		Closing UCC 2019 PILs Return	Opening UCC 2020 Test
1	**Buildings, Distribution System (acq'd post 1987)**	$ 1,234,094	$ 1,234,094
8	**General Office Equipment, Furniture, Fixtures**	$ 18,375	$ 18,375
10	**Motor Vehicles, Fleet**	$ 82,561	$ 82,561
45	**Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)**	$ 5	$ 5
47	**Distribution System (acq'd post Feb 22/05)**	$ 4,219,025	$ 4,219,025
50	**General Purpose Computer Hardware & Software (acq'd post Mar 18/07)**	$ 3,384	$ 3,384
	TOTALS	**$ 5,557,444**	**$ 5,557,444**

(ii) Accelerated Capital Cost Allowance (CCA)

On June 21, 2019, Bill C-97, the Budget Implementation Act, 2019, No. 1, was given Royal Assent. Included in Bill C-97 are various changes to the federal income tax regime. One of the changes introduced by Bill C-97 is the Accelerated Investment Incentive program, which provides for a first-year increase in CCA deductions on eligible capital assets acquired after November 20, 2018. As per the OEB's July 25, 2019 letter, the OEB expected distributors to:

1. Record the impacts of CCA rule changes in Account 1592 - PILs and Tax Variances – CCA Changes for the period November 21, 2018 until the effective date of the distributor's next cost-based rate order.

2. Record the full revenue requirement impact of any changes in CCA rules that are not reflected in base rates in Account 1592 – PILs and Tax Variances – CCA Changes.

3. Bring forward any amounts tracked in Account 1592 - PILs and Tax Variances – CCA Changes for review and disposition in accordance with the OEB's filing requirements for the disposition of deferral and variance accounts, which would generally coincide with a distributor's next cost-based rate application.

Accordingly, ERHDC has tracked the impact of Bill C-97 in Account 1592 - PILs and Tax Variances – CCA Changes and is requesting settlement as detailed in Exhibit 9 of this cost of service rate application.

(iii) Loss Carry Forwards

At the end of 2021, ERHDC has projected a non-capital loss carry forward of $1,257,849 and has not requested a PILs recovery in its revenue requirement in anticipation that the loss carry forwards will be sufficient to eliminate taxable income during this Cost of Service period.

(iv) Calculation of Tax Credits

ERHDC did not have any tax credits, other additions or other deductions in its 2021 Test Year.

(v) Integrity Checks

ERHDC confirms the following in Table 4-58: Integrity Checks below:

Table 4 - 58 : Integrity Checks

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	
2	The capital additions and deductions in the CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non-distribution tax amounts on Schedule 8.	Y	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the CCA Schedule 8 for the same years filed in the application		
5	Loss carry-forwards, if any, from prior year tax returns' Schedule 4 agree with those disclosed in the application	Y	
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	Y	
7	CCA is maximized even if there are tax loss carry-forwards	Y	
8	Other post-employment benefits and pension expenses that are added back on Schedule 1 to reconcile accounting income to net income for tax purposes agree with the OM&A analysis for compensation. The amounts deducted are reasonable when compared with the notes to the audited financial statements, Financial Services Commission of Ontario reports, and actuarial valuations.	Y	amounts added back to Schedule 1 in 2019 was $976 and is not expected to be significant in future years
9	The income tax rate used to calculate the tax expense is consistent with the utility's actual tax facts and evidence filed in the application	Y	

2.4.5.2 Other Taxes

(a) Property Taxes

ERHDC pays property taxes to the Town of Espanola based on assessed property value and municipal tax rate. Property taxes are allocated to OM&A as an expense to the cost centre related to those facilities. ERHDC includes property taxes paid to the Town in operating accounts 5017 and 5620, which have been recorded in these accounts prior to January 1, 2012. Table 4 - 59 – Total Taxes, Other than Income Taxes below shows the continuity of total property taxes for the years 2017 to the 2021 Test Year.

Table 4 - 59 : Total Taxes, Other than Income

	2017	2018	2019	2020 Bridge	2021 Test
Office - 5620	$3,978.87	$3,979.36	$6,048.86	$4,000.00	$4,060.00
Substations- 5017	$8,008.23	$8,214.24	$6,156.99	$7,488.00	$7,566.00
	$11,987.10	$12,193.60	$12,205.85	$11,488.00	$11,626.00

2.4.5.3 Non-Recoverable and Disallowed Expenses

ERHDC does not have any expenses that are deducted for general tax purposes but for which recovery in 2021 distribution rates would be disallowed.

2.4.6. Conservation and Demand Management ("CDM")

2.4.6.1 Lost Revenue Adjustment Mechanism Variance Account

ERHDC's claim for the year 2021 is $329,270 including carrying charges to May 1, 2021. Attached to this Exhibit is a live LRAMVA Workform. ERHDC is requesting disposition of the LRAMVA programs offered between 2011 and 2019, with persistence to April 30, 2021 in accordance with the recommendation in the most recent filing requirements (May 2020).

As provided in the Ontario Energy Board, 2020. *Filing Requirements for Electricity Distribution Rate Applications - 2020 Edition for 2021RateApplications*. Chapter 2 Cost of Service:

"Distributors should strive to dispose of all CFF-related LRAMVA balances as part of its 2021 rate application. The OEB will rely on the Participation and Cost Reports and detailed project level savings files as supporting documentation when assessing applications for lost revenues in relation to energy and demand savings from programs delivered under the CFF where final verified results from the IESO are not available."

LRAM persisting in 2011 and January to April 2012 for 2006 to 2010 programs was claimed in OEB rate case EB-2013-0127. ERHDC has not made a claim for LRAMVA since then.

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by rate class. The difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast. A copy of the IESO Participation and Cost Report for ERHDC as of April 15, 2019 fis included with this application in Excel format.

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. For most electricity distribution utilities in Ontario, including ERHDC, distribution rates are set for the period from 1 May to 30 April of the next year. CDM results are reported as first-year savings for programs by calendar year, so average rates for the calendar year need to be calculated. For simplicity, the average rate is estimated based on the rate being four-twelfths of the previous year's rate (for January through April), and eight-twelfths of the current year's rate (for May through December).

Because these revenues are lost throughout the year and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB and published on the Board's website. The carrying charges are simple interest, not compounded, and are calculated on the monthly lost revenue balance. Because the IESO final results estimates are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. Thus, 1/12 of the annual results are allocated to each month of the year. Carrying charges accrue from the time of the results, until disposition.

Details of the calculation of the LRAMVA balance are presented in the third party report prepared by IndEco Strategic Consulting Inc., *Espanola Regional Hydro Distribution Corporation 2011-20121 LRAMVA* attached as Appendix 4-K and in the OEB LRAMVA work form. A copy of the CDM Annual Report and Persistence Savings Report issued by the IESO as at April 15, 2019 is filed inexcel format.

Table 4-60 summarizes the LRAMVA amounts by customer class.

Table 4 - 60 : LRAMVA by Customer Class

Customer Class	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	$93,764	$3,421	$97,185
GS < 50 kW	$71,525	$5,495	$77,019
GS 50 to 4,999 kW	$46,194	$1,879	$48,073
Unmetered scattered load	-$312	-$20	-$332
Sentinel lighting	-$169	-$11	-$180
Street light service	$103,186	$4,317	$107,503
Total	$314,188	$15,082	$329,270

2.4.6.2 Disposition of the LRAMVA

ERHDC proposes to recover these amounts over five years. Table 4 - 61 below presents the proposed LRAMVA rate riders as calculated in the 2021 COS Rate Generation Model for ERHDC customers.

Table 4 - 61 : Proposed LRAMVA Rate Riders

Customer class	Billing determinant	LRAMVA amount	Proposed rate rider
Residential	kWh	$97,185	$0.0006
GS<50 kW	kWh	$77,019	$0.0015
GS 50 to 4,999 kW	kW	$48,073	$0.2493
Unmetered scattered load	kWh	-$332	-$0.0006
Sentinel lighting	kW	-$180	-$0.5328
Street lighting	kW	$107,503	$32.5767

Appendix 4 – A

Service Agreement and amending agreement with PUC Services

SERVICES AGREEMENT FIRST AMENDING AGREEMENT

This **SERVICES AGREEMENT FIRST AMENDING AGREEMENT** (the "**Agreement**") dated December 21, 2018, between **PUC SERVICES INC. ("ServiceCo")** and **ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION** (the "**Client**").

WHEREAS, ServiceCo and Client entered into a Services Agreement executed by ServiceCo on July 11, 2016 and by Client on June 21, 2016 (the "**Services Agreement**");

AND WHEREAS, each of Espanola Regional Hydro Holdings Corporation, The Corporation of the Town of Espanola ("**Espanola**") and The Corporation of the Township of Sables-Spanish Rivers ("**SSR**") are the owners of all of the issued and outstanding shares of the Client;

AND WHEREAS, Espanola, SSR, North Bay Acquisition (Espanola) Inc. (the "**Buyer**") and North Bay Hydro Holdings Inc. entered into a Securities Purchase Agreement dated October 12, 2018 (the "**SPA**"), wherein among other things, the Buyer agreed to purchase all of the issued and outstanding shares of Espanola Regional Hydro Holdings Corporation and the Client (the "**Proposed Transaction**");

AND WHEREAS, in connection with the Proposed Transaction contemplated pursuant to the SPA, ServiceCo and the Client (collectively, the "**Parties**") have agreed to enter into this Agreement to confirm and amend various provisions of the Services Agreement;

NOW THEREFORE for good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, the Parties agree as follows:

1 TERM

ServiceCo and the Client acknowledge that section 3 of the Services Agreement contained a typographical error requiring correction and ServiceCo and the Client wish to record and give effect to the original intention of ServiceCo and the Client hereby by deleting the reference to "May 31, 2020" and replacing it with "May 31, 2021".

2 TRANSITION PERIOD UPON CHANGE OF CONTROL

The Parties agree to automatically extend the term of the Services Agreement and continue the performance of the Services (as such term is defined in the Services Agreement) upon the completion of the Proposed Transaction (a "**Change of Control**") for a period of time commencing upon the completion of the term (as set forth in Section 1 above) and ending nine months thereafter (the "**Transition Period**") subject to the same terms and conditions (including pricing, subject to an escalation factor) set forth in the Services Agreement, as amended by this Agreement. For certainty and notwithstanding section 3 of the Services Agreement, no further automatic renewal of the term of the Services Agreement will occur after the expiration of the Transition Period.

Following completion of the Proposed Transaction the Parties shall work together in good faith to develop a detailed transition plan setting out each of the Parties' respective roles and responsibilities during the Transition Period. The objective of the transition plan shall be the implementation of a seamless transition of the performance of Services from ServiceCo to the Client or such other service provider as the Client may direct in order to minimize operational impacts to the Client. The Client shall pay the additional costs and expenses incurred by ServiceCo in connection with such transition activities; provided, however that ServiceCo receives the prior written consent of the Client (acting reasonably) to incur such additional costs and expenses in connection with such transition activities. Without limiting the generality of the foregoing, during the Transition Period ServiceCo shall provide all assistance reasonably requested by Client, including the following:

(a) transfer of all Client-owned tangible and intangible assets to Client;
(b) transfer of all Client related data and information to Client, including data conversion assistance, as applicable;
(c) knowledge transfer for the ongoing conduct of the Services, including all applicable procedures, standards and operating schedules applied by ServiceCo in the provision of the Services;
(d) reasonable access to the applicable data used by the ServiceCo to provide the Services; and
(e) such consents and assistance to transfer third party contracts used by ServiceCo in the provision of the Services and requested by Client for assignment.

3 CONFIRMATION

ServiceCo acknowledges and confirms that the Change of Control contemplated pursuant to the SPA is not subject to the provisions of Section 16.4 of the Services Agreement.

4 PROPOSED TRANSACTION NOT COMPLETED

The Client shall deliver a written notice to ServiceCo if the Proposed Transaction is not completed or terminated in accordance with the SPA no later than November 30, 2020 and, in such event, the provisions of Section 2 of this Agreement shall be inoperative and of no further force and effect.

5 GOVERNING LAW

This Agreement is a contract made under and shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable in the Province of Ontario.

6 BENEFIT OF THE AGREEMENT

This Agreement shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

7 FURTHER ASSURANCES

The Parties shall, with reasonable diligence, do all such things and provide all such reasonable assurances as may be required to effect the matters contemplated by this Agreement.

8 SEVERABILITY

If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof shall continue in full force and effect. To the extent permitted by applicable law, the parties hereby waive any provision of law that renders any provision hereof prohibited or unenforceable in any respect.

9 EXECUTION AND DELIVERY

This Agreement may be executed by the parties in counterparts and may be executed and delivered by email and all such counterparts or emails together constitute one and the same agreement.

[Remainder of page left intentionally blank. Execution page follows.]

Each of the Parties has executed and delivered this Amending Agreement as of the date noted at the beginning of this Amending Agreement.

PUC SERVICES INC.

By: ____________________
Name: Robert Brewer
Title: President & CEO

By: ____________________
Name:
Title:

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION

By: ____________________
Name: KELLY McLELLAN
Title: TREASURER, ERHDC

By: ____________________
Name:
Title:

Services Agreement

THIS AGREEMENT IS BETWEEN:

PUC SERVICES INC.

(Hereinafter referred to as "**ServiceCo**")

- And -

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION

(Hereinafter referred to as the "**Client**")

In consideration of the mutual covenants contained in this Agreement and the sum of ten dollars now paid by each party to the other, receipt of which is hereby acknowledged, the parties agree as follows:

ARTICLE 1 - Definitions and Interpretation

1. In this Agreement, unless otherwise expressly defined or the context otherwise requires:

   1.1. "Agreement" means this Services Agreement and the Schedule 'A'-Services, Schedule 'B'-Fees and Schedule 'C" – Proposal.

   1.2. "Confidential Information" means any oral, written or electronic data and information now or hereafter existing during the currency of this Agreement, relating to the business and management of either party which is treated by such party as confidential, to which access is granted or obtained by the other party, but does not include any data or information which was known to the recipient prior to the disclosure to it by the other party; or (ii) was independently developed by the recipient as evidenced by records; or (iii) is subsequently lawfully obtained by the recipient from a third party, without breach of this Agreement by the recipient; or (iv) becomes publicly available other than through a breach of this Agreement; or (v) is disclosed where the other party has provided its prior written consent to such disclosure by the recipient; or (vi) is disclosed by legal requirement.

   1.3. "Data" means all information in hard copy or in electronic form, which is used in the performance of Services under this Agreement.

   1.4. "Due Date" means thirty days after the date of the invoice.

   1.5. "Service" means a service as specified in the Services Schedule, which ServiceCo provides to Client under this Agreement.

   1.6. "Service Level" means a service level agreed in writing by the parties as applicable to a particular measurable component of a Service.

   1.7. "Services Schedule" the Schedule 'A'- Services, attached hereto which describes the Services to be provided by ServiceCo to Client and any additional terms and conditions relating specifically to such Services.

   1.8. "Services Agreement" means this agreement between ServiceCo and Client as may be amended from time to time as provided in this Agreement.

   1.9. "Software" means computer programs, regardless of format or medium, their documentation and specifications.

ARTICLE 2 - Interpretation

2. In this Agreement, unless otherwise expressly provided or as the context otherwise requires:

2.1. headings are solely for convenience of reference and are not intended to be complete or accurate descriptions of content or to be guides to interpretation of this Agreement or any part of it;

2.2. an accounting term not otherwise defined in this Agreement has the meaning assigned to it, and every calculation to be made under this Agreement is to be made, in accordance with accounting principles generally accepted in Canada applied on a consistent basis;

2.3. reference to currency means Canadian currency;

2.4. a reference to a statute includes all regulations made thereunder, all amendments to the statute or regulations in force from time to time, and every statute or regulation that supplements or supersedes such statute or regulations;

2.5. a reference to an entity includes any successor to that entity;

2.6. a word importing the masculine gender includes the feminine and neuter, a word in the singular includes the plural, a word importing a corporate entity includes an individual, and vice versa;

2.7. a reference to "approval", "authorization" or "consent" means written approval, authorization or consent;

2.8. if there is any conflict or inconsistency between the terms of this Services Agreement and the Services Schedule, the terms of the Services Schedule will prevail;

2.9. the word "including", when following a general statement or term, is not to be construed as limiting the general statement or term to any specific item or matter set forth or to similar items or matters, but rather as permitting the general statement or term to refer also to all other items or matters that could reasonably fall within its broadest possible scope; and

2.10. a reference to a Part or Article is to a Part or Article of this Agreement.

ARTICLE 3 - Term

3. This Agreement shall remain in full force and effect for a period of five years commencing on June 1, 2016 to May 31, 2020 subject to early termination as hereinafter provided. The Agreement includes for an option to extend it for an additional five year term, subject to negotiation between the parties and mutually agreeable terms and conditions. The term will automatically renew for one year extensions unless written notification is received by either party 90 days prior to the expiration date of the current term.

ARTICLE 4 - ServiceCo Responsibilities

4. In the performance of Services, ServiceCo agrees to:

4.1. perform the Services as described in the Services Schedule and otherwise in accordance with the terms of this Agreement and the policies and procedures in place by Client;

4.2. ensure that experienced and properly qualified personnel perform the Services by ServiceCo;

4.3. liaise with Client through Client's Board of Directors Chair or designate on matters of a material nature related to the Services Schedule and through the Financial Officer or designate on other Services and operations of Client;

4.4. notify Client, whenever practicable, if expenses beyond the charges set forth within the Services Schedule may be incurred together with any explanation therefor;

4.5. invoice Client according to the terms of the Services Schedule for the Services performed;

4.6. notify Client, as appropriate, of any planned or anticipated material changes to ServiceCo procedures in the provision of Services;

4.7. work cooperatively with Client and its customers as may be reasonable to facilitate the efficient provision of the Services;

4.8. perform the Services contemplated herein on terms not less favourable than those provided to its own customers;

4.9. observe and comply with any and all applicable government laws and regulations now or hereafter in force or effect;

4.10. observe Client's reasonable policies and procedures in relation to the performance of the Services such that Client's customers will not encounter any noticeable difference in the services formerly provided by Client and the Services now provided by ServiceCo in accordance with this Agreement; and

4.11. maintain adequate comprehensive general liability insurance showing Client as an additional insured.

ARTICLE 5 - Client's Responsibilities

5. Client agrees to:

5.1. provide all necessary Data or other required materials to ServiceCo on schedule or in a timely fashion to enable ServiceCo to provide the Services;

5.2. liaise with ServiceCo through Client's Financial Officer or designate for normal operations and/or the Board of Directors Chair or designate to make material decisions on behalf of Client in relation to the implementation of this Agreement and the Services and any changes thereto;

5.3. reasonably provide advance consent or direction for the release of Client's reports and other information by ServiceCo to any third party, as required in the performance of the Service;

5.4. restrict Client's employees and agents from interfering with, and from any unauthorized use of equipment which is owned by ServiceCo, in ServiceCo's possession, or under ServiceCo's control;

5.5. ensure the accuracy, legibility, and completeness of all Data supplied to ServiceCo and be responsible for the results obtained from Client's use of any of the Services;

5.6. provide information in addition to that specified in the Services Schedule as ServiceCo may reasonably require from time to time to perform the Service;

5.7. allow ServiceCo the sole responsibility and authority to make any and all decisions with respect to the day-to-day operations of Client as outlined in the Services Schedule;

5.8. authorize ServiceCo to make expenditures and enter into contracts for items as approved in the annual budget subject to agreed upon expenditure limits;

5.9. within a reasonable time period provide a decision on the acceptance or rejection of recommendations from ServiceCo pertaining to the operation of Client;

5.10. provide reasonable access to Client's computer hardware and software strictly for the purposes of correcting and repairing any problems with the equipment, hardware and/or software as they relate to this Agreement;

5.11. provide adequate office space, furnishings, computer, office equipment, supplies, and communication devices for ServiceCo to perform its obligations under the Agreement; and

5.12. perform any other activities as defined in the Services Schedule.

ARTICLE 6 - Data

6.1 All Data supplied by Client related to the performance of a Service remains Client's exclusive property. All supplied Data must be on media compatible with ServiceCo processing equipment and, where applicable, in the format which ServiceCo, acting reasonably, prescribes.

6.2 Client will arrange transportation of Data and reports between Client's location and ServiceCo's processing centre at its expense. Client may specify in writing an agent for the collection of Data and reports from ServiceCo's location and ServiceCo will use such service on Client's behalf. All risk of loss or damage during transportation (save and except for situations where ServiceCo is negligent or willfully reckless) will remain Client's responsibility.

6.3 If Client provides Software for use by ServiceCo in the provision of Services, Client warrants that:

6.3.1 Client has obtained any necessary permission, right and licence to enable the Software to be copied, modified and run by ServiceCo on equipment under ServiceCo's control without infringing any third party right;

6.3.2 in using the Software to furnish the Services, ServiceCo will not be infringing the rights of any third parties; and

6.3.3 the disclosure to ServiceCo or the use by ServiceCo of the Software will not involve a breach of any confidential or contractual relationship.

6.4 Client agrees to defend, indemnify and hold harmless ServiceCo against all losses, damages, costs, expenses and liabilities, including reasonable legal expenses, incurred in relation to such claim arising from any breach of the warranties stated under Article 6.3 above.

6.5 All Data, Software, methodology, know-how, ideas, techniques, concepts, information and processes supplied or developed by ServiceCo in the performance of a service remains ServiceCo's exclusive property.

ARTICLE 7 - Software

7.1. In the performance of Services, either party may provide Software to the other. Both parties agree to the following with respect to the handling of the other's Software:

7.1.1. not to modify the Software, except as permitted under the terms of this Agreement;

7.1.2. to copy the Software only as required for use on a processor under the control of either party;

7.1.3. to use the Software only as required for the applicable Service;

7.1.4. to confine the use of the Software to the employees or agents of either party who require it for the Services;

7.1.5. to maintain and disallow the removal of any proprietary or copyright notices; and

7.1.6. to return the Software to the other party promptly on the termination of the applicable Service Schedule and warrant in writing that all copies have been returned and removed from all computers on which they were installed and that no further use will be made of them.

7.2. ServiceCo may inspect any of Client's Software required in the performance of this Agreement and which requires access to system control program instructions, system libraries or other secure data. If reasonably required by Client from time to time, Client may inspect any of ServiceCo's Software used in relation to the performance of this Agreement.

ARTICLE 8 - Confidentiality

8.1 Each of the parties agrees:

8.1.1 to keep all Confidential Information of the other party to which access is or has been granted to or obtained in strictest confidence and not to disclose or permit disclosure of all or any portion of such Confidential Information to any person, firm, corporation, business or other entity, except as otherwise expressly permitted by this Agreement or with the prior written consent of the other party which consent may be unreasonably withheld;

8.1.2 to exercise a degree of care in protecting the confidentiality of the Confidential Information of the other party which is at least equivalent to that which the party uses to protect its own Confidential Information;

8.1.3 not to use all or any portion of the Confidential Information of the other party in any way which may be reasonably considered detrimental to the business operations of the other party;

8.1.4 not to reproduce any Confidential Information of the other party without the prior written consent of such party, which consent may be unreasonably withheld, except to make available the Confidential Information to such of its directors, officers, employees, agents and subcontractors who need to use the Confidential Information in the performance of Services and who have agreed to be bound by the terms of this Article; and

8.1.5 to provide access to the Confidential Information of the other party only to such of its directors, officers, agents and subcontractors with a need to use the Confidential Information in the performance of Services and who have agreed to be bound by the terms of this Article.

8.2 Notwithstanding anything to the contrary in this Agreement, ServiceCo will not be required to keep confidential, and may use or license without restriction, any ideas, concepts, know-how or techniques related to information processing which are developed by ServiceCo in the performance of services.

ARTICLE 9 - Patents and Copyrights

9.1 If a third party claims that any Software or a Service provided by either party (the "Providing Party") infringes a patent, copyright, trade secret or other intellectual property right, the Providing Party will defend, indemnify and hold harmless the other party (the "Indemnified Party") against all losses, damages, costs, expenses and liabilities, including reasonable legal expenses, incurred in relation to such claim. The Indemnified Party will promptly notify the Providing Party of any such claims and the Providing Party will have the right, in consultation with the Indemnified Party, to defend or settle such claim. The Indemnified Party may not settle or compromise any claim, action or proceeding in respect of which it may seek indemnification without the prior written consent of the Providing Party.

9.2 If such claim is made, the Providing Party may modify the Service delivered by it or the payments made by it as it determines necessary or advisable to address the claim, provided that any such modification will not result in a material deterioration in Services or security standards.

ARTICLE 10 – Fees and Charges

10.1 Fees and charges for ServiceCo's services will be specified in the Schedule 'A'-Services and Schedule 'B'-Fees. ServiceCo will, increase the charges specified in the Schedule 'B'-Fees table effective the first day of each contract year during the Term.

10.2 The services to be provided and the fees quoted reflect the applicable current legislated, regulatory requirements and guidelines specified by the Municipality, Federal and Ontario Provincial Government, by the Ontario Energy Board, and the Independent Electricity System Operator. If there should be a material change in the legislation, regulations or guidelines that affects the nature of the services provided, the fees shall be adjusted accordingly after agreement with Client.

10.3 Client will also be responsible to ServiceCo for its reasonable expenses associated with any additional services or incremental costs incurred by ServiceCo in providing the services caused by Client's failure to perform any of its obligations under this Agreement, where Client has been advised in writing of its failure to perform its obligations under this Agreement and has been given a reasonable opportunity to correct any deficiency.

ARTICLE 11 - Invoicing and Payment

11.1 Unless otherwise stated within the Service Schedule, ServiceCo will invoice Client in advance thirty days prior to the beginning of each month for charges for the Services to be provided in that forthcoming month. Payment of invoiced amounts will be due on the Due Date. Amounts remaining unpaid will bear interest from the Due Date at an annual rate that is the lesser of:

11.1.1 the rate of interest set forth on the applicable invoice; and

11.1.2 the rate that is five percentage points above the prime commercial annual lending rate of interest designated by the Royal Bank of Canada in effect in Canada from time to time for its most creditworthy commercial Clients on Canadian dollar loans.

11.1.3 Any other amount payable under this Agreement will bear interest at the rate set out above.

ARTICLE 12 - Taxes

12.1 Client will make timely payment of any taxes, duties or government levies related to this Agreement.

ARTICLE 13 - Warranty

13.1 ServiceCo represents and warrants that the service level provided by it under this agreement shall be as good as, or superior to those service levels generally enjoyed by ServiceCo's own customers and other utilities of a similar size within the Province of Ontario.

13.2 Except as expressly stated in this Article, ServiceCo makes no warranty, representation, condition or covenant of any kind, express or implied, oral or written, statutory or otherwise, including but not limited to, the implied warranties, representations, conditions or covenants of merchantable quality or fitness for a particular purpose or warranties arising from a course of dealing or usage of trade.

13.3 ServiceCo warrants that it will use reasonable skill and care in providing any Customer Services and that it will, at its expense:

13.3.1 make commercially reasonable attempts to correct any errors for which ServiceCo is directly and solely responsible by rerunning the Service, provided that the Data necessary to correct such errors is available to ServiceCo;

13.3.2 or at ServiceCo's option, provide a credit to Client equivalent to the charge that would have been applicable for correcting that portion of the Service that is in error, such credit will be only for errors due solely to malfunction of a system or Software provided by ServiceCo or any error made by ServiceCo's personnel in the performance of the Service; and

13.3.3 if ServiceCo provides hardware, Software or firmware as part of the Services, it will make commercially reasonable efforts to obtain assurances from the vendors of such hardware and Software that such hardware and Software is capable of processing date sensitive information.

13.4 To obtain the rerun Service or the credit, Client must notify ServiceCo in writing of such errors within thirty days of receipt of the Data or reports believed to contain the errors.

ARTICLE 14 - Indemnity

14.1 Client will indemnify and hold ServiceCo harmless, to the extent that Client is responsible, against any losses, claims, damages, judgments, liabilities or expenses (including reasonable legal fees and expenses) resulting from action taken or permitted to be taken by ServiceCo in good faith in reliance on instructions or orders received from Client arising in connection with ServiceCo's performance of its obligations under this Agreement. ServiceCo will be without liability to Client with respect to anything done or omitted to be done, in accordance with the terms of this Agreement or instructions properly received pursuant to this Agreement, if done in good faith and with reasonable skill and care and without willful or wanton misconduct on ServiceCo's part.

14.2 Subject to Article 14, ServiceCo will indemnify and hold Client, its officers, directors, employees and servants harmless, to the extent that ServiceCo is responsible, against any losses, claims, damages, judgments, liabilities or expenses (including reasonable legal fees and expenses) resulting from action taken or permitted to be taken by Client in good faith in reliance on instructions or orders received from ServiceCo arising in connection with Client's performance of its obligations under this Agreement. Client will be without liability to ServiceCo with respect to anything done or omitted to be done, in accordance with the terms of this Agreement or instructions properly received pursuant to this Agreement, if done in good faith and without negligence or willful or wanton misconduct on Client's part.

14.3 ServiceCo agrees to indemnify and save Client, its officers, directors, employees and servants, harmless from all damages, expenses or losses on account of the misuse, loss, theft or forgery of any documents or other Confidential Information.

ARTICLE 15 - Notices

15.1 Any notice or demand to be given by either party to the other under this Agreement will be in writing and may be delivered personally, by facsimile, e-mail or by first class prepaid mail to the following addresses:

If to ServiceCo:	PUC SERVICES INC. 500 Second Line East P.O. Box 9000 Sault Ste. Marie, Ontario P6A 6P2 Attention: Vice-President, Customer Engagement & Business Development
If to Client:	ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION 598 Second Avenue Espanola, Ontario P5E 1C4 Attention: Chair, Board of Directors

15.2 Notices delivered in person, by e-mail or by facsimile will be effective on the date of such delivery. Notices issued by mail will be effective on the third business day following the date that the envelope containing the notice is post-marked unless between the time of mailing and the time the notice is deemed effective there is an interruption in postal service, in which case, the notice will not be effective until actually received. In the event of a postal strike or lockout, notices or demands under this Agreement must be delivered personally, by e-mail or by facsimile.

ARTICLE 16 - Termination

16.1 In the event of a material breach, as defined herein, of the Agreement by a party (the "Defaulting Party"), the other party (the "Non-Defaulting Party") will have the right to give written notice to the Defaulting Party to remedy the breach within thirty days after the date of such notice (the "Notice"). The Defaulting Party will make all reasonable efforts to rectify the breach to the satisfaction of the Non-Defaulting Party at the earliest possible time. If the Defaulting Party fails to remedy the breach specified in the Notice to the satisfaction of the Non-Defaulting Party within thirty days after the date of the Notice, then the Non-Defaulting Party will have the right to terminate the Agreement on giving 30 days' notice to the Defaulting Party. If the Defaulting Party corrects the breach to the satisfaction of the Non-Defaulting Party within the time prescribed in the Notice, the notice of termination of the Agreement will be void.

16.2 In the event that the Agreement is terminated in accordance with 16.1 or 16.4, then:

16.2.1 ServiceCo. will cooperate fully with Client and act in good faith toward Client and its customers in order to allow for the smooth and orderly transition of the Services to Client or its nominee. In addition, ServiceCo will make reasonable efforts to continue the Services to the extent mutually agreed to by the parties at mutually agreed to prices; and

16.2.2 ServiceCo will return to Client, Client's Data and supplies.

16.3 For the purposes of this agreement material breach shall include without limitation failure by ServiceCo to perform any of its obligations stated in Article 4 of this Agreement to the standards contained herein.

16.4 If Client determines to sell its business and the purchaser is not prepared to accept an assignment of this Agreement or in the event of regulatory change which results in the frustration of this Agreement, Client shall have the option to terminate this Agreement at any time after one year on 60 days prior written notice to ServiceCo and upon payment of the following amounts as liquidated damages:

16.4.1 During years 2 and 3; 50% of the estimated annual cost set forth in the Services Schedule.

16.4.2 During years 4 and 5; 25% of the estimated annual cost set forth in the Services Schedule.

ARTICLE 17 - Mediation

17. In the event a dispute arises out of or in connection with this Agreement, including a dispute as to what constitutes a material breach for the purposes of Article 18 or in respect of any defined legal relationship associated with or derived from this Agreement, the parties will follow the step-by-step correction and resolution procedure set out below:

Step 1. The non-breaching party will advise the other party in writing of the alleged breach.

Step 2. The party allegedly in breach will investigate the allegation and provide a written report to the other party within five business days of receiving the notice alleging breach given under Step 1 to the effect that

(a) the investigation reveals that the alleged breach was not committed;

(b) the breach has been cured; or

(c) the breach remains uncured.

Step 3. If the party alleging the breach

(a) is not satisfied that the other party is not, or is no longer in breach; or

(b) wishes to pursue the dispute, then the party will immediately notify the other party in writing that it wishes to escalate the dispute to Step 4.

Step 4. Each party, will within two business days after receipt of the notice in Step 3, submit to the following people, or their delegates, a written report on the facts of the dispute, any relevant provisions of this Agreement and any other relevant information:

ServiceCo - Vice-President, Customer Engagement & Business Development
Client: - Chair, Board of Directors

Step 5. If the parties referred to in Step 4 cannot resolve the dispute through mediation, the dispute may be referred to arbitration in accordance with the arbitration provisions of this Agreement.

ARTICLE 18 - Arbitration

18. Except for applications for injunctions or restraining orders, any disputes arising out of or in connection with this Agreement or in respect of any defined legal relationship associated therewith or derived therefrom, including any failure of the parties to reach agreement will be referred to and finally resolved or

determined by arbitration under the Arbitrations Act (Ontario). In the event that this Agreement has been terminated in accordance with Article 14 above and an arbitrator under this article determines that a material breach did not exist, the arbitrator's jurisdiction shall be limited to the extent of awarding compensation for damages resulting from the failure to give proper notice of termination.

ARTICLE 19 - General

19.1 Neither party will be responsible for any failure to fulfill its respective obligations under this Agreement due to causes beyond its reasonable ability to control provided that the party affected by such cause has used and continues to use all reasonable efforts to perform its obligations and makes reasonable attempts to notify the other party in writing within five business days of its inability to fulfill its obligations under this Agreement. Regardless of the foregoing, ServiceCo will continue to provide all Services deemed by Client to be critical to its business, notwithstanding any strike by or labour dispute with ServiceCo's personnel.

19.2 Client and ServiceCo agree not to assign or transfer this Agreement or any of their respective rights or obligations under this Agreement, without the prior written consent of the other party, which such consent shall not be unreasonably or arbitrarily withheld, notwithstanding the foregoing in the event of a sale of its business Client shall have the right to assign this Agreement without the consent of ServiceCo provided that the Purchaser agrees to assume Client's obligations under this Agreement.

19.3 If either party becomes insolvent or bankrupt within the meaning of the *Bankruptcy and Insolvency Act* (Canada), the other party may, with notice in writing, immediately terminate this Agreement.

19.4 No changes to the terms and conditions of this Agreement will be effective unless specified in an amendment to the Agreement signed by both parties.

19.5 If any portion of this Agreement is found by a court of competent jurisdiction to be invalid, illegal or unenforceable, that portion will be severed from this Agreement and will not affect the validity, legality or enforceability of the remaining provisions of this Agreement and the remainder of the Agreement will continue in full force and effect.

19.6 Nothing contained herein and no actions taken in accordance with this Agreement shall constitute ServiceCo, or any of its officers, directors, employees, or servants as employees of Client and the parties agree that the nature of ServiceCo's relationship with Client is that of independent contractor.

19.7 Any waiver by either party of any obligation under this Agreement must be in writing and will not be deemed or constitute a waiver of that or any other provision (whether or not similar) nor will such waiver constitute a continuous waiver unless otherwise expressly provided.

19.8 On termination of this Agreement, all accrued obligations or liabilities and the provisions that by their nature are intended to endure beyond such termination will remain in effect including without limitation, obligations of confidentiality.

19.9 This Agreement will be binding on and inure to the benefit of both parties and their respective successors and permitted assigns.

19.10 This Agreement will be governed by the laws of the Province of Ontario and in the event that the parties are required to make application to court, the parties agree to be subject to the jurisdiction of the courts of the Province of Ontario.

19.11 Each party will execute and deliver such further and other agreements, documents and instruments and do such further acts and things as are within its power and as may be necessary or desirable to fully implement and carry out the intent of this Agreement.

ARTICLE 20 - Acceptance

20. Both parties, by authorized signatures below, agree that this Agreement is the complete agreement between the parties and replaces all prior communications, agreements and understandings related to the subject matter of this Agreement. There are no warranties, representations, conditions, covenants or other agreements between the parties in connection with the subject matter of this Agreement except those specifically set out herein. The execution of this Agreement has not been induced by, nor do either of the parties rely on or regard as material, any representations not included in this Agreement. No supplement, modification or waiver of this Agreement will be binding unless executed by the parties.

PUC SERVICES INC.

Per:____________________
Name: D. Parrella
Position: President & C.E.O.

Per:____________________
Name: K. D. Bell
Position: Vice President, Customer Engagement & Business Development

Date: 2016 - 07 - 12

We have the authority to bind the Corporation.

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION

Per:____________________
Name:
Position:

Per:____________________
Name:
Position:

Date: June 21, 2016

I/ We have the authority to bind the Corporation.

SCHEDULE 'A' - SERVICES

The intent of this agreement is to have ServiceCo undertake the oversight, management and control of the business for Client as well as providing identified regular ongoing utility functions, with the aim of providing a stable and reliable electricity distribution service to its customers at a reasonable cost through the provision of the services described below.

DESCRIPTION OF MANAGEMENT SERVICES

The following summary description is intended to set forth the various activities to be undertaken by ServiceCo on behalf of Client under provision of Management Services:

1. Board attendance in person on a quarterly basis or by conference call/video for those meetings not attended to in person.
2. Provision of management oversight and direction to Client's Supervisor, Line Operations.
3. Provision of human resource functions including the evaluation of staff performance, hiring, discharge, promotion, remuneration and planning for training.
4. Oversight, awareness and monitoring for the following requirements:
   - Ongoing operation of the utility including work planning,
   - Regulatory and legislative requirements,
   - Contract administration including labour negotiations and collective agreement as well as third party contracts,
   - Purchasing of capital and operational items,
   - Financial requirements including the review of monthly and annual financial statements, cash flow, regulatory reporting and statistical reporting.
5. Preparation of annual capital and OM&A budgets including a 5 year forecast.
6. Recommending policy to the Board and ensuring that approved policy is carried out.
7. Provision of monthly management reports.

DESCRIPTION OF CUSTOMER SERVICES

The following summary description is intended to set forth the various activities to be undertaken by ServiceCo on behalf of Client under provision of Customer Services:

1. Customer invoice preparation and mailing for both electricity and water consumption. This will include inputting consumption reads provided to ServiceCo by Client, data validation, invoice generation, reporting of hi/low readings, and billing adjustments. This does not include requirements which are the result of the provincial government smart meter initiative, integration with the IESO's MDM/R and implementation and MDMR administration of time-of-use billing.
2. Scheduling and arranging for hydro meter readings having regard to the current time or times that same are scheduled by Client.
3. Cash processing including inputting and processing payments to customer accounts.
4. Collections including monitoring account activity, notifying customers of past due accounts and advising Client of past due accounts as specified by Client policies.
5. Customer service activities including handling customer calls with respect to service, rates, consumption and billing, and issuing customer notifications as required by regulation. Calls not related to services covered by this Agreement will be redirected to Client.
6. Procedures and applications required to support billing requirements as of the date of this Agreement stipulated in the Standard Service Supply and Retail Settlement codes. This will include Electronic Business Transactions, Retail Settlement and MDMA – MV90 services.
7. Billing for unmetered electricity customers including sentinel lights and street lighting.
8. The cost per meter per month rate is to provide the above services for up to 3,700 meters for residential and general service customers.

9. Hosting of the Harris Customer Information System (CIS) and eCare software. This includes administration of software updates and program fixes as covered under the Harris Software Maintenance Agreement. Enhancements for requirements specific to Client and those that are the result of new legislative requirements will be billed at cost plus 10%. Direct software licence and maintenance fees payable by Client are subject to change in accordance with the price schedule from Harris.
10. Costs payable for Electronic Business Transaction (EBT) hub services for retail electricity customers is premised on fees payable to our EBT Service Provider. Current fees are $0.25 per customer and are subject to a minimum monthly charge of $150.00. Invoices will be billed at cost plus 15%. Fees payable by Client are subject to change in accordance with the price schedule from the EBT Service Provider.

CLIENT RESPONSIBILITIES

Client's permanent staff that is in place at the start of the Agreement will continue to perform their current duties. Any changes to Client's staffing levels will be agreed to by ServiceCo and Client.

1. Maintenance on software other than as provided in the Service Schedule.
2. Customization of any software to meet requirements specific to Client.
3. Setup, operations and any charges for communications service between Sault Ste. Marie and Espanola.
4. Any additional licensing fees (Unix, Terminal Server, GUI, etc.) Client will maintain an adequate service level with respect to the number of users.
5. Purchase of additional software that may be required to meet legislative and regulatory requirements.
6. Staff input to annual capital and OM&A budget.

ADDITIONAL SERVICES

The costs of the following services are not included in the estimated cost of services noted above:

- Cost-of-service study
- Rate applications
- Application of legislation, regulations and code changes
- Ongoing costs related to Smart Meter initiative and the IESO Smart Metering Entity (SME) contract requirements including AMI Network operations
- Engineering services including distribution system design
- Client obligations for IESO FIT Program
- Ontario Regulation 22/04 requirements and compliance
- Accounting services including payroll, account payable, inventory, miscellaneous billing
- Purchasing
- Training required to satisfy legislation and due diligence
- Implementation of International Financial Reporting Standards (IFRS)
- Conservation and Demand Management (CDM) Code requirements and compliance inclusive of the development of a CDM Strategy and achievement of OEB energy conservation targets.

These services will be performed as approved by Client as part of the budget process. The services may be performed by ServiceCo or a third party as approved by Client subject to clause 5.8 above or as otherwise approved by Client. ServiceCo agrees to cooperate and work with such third parties for the purposes of its performance under this agreement.

SCHEDULE 'B' – FEES

Price Table

Price (*)	Year 1	Year 2	Year 3	Year 4	Year 5
Management Services	$156,141.32	$160,044.86	$164,045.98	$167,326.90	$170,673.44
Customer Services	$5.26/ meter/month	$5.39/ meter/month	$5.53/ meter/month	$5.64/ meter/month	$5.75/ meter/month
IT Server Hosting Services	$7,500.00	$7,687.50	$7,879.69	$8,037.28	$8,198.03

Please Note: (*) Applicable taxes not included.

	June 1 2016: 2.75%	June 1 2017: 2.50%	June 1 2018: 2.50%	June 1 2019: 2.0%	June 1 2020: 2.0%

PUC SERVICES INC.
500 SECOND LINE EAST, P.O. Box 9000
SAULT STE. MARIE, ONTARIO, P6A 6P2

June 17, 2016 VIA Email: ron.duplessis@hotmail.com

Mr. Ron Duplessis, Chairman of the Board
Espanola Regional Hydro Distribution Corp.
598 Second Avenue
Espanola, Ontario
P5E 1C4

Dear Mr. Duplessis,

Re: Revised Management and Customer Services Proposal

Further to our conference call of June 13, 2016 please find attached the revised services proposal with the updated price table arising from our discussions. We anticipate getting the formal full form of agreement to you in the next few days as well and will make arrangements for ERH office staff to print for you for signatures and execution as required.

As previously noted in our letter of April 11, 2016, noting the request from the Board from the last Board of Directors meeting, PUC Services Inc. (PUC) is pleased to present this proposal for renewal and continuation of the services provided to Espanola Regional Hydro Distribution Corp. (ERHD) through the Management and Customer Services Agreements which are currently expiring at the end of May this year.

PUC is proposing combining the present two agreements, the Management Services Agreement and the (Customer) Services Agreement in to a combined single agreement. Our proposal reaffirms our commitment of service excellence to ERHD and adherence to the following principles:

- Adherence to an exemplary Health and Safety for all staff;
- Compliance with all applicable regulatory requirements;
- Effective and timely communication between all stakeholders; and
- Identification of opportunities for improved customer service through innovation and continuous improvement.

PUC and ERHD will keep this letter and proposal and their mutual interest in a proposed Agreement, including any negotiations between the parties in respect thereof, strictly confidential. Any press or news releases or other dissemination of information regarding this letter or the matters or transactions contemplated hereby by any of the parties hereto shall require the mutual review of and approval by the parties hereto prior to its release.

This letter and proposal shall remain in effect for a mutually agreeable period (the "Negotiation Period") during which time the parties shall negotiate in good faith to conclude the Agreement. During the Negotiation Period, ERHD shall negotiate exclusively with PUC.

This letter and proposal contains an outline of terms only and except for the provisions relating to confidentiality shall not be legally binding upon any party hereto. Each party hereto represents and warrants that it is duly authorized and has all necessary power and authority to execute and deliver this letter and to perform its obligations hereunder. It is expressly agreed and acknowledged that no other agreement or meeting of the minds has been reached. Accordingly, if for any reason whatsoever, the Agreement is not consummated, no party hereto shall be entitled to any form of relief whatsoever, including, without limitation, injunctive relief or damages. The provisions contained herewith with respect to confidentiality shall survive the termination of this letter and shall be legally binding upon and enforceable against the parties hereto and their successors and permitted assigns.

No party hereto may transfer or assign its rights or obligations hereunder without the prior written consent of the other parties hereto.

This letter may be signed in two or more counterparts, any one of which need not contain the signatures of more than one party. But all such counterparts taken together will constitute one and the same agreement shall be governed by the laws of the Province of Ontario.

We truly appreciate this opportunity to provide you with this proposal and look forward to assisting you in meeting the needs of your distribution utility.

Please indicate your consent and agreement to the foregoing by signing both copies of this letter in the space provided below and returning one fully executed copy to us, which return may be made by fax to (705) 759-6596 or e-mail at kevin.bell@ssmpuc.com.

Yours very truly,
PUC SERVICES INC.

Kevin D. Bell, P.Eng.
Vice President, Customer Engagement & Business Development

Attach: Management & Customer Services Proposal for Espanola Regional Hydro Distribution

Cc: Dominic Parrella, PUC Services
Terry Greco, PUC Services
Claudio Stefano, PUC Services

Agreed to and acknowledged this 21 day of JUNE, 2016.

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION

Per: ______________________	Per: ______________________
Mr. Ron Duplessis,	Name: Doug Bois
Chairman of the Board	Position: Director

SCHEDULE 'C' - PROPOSAL

Attach proposal

PUC SERVICES

PUC Services Inc.

Management & Customer Services Proposal for Espanola Regional Hydro Distribution

Version 1.3
June 13, 2016

Presented by:
K.D. Bell, P. Eng., V.P. Customer Engagement & Business Development

MANAGEMENT & CUSTOMER "SERVICES" PROPOSAL

Introduction

PUC Services operates, maintains and manages multiple utilities within Northern Ontario, headquartered in Sault Ste. Marie. Services offered include electric utility distribution, treatment and distribution of drinking water, treatment and collection of wastewater.

PUC Services is the successor company to the former Public Utilities Commission (better known as "the PUC") of the City of Sault Ste. Marie. All the former staff of the PUC are now employed by PUC Services. We have operated, maintained and managed the electrical distribution system for the City of Sault Ste. Marie since 1917.

PUC is committed to delivering high quality utility services in the communities we serve. As a municipally owned shareholder company we believe we understand and have in common, shared community and customer centric values with Espanola Regional Hydro Distribution (ERH). With the continued pace of change in the electric industry the success of small electrical distribution utilities is highly dependent on developing a network of service providers to help meet the demands of this business environment.

We understand your desire to provide superior services for your citizens, at an economical cost. We are committed to establishing and maintaining a quality working relationship based on open communication and understanding with all our clients.

Benefits of PUC Services Delivery

As Ontario LDC's started on the provincial deregulation path over 15 years ago, PUC Services was formed as an integrated water and electric utility services provider with a goal to expand our services offering to other utility and business owners. Our integrated utility model has allowed us to provide cost competitive service offerings in a market that is sometimes overly focused on the "bigger is better" solutions.

A key advantage to your community in awarding this contract to PUC Services is the extensive breadth and depth of knowledge and "hands-on" experience the Company is able to deploy to address any operational issues that may arise.

We believe we bring value added service by utilizing staff having a real working knowledge and solid understanding of all management, operational and customer service requirements and expectations in your industry. Management Services and operational oversight are provided through experienced and knowledgeable staff covering all aspects of an electrical distribution utility. Staff providing direct daily Customer Services are performing the same work for the SSM PUC Distribution utility area and are coached and developed to deliver service to all our clients and customers with the same quality and service expectations. We don't operate as just a billing centre or a call centre, we operate like an integrated utility to deliver all aspects of service with the same high quality standards.

Proposed Services

Description of Management Services

The following summary description is intended to set forth the various activities to be undertaken by PUC Services on behalf of ERH under provision of Management Services:

1. Board attendance in person on a quarterly basis or by a conference call/video for those meetings not attended to in person.

2. Management oversight and direction to ERH's management staff.

3. Provision of human resource functions including the evaluation of staff performance, hiring, discharge, promotion, remuneration and planning for training.

4. Oversight, awareness and monitoring for the following requirements:-
    - Ongoing operation of the utility including work planning,
    - Regulatory and legislative requirements,
    - Contract administration including labour negotiations and collective agreement as well as third party contracts,
    - Purchasing of capital and operational items,
    - Financial requirements including the review of monthly and annual financial statements, cash flow, regulatory reporting and statistical reporting.

5. Preparation of annual capital and OM&A budgets including a 5 year forecast.

6. Recommending policy to the Board and ensuring that approved policy is carried out.

7. Provision of monthly management reports.

Description of Customer Services

(Customer Care, Customer Billing, Customer Account Services, IT)

The following summary description is intended to set forth the various activities to be undertaken by PUC Services on behalf of ERH under provision of Customer Services:

1. Customer invoice preparation and mailing for both electricity and water consumption. This will include inputting consumption reads provided to PUC by ERH, data validation, invoice generation, reporting of hi/low readings, and billing adjustments. *This does not include requirements which are the result of the provincial government smart meter initiative, integration with the IESO's MDM/R and implementation and MDMR administration of time-of-use billing.*

2. Scheduling and arranging for hydro meter readings having regard to the current time or times that same are scheduled by ERH.

3. Cash processing including inputting and processing payments to customer accounts.

4. Collections including monitoring account activity, notifying customers of past due accounts and advising ERH of past due accounts as specified by ERH policies.

5. Customer service activities including handling customer calls with respect to service, rates, consumption and billing, and issuing customer notifications as required by regulation. Calls not related to services covered by this Agreement will be redirected to ERH.

6. Procedures and applications required to support billing requirements as of the date of this Agreement stipulated in the Standard Service Supply and Retail Settlement codes. This will include Electronic Business Transactions, Retail Settlement and MDMA – MV90 services.

7. Billing for unmetered electricity customers including sentinel lights and street lighting. The cost per meter per month rate in the Price Schedule is to provide the above services for up to 3,700 meters for residential and general service customers.

8. Hosting of the Harris Customer Information System (CIS) and eCare software. This includes administration of software updates and program fixes as covered under the Harris Software Maintenance Agreement. The cost per year as shown in the Price Schedule to be billed in equal monthly installments. *Enhancements for requirements specific to ERH and those that are the result of new legislative requirements will be billed at cost plus 10%. Direct software licence and maintenance fees are payable by ERH.*

9. Costs payable for Electronic Business Transaction (EBT) hub services for retail electricity customers is premised on fees payable to our EBT Service Provider. Current fees are $.25 per customer and are subject to a minimum monthly charge of $150.00. Invoices will be billed at cost plus 15%. Fees payable by ERH are subject to change in accordance with the price schedule from the EBT Service Provider.

Description of Additional Services

The following services are not included in the services noted above:

- Cost-of-service study
- Rate applications
- Application of legislation, regulations and code changes
- Ongoing costs related to Smart meter initiative and the IESO Smart Metering Entity (SME) contract requirements including AMI Network operations
- Engineering services including distribution system design
- ERH obligations for IESO FIT Program
- Ontario Regulation 22/04 requirements and compliance
- Accounting services including payroll, account payable, inventory, miscellaneous billing

- Purchasing
- Training required to satisfy legislation and due diligence
- Implementation of International Financial Reporting Standards (IFRS)
- Conservation and Demand Management (CDM) Code requirements and compliance inclusive of the development of a CDM Strategy and achievement of OEB energy conservation targets.

These services will be performed as approved by ERH as part of the budget process. The services may be performed by PUC or another third party as approved by ERH. PUC agrees to cooperate and work with such third parties for the purposes of its performance under the agreement.

Description of ERH Responsibilities

ERH permanent staff that is in place at the start of the Agreement will continue to perform their current duties. Any changes to ERH staffing levels will be agreed to by PUC and the ERH.

ERH will be responsible for the following:

1. All third party software maintenance fees.
2. Customization of any software to meet requirements specific to ERH.
3. Setup, operations and any charges for communications service between Sault Ste. Marie and Espanola.
4. Any additional licensing fees (Unix, Terminal Server, GUI, etc.) ERH will maintain an adequate service level with respect to the number of users.
5. Purchase of additional software that may be required to meet legislative and regulatory requirements.
6. Staff input to annual capital and OM&A budget

Price Schedule

Price (*)	Year 1	Year 2	Year 3	Year 4	Year 5
Management Services	$156,141.32	$160,044.86	$164,045.98	$167,326.90	$170,673.44
Customer Services	$5.26/ meter/mnth	$5.39/ meter/mnth	$5.53/ meter/mnth	$5.64/ meter/mnth	$5.75/ meter/mnth
IT Server Hosting Services(**)	$7,500.00	$7,687.50	$7,879.69	$8,037.28	$8,198.03

Please Note: (*) Applicable taxes not included.

	June 1 2016: 2.75%	June 1 2017: 2.50%	June 1 2018: 2.50%	June 1 2019: 2.0%	June 1 2020: 2.0%

June 1, 2015 Management Services current rate -- $12,663.53/month [$151,962.36 annual]
June 1, 2015 Customer Services current rate – $5.12/meter/month/month [3220 meters on last invoice]
June 1, 2015 IT CIS Hosting current rate – $1,664.58/month [$19,975.00 annual](**) Reduction reflects software maintenance fees payable by ERH in future while PUC will continue hosting for CIS. Additional server application also includes hosting for MDM/R, EBT and customer eCare.

Appendix 4 – B

BDR Report August 31, 2010

Recommendations on Support for Reasonableness of PUC Services Inc. Contract to Supply Services to Espanola Regional Hydro Distribution Corporation

Submitted to
Espanola Regional Hydro Distribution Corp.
August 31, 2010

BDR

BDR
34 King Street East
Suite 1000
Toronto, ON M5C 2X8
416-214-4848 phone
416-214-1643 fax

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1 PURPOSE OF THE REPORT

1.1 *Background*

Both PUC Services Inc. ("PUC Services") and Espanola Regional Hydro Distribution Corp. ("Espanola Hydro") wish to continue the current management services agreement. Since most necessary functions are handled by PUC Services, Espanola Hydro is able to function with only 4 full time staff on its payroll. Both PUC Services and Espanola Hydro believe that the arrangement meets the requirements of Espanola Hydro at a competitive cost to ratepayers, while providing a level of service (and particularly specialized expert services) that would not otherwise be available to so small an LDC at reasonable cost through self-service.

Any new agreement(s) will be subject to scrutiny as to the reasonableness of costs in Espanola's next cost of service review before the OEB.

This report sets out the results of the research and review carried out by BDR in order that Espanola Hydro can make an informed decision regarding the renewal of the management services contract with PUC Services Inc.

1.2 *Limitations*

BDR has made a review and gathered information as documented in this report, and believes on the basis of experience before regulators that these support the conclusions drawn. However the outcome of any regulatory process is always uncertain, being subject to the positions of other parties as put forward at the hearing and to the individual judgments of the panel members deciding the case. Furthermore, the present process in LDC rate approvals is that considerable elements of the revenue requirement may be determined through a negotiated settlement, settling the amounts involved without specific reference to a framework of regulatory principles.

Therefore in offering its best judgment in this matter, BDR can nevertheless provide no guarantee that following the advice in this report will result in a decision by the OEB approving Espanola Hydro's revenue requirement in full as requested in the application.

2 Methodology

The methodology of the study was as follows:

- Review the scope of services provided to Espanola Hydro, the history of the arrangement, and the history of any questions and issues raised and decided in regulatory process;
- Document the issues, considerations and qualitative advantages of the existing services arrangement;
- Review any existing precedents and comparable situations;
- Review published statistical comparators of costs for reasonableness; and
- Conduct discussion with OEB staff on a no-names basis to identify further issues.

3 Rate Application Issues

3.1 *Qualitative Advantages of the Service Agreements with PUC Services*

The following are the qualitative advantages to Espanola Hydro, its Board of Directors and customers, of the arrangement under which billing/customer services and management services are contracted out to PUC Services:

- The ability of PUC Services to provide regular and frequent on-site participation and interaction with the Board of Directors and employees provides the same genuine leadership that would be the case with an internal manager. The location of the service provider in geographic proximity to Espanola Hydro, plus the advantage of offering a supervisor permanently on site is a requirement in providing this benefit.
- The services are provided by a team, rather than an individual, so that professional expertise is available in all of the key management areas, just as it would be for a larger LDC.
- The long-term contract provides for continuity in dealing with issues, and the development of relationships between the management team and the employees.
- Both utilities use the same CIS software thereby avoiding disruption in having to switch to different billing software.
- Espanola Hydro can take advantage of the work that PUC Services is doing on behalf of its affiliate PUC Distribution Inc., to implement the smart meter programme, developing the smart grid, connecting renewable generation facilities and achieving OEB mandated CDM targets.
- Requirements for succession planning and the risks associated with replacement of an internal manager are reduced.

3.2 *2008 Rate Case – EB-2007-0901*

BDR examined Espanola Hydro's 2008 cost of service application, the interrogatories received from intervening parties, and the OEB's decision at that time. The 2008 rate case represented an opportunity for OEB staff and intervenors to express concerns about the arrangement, and for the hearing panel to include in its Decision and Order a requirement for review of alternative arrangements.

Only two interrogatories were found by BDR that deal directly with the provision of services by PUC Services: VECC Questions #4 and #12.

In Question #4, VECC requested to be provided with the specific services covered by the Management Services Agreement and the Billing/Customer Service Agreement, and the associated charges, and that information was provided.

In Question #12, VECC requested specific information as to the tendering process for each type of service purchased from PUC Services, how many parties submitted tenders for each type of services, and whether PUC Services was the lowest cost. The question was answered with the historic information leading to the management services agreement. It does not appear that Espanola Hydro responded directly to VECC's question as to specifically which services were tendered and what prices were obtained.

In the OEB's Decision dated June 3, 2008, reference is made to the contract with PUC Services, and it appears that only Board Staff took a position after filing of the interrogatory responses. The Decision states, at page 6:

> "Board staff questioned whether Espanola's new arrangements with PUC Services produce reasonable costs compared to the old arrangement it had with Espanola Regional Hydro Services Corporation. Espanola responded that the increased costs were not arising from the management services agreement with PUC Services, but from the incorrect allocation of costs in the 2004 year, which was used as a basis to set 2006 rates. Espanola argued that the service agreement with PUC Services had allowed it to contain its costs and reduce costs in some areas, while also managing increased regulatory requirements."

The OEB's findings in the matter are as follows:

> "The Board notes that the 2008 controllable OM&A forecast expense of $964,229 represents a 2.5% increase over 2007 levels and is 3% lower compared to 2006 actual. The Board accepts the Company's proposed controllable OM&A expense as reasonable. In so finding, the Board accepted

> the explanations given by Espanola with respect to the issues raised by intervenors and Board staff."

In accepting Espanola Hydro's OM&A costs for 2008, therefore, it is clear that the OEB looked only at the relative reasonableness of cost levels in comparison to the levels incurred by Espanola Hydro as a self-supplier of the services. There is no issue raised as to the appropriateness of the procurement process or of the supplier, and no direction was issued for investigation of alternative arrangements on expiration of the existing contract.

BDR therefore concludes that the reasonableness of year-over-year cost increases will be a major factor as to whether the OEB will accept the supply arrangement and costs in a future rate hearing.

3.3 *Requirement for Competitive Tendering*

The fact that Espanola Hydro is able to procure the services from a third party supplier (PUC Services), and that it once received an offer from an alternative supplier (Greater Sudbury Hydro) to provide the services, raised concerns that it would be considered by intervenors or the Board that a "reasonably competitive" market exists, and that perhaps a process of competitive tendering or obtaining quotes would be considered as necessary to support pricing.

BDR therefore approached OEB Staff, without naming the parties that were the source of the issue, and asked the following question:

> "Does Staff or the Board have any special concerns related to the procurement of services by one LDC from another LDC or its affiliate? Specifically, is it a requirement for an LDC seeking to procure services from another LDC or its affiliate to have tendered or alternatively obtained other price quotes, given that the transaction is arms length as regards these two parties."

The following answer was received by email:

> "If one LDC purchases services from another unrelated LDC or an affiliate of the unrelated LDC, then the requirements of the ARC ***would not apply***. In such cases, a distributor's costs would be subject to the normal prudency review that occurs during the distributor's rate setting hearing. In these cases the distributor must be able to demonstrate that its costs are reasonable. The ability to demonstrate that the LDC did research the marketplace for the best

> price either through tendering or obtaining quotes, would certainly be helpful and provide support for the distributor's position."[1],[2]

This answer confirms BDR's conclusions that only the normal prudency review as to costs would apply, and while research as to competitive levels of pricing would support Espanola Hydro's case, it would not be mandatory.

Should the question arise, the initial issue would be whether there is reason to conclude that a "reasonably competitive" market would exist for the services, and if so, whether that establishes a requirement to request competitive offers every five years. Two types of alternative supply exist: external services on the basis that PUC Services is now providing the service; and internal service—recruitment of a full-time manager, as was attempted in 2005 as an alternative to an external service provider.

"Reasonably Competitive Market" for External Services

Espanola Hydro sought proposals for management services in 2005, at the time that the decision was made to seek external services instead of self-supply, and received only one acceptable response.

While it is possible that one or more parties may be willing to provide Espanola with the services, the contracting out of a broad spectrum of management and administrative functions, including reporting directly to the Board of Directors, is not common enough to make such services a "commodity" (i.e. such that price would be the only, or at least a major, determinant of the desirability of one supplier's proposal over another). Key features in the selection for Espanola Hydro would include:

- ability to tailor the services to the needs of Espanola Hydro and its service territory, while providing synergies with the operations of a larger entity to reduce costs;
- ability to provide a team of staff specialized in the range of functions required (finance and accounting, information systems, human resources and labour relations, system planning and operations, budgeting, regulatory compliance, and team leadership); and
- ability to provide the services on site to the degree required to ensure diligent oversight and regular communication with employees, the Board of Directors, and the shareholders.

[1] Emphasis added by BDR.
[2] Paul Gasparatto, Regulatory Policy and Compliance, Policy Advisor

In considering alternative proposals, Espanola Hydro would clearly need to give strong preference to a supplier with verifiable successful experience in providing the services on a third-party basis. PUC Services has met these criteria for Espanola Hydro, and has provided fully satisfactory services for five years. From Espanola Hydro's point of view, PUC Services has the best client reference to support its proposal.

Furthermore, the potential negative consequences of a poor decision in such an important matter are too great to support change without a strong reason.

Even if an alternative supplier were able to offer the same high quality services as PUC Services, and even if a small savings in cost could be realized on the contract fees, there are costs associated with the transition. Some of these are quantifiable, and some, although not quantifiable, are nonetheless real.

Potential quantifiable transition costs include re-alignment of key program implementation (smart meters, CDM, smart grid, rate approvals and regulatory compliance, etc.), and changes to key systems. Systems changes in particular carry significant risks, as well as potentially significant costs.

Non-quantifiable transition issues include loss of continuity and "organizational memory", requirement to establish new relationships with Board of Directors and employees, and the learning curve associated with Espanola Hydro's unique community, distribution system, service territory and customers.

A change in management service provider would entail many of the same adjustment issues for Espanola Hydro as a merger or acquisition.

All of these reasons support Espanola Hydro's decision to maintain a relationship with its well-established and trusted service provider for a further five years, especially through this period of implementation of key government- and OEB-mandated change, as long as the quality of service is satisfactory and the cost is reasonable.

PUC Services has already proven its reliability in providing the required services. The following sections of this report address information that could be used to support the argument that the cost of the services is reasonable.

"Reasonably Competitive Market" for Internal Services

An option would be to once again post an internal management position for recruitment, to test whether a suitable candidate might now be available. Information as to the value of the compensation package necessary to attract such a person is available through an industry salary survey, and supports an estimate of $120,000 to $130,000.

In such case, continuation of the management services agreement with PUC Services would be supported if the price under the agreement compared relatively favourably with the estimated required compensation package of a qualified person, plus Espanola Hydro's estimate of the cost of additional consulting services provided. The terminology "reasonably favourably" is used here, because in BDR's view, it would not necessarily be required to show that Espanola Hydro has selected the very lowest cost option. Espanola Hydro has now had five years' experience with PUC Services as a provider of management services and has confidence in the quality of services. A change to a self-supply arrangement would subject Espanola Hydro to transitional issues, and to the risks that the services of the new manager and/or consultants would not be as satisfactory. There would also be significant costs associated with recruitment. With an internal employee, Espanola Hydro would also bear the risk that the employee would leave after some period of time, resulting in further transitional issues, delays in recruitment of a substitute, and recruitment costs. The arrangement with PUC Services, which is well staffed with qualified people, protects Espanola Hydro against these risks.

It is BDR's belief that on the basis of the industry compensation survey as stated above, a price for a full spectrum of management services of $150,000 or less would provide a favourable comparison with the compensation expectations of an employee over five years, including salary, benefits, and overheads, combined with recruitment costs and relocation costs for a person of suitable qualifications, assuming that one could be found and was willing to take the position. Supplementary contracting or consulting cost estimates would depend on the requirements for supplementation of the skills and level of effort of a specific individual.

The arrangement with PUC Services, if continued, also provides the qualitative benefits of internal services, such as consistency of reporting relationships and the familiarity with Espanola Hydro's operating conditions, distribution system, customer base and community that have developed over time.

3.4 *Comparative Cost Benchmarking as a Basis of Support for Reasonableness Cost*

In assessing this, BDR used available public source data from statistical summaries of LDC costs published by the OEB.

Table 2 was prepared by using historic year (2007)[3] statistics for administrative and general expenses and billing/collection expenses collected by the OEB and published in spreadsheet form at the OEB website.[4] In preparing Table 2, BDR sorted the LDCs by number of customers and extracted the number of customers and dollar figures for each type of OM&A expense for all Ontario LDCs with 6,000 or fewer customers (a size range reasonably comparable to Espanola Hydro). Each dollar value was divided by the number of customers to obtain 2007 amount of expense per customer. The mean and median values were computed and compared with the value for Espanola Hydro, for each of (a) Administrative and General Expense and (b) Billing and Collection Expense. The data for one LDC in the size range, West Perth Power, was deleted because the Administrative and General amounts did not appear reasonable.

As shown in Table 2, the cost of Administrative and General Expenses for Espanola Hydro are, at $89 per customer, considerably below the group average of $121 per customer, and also well below the median value of $107 per customer. For Billing and Collection Expenses, the annual cost per customer of $75 is very slightly above the mean of $70 and the median of $67, but well below the cost levels incurred by some of the other LDCs in the group.

[3] The OEB website was searched for comparable data for later years. The only data found was the 2008 Electricity Distribution Yearbook, published in 2009, which does not contain the same level of breakdown for operating, maintenance and administrative costs.
[4] Comparison_of_Distributors_with_2007_data.xls Source: www.oeb.gov.on.ca

Table 2 – Comparison of A&G and Billing/Collection Costs for LDCs with Fewer than 6,000 Customers, 2007 Data

		Total Expense		Expense Per Customer		
Distributor Data for Year ended Dec 31st, 2007	Number of Customers	Billing Expense	Administrative and General	Billing and Collection	Administrative and General	Total
Atikokan Hydro Inc.	1711	$ 151,553	$ 238,007	$ 89	$ 139	$ 228
Chapleau Public Utilities Corporation	1338	$ 60,149	$ 299,956	$ 45	$ 224	$ 269
Clinton Power Corporation	1639	$ 110,809	$ 291,575	$ 68	$ 178	$ 246
Cooperative Hydro Embrun Inc.	1882	$ 134,383	$ 201,266	$ 71	$ 107	$ 178
Eastern Ontario Power (CNP)	3552	$ 241,674	$ 604,945	$ 68	$ 170	$ 238
Espanola Regional Hydro Distribution Corporation	3316	$ 247,344	$ 296,547	**$ 75**	**$ 89**	**$ 164**
Fort Frances Power Corporation	3864	$ 232,614	$ 586,470	$ 60	$ 152	$ 212
Grand Valley Energy Inc.	677	$ 58,527	$ 118,172	$ 86	$ 175	$ 261
Hearst Power Distribution Company Limited	2772	$ 144,018	$ 226,755	$ 52	$ 82	$ 134
Hydro 2000 Inc.	1159	$ 77,332	$ 126,348	$ 67	$ 109	$ 176
Hydro Hawkesbury Inc.	5428	$ 226,736	$ 285,918	$ 42	$ 53	$ 94
Kenora Hydro Electric Corporation Ltd.	5642	$ 383,183	$ 595,620	$ 68	$ 106	$ 173
Newbury Power Inc.	199	$ 12,139	$ 34,888	$ 61	$ 175	$ 236
Parry Sound Power Corporation	3365	$ 347,089	$ 347,580	$ 103	$ 103	$ 206
Renfrew Hydro Inc.	4149	$ 276,955	$ 320,437	$ 67	$ 77	$ 144
Rideau St. Lawrence Distribution Inc.	5864	$ 354,643	$ 591,529	$ 60	$ 101	$ 161
Sioux Lookout Hydro Inc.	2754	$ 319,949	$ 251,469	$ 116	$ 91	$ 207
Wellington North Power Inc.	3486	$ 206,852	$ 371,224	$ 59	$ 106	$ 166
West Coast Huron Energy Inc.	3853	$ 334,234	$ 570,196	$ 87	$ 148	$ 235
West Nipissing Energy Services Ltd.	3284	$ 207,688	$ 104,436	$ 63	$ 32	$ 95
Mean				**$ 70**	**$ 121**	**$ 191**
Median				**$ 67**	**$ 107**	**$ 192**

The services provided in the Management Services agreement would for the most part be classified as Administrative and General ("A&G") expenses. A review of the Ontario small LDCs used in Table 2 revealed that the proportion which A&G expense (which cover the services provided under the management services agreement) represents of total OM&A varies from 21% to 59%. BDR therefore considered that in order to cover all aspects of reasonableness of the cost incurred, it was appropriate to look at total OM&A costs among a group of comparator LDCs. Use of the total OM&A statistic allows the addition of 2008 and 2009 data, which is the most recent published by the OEB at the date of this report.

Table 3 shows that the overall OM&A expenses for Espanola Hydro, including the contracted services from PUC Services, are very close to the average level for small LDCs in Ontario for 2007, 2008 and 2009.

Table 3 – Comparison of Total OM&A Costs for LDCs with Fewer than 6,000 Customers, 2007, 2008, and 2009 Data

	OM&A Per Customer		
	2007	2008	2009
Atikokan Hydro Inc.	$ 438	$504	$535
Chapleau Public Utilities Corporation	$ 459	$442	$377
Clinton Power Corporation	$ 331	--	$332
Cooperative Hydro Embrun Inc.	$ 206	$209	$212
Eastern Ontario Power (CNP)	$ 352	$335	--
Espanola Regional Hydro Distribution Corporation	**$ 286**	**$300**	**$334**
Fort Frances Power Corporation	$ 285	$313	$353
Grand Valley Energy Inc.	$ 311	$313	--
Hearst Power Distribution Company Limited	$ 237	$252	$306
Hydro 2000 Inc.	$ 189	$207	$227
Hydro Hawkesbury Inc.	$ 137	$148	$147
Kenora Hydro Electric Corporation Ltd.	$ 240	$293	$307
Newbury Power Inc.	$ 299	--	--
Parry Sound Power Corporation	$ 303	$362	$369
Renfrew Hydro Inc.	$ 226	$251	$247
Rideau St. Lawrence Distribution Inc.	$ 226	$253	$280
Sioux Lookout Hydro Inc.	$ 362	$420	$526
Wellington North Power Inc.	$ 276	$336	$323
West Coast Huron Energy Inc.	$ 297	$335	$381
West Nipissing Energy Services Ltd.	$ 154	--	--
Mean	**$ 281**	**$ 310**	**$ 329**
Median	**$ 286**	**$ 313**	**$ 328**

BDR also considered the work done by Pacific Economics Group LLC ("PEG") in establishing a benchmarking approach for the Ontario LDCs[5]. PEG's work primarily relied on cost data for the years 2002-2006 and averaged that data in comparing and

[5] Benchmarking the Costs of Ontario Power Distributors, Pacific Economics Group, 20 March, 2008 (hereafter cited as the "PEG Report").

ranking LDCs. Since the PUC Services management agreement commenced in 2006, the specific ranking of Espanola Hydro done by PEG is not directly relevant in an assessment of whether the costs of the PUC Services agreement are reasonable.

However we can use PEG's work in another way. PEG grouped the LDCs into peer groups based on similarity of operating conditions outside the short-term control of management (number of customers, rate of customer growth, degree of system undergrounding, and location on the Canadian Shield). Espanola Hydro's peer group was designated as "Small Northern Low Undergrounding". Based on the historic years, Espanola was ranked third best in productivity in a group of eleven. For the current analysis, one LDC, Terrace Bay, is not included because that LDC has since ceased to operate independently.

The PEG report therefore results in selection of a smaller and slightly different comparator group than simply choosing all LDCs across the province with a small number of customers.

Table 4 sets out the comparison using 2007 data for billing/collection and A&G expenses, and 2007, 2008 and 2009 data for total OM&A expenses.

Table 4 – Comparison of Total OM&A Costs for 2007, 2008 and 2009, and Billing/Collection and A&G Costs for 2007 Only, for Espanola Hydro's Peer Group of LDCs as Defined by PEG

	Expense Per Customer, 2007					2008	2009
	Billing and Collection	Operation	Maintenance	Admin and General	Total	Total OM&A Per Customer	Total OM&A Per Customer
Atikokan Hydro Inc.	$ 89	$ 168	$ 42	$ 139	$ 438	$ 504	$ 535
Chapleau Public Utilities Corporation	$ 45	$ 190	$ -	$ 224	$ 459	$ 442	$ 377
Espanola Regional Hydro Distribution Corporation	**$ 75**	**$ 83**	**$ 39**	**$ 89**	**$ 286**	**$ 300**	**$ 334**
Fort Frances Power Corporation	$ 60	$ 43	$ 29	$ 152	$ 285	$ 313	$ 353
Great Lakes Power Limited/Algoma Power	$ 90	$ 129	$ 292	$ 173	$ 684	$ 736	$ 1,777
Northern Ontario Wires Inc.	$ 93	$ 54	$ 28	$ 117	$ 292	$ 321	$ 335
Parry Sound Power Corporation	$ 103	$ 19	$ 78	$ 103	$ 303	$ 362	$ 369
Renfrew Hydro Inc.	$ 67	$ 55	$ 27	$ 77	$ 226	$ 251	$ 247
Sioux Lookout Hydro Inc.	$ 116	$ 132	$ 23	$ 91	$ 362	$ 420	$ 526
West Nipissing Energy Services Ltd.	$ 63	$ 39	$ 20	$ 32	$ 154	--	--
Espanola Rank	**5**	**6**	**5**	**3**	**4**	**2**	**2**
Mean	**$ 80**	**$ 91**	**$ 58**	**$ 120**	**$ 349**	**$ 405**	**$ 539**
Median	**$ 82**	**$ 69**	**$ 29**	**$ 110**	**$ 297**	**$ 362**	**$ 369**

The comparison implies that Espanola Hydro's cost levels for administrative and general functions and for billing and collection functions, and for total OM&A are reasonable by comparison with a peer group of similarly situated LDCs.

Appendix 4 – C

Chapter 2 Appendices 2-JA

Appendix 2-JA

Summary of Recoverable OM&A Expenses

	2012 Last Rebasing Year OEB Approved	2012 Last Rebasing Year Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Reporting Basis											
Operations	$ 249,346						$ 300,622	$ 374,022	$ 428,161	$ 388,361	$ 401,109
Maintenance	$ 397,158						$ 285,287	$ 267,091	$ 291,771	$ 334,884	$ 333,727
SubTotal	**$ 646,504**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 585,908**	**$ 641,113**	**$ 719,932**	**$ 723,245**	**$ 734,837**
%Change (year over year)		-100.0%						9.4%	12.3%	0.5%	1.6%
%Change (Test Year vs Last Rebasing Year - Actual)											
Billing and Collecting	$ 371,722						$ 436,238	$ 429,999	$ 452,917	$ 421,987	$ 428,448
Community Relations	$ 1,000						$ -	$ -	$ -	$ -	$ -
Administrative and General	$ 338,898						$ 377,398	$ 339,127	$ 496,779	$ 385,124	$ 490,146
SubTotal	**$ 711,620**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 813,636**	**$ 769,127**	**$ 949,696**	**$ 807,111**	**$ 918,594**
%Change (year over year)		-100.0%						-5.5%	23.5%	-15.0%	13.8%
%Change (Test Year vs Last Rebasing Year - Actual)											
Total	**$ 1,358,124**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,530,356**	**$ 1,653,431**
%Change (year over year)		-100.0%						0.8%	18.4%	-8.3%	8.0%

	2012 Last Rebasing Year OEB Approved	2012 Last Rebasing Year Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Operations	$ 249,346	$ -	$ -	$ -	$ -	$ -	$ 300,622	$ 374,022	$ 428,161	$ 388,361	$ 401,109
Maintenance	$ 397,158	$ -	$ -	$ -	$ -	$ -	$ 285,287	$ 267,091	$ 291,771	$ 334,884	$ 333,727
Billing and Collecting	$ 371,722	$ -	$ -	$ -	$ -	$ -	$ 436,238	$ 429,999	$ 452,917	$ 421,987	$ 428,448
Community Relations	$ 1,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Administrative and General	$ 338,898	$ -	$ -	$ -	$ -	$ -	$ 377,398	$ 339,127	$ 496,779	$ 385,124	$ 490,146
Total	**$ 1,358,124**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,530,356**	**$ 1,653,431**
%Change (year over year)		-100.0%						0.8%	18.4%	-8.3%	8.0%

	Last Rebasing Year 2012 OEB Approved	Last Rebasing Year 2012 Actuals	Variance 2012 OEB Approved - 2012 Actuals	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	Variance 2020 Bridge vs. 2019 Actuals	2021 Test Year	Variance 2021 Test vs. 2020 Bridge
Operations	**$ 249,346**	**$ -**	**$ 249,346**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 300,622**	**$ 374,022**	**$ 428,161**	**$ 388,361**	**-$ 39,800**	**$ 401,109**	**$ 12,748**
Maintenance	**$ 397,158**	**$ -**	**$ 397,158**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 285,287**	**$ 267,091**	**$ 291,771**	**$ 334,884**	**$ 43,114**	**$ 333,727**	**-$ 1,157**
Billing and Collecting	**$ 371,722**	**$ -**	**$ 371,722**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 436,238**	**$ 429,999**	**$ 452,917**	**$ 421,987**	**-$ 30,929**	**$ 428,448**	**$ 6,461**
Community Relations	**$ 1,000**	**$ -**	**$ 1,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Administrative and General	**$ 338,898**	**$ -**	**$ 338,898**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 377,398**	**$ 339,127**	**$ 496,779**	**$ 385,124**	**-$ 111,655**	**$ 490,146**	**$ 105,023**
Total OM&A Expenses	**$ 1,358,124**	**$ -**	**$ 1,358,124**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,530,356**	**-$ 139,271**	**$ 1,653,431**	**$ 123,074**
Adjustments for Total non-recoverable items[3]														
Total Recoverable OM&A Expenses	**$ 1,358,124**	**$ -**	**$ 1,358,124**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,399,544**	**$ 1,410,240**	**$ 1,669,628**	**$ 1,530,356**	**-$ 139,271**	**$ 1,653,431**	**$ 123,074**
Variance from previous year				$ -	$ -	$ -	$ -	$ 1,399,544	$ 10,696	$ 259,388	-$ 139,271		$ 123,074	
Percent change (year over year)									1%	18%	-8%		8%	
Percent Change: Test year vs. Most Current Actual													-0.97%	
Simple average of % variance for all years													4.71%	
Compound Annual Growth Rate for all years														#DIV/0!
Compound Growth Rate (2019 vs. 2012 Actuals)													#DIV/0!	

Appendix 4 – D

Chapter 2 Appendies 2-JB

Appendix 2-JB
Recoverable OM&A Cost Driver Table[1,3]

OM&A	Last Rebasing Year (2012 Actuals)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Reporting Basis						
Opening Balance²	$ 1,358,127	$ 1,384,120	$ 1,399,544	$ 1,410,239	$ 1,669,627	$ 1,530,357
Regulatory (5655)		$ 37,717	-$ 77,188	$ 12,141		$ 99,598
Metering (5065) Labour				$ 22,469		
Line Clearing (5135) Expense		-$ 14,201		$ 63,850		
Line Clearing (5135) Labour				-$ 21,010		
O/H Lines Lab (5020)				$ 17,686		
O/H Lines Trucking (5020)		$ 15,931	$ 9,657			
O/H Lines Material (5025)		-$ 13,599		$ 23,896		
5005 PUC Supervision		$ 15,503				
5105 PUC Supervision				-$ 19,178		
5016 Sub 1 & 3 Labour			$ 7,885			
5035 O/H transformer labour			$ 8,299			
5040 U/G lines labour			$ 11,837	-$ 19,178		
5045 U/G lines expense			$ 14,126			
5055 U/G transformers labour			$ 9,307			
5070 Customer Premise Labour			$ 8,255			
5125 O/H Conductor Labour		-$ 46,818			$ 23,634	
5130 O/H Services Labour			$ 8,763			
5320 Collecting Labour, S/W, coll agency		$ 16,124	$ 12,578			
5335 Bad Debts		$ 17,435	-$ 27,595	$ 27,395	-$ 35,188	
5610 Management Salaries				$ 11,113		
5615 Admin Labour			$ 9,804	$ 35,204	-$ 22,901	
5630 PUC Supervision				$ 23,854	-$ 12,504	
5630 Audit		-$ 15,751		$ 73,863	-$ 67,616	
5645 Pension			$ 9,573		-$ 20,152	
Misc 2013 to 2016	$ 25,993					
Misc		$ 3,083	$ 5,393	$ 7,283	-$ 4,543	$ 23,476
Closing Balance²	$ 1,384,120	$ 1,399,544	$ 1,410,239	$ 1,669,627	$ 1,530,357	$ 1,653,431

Appendix 4 – E

Chapter 2 Appendices – 2-L

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year 2012 - OEB Approved	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs						
O&M	$ 646,504	$ 585,908	$ 641,113	$ 719,932	$ 723,245	$ 734,837
Admin Expenses	$ 711,620	$ 813,636	$ 769,127	$ 949,696	$ 807,111	$ 918,594
Total Recoverable OM&A from Appendix 2-JB [5]	$ 1,358,124	$ 1,399,544	$ 1,410,240	$ 1,669,628	$ 1,530,356	$ 1,653,431
Number of Customers [2,4]	3,359	3,336	3,351	3,357	3,357	3,357
Number of FTEs [3,4]	5.40	7.00	6.67	7.00	7.07	7.31
Customers/FTEs	622	477	502	480	475	459
OM&A cost per customer						
O&M per customer	$192	$176	$191	$214	$215	$219
Admin per customer	$212	$244	$230	$283	$240	$274
Total OM&A per customer	$404	$420	$421	$497	$456	$493
OM&A cost per FTE						
O&M per FTE	$119,723	$83,701	$96,119	$102,847	$102,298	$100,525
Admin per FTE	$131,781	$116,234	$115,311	$135,671	$114,160	$125,663
Total OM&A per FTE	$251,504	$199,935	$211,430	$238,518	$216,458	$226,188

Appendix 4 – F

Chapter 2 Appendicies – 2-JC

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2012 OEB-Approved)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year	Variance (Test Year vs. 2019 Actuals)	Variance (Test Year vs. Last Rebasing Year (2012 OEB-
Reporting Basis								
Programs with Variances > Materiality								
5135 Right of Way								
Labour	$45,419	$13,182	$42,994	$21,984	$28,754	$32,431	10,447	-12,988
Expenses	$126,500	$47,566	$2,997	$66,847	$59,056	$48,260	-18,587	-78,240
Trucking	$14,083	$1,457	$5,931	$2,695	$4,198	$4,261	1,566	-9,822
Sub-Total 5135	$186,001	$62,206	$51,922	$91,525	$92,008	$84,951	-$6,575	-$101,051
5615 General Admin Salaries								
Labour	$0	$35,287	$45,092	$80,295	$57,394	$58,398	-21,897	58,398
Expenses	$0	$0	$0	$0	$0	$0	0	0
Sub-Total 5615	$0	$35,287	$45,092	$80,295	$57,394	$58,398	-$21,897	$58,398
5630 Outside Services								
Audit	$35,000	$27,000	$29,253	$103,116	$35,500	$36,033	-$67,084	1,033
Consultant	$2,200	$44	$0	$0	$0	$0	$0	-2,200
Legal	$2,000	$26	$0	$216	$250	$254	$38	-1,746
Negotiations	$1,000	$0	$0	$200	$0	$0	-$200	-1,000
Management, Billing, Collection Contr	$37,742	$28,563	$32,662	$56,517	$44,013	$44,673	-$11,844	6,930
Study Projects			$1,078	$0	$0	$0	$0	0
Sub-Total 5630	$77,942	$55,633	$62,993	$160,049	$79,763	$80,959	-$79,090	$3,017
5655 Regulatory Expenses								
OEB Annual	$8,500	$15,167	$14,006	$14,083	$15,000	$15,415	1,332	6,915
CoS Consulting (BLG, PUC)	$24,375	$18,532		$2,379	$16,000	$87,508	85,129	63,133
Customer Satisfaction Survey		$21,450	$850	$12,000		$12,000	0	12,000
Safety Survey					$12,000			
Training	$1,700			$1,454	$1,500		-1,454	-1,700
Cost Assessments	$425	$384	$299	$413	$500	$675	262	250
CoS Distribution System Plan		$37,650				$13,000		
CoS CDM Consultant						$2,000		
CoS Intervenor Costs						$10,000		
CoS OEB Costs						$4,000		
Software			$840					
Miscellaneous								
Sub-Total 5655	$35,000	$93,183	$15,995	$30,329	$45,000	$144,598	$114,269	$109,598
Programs with Variances < Materiality								
5005 Operations Supervision	$28,199	$67,085	$72,015	$74,847	$68,063	$69,084	-5,763	40,884
5012 Station Buildings	$20,896	$2,792	$2,712	$499	$1,443	$1,467	968	-19,429
5016 Station Equipment - Labour	$8,716	$4,798	$12,683	$7,398	$8,285	$8,428	1,029	-288
5017 Station Equipment - Expenses	$20,100	$20,215	$21,535	$20,048	$19,152	$19,440	-608	-660
5020 O/H Lines Labour	$38,128	$53,407	$63,064	$85,118	$65,856	$66,999	-18,119	28,871
5025 O/H Lines Expenses	$25,750	$45,664	$42,520	$66,416	$59,348	$60,239	-6,178	34,489
5035 O/H Distribution Transformers	$11,657	$10,546	$18,845	$18,675	$18,821	$22,386	3,712	10,729
5040 U/G Lines Labour	$10,969	$29,427	$41,263	$23,334	$28,608	$29,105	5,772	18,136
5045U/g Lines Expenses	$19,000	$9,695	$23,822	$15,624	$15,522	$15,755	131	-3,245
5055 U/G Distributions Transformers	$7,584	$2,188	$11,495	$3,236	$6,847	$10,213	6,977	2,629
5065 Meter Expense	$3,357	$2,160	$6,105	$32,296	$18,638	$18,955	-13,341	15,598
5070 Customer Premise Labour	$12,959	$26,420	$34,674	$37,798	$32,301	$32,860	-4,938	19,901
5075 Customer Premise Expenses	$7,000	$1,589	$1,323	$3,036	$1,578	$1,602	-1,434	-5,398
5085 Misc. Distribution Expenses	$21,631	$10,080	$7,309	$18,421	$22,272	$22,626	4,205	995
5095 O/H Lines - Rental	$13,400	$14,556	$14,658	$21,416	$21,627	$21,951	535	8,551
5105 Maintenance Supervision	$28,199	$71,096	$71,465	$55,280	$64,440	$65,407	10,127	37,208
5110 Maintenance Station Buildings	$35,332	$8,677	$7,368	$14,839	$9,743	$9,912	-4,927	-25,420
5114 Distribution Station Equipment	$9,566	$12,961	$3,263	$2,871	$5,016	$5,097	2,226	-4,469
5120 Maint. Poles/Towers/Fixtures	$18,355	$24,713	$14,127	$16,596	$32,907	$33,406	16,810	15,051
5125 Maint. O/H Conductors	$27,929	$44,197	$47,908	$44,141	$67,774	$68,935	24,794	41,006
5130 Maint. O/H Services	$51,899	$50,210	$58,973	$52,560	$51,261	$52,136	-425	237
5145 Maint. U/G Conduit	$11,473	$0	$0	$1,346	$582	$2,543	1,197	-8,929
5150 Maint. U/G Conductors	$10,162	$2,977	$8,995	$3,905	$5,217	$5,306	1,401	-4,856
5155 Maint. U?G Services	$584	$1,209	$598	$912	$408	$416	-497	-168
5160 Maint. Line Transformers	$16,234	$3,835	$2,306	$4,809	$3,496	$3,555	-1,254	-12,679
5175 Maint. Meters	$1,425	$3,205	$165	$2,986	$2,031	$2,064	-921	639
5310 Meter Reading Expenses	$100,327	$65,821	$70,654	$73,580	$74,105	$75,220	1,640	-25,107
5315 Customer Billing	$175,668	$183,806	$187,750	$186,966	$200,118	$203,144	16,179	27,476
5320 Collecting	$87,727	$128,224	$140,802	$134,184	$124,764	$126,739	-7,445	39,012
5335 Bad Debt Expense	$8,000	$58,387	$30,792	$58,188	$23,000	$23,345	-34,843	15,345
5410 Community Relations	$1,000	$0	$0	$0	$0	$0	0	-1,000
5605 Executive Salaries & Expenses	$19,200	$18,540	$18,540	$15,405	$14,000	$14,210	-1,195	-4,990
5610 Management Salaries	$98,958	$70,935	$75,133	$86,037	$76,213	$77,535	-8,502	-21,423
5620 Office Supplies	$66,998	$74,115	$79,530	$81,227	$77,955	$79,124	-2,103	12,126
5635 Property Insurance	$5,600	$5,815	$5,928	$8,550	$16,000	$16,240	7,690	10,640
5640 Injuries & Damages	$5,000	$10,059	$10,728	$8,088	$12,000	$12,180	4,092	7,180
5645 Employee Pension & Benefits	$20,000	$9,088	$18,661	$22,652	$2,500	$2,538	-20,114	-17,463
5660 General Advertising	$600	$572	$300	$11	$0	$0	-11	-600
5665 Misc. General	$6,800	$1,154	$1,136	$1,212	$1,300	$1,320	108	-5,481
5680 ESA	$2,800	$3,017	$5,090	$2,926	$3,000	$3,045	119	245
Sub-Total Miscellaneous	$1,059,180	$1,153,235	$1,234,238	$1,307,430	$1,256,192	$1,284,525	-$22,905	$225,344
Total	**$1,358,124**	**$1,399,544**	**$1,410,240**	**$1,669,628**	**$1,530,356**	**$1,653,431**	**-$16,197**	**$295,307**

Appendix 4 – G

Chapter 2 Appendicies – 2-K

Appendix 2-K
Employee Costs

	Last Rebasing Year (2012 OEB Approved)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
****						
Management (including executive)						
Non-Management (union and non-union)	5.42	7.00	6.67	7.00	7.07	7.31
Total	5.42	7.00	6.67	7.00	7.07	7.31
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)						
Non-Management (union and non-union)	$ 380,771	$ 625,466	$ 600,085	$ 624,367	$ 561,748	$ 571,579
Total	$ 380,771	$ 625,466	$ 600,085	$ 624,367	$ 561,748	$ 571,579
Total Benefits (Current + Accrued)						
Management (including executive)						
Non-Management (union and non-union)	$ 183,948	$ 277,222	$ 208,767	$ 253,584	$ 255,182	$ 259,648
Total	$ 183,948	$ 277,222	$ 208,767	$ 253,584	$ 255,182	$ 259,648
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ -	$ -	$ -	$ -	$ -	$ -
Non-Management (union and non-union)	$ 564,719	$ 902,688	$ 808,852	$ 877,951	$ 816,930	$ 831,227
Total	$ 564,719	$ 902,688	$ 808,852	$ 877,951	$ 816,930	$ 831,227

Appendix 4 – H

Espanola 2019 Actuarial Report

Espanola Regional Hydro Distribution Corporation

Estimated Benefit Expense (IAS 19)

FINAL

	Jan 1 - Sep 30 2019	Projected * Oct 1 - Dec 31 2019
Discount Rate at the Beginning of the Period	4.00%	3.00%
Discount Rate at the End of the Period	3.00%	3.00%
Health Benefit Cost Trend Rate	4.00%	4.00%
Dental Benefit Cost Trend Rate	4.30%	4.30%
Long Term Health and Dental Benefit Cost Trend Rate	4.00%	4.00%
First Year Of Long Term Health and Dental Benefit Cost Trend Rate	2040	2040
Salary Scale Rate	2.50%	2.50%
Assumed Increase in Employer Contributions	expected **	expected **

A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet

	Jan 1 - Sep 30 2019	Oct 1 - Dec 31 2019
Net Defined Benefit Liability/(Asset) at the Beginning of the Period	84,387	98,197
Defined Benefit Cost Recognized in Income Statement	3,228	976
Defined Benefit Cost Recognized in Other Comprehensive Income	12,469	-
Benefits Paid by the Employer	(1,888)	(629)
Net Defined Benefit Liability/(Asset) at the End of the Period	98,197	98,543

B. Determination of Defined Benefit Cost

B1. Determination of Defined Benefit Cost Recognized in Income Statement

	Jan 1 - Sep 30 2019	Oct 1 - Dec 31 2019
Current Service Cost	725	242
Interest Cost	2,503	734
Defined Benefit Cost Recognized in Income Statement	3,228	976

B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income

	Jan 1 - Sep 30 2019	Oct 1 - Dec 31 2019
Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	12,469	-
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	-	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments	-	-
Return on Plan Assets (Excluding Amounts Included in Net Interest Cost)	-	-
Change in Effect of Asset Ceiling	-	-
Defined Benefit Cost Recognized in Other Comprehensive Income	12,469	-
Total Defined Benefit Cost	15,698	976

C. Change in the Present Value of Defined Benefit Obligation

	Jan 1 - Sep 30 2019	Oct 1 - Dec 31 2019
Present Value of Defined Benefit Obligation at the Beginning of the Period	84,387	98,197
Current Service Cost	725	242
Interest Cost	2,503	734
Benefits Paid	(1,888)	(629)
Net Actuarial Loss/(Gain)	12,469	-
Present Value of Defined Benefit Obligation at the End of the Period	98,197	98,543

* The expected September 30, 2019 PV DBO and defined benefit cost for the period January 1, 2019 to September 30, 2019 are calculated based on membership data at December 31, 2018 and management's best estimate assumptions at December 31, 2018.

** Based on expected benefits to be paid to those eligible for benefits.

Espanola Regional Hydro Distribution Corporation

Estimated Benefit Expense (IAS 19)

FINAL

	Jan 1 - Sep 30 2019	Projected * Oct 1 - Dec 31 2019
Discount Rate at the Beginning of the Period	4.00%	3.00%
Discount Rate at the End of the Period	3.00%	3.00%
Health Benefit Cost Trend Rate	4.00%	4.00%
Dental Benefit Cost Trend Rate	4.30%	4.30%
Long Term Health and Dental Benefit Cost Trend Rate	4.00%	4.00%
First Year Of Long Term Health and Dental Benefit Cost Trend Rate	2040	2040
Salary Scale Rate	2.50%	2.50%
Assumed Increase in Employer Contributions	expected **	expected **

D. Calculation of Component Items

	Jan 1 - Sep 30 2019	Projected * Oct 1 - Dec 31 2019
Interest Cost		
Present Value of Defined Benefit Obligation at the Beginning of the Period	84,387	98,197
Benefits Paid	(944)	(315)
Accrued Benefits	83,443	97,882
Interest Cost	2,503	734
Expected Present Value of Defined Benefit Obligation at the End of the Period		
Present Value of Defined Benefit Obligation at the Beginning of the Period	84,387	98,197
Current Service Cost	725	242
Benefits Paid	(1,888)	(629)
Interest Cost	2,503	734
Expected Present Value of Defined Benefit Obligation at the End of the Period	85,727	98,543

E. Net Actuarial Loss/(Gain)

	Jan 1 - Sep 30 2019	Projected * Oct 1 - Dec 31 2019
Net Actuarial Loss/(Gain) at the End of the Period		
Expected Present Value of Defined Benefit Obligation	85,727	98,543
Actual Present Value of Defined Benefit Obligation	98,197	98,543
Net Actuarial Loss/(Gain) at the End of the Period	12,469	-

* The expected September 30, 2019 PV DBO and defined benefit cost for the period January 1, 2019 to September 30, 2019 are calculated based on membership data at December 31, 2018 and management's best estimate assumptions at December 31, 2018.

** Based on expected benefits to be paid to those eligible for benefits.

Appendix 4 – I

2019 Federal T2 and Ontario C23

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

Identification

Business number (BN) 001 86489 8390 RC0001

Corporation's name
002 ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION

Address of head office
Has this address changed since the last time we were notified? . . . . 010 Yes [ ] No [X]
If **yes**, complete lines 011 to 018.
011 598 SECOND STREET
012
015 City: ESPANOLA
016 Province, territory, or state: ON
017 Country (other than Canada):
018 Postal or ZIP code: P5E 1C4

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . 020 Yes [ ] No [X]
If **yes**, complete lines 021 to 028.
021 c/o
022
023
025 City:
026 Province, territory, or state:
027 Country (other than Canada):
028 Postal or ZIP code:

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? . . . . 030 Yes [ ] No [X]
If **yes**, complete lines 031 to 038.
031 598 SECOND ST
032
035 City: ESPANOLA
036 Province, territory, or state: ON
037 Country (other than Canada):
038 Postal or ZIP code: P5E 1T1

040 **Type of corporation at the end of the tax year** (tick one)
- [ ] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [ ] 4 Corporation controlled by a public corporation
- [X] 5 Other corporation (specify) MUNICIPAL ELECTRIC UTILITY

If the type of corporation changed during the tax year, provide the effective date of the change . . . . 043 Year Month Day

To which tax year does this return apply?
Tax year start: 060 Year Month Day 2019-10-01
Tax year-end: 061 Year Month Day 2019-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . 063 Yes [X] No [ ]

If **yes**, provide the date control was acquired . . . . 065 Year Month Day 2019-10-01

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . 066 Yes [ ] No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 Yes [ ] No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 Yes [ ] No [X]
Amalgamation? . . . . 071 Yes [X] No [ ]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 Yes [ ] No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 Yes [ ] No [X]

Is this the final return up to dissolution? . . . . 078 Yes [ ] No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 Yes [X] No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 Yes [ ] No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 3 Exempt under paragraph 149(1)(t) (for tax years starting before 2019)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area
095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170		29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet web pages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II – Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit?	253		T1131
Is the corporation claiming a film or video production services tax credit?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		Yes	No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	ELECTRICITY	285	100.000 %
286		287	%
288		289	%

		Yes	No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 Yes No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300		210,350	A
Deduct:				
Charitable donations from Schedule 2	311			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine made before March 22, 2017, from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331	210,350		
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Employer deduction for non-qualified securities under an employee stock options agreement			a	
Subtotal		210,350	210,350	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360			
Income exempt under paragraph 149(1)(t) (for tax years starting before 2019)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7 . . . **400** 210,350 A

Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . **410** ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction

Amount C ______ x **415** *** ______ D / 11,250 = . . . ______ E

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** . **417** ______ – 50,000 = . . ______ F

Amount C ______ x Amount F ______ / 100,000 = . . . ______ G

Subtotal (the greater of amount E and amount G) **422** ______ H

Reduced business limit for tax years starting before 2019 (amount C **minus** amount E) (if negative, enter "0") . . . **425** ______ I

Reduced business limit for tax years starting after 2018 (amount C **minus** amount H) (if negative, enter "0") . . . **426** ______ J

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 on page 5) . . . ______ K

Reduced business limit after assignment for tax years starting before 2019 (amount I **minus** amount K) . . . **427** ______ L

Reduced business limit after assignment for tax years starting after 2018 (amount J **minus** amount K) . . . **428** ______ M

Small business deduction

Tax years starting before 2019

Amount A, B, C, or L, whichever is the least ______ x Number of days in the tax year before January 1, 2018 ______ / Number of days in the tax year 92 x 17.5 % = ______ 1

Amount A, B, C, or L, whichever is the least ______ x Number of days in the tax year after December 31, 2017, and before January 1, 2019 ______ / Number of days in the tax year 92 x 18 % = ______ 2

Amount A, B, C, or L, whichever is the least ______ x Number of days in the tax year after December 31, 2018 92 / Number of days in the tax year 92 x 19 % = ______ 3

Tax years starting after 2018

Amount A, B, C, or M, whichever is the least . . . . ______ . . . x 19 % = ______ 4

Small business deduction (total of amounts 1 to 4) . . . **430** ______ N

Enter amount N at amount J on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations. For the first tax year starting after 2018, use the total of lines 744 of Schedule 7. Otherwise, use the total of lines 745 of the preceding tax year.

Small business deduction (continued)

Specified corporate income and assignment under subsection 125(3.2)

	O1 Name of corporation receiving the income and assigned amount	O Business number of the corporation receiving the assigned amount 490	P Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column O [3] 500	Q Business limit assigned to corporation identified in column O [4] 505
1.				
			Total 510	Total 515

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
(A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
(B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column P in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 425 (426 for tax years starting after 2018).

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies) . . . . ______ A

Lesser of amounts 9B and 9H from Part 9 of Schedule 27 . . . . ______ B

Amount 13K from Part 13 of Schedule 27 . . . . ______ C

Personal services business income . . . . 432 ______ D

Amount from line 400, 405, 410, or 427 (428 instead of 427 for tax years starting after 2018) on page 4, whichever is the least . . . . ______ E

Aggregate investment income from line 440 on page 6* . . . . ______ F

Subtotal (**add** amounts B to F) ______ ► ______ G

Amount A **minus** amount G (if negative, enter "0") . . . . ______ H

General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 % . . . . ______ I

Enter amount I on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies) . . . . ______ J

Lesser of amounts 9B and 9H from Part 9 of Schedule 27 . . . . ______ K

Amount 13K from Part 13 of Schedule 27 . . . . ______ L

Personal services business income . . . . 434 ______ M

Subtotal (**add** amounts K to M) ______ ► ______ N

Amount J **minus** amount N (if negative, enter "0") . . . . ______ O

General tax reduction – Amount O **multiplied** by 13 % . . . . ______ P

Enter amount P on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ______ x 30 2 / 3 % = ... ______ A

Foreign non-business income tax credit from line 632 on page 8 . . . . ______ B

Foreign investment income from Schedule 7 . . . . **445** ______ x 8 % = ______ C

Subtotal (amount B **minus** amount C) (if negative, enter "0") ______ ► ______ D

Amount A **minus** amount D (if negative, enter "0") . . . . ______ E

Taxable income from line 360 on page 3 . . . . ______ F

Amount from line 400, 405, 410, or 427 (428 instead of 427 for tax years starting after 2018) on page 4, whichever is the least . . . . ______ G

Foreign non-business income tax credit from line 632 on page 8 . . . . ______ x 75 / 29 = ______ H

Foreign business income tax credit from line 636 on page 8 . . ______ x 4 = ______ I

Subtotal (**add** amounts G to I) ______ ► ______ J

Subtotal (amount F **minus** amount J) (if negative, enter "0") ______ K x 30 2 / 3 % = ______ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . ______ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ______ N

Refundable dividend tax on hand (for tax years starting before 2019)

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ______

Dividend refund for the previous tax year . . . . **465** ______

Subtotal (line 460 **minus** line 465) ______ ► ______ O

Refundable portion of Part I tax from line 450 above . . . . ______ P

Total Part IV tax payable from Schedule 3 . . . . ______ Q

Net refundable dividend tax on hand transferred on an amalgamation or the wind-up of a subsidiary . . . . **480** ______

Subtotal (amount P **plus** amount Q **plus** line 480) ______ ► ______ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . **485** ______

Dividend refund (for tax years starting before 2019)

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 . . . . . . ______ x 38 1 / 3 % = ______ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ______ T

Dividend refund – Amount S or T, whichever is less . . . . ______ U

Enter amount U on line 784 on page 9.

Refundable dividend tax on hand (for tax years starting after 2018)

Refundable dividend tax on hand (RDTOH) at the end of the previous tax year	460				
Dividend refund for the previous tax year	465				
Net RDTOH transferred on an amalgamation or the wind-up of a subsidiary	480				
Subtotal (line 460 **minus** line 465 **plus** line 480)					A
General rate income pool (GRIP) at the end of the previous tax year (from line 100 of schedule 53)					B
Total eligible dividends paid in the previous tax year (from line 300 of schedule 53)			C		
Total excessive eligible dividend designation in the previous tax year (from line 310 of Schedule 53)			D		
Subtotal (amount C **minus** amount D) (if negative, enter "0")			▶		E
Net GRIP at the end of the previous tax year (amount B **minus** amount E) (if negative, enter "0")			F		
GRIP transferred on an amalgamation or the wind-up of a subsidiary (total of lines 230 and 240 of schedule 53)			G		
Subtotal (amount F **plus** amount G)			▶		H
Amount H **multiplied** by 38 1 / 3 %					I
Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A or I, whichever is less, otherwise, use line 530 ______ of the preceding tax year)	520				J
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A **minus** amount I, otherwise, use line 545 ______ of the preceding tax year) (if negative, enter "0")	535				K
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)			L		
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)			M		
Subtotal (amount L **plus** amount M)			▶		N
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary	525				O
ERDTOH dividend refund for the previous tax year	570				P
Refundable portion of Part I tax (from line 450 on page 6)					Q
Part IV tax before deductions (amount 2A from Schedule 3)			R		
Part IV tax allocated to ERDTOH (amount N)			S		
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)			T		
Subtotal (amount R **minus** total of amounts S and T)			▶		U
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary	540				V
NERDTOH dividend refund for the previous tax year	575				W
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)					X
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount U **minus** amount X) (if negative enter "0")					Y
NERDTOH at the end of the tax year* (total of amounts K, Q, V, and Y **minus** amount W) (if negative, enter "0")	545				
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount N **minus** the amount, if any, by which amount X exceeds amount U) (if negative, enter "0")					Z
ERDTOH at the end of the tax year* (total of amounts J, O, and Z **minus** amount P) (if negative, enter "0")	530				

* For more information, consult the Help (F1).

Dividend refund (for tax years starting after 2018)

Description	Amount	
38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)		AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)		DD
NERDTOH balance at the end of the tax year (line 545)		EE
Non-eligible dividend refund (amount DD or EE, whichever is less)		FF
Amount DD **minus** amount EE (if negative, enter "0")		GG
Amount BB **minus** amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund* – Amount CC **plus** amount FF **plus** amount II		JJ

Enter amount JJ on line 784 on page 9.

* For more information, consult the Help (F1).

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % . . . . 550 ______ A

Additional tax on personal services business income (section 123.5)

Taxable income from a personal services business . . . . 555 ______ x 5 % = 560 ______ B

Recapture of investment tax credit from Schedule 31 . . . . 602 ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . ______ D

Taxable income from line 360 on page 3 . . . . ______ E

Deduct:

Amount from line 400, 405, 410, or 427 (428 instead of 427 for tax years starting after 2018) on page 4, whichever is the least . . . . ______ F

Net amount (amount E **minus** amount F) ______ ► ______ G

Refundable tax on CCPC's investment income – 10 2 / 3 % of whichever is less: amount D or amount G . . . . 604 ______ H

Subtotal (**add** amounts A, B, C, and H) ______ I

Deduct:

Small business deduction from line 430 on page 4 . . . . ______ J

Federal tax abatement . . . . 608 ______

Manufacturing and processing profits deduction from Schedule 27 . . . . 616 ______

Investment corporation deduction . . . . 620 ______

Taxed capital gains 624 ______

Federal foreign non-business income tax credit from Schedule 21 . . . . 632 ______

Federal foreign business income tax credit from Schedule 21 . . . . 636 ______

General tax reduction for CCPCs from amount I on page 5 . . . . 638 ______

General tax reduction from amount P on page 5 . . . . 639 ______

Federal logging tax credit from Schedule 21 . . . . 640 ______

Eligible Canadian bank deduction under section 125.21 . . . . 641 ______

Federal qualifying environmental trust tax credit . . . . 648 ______

Investment tax credit from Schedule 31 . . . . 652 ______

Subtotal ______ ► ______ K

Part I tax payable – Amount I **minus** amount K . . . . ______ L

Enter amount L on line 700 on page 9.

Privacy statement

Personal information (including the SIN) is collected for the purposes of the administration or enforcement of the Income Tax Act and related programs and activities such as administering tax and benefits, audit, compliance, and collection. Personal information may be shared for purposes of other federal acts that provide for the imposition and collection of a tax or duty. Personal information may also be shared with other federal, provincial, territorial or foreign government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the Privacy Act, individuals have the right to access their personal information, request correction, or file a complaint to the Privacy Commissioner of Canada regarding the handling of the individual's personal information. Refer to Personal Information Bank CRA PPU 047 at **canada.ca/cra-info-source**.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760		
Total tax payable	770		A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount U on page 6 or JJ on page 7	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit (Form T1131)	796	
Film or video production services tax credit (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld 801		
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Labour tax credit for qualifying journalism organizations		
Total credits	890	▶ B

Balance (amount A **minus** amount B)

Refund code 894 Refund ◀

If the result is negative, you have a **refund**.
If the result is positive, you have a **balance owing**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance owing

For information on how to make your payment, go to **canada.ca/payments**.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 Yes ☐ No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920 A3529

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 MELISSA (Last name) 951 CASSON (First name) 954 VICE PRESIDENT OF FINANCE (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2020-05-07 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (705) 474-8100 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 Yes ☒ No ☐

958 Name of other authorized person 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 101

Form identifier 101

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

Opening balance sheet information

Account	Description	GIFI		Amount
	Assets			
	Total current assets	1599	+	
	Total tangible capital assets	2008	+	
	Total accumulated amortization of tangible capital assets	2009	–	
	Total intangible capital assets	2178	+	
	Total accumulated amortization of intangible capital assets	2179	–	
	Total long-term assets	2589	+	
	* Assets held in trust	2590	+	
	Total assets (mandatory field)	2599	=	
	Liabilities			
	Total current liabilities	3139	+	
	Total long-term liabilities	3450	+	
	* Subordinated debt	3460	+	
	* Amounts held in trust	3470	+	
	Total liabilities (mandatory field)	3499	=	
	Shareholder equity			
	Total shareholder equity (mandatory field)	3620	+	
	Total liabilities and shareholder equity	3640	=	
	Retained earnings			
	Retained earnings/deficit – end (mandatory field)	3849	=	

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	2,660,611	2,209,844
	Total tangible capital assets	2008	+	6,120,501	6,032,771
	Total accumulated amortization of tangible capital assets	2009	–	975,386	926,765
	Total intangible capital assets	2178	+	3,322,007	
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	2,697,128	2,775,259
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	13,824,861	10,091,109
	Liabilities				
	Total current liabilities	3139	+	2,964,179	2,138,205
	Total long-term liabilities	3450	+	11,323,402	4,807,185
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	14,287,581	6,945,390
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	-462,720	3,145,719
	Total liabilities and shareholder equity	3640	=	13,824,861	10,091,109
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-462,820	864,719

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	2,589,798	6,332,144
	Cost of sales	8518	–	2,043,330	5,171,386
	Gross profit/loss	8519	=	546,468	1,160,758
	Cost of sales	8518	+	2,043,330	5,171,386
	Total operating expenses	9367	+	573,960	1,500,148
	Total expenses (mandatory field)	9368	=	2,617,290	6,671,534
	Total revenue (mandatory field)	8299	+	2,640,075	6,477,803
	Total expenses (mandatory field)	9368	–	2,617,290	6,671,534
	Net non-farming income	9369	=	22,785	-193,731
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	22,785	-193,731
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–		-2,025
	Future (deferred) income tax provision	9995	–	116,982	-51,934
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	-94,197	-139,772

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax Year End Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** Yes [X] No [ ]

Is the accountant connected* with the corporation? . . . . . **097** Yes [ ] No [X]

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

- Completed an auditor's report . . . . . 1 [X]
- Completed a review engagement report . . . . . 2 [ ]
- Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** Yes [ ] No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

- Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]
- Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** Yes [X] No [ ]

If **yes**, complete lines 104 to 107 below:

- Are subsequent events mentioned in the notes? . . . . . **104** Yes [ ] No [X]
- Is re-evaluation of asset information mentioned in the notes? . . . . . **105** Yes [ ] No [X]
- Is contingent liability information mentioned in the notes? . . . . . **106** Yes [ ] No [X]
- Is information regarding commitments mentioned in the notes? . . . . . **107** Yes [ ] No [X]
- Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** Yes [ ] No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** Yes ☐ No ☐

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** Yes ☐ No ☐

Did the corporation apply hedge accounting during the tax year? . . . . . **255** Yes ☐ No ☐

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** Yes ☐ No ☐

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** Yes ☐ No ☐

If **yes**, you have to maintain a separate reconciliation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

Assets – lines 1000 to 2599

1000	317,887	1060	2,174,624	1066	1,816
1120	48,049	1484	118,235	1599	2,660,611
1600	88,880	1680	183,831	1681	-27,231
1740	47,995	1741	-26,971	1742	385,981
1743	-133,468	1785	5,354,183	1786	-787,716
1900	59,631	2008	6,120,501	2009	-975,386
2012	3,322,007	2178	3,322,007	2182	100
2420	2,697,028	2589	2,697,128	2599	13,824,861

Liabilities – lines 2600 to 3499

2620	2,088,458	2701	235,000	2860	551,351
2920	89,370	3139	2,964,179	3140	9,818,431
3220	104,799	3240	167,980	3320	1,232,192
3450	11,323,402	3499	14,287,581		

Shareholder equity – lines 3500 to 3640

3500	100	3600	-462,820	3620	-462,720
3640	13,824,861				

Retained earnings – lines 3660 to 3849

3660	-368,623	3680	-94,197	3849	-462,820

SCHEDULE 101

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 101

Name of corporation	Business Number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

Assets – lines 1000 to 2599

2599 0

Liabilities – lines 2600 to 3499

3499 0

Shareholder equity – lines 3500 to 3640

3620 0

Retained earnings – lines 3660 to 3849

3849 0

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	2,589,798	**8089**	2,589,798	**8090**	26,048
8230	24,229	**8299**	2,640,075		

Cost of sales – lines 8300 to 8519

8320	2,043,330	**8518**	2,043,330	**8519**	546,468

Operating expenses – lines 8520 to 9369

8590	-4,911	**8670**	48,621	**8710**	73,810
8810	108,270	**8871**	107,785	**8960**	43,108
9060	150,617	**9270**	46,660	**9367**	573,960
9368	2,617,290	**9369**	22,785		

Extraordinary items and taxes – lines 9970 to 9999

9970	22,785	**9995**	116,982	**9999**	-94,197

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			-94,197	A
Add:				
Provision for income taxes – deferred	102	116,982		
Amortization of tangible assets	104	46,094		
Subtotal of additions		163,076	163,076	

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Accrued future benefit costs	976
2	Regulatory assets current year	320,108
3	Interest rate swap mark-to-market adj.	46,660
	Total of column 2	367,744

Total of column 2	296	367,744		
Subtotal of other additions	199	367,744	367,744	D
Total additions	500	530,820	530,820	
Amount A **plus** line 500			436,623	B
Deduct:				
Capital cost allowance from Schedule 8	403	108,661		
Subtotal of deductions		108,661	108,661	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Regulatory assets current year	116,982
2	Actual benefits paid	630
	Total of column 2	117,612

Total of column 2	396	117,612		
Subtotal of other deductions	499	117,612	117,612	E
Total deductions	510	226,273	226,273	
Net income (loss) for income tax purposes (amount B **minus** line 510)			210,350	C

Enter amount C on line 300 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				210,350	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)			b		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Amount of an employer for non-qualified securities under an employee stock options agreement deductible under paragraph 110(1)(e)			1d		
Subtotal (total of amounts a to 1d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")					C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)					E
Add: (decrease a loss)					
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0") If amount G is negative, enter it on line 110 as a positive.					G

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		561,478	e		
Deduct: Non-capital loss expired (note 1)	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102	561,478	▶	561,478	H
Add:					
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary (note 2) corporation	105		g		
Current-year non-capital loss (from amount G)	110		h		
Subtotal (amount g **plus** amount h)			▶		I
Subtotal (amount H **plus** amount I)				561,478	J

Note 1: A non-capital loss expires as follows:
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i	
Section 80 – Adjustments for forgiven amounts	140		j	
Subsection 111(10) – Adjustments for fuel tax rebate			j.1	
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	130	210,350	k	
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (note 3)	135		l	
Subtotal (total of amounts i to l)		210,350 ▶		210,350 K
Non-capital losses before any request for a carryback (amount J **minus** amount K)				351,128 L

Deduct – **Request to carry back non-capital loss to:**

First previous tax year to reduce taxable income	901		m	
Second previous tax year to reduce taxable income	902		n	
Third previous tax year to reduce taxable income	903		o	
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p	
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q	
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r	
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)		▶		M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180			351,128 N

Note 3: Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200	23,996	a	
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205		b	
Subtotal (amount a **plus** amount b)		23,996 ▶		23,996 A

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	250		c	
Section 80 – Adjustments for forgiven amounts	240		d	
Subtotal (amount c **plus** amount d)		▶		B
Subtotal (amount A **minus** amount B)				23,996 C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)	210			D
Unused non-capital losses that expired in the tax year (note 4)			e	
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year (note 5)			f	
Enter amount e or f, whichever is less	215		g	
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220			E
Subtotal (total of amounts C to E)				23,996 F

Note

If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220 above.

Note 4: If the loss was incurred in a tax year ending after March 22, 2004, determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not used in previous years and the current year on line e.

Note 5: If the ABILs were incurred in a tax year ending after March 22, 2004, enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (note 6)				225	G
Capital losses before any request for a carryback (amount F **minus** amount G)				23,996	H

Deduct – **Request to carry back capital loss to** (note 7):

	Capital gain (100%)		Amount carried back (100%)		
First previous tax year		951		h	
Second previous tax year		952		i	
Third previous tax year		953		j	
Subtotal (total of amounts h to j)					I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)			280	23,996	J

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current-year tax, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, divide this amount by 2. The result represents the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired (note 8)	300		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302				A
Add:					
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305		c		
Current-year farm loss (amount F in Part 1)	310		d		
Subtotal (amount c **plus** amount d)					B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	350		e		
Section 80 – Adjustments for forgiven amounts	340		f		
Farm losses of previous tax years applied in the current tax year Enter amount g on line 334 of the T2 Return.	330		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (note 9)	335		h		
Subtotal (total of amounts e to h)					D
Farm losses before any request for a carryback (amount C **minus** amount D)					E

Deduct – **Request to carry back farm loss to:**

First previous tax year to reduce taxable income	921		i		
Second previous tax year to reduce taxable income	922		j		
Third previous tax year to reduce taxable income	923		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n		
Subtotal (total of amounts i to n)					F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)	380				G

Note 8: A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Note 9: Amount h is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			**485**	A
Minus the deductible farm loss:				
(amount A above ______ – $2,500) **divided** by 2 =		a		
Amount a or $ 15,000 (note 10), whichever is less		b		
	2,500	c		
Subtotal (amount b **plus** amount c)	2,500		2,500	B
Current-year restricted farm loss (amount A **minus** amount B)				C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d		
Deduct: Restricted farm loss expired (note 11)	**400**		e		
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	**402**				D
Add:					
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	**405**		f		
Current-year restricted farm loss (from amount C) Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.	**410**		g		
Subtotal (amount f **plus** amount g)					E
Subtotal (amount D **plus** amount E)					F
Deduct:					
Restricted farm losses from previous tax years applied against current farming income Enter amount h on line 333 of the T2 return.	**430**		h		
Section 80 – Adjustments for forgiven amounts	**440**		i		
Other adjustments	**450**		j		
Subtotal (total of amounts h to j)					G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)					H
Deduct – **Request to carry back restricted farm loss to:**					
First previous tax year to reduce farming income	**941**		k		
Second previous tax year to reduce farming income	**942**		l		
Third previous tax year to reduce farming income	**943**		m		
Subtotal (total of amounts k to m)					I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	**480**				J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 10: For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

Note 11: A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a		
Deduct: Listed personal property loss expired after 7 tax years	500		b		
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶		A
Add: Current-year listed personal property loss (from Schedule 6)				510	B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Listed personal property losses from previous tax years applied against listed personal property gains Enter amount c on line 655 of Schedule 6.	530		c		
Other adjustments	550		d		
Subtotal (amount c **plus** amount d)			▶		D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back listed personal property loss to:**					
First previous tax year to reduce listed personal property gains	961		e		
Second previous tax year to reduce listed personal property gains	962		f		
Third previous tax year to reduce listed personal property gains	963		g		
Subtotal (total of amounts e to g)			▶		F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)				580	G

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number	Tax year ending yyyy/mm/dd	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6)
	600	602	604	606	608		620
1.							

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number	Tax year ending yyyy/mm/dd	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
	630	632	634	636	638		650
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary	Current-year limited partnership losses (from line 620)	Limited partnership losses applied in the current year (must be equal to or less than line 650)	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5)
	660	662	664	670	675	680
1.						

Total (enter this amount on line 335 of the T2 return)

Note
If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note
This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce Taxable income	Applied to reduce Part IV tax	Balance at end of year
Current	N/A				N/A		
1st preceding taxation year 2019-09-30	561,478	N/A		N/A	210,350		351,128
2nd preceding taxation year 2018-12-31		N/A		N/A			
3rd preceding taxation year 2017-12-31		N/A		N/A			
4th preceding taxation year 2016-12-31		N/A		N/A			
5th preceding taxation year 2015-12-31		N/A		N/A			
6th preceding taxation year 2014-12-31		N/A		N/A			
7th preceding taxation year 2013-12-31		N/A		N/A			
8th preceding taxation year 2012-12-31		N/A		N/A			
9th preceding taxation year 2011-12-31		N/A		N/A			
10th preceding taxation year 2010-12-31		N/A		N/A			
11th preceding taxation year 2009-12-31		N/A		N/A			
12th preceding taxation year 2008-12-31		N/A		N/A			
13th preceding taxation year 2007-12-31		N/A		N/A			
14th preceding taxation year 2006-12-31		N/A		N/A			
15th preceding taxation year 2005-12-31		N/A		N/A			
16th preceding taxation year 2004-12-31		N/A		N/A			
17th preceding taxation year 2003-12-31		N/A		N/A			
18th preceding taxation year 2002-12-31		N/A		N/A			
19th preceding taxation year 2001-12-31		N/A		N/A			
20th preceding taxation year 2001-09-30		N/A		N/A			*
Total	561,478				210,350		351,128

*** This balance expires this year and will not be available next year.**

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under Regulation 1101(5q)? **101** Yes [ ] No [X]

	1 Class number * See note 1 (200)	Description	2 Undepreciated capital cost (UCC) at the beginning of the year (201)	3 Cost of acquisitions during the year (new property must be available for use) See note 2 (203)	4 Cost of acquisitions from column 3 that are accelerated investment incentive properties (AIIP) See note 3 (225)	5 Adjustments and transfers See note 4 (205)	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition See note 5 (221)	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition See note 6 (222)	8 Proceeds of dispositions See note 7 (207)	For tax years ending before November 21, 2018: 50% rule (1/2 of net acquisitions) (211)
1.	1	Distribution	148,378						0	
2.	1	Distribution	3,732						0	
3.	1	SYSTEM	1,094,553						0	
4.	8	equipment	13,604	5,903	5,903				0	
5.	10	COMPUTERS	184						0	
6.	10	computers	108						0	
7.	10	vehicles	89,023						0	
8.	45	Computer Equipment	6						0	
9.	47	Transmission & Distribution Equip	4,228,886	77,764	77,764				0	
10.	50	Computer Equipment	3,526	438	438				0	
		Totals	5,582,000	84,105	84,105					

	1 Class number * See note 1 (200)	Description	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See note 8	10 Proceeds of disposition available to reduce the UCC of AIIP (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for non-AIIP acquired during the year (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 (224)	14 CCA rate % See note 11 (212)	15 Recapture of CCA See note 12 (213)	16 Terminal loss See note 13 (215)	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 (217)	18 UCC at the end of the year (column 9 **minus** column 17) (220)
1.	1	Distrib	148,378					4	0	0	1,496	146,882

	1 Class number * See note 1 200	Des-crip-tion	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See note 8	10 Proceeds of disposition available to reduce the UCC of AIIP (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for non-AIIP acquired during the year (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 224	14 CCA rate % See note 11 212	15 Recapture of CCA See note 12 213	16 Terminal loss See note 13 215	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 217	18 UCC at the end of the year (column 9 **minus** column 17) 220
2.	1	Distrib	3,732					4	0	0	38	3,694
3.	1	SYSTEI	1,094,553					4	0	0	11,035	1,083,518
4.	8	equipn	19,507		5,903	2,952		20	0	0	1,132	18,375
5.	10	COMPL	184					30	0	0	14	170
6.	10	compu	108					30	0	0	8	100
7.	10	vehicle	89,023					30	0	0	6,732	82,291
8.	45	Compu	6					45	0	0	1	5
9.	47	Transn	4,306,650		77,764	38,882		8	0	0	87,625	4,219,025
10.	50	Compu	3,964		438	219		55	0	0	580	3,384
		Totals	5,666,105		84,105	42,053					108,661	5,557,444

Enter the total of column 15 on line 107 of Schedule 1.
Enter the total of column 16 on line 404 of Schedule 1.
Enter the total of column 17 on line 403 of Schedule 1.

Note 1. If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101. Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 2. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule.

Note 3. An accelerated investment incentive property (AIIP) is a property (other than property included in Class 54 or 55) that you acquired after November 20, 2018 and became available for use before 2028. See the T2 Corporation Income Tax Guide for more information. Classes 54 and 55 include property that is a zero-emission vehicle you acquired after March 18, 2019 and became available for use before 2028.

Note 4. Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost (column 9). Items that increase the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the undepreciated capital cost (show amounts that reduce the undepreciated capital cost in brackets) include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the T2 Corporation Income Tax Guide for other examples of adjustments and transfers to include in column 5.

Note 5. Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 6. Include all amounts you have repaid during the year with respect to any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d); and
- an inducement, assistance or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b).

Also include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) of the Act (also known as "butterfly reorganization") or in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year.

Note 7. For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).

Note 8. If the amount in column 5 reduces the undepreciated capital cost (i.e. it is shown in brackets), you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 9. The relevant factors for AIIP of a class in Schedule II and for property included in classes 54 and 55, available for use before 2024, are:

- 2 1/3 for property in Classes 43.1 and 54;
- 1 1/2 for property in Class 55;
- 1 for property in Classes 43.2 and 53;
- 0 for property in Classes 12, 13, 14, and 15, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 14 for additional information); and
- 0.5 for all other property that is AIIP.

Note 10. The UCC adjustment for non-AIIP acquired during the year (formerly known as the half-year rule or 50% rule) does not apply to certain property (including AIIP). For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 11. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 17.

Note 12. If the amount in column 9 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 9 in column 15 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1.

Note 13. If no property is left in the class at the end of the tax year and there is still a positive amount in the column 9, you have a terminal loss. If applicable, enter the positive amount from column 9 in column 16. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1;
- property in Class 14.1, unless you have ceased carrying on the business to which it relates; or
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply.

Note 14. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the T2 Corporation Income Tax Guide for more information. For property in class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year. For AIIP listed below, the maximum first year allowance you can claim is determined as follows:

- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction).
- Class 14: the lesser of 150% of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction).
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction).
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction).
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraph 1100(1)(y.2)(for single mine properties) and 1100(1)(ya.2)(for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive.
- Property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit: 150% of the amount determined by first subtracting the total of the residual value of the timber limit and all amounts you expended for the 1949 or later tax years for surveys, cruises or preparation of prints, maps or plans for the purpose of obtaining a licence or right to cut timber from the capital cost of the limit or right, and then dividing the result by the quantity of timber in the limit or the quantity of timber you have the right to cut.
- Industrial mineral mine or a right to remove industrial minerals from an industrial mineral mine: 150% of the amount determined by first subtracting the residual value, if any, of the mine or right from the capital cost of the mine or right, and then dividing the result by the number of units of commercially mineable material estimated to be in the mine when the mine or right was acquired (alternatively, if you have acquired a right to remove only a specified number of units, that number of units that you acquired a right to remove).

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		84,105		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Other (specify):	+			
Total additions per books	=	84,105	▶	84,105
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):	+			
Total proceeds per books	=		▶ –	
Depreciation and amortization per accounts – Schedule 1			–	46,094
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	38,011

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		8,378,242
Opening net book value	–	5,017,126
Net change per financial statements	=	3,361,116

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	North Bay Hydro Distribution Limite		88246 3128 RC0001	3					
2.	North Bay Hydro Generation Limitec		89117 4401 RC0001	3					
3.	North Bay Hydro Holdings Limited		86712 3580 RC0001	1					
4.	North Bay Hydro Services Inc.		86450 3511 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year must file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group, including those deemed to be associated under subsection 256(2) of the Income Tax Act.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless association code 5 applies)
2 – CCPC that is a **third corporation** as referred to in subsection 256(2) and has filed Schedule 28, Election not to be Associated Through a Third Corporation
3 – Non-CCPC that is a **third corporation**
4 – Associated non-CCPC
5 – Associated CCPC to which association code 1 does not apply because a **third corporation** has filed Schedule 28

Column 4: Enter the business limit for the year of each corporation in the associated group. Enter "0" if the corporation has association code 2, 3 or 4 in column 3 (except if the corporation is a cooperative or a credit union eligible for the SBD and it has association code 4).

Column 5: Assign a percentage to allocate the business limit to each corporation that has association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . **025** Year Month Day

Enter the calendar year the agreement applies to . . . . . **050** Year 2019

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** ☐ Yes ☒ No

	1 Name of associated corporations **100**	2 Business number of associated corporations **200**	3 Asso-ciation code **300**	4 Business limit for the year before the allocation $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	ESPANOLA REGIONAL HYDRO DISTRIBUTION	86489 8390 RC0001	1	500,000			
2	North Bay Hydro Distribution Limited	88246 3128 RC0001	1	500,000			
3	North Bay Hydro Generation Limited	89117 4401 RC0001	1	500,000			
4	North Bay Hydro Holdings Limited	86712 3580 RC0001	1	500,000			
5	North Bay Hydro Services Inc.	86450 3511 RC0001	1	500,000	100.0000	500,000	
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (C - $10,000,000). Another factor is the "adjusted aggregate investment income" from lines 744 and 745 of Schedule 7, Aggregate Investment Income and Income Eligible for the Small Business Deduction. Details of these formulas and variable C are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the lesser of: the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year.

T2 SCH 23 E (19)

Canada

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SCHEDULE 24

FIRST-TIME FILER AFTER INCORPORATION, AMALGAMATION, OR WINDING-UP OF A SUBSIDIARY INTO A PARENT

Name of corporation	Business Number	Tax year end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

This schedule must be filed by corporations for the first year of filing after incorporation, amalgamation, or by parent corporations filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act* during the current taxation year.

Part 1 – Type of operation

100 For those corporations filing for the first time after incorporation or amalgamation, please identify the type of operation that applies to your corporation:

99 Other

Part 2 – First year of filing after amalgamation

For the first year of filing after an amalgamation, please provide the following information:

	Name of predecessor corporation(s) **200**	Business Number (If a corporation is not registered, enter "NR") **300**
1	ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001
2	ESPANOLA REGIONAL HYDRO HOLDINGS CORPORATION	89110 5611 RC0001
3	NORTH BAY (ESPANOLA) ACQUISITION INC.	74197 2483 RC0001

Part 3 – First year of filing after wind-up of subsidiary corporation(s)

For the parent corporation filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act*, please provide the following information:

Name of subsidiary corporation(s) **400**	Business Number (If a corporation is not registered, enter "NR") **500**	Commencement date of wind-up (YYYY/MM/DD) **600**	Date of wind-up (YYYY/MM/DD) **700**

T2 SCH 24 (04)

Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	104,799	
Capital stock (or members' contributions if incorporated without share capital)	103	100	
Retained earnings	104		
Contributed surplus	105		
Any other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	10,459,152	
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112		
Subtotal (**add** lines 101 to 112)		10,564,051 ▶	10,564,051 A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if

a) those lines applied to partnerships in the same manner that they apply to corporations, and

b) those amounts were computed without reference to amounts owing by the partnership

(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or

(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			10,564,051	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121			
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122	462,820		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123			
Deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal (**add** lines 121 to 124)		462,820 ▶	462,820	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		10,101,231	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		10,101,231	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	10,101,231	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 10,101,231 x (Taxable income earned in Canada **610** 1,000 / Taxable income 1,000) = **Taxable capital employed in Canada** **690** 10,101,231

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ______

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ______

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ______

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ______

Total deductions (**add** lines 711, 712, and 713) ______ ► ______ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ______

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . ______ F

Deduct: . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") ______ H

Calculation for purposes of the small business deduction (amount H x 0.225%) . . . . ______ I

Enter this amount at line 415 of the T2 return.

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Schedule 50

Shareholder Information

Corporation's name	Business number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.
- Provide only one number per shareholder (business number, social insurance number or trust number).

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	North Bay Hydro Holdings Limited	86712 3580 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	13,824,861
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		13,824,861
Total revenue of the corporation for the tax year **	142	10,474,211
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		10,474,211

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	-94,197
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220			
Provision for deferred income taxes (debits)/cost of future income taxes	222	116,982		
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		116,982 ▶		116,982 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal		▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	22,785

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515		
Deduct:				
CMT loss available (amount R from Part 7)		193,731		
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available		193,731 ▶	193,731	C
Net income subject to CMT calculation (if negative, enter "0")		520		

Amount from line 520 ______ x (Number of days in the tax year before July 1, 2010 ______ / Number of days in the tax year 92) x 4 % = ______ 1

Amount from line 520 ______ x (Number of days in the tax year after June 30, 2010 92 / Number of days in the tax year 92) x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) ______ 3

Gross CMT: amount on line 3 above x OAF **	540		
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")			D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		G		
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		►	620	
Add:				
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)				I
Subtotal (amount H **minus** amount I)				J
Add:				
Net CMT payable (amount E from Part 3)				
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		►		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

– do not enter an amount on line G or line 600;

– for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			1	
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)		2		
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)		3		
Gross SAT (line 460 from Part 6 of Schedule 512)		4		
The **greater** of amounts 3 and 4		5		
Deduct: line 2 or line 5, whichever applies:			6	
Subtotal (if negative, enter "0")			►	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)				
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)				
Subtotal (if negative, enter "0")			►	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year *		193,731 Q		
Deduct:				
CMT loss expired *	700			
CMT loss carryforward at the beginning of the tax year * (see note below)		193,731 ▶	720	193,731
Add:				
CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below)			750	
CMT loss available (line 720 **plus** line 750)				193,731 R
Deduct:				
CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3)				22,785
Subtotal (if negative, enter "0")				170,946 S
Add:				
Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount)			760	
CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760)			770	170,946 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	North Bay Hydro Distribution Limited	88246 3128 RC0001	0	0
2	North Bay Hydro Generation Limited	89117 4401 RC0001	0	0
3	North Bay Hydro Holdings Limited	86712 3580 RC0001	0	0
4	North Bay Hydro Services Inc.	86450 3511 RC0001	0	0
		Total	450	550

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 524

ONTARIO SPECIALTY TYPES

Name of corporation	Business Number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- Use this schedule to identify the specialty type of a corporation carrying on business in the province of Ontario through a permanent establishment if:
  - its tax year includes January 1, 2009;
  - the tax year is the first year after incorporation or an amalgamation; or
  - there is a change to the specialty type.
- If none of the listed specialty types applies, tick box 99 "Other."
- Unless otherwise noted, references to sections, subsections, and clauses are from the *Taxation Act, 2007* (Ontario).

Specialty types

100 Identify the specialty type that applies to your corporation:

- [ ] 01 Family farm corporation – See subsection 64(3).
- [ ] 02 Family fishing corporation – See subsection 64(3).
- [ ] 03 Mortgage investment corporation – See subsection 130.1(6) of the federal *Income Tax Act*.
- [ ] 04 Credit union – See subsection 137(6) of the federal Act.
- [ ] 06 Bank – See subsection 248(1) of the federal Act.
- [ ] 08 Financial institution prescribed by regulation only – See clause 66(2)(f).
- [ ] 09 Registered securities dealer – See subsection 248(1) of the federal Act.
- [ ] 10 Farm feeder finance co-operative corporation
- [ ] 11 Insurance corporation – See subsection 248(1) of the federal Act.
- [ ] 12 Mutual insurance – See subsection 27(2) of the *Taxation Act, 2007* (Ontario) and paragraph 149(1)(m) of the federal Act.
- [ ] 13 Specialty mutual insurance
- [ ] 14 Mutual fund corporation – See subsection 131(8) of the federal Act.
- [ ] 15 Bare trustee corporation
- [ ] 16 Professional corporation (incorporated professional only) – See subsection 248(1) of the federal Act.
- [ ] 17 Limited liability corporation
- [ ] 18 Generator of electrical energy for sale, or producer of steam for use in the generation of electrical energy for sale – See subsection 33(7).
- [X] 19 Hydro successor, municipal electrical utility, or subsidiary of either – See subsection 91.1(1) and section 88 of the *Electricity Act, 1998* (Ontario).
- [ ] 20 Producer and seller of steam for uses other than for the generation of electricity – See subsection 33(7).
- [ ] 21 Mining corporation
- [ ] 22 Non-resident corporation
- [ ] 99 Other (if none of the previous descriptions apply)

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	86489 8390 RC0001	2019-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	110 Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	120 Ontario Corporation No.
Ontario	2019-10-01	1446456

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	220 Street name/Rural route/Lot and Concession number	230 Suite number
598	SECOND STREET	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	260 Province/state	270 Country	280 Postal/zip code
ESPANOLA	ON	CA	P5E 1C4

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 2 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 MELISSA (Last name) **451** CASSON (First name)

454 ______ , (Middle name(s))

460 3 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number **530** Street name/Rural route/Lot and Concession number **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) **570** Province/state **580** Country **590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Corporate Taxpayer Summary

Corporate information

Corporation's name	ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION
Taxation Year	2019-10-01 to 2019-12-31
Jurisdiction	Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated	Y
Corporation is related	Y
Number of associated corporations	4
Type of corporation	Other Corporation
Total amount due (refund) federal and provincial*	

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		210,350
Taxable income		
Donations		
Calculation of income from an active business carried on in Canada		210,350
Dividends paid		
Dividends paid – Regular		
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		
Balance of the general rate income pool at the end of the year		
Part I tax (base amount)		

Summary of federal carryforward/carryback information

Carryforward balances

Non-capital losses	351,128
Capital losses/L.P.P.	23,996

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	210,350		
Taxable income			
% Allocation	100.00		
Attributed taxable income			
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***			
Instalments and refundable credits			
Balance due/Refund (-)			
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax loss that can be carried forward over 20 years – Schedule 510 . . . 170,946

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	6,877,807	6,877,807	10,101,231	10,101,231
North Bay Hydro Distribution Limited				
North Bay Hydro Generation Limited				
North Bay Hydro Holdings Limited				
North Bay Hydro Services Inc.				
Total	6,877,807	6,877,807	10,101,231	10,101,231

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN) and to determine the applicability of Form CO-1029.8.33.TE	Paid-up capital used to calculate the $1 million deduction (CO-1137.A and CO-1137.E)	Paid-up capital used to determine the applicability of Form CO-737.SI
Total				

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2019-12-31**	**2019-09-30**	**2018-12-31**	**2017-12-31**	**2016-12-31**
Net income	210,350	-574,914	13,436	-407,718	-155,810
Taxable income			13,436		
Active business income	210,350		13,436		
Dividends paid					
Dividends paid – Regular					
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations					
Balance due/refund (-)			1,814		-12,568
Line 996 – Amended tax return	☐	☐	☐	☐	☐

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	**2019-12-31**	**2019-09-30**	**2018-12-31**	**2017-12-31**	**2016-12-31**
Taxable income before loss carrybacks	N/A	N/A	13,436		
Non-capital losses	N/A	N/A	13,436		
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A	13,436		
Adjusted taxable income after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	**2019-12-31**	**2019-09-30**	**2018-12-31**	**2017-12-31**	**2016-12-31**
Adjusted taxable income before current year loss carrybacks*	N/A				N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A				N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2019-12-31	2019-09-30	2018-12-31	2017-12-31	2016-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2019-12-31	2019-09-30	2018-12-31	2017-12-31	2016-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks***	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A				N/A

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2019-12-31	2019-09-30	2018-12-31	2017-12-31	2016-12-31
Part I			1,344		
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Taxation year end	2019-12-31	2019-09-30	2018-12-31	2017-12-31	2016-12-31
Small business deduction			2,418		
M&P deduction					
Foreign tax credit					
Investment tax credit					
Abatement/other*			1,344		

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2019-12-31	2019-09-30	2018-12-31	2017-12-31	2016-12-31
ITC refund					
Dividend refund					
– Eligible dividends					
– Non-eligible dividends					
Instalments					12,568
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2019-12-31	2019-09-30	2018-12-31	2017-12-31	2016-12-31
Net income	210,350	-574,914	13,436	-407,718	-155,810
Taxable income			13,436		
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income			13,436		
Surtax					
Income tax payable before deduction			1,545		
Income tax deductions /credits			1,075		
Net income tax payable			470		
Taxable capital					
Capital tax payable					
Total tax payable*			470		
Instalments and refundable credits					
Balance due/refund**			470		

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Appendix 4 – J

2021 Test Year Income Tax PILS

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Version 1.20

Utility Name	North Bay Hydro Distribution Limited - Espanola service territory
Assigned EB Number	EB-2020-0020
Name and Title	Tyler Kasubeck
Phone Number	
Email Address	
Date	
Last COS Re-based Year	**2012**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

No inputs required on this worksheet.

Inputs on Service Revenue Requirement Worksheet

The Service Revenue Requirement is in the 'Revenue Requirement Workform' - Tab 3.

Item	Working Paper Reference		
Adjustments required to arrive at taxable income	as below	**-409,579**	
Test Year - Payments in Lieu of Taxes (PILs)	T0	**-**	
Test Year - Grossed-up PILs	T0	**-**	
Effective Federal Tax Rate	T0	**9.0%**	
Effective Ontario Tax Rate	T0	**3.2%**	

Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	253,504	
Taxable Income	T1	-156,074	
Difference	calculated	-409,579	as above

Income Tax/PILs Workform for 2021 Filers

Integrity Checks

The applicant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or provide an explanation if this is not the case:

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	
2	The capital additions and deductions in the CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non-distribution tax amounts on Schedule 8.	Y	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the CCA Schedule 8 for the same years filed in the application		
5	Loss carry-forwards, if any, from prior year tax returns' Schedule 4 agree with those disclosed in the application	Y	
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	Y	
7	CCA is maximized even if there are tax loss carry-forwards	Y	
8	Other post-employment benefits and pension expenses that are added back on Schedule 1 to reconcile accounting income to net income for tax purposes agree with the OM&A analysis for compensation. The amounts deducted are reasonable when compared with the notes to the audited financial statements, Financial Services Commission of Ontario reports, and actuarial valuations.	Y	amounts added back to Schedule 1 in 2019 was $976 and is not expected to be significant in future years
9	The income tax rate used to calculate the tax expense is consistent with the utility's actual tax facts and evidence filed in the application	Y	

1

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

				Test Year	Bridge Year
Rate Base		S	**$**	**7,599,049**	**$ 7,078,162**

Return on Ratebase

Deemed ShortTerm Debt %	4.00%	T	$	303,962	*W = S * T*	
Deemed Long Term Debt %	56.00%	U	$	4,255,467	*X = S * U*	
Deemed Equity %	40.00%	V	$	3,039,620	*Y = S * V*	
Short Term Interest Rate	1.75%	Z	$	5,319	*AC = W * Z*	
Long Term Interest	3.03%	AA	$	128,776	*AD = X * AA*	
Return on Equity (Regulatory Income)	8.34%	AB	**$**	**253,504**	*AE = Y * AB*	T1
Return on Rate Base			**$**	**387,599**	*AF = AC + AD + AE*	

Questions that must be answered

	Historical Year	Bridge Year	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	Yes	Yes	Yes
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	Yes	Yes	Yes
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe the tax treatment in the manager's summary.*	No	No	No
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Tax Rates **Federal & Provincial** **As of MMM XX, 2019**	**Effective January 1, 2015**	**Effective January 1, 2016**	**Effective January 1, 2017**	**Effective January 1, 2018**	**Effective January 1, 2019**	**Effective January 1, 2020**	**Effective January 1, 2021**
Federal income tax							
General Corporate Rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal Tax Abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted Federal Rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate Reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario Income Tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined Federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business							
Federal Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Federal Small Business Rate	11.00%	10.50%	10.50%	10.00%	9.00%	9.00%	9.00%
Ontario Small Business Rate	4.50%	4.50%	4.50%	3.50%	3.50%	3.20%	3.20%

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PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

					Wires Only	
Regulatory Taxable Income				H1	$ -	A
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	B			
	Federal tax rate (Maximum 15%)	15.00%	C			
	Combined tax rate (Maximum 26.5%)				26.50%	D = B+C
Total Income Taxes					$ -	E = A * D
Investment Tax Credits						F
Miscellaneous Tax Credits						G
Total Tax Credits					$ -	H = F + G
Corporate PILs/Income Tax Provision for Historical Year					$ -	I = E - H

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Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	(A + 101 + 102)	-94,197		-94,197
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	46,094		46,094
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations and gifts from Schedule 2	112			0
Taxable capital gains from Schedule 6	113			0
Political contributions	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121			0
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements – balance at the end of the year	126			0
Soft costs on construction and renovation of buildings	127			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other additions				
Interest Expensed on Capital Leases	295			0
Realized Income from Deferred Credit Accounts	295			0
Pensions	295			0
Non-deductible penalties	295			0
	295			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Provision of Income Taxes – Deferred		116,982		116,982
Accrued Future Benefit Costs		976		976
Regulatory Assets Current Year		320,108		320,108
Interest Rate Swap mark-to-market adj.		46,660		46,660
				0
				0
				0
				0
				0
				0
Total Additions		**530,820**	**0**	**530,820**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Non-taxable dividends under section 83	402			0
Capital cost allowance from Schedule 8	403	108,661		108,661
Terminal loss from Schedule 8	404			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions				
Interest capitalized for accounting deducted for tax	395			0
Capital Lease Payments	395			0
Non-taxable imputed interest income on deferral and variance accounts	395			0
	395			0
	395			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Regulatory Assets current year		116,982		116,982
Actual Benefits Paid		630		630
				0
				0
				0
				0
				0
				0
Total Deductions		**226,273**	**0**	**226,273**
Net Income for Tax Purposes		**210,350**	**0**	**210,350**
Charitable donations from Schedule 2	311			0
Taxable dividends received under section 112 or 113	320			0
Non-capital losses of previous tax years from Schedule 4	331	210,350		210,350
Net capital losses of previous tax years from Schedule 4	332			0
Limited partnership losses of previous tax years from Schedule 4	335			0
TAXABLE INCOME		**0**	**0**	**0**

H0

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Schedule 4 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	351,128		351,128	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	23,996		23,996	B4

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Income Tax/PILs Workform for 2021 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year	Working Paper Reference
1	Buildings, Distribution System (acq'd post 1987)	$ 1,234,094		$ 1,234,094	B8
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]			$ -	B8
2	Distribution System (acq'd pre 1988)			$ -	B8
3	Buildings (acq'd pre 1988)			$ -	B8
6	Certain Buildings; Fences			$ -	B8
8	General Office Equipment, Furniture, Fixtures	$ 18,375		$ 18,375	B8
10	Motor Vehicles, Fleet	$ 82,561		$ 82,561	B8
10.1	Certain Automobiles			$ -	B8
12	Computer Application Software (Non-Systems)			$ -	B8
13_1	Lease # 1			$ -	B8
13_2	Lease # 2			$ -	B8
13_3	Lease # 3			$ -	B8
13_4	Lease # 4			$ -	B8
14	Limited Period Patents, Franchises, Concessions or Licences			$ -	B8
14.1	Eligible Capital Property (acq'd pre 2017)			$ -	B8
14.1	Eligible Capital Property (acq'd post 2016)			$ -	B8
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage			$ -	B8
42	Fibre Optic Cable			$ -	B8
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -	B8
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -	B8
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	$ 5		$ 5	B8
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			$ -	B8
47	Distribution System (acq'd post Feb 22/05)	$ 4,219,025		$ 4,219,025	B8
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	$ 3,384		$ 3,384	B8
95	CWIP			$ -	B8
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
	SUB-TOTAL - UCC	5,557,444	0	5,557,444	

Only if election under ONTARIO REGULATION 162/01 ss. 5 or 7 filed in 2001 to have ITR 1102(14) apply

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only	
Capital gains reserves ss.40(1)			0	B13
Tax reserves not deducted for accounting purposes				
Reserve for doubtful accounts ss. 20(1)(l)			0	B13
Reserve for undelivered goods and services not rendered ss. 20(1)(m)			0	B13
Reserve for unpaid amounts ss. 20(1)(n)			0	B13
Debt & share issue expenses ss. 20(1)(e)			0	B13
Other tax reserves			0	B13
			0	
			0	
			0	
			0	
			0	
Total	0	0	0	
Financial Statement Reserves (not deductible for Tax Purposes)				
General reserve for inventory obsolescence (non-specific)			0	B13
General reserve for bad debts			0	B13
Accrued Employee Future Benefits:			0	B13
- Medical and Life Insurance			0	B13
-Short & Long-term Disability			0	B13
-Accmulated Sick Leave			0	B13
- Termination Cost			0	B13
- Other Post-Employment Benefits			0	B13
Provision for Environmental Costs			0	B13
Restructuring Costs			0	B13
Accrued Contingent Litigation Costs			0	B13
Accrued Self-Insurance Costs			0	B13
Other Contingent Liabilities			0	B13
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0	B13
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0	B13
Other			0	B13
			0	
			0	
Total	0	0	0	

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PILS Tax Provision - Bridge Year

						Reference	Wires Only	
Regulatory Taxable Income						B1	-$ 750,646	A
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				
Ontario (Max 11.5%)	11.5%	3.2%	-$ 24,021	3.2%	B			
Federal (Max 15%)	15.0%	9.0%	-$ 67,558	9.0%	C			
Combined effective tax rate (Max 26.5%)							12.20%	D = B + C
Total Income Taxes							$ -	E = A * D
Investment Tax Credits								F
Miscellaneous Tax Credits								G
Total Tax Credits							$ -	H = F + G
Corporate PILs/Income Tax Provision for Bridge Year							$ -	I = E - H

1

2

3

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Income Tax/PILs Workform for 2021 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	(A + 101 + 102)		-314,606
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		229,039
Amortization of intangible assets	106		
Recapture of capital cost allowance from Schedule 8	107	B8	0
Income inclusion under subparagraph 13(38)(d)(iii)	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations and gifts from Schedule 2	112		
Taxable capital gains	113		
Political contributions	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	0
Reserves from financial statements- balance at end of year	126	B13	0
Soft costs on construction and renovation of buildings	127		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			**229,039**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	665,079
Terminal loss from Schedule 8	404	B8	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	0
Reserves from financial statements - balance at beginning of year	414	B13	0
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions			
Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		
Non-taxable imputed interest income on deferral and variance accounts	395		
	395		
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**665,079**
Net Income for Tax Purposes		calculated	**-750,646**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	B4	0
Net capital losses of previous tax years from Schedule 4	332	B4	0
Limited partnership losses of previous tax years from Schedule 4	335		
TAXABLE INCOME		calculated	**-750,646**

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Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	351,128	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	750,646	
Other Adjustments			
Balance available for use post Bridge Year	calculated	1,101,774	T4

Net Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	23,996	
Amount to be used in Bridge Year			
Loss Carry Forward Generated in Bridge Year (if any)	B1		
Other Adjustments			
Balance available for use post Bridge Year	calculated	23,996	T4

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Schedule 8 CCA - Bridge Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the bridge year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")
1	Buildings, Distribution System (acq'd post 1987)	H6	$ 1,234,094							$ 1,234,094	$ -	$ -	0.50	$ -	$ -
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	H6	$ -							$ -	$ -	$ -	0.50	$ -	$ -
2	Distribution System (acq'd pre 1988)	H6	$ -							$ -	$ -	$ -		$ -	$ -
3	Buildings (acq'd pre 1988)	H6	$ -							$ -	$ -	$ -		$ -	$ -
6	Certain Buildings; Fences	H6	$ -							$ -	$ -	$ -	0.50	$ -	$ -
8	General Office Equipment, Furniture, Fixtures	H6	$ 18,375	$ 8,000	$ 8,000					$ 26,375	$ -	$ 8,000	0.50	$ 4,000	$ -
10	Motor Vehicles, Fleet	H6	$ 82,561	$ 5,000	$ 5,000					$ 87,561	$ -	$ 5,000	0.50	$ 2,500	$ -
10.1	Certain Automobiles	H6	$ -							$ -	$ -	$ -	0.50	$ -	$ -
12	Computer Application Software (Non-Systems)	H6	$ -	$ 10,000						$ 10,000	$ -	$ -	0.00	$ -	$ 5,000
13_1	Lease #1	H6	$ -							$ -	$ -	$ -	0.00	$ -	$ -
13_2	Lease #2	H6	$ -							$ -	$ -	$ -	0.00	$ -	$ -
13_3	Lease #3	H6	$ -							$ -	$ -	$ -	0.00	$ -	$ -
13_4	Lease #4	H6	$ -							$ -	$ -	$ -	0.00	$ -	$ -
14	Limited Period Patents, Franchises, Concessions or Licences	H6	$ -							$ -	$ -	$ -	0.00	$ -	$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	H6	$ -							$ -	$ -	$ -		$ -	$ -
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	H6	$ -							$ -	$ -	$ -	0.50	$ -	$ -
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	H6	$ -							$ -	$ -	$ -	0.50	$ -	$ -
42	Fibre Optic Cable	H6	$ -							$ -	$ -	$ -	0.50	$ -	$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	H6	$ -							$ -	$ -	$ -	2.33	$ -	$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	H6	$ -							$ -	$ -	$ -	1.00	$ -	$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	H6	$ 5							$ 5	$ -	$ -		$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H6	$ -							$ -	$ -	$ -	0.50	$ -	$ -
47	Distribution System (acq'd post Feb 22/05)	H6	$ 4,219,025	$ 685,817	$ 685,817	$ 1,949,234				$ 6,854,076	$ -	$ 685,817	0.50	$ 342,909	$ -
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	H6	$ 3,384							$ 3,384	$ -	$ -	0.50	$ -	$ -
95	CWIP	H6	$ -							$ -	$ -	$ -	0.00	$ -	$ -
		H6	$ -							$ -	$ -	$ -		$ -	$ -
		H6	$ -							$ -	$ -	$ -		$ -	$ -
		H6	$ -							$ -	$ -	$ -		$ -	$ -
		H6	$ -							$ -	$ -	$ -		$ -	$ -
		H6	$ -							$ -	$ -	$ -		$ -	$ -
		H6	$ -							$ -	$ -	$ -		$ -	$ -
		H6	$ -							$ -	$ -	$ -		$ -	$ -
		H6	$ -							$ -	$ -	$ -		$ -	$ -
	TOTALS		$ 5,557,444	$ 708,817	$ 698,817	$ 1,949,234	$ -	$ -	$ -	$ 8,215,495	$ -	$ 698,817		$ 349,409	$ 5,000

1

(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the bridge year (column 9 minus column 17)
4%			$ 49,364		$ 1,184,730
6%			$ -		$ -
6%			$ -		$ -
5%			$ -		$ -
10%			$ -		$ -
20%			$ 6,075		$ 20,300
30%			$ 27,018		$ 60,543
30%			$ -		$ -
100%			$ 5,000		$ 5,000
NA					$ -
NA					$ -
NA					$ -
NA					$ -
NA					$ -
7%			$ -		$ -
5%			$ -		$ -
8%			$ -		$ -
12%			$ -		$ -
30%			$ -		$ -
50%			$ -		$ -
45%			$ 2		$ 3
30%			$ -		$ -
8%			$ 575,759		$ 6,278,317
55%			$ 1,861		$ 1,523
0%			$ -		$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
	$ -	**$ -**	**$ 665,079**	B1	**$ 7,550,416**

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Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Reference	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Bridge Year Adjustments		Balance for Bridge Year		Change During the Year	Disallowed Expenses
						Additions	Disposals				
Capital gains reserves ss.40(1)	H13	0		0				0	T13	0	
Tax Reserves Not Deducted for Accounting Purposes											
Reserve for doubtful accounts ss. 20(1)(l)	H13	0		0				0	T13	0	
Reserve for goods and services not delivered ss. 20(1)(m)	H13	0		0				0	T13	0	
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0	
Debt & share issue expenses ss. 20(1)(e)	H13	0		0				0	T13	0	
Other tax reserves	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		0	0	0	B1	0	0	0	B1	0	0
Financial statement reserves (not deductible for tax purposes)											
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0	
General Reserve for Bad Debts	H13	0		0				0	T13	0	
Accrued Employee Future Benefits:	H13	0		0				0	T13	0	
- Medical and Life Insurance	H13	0		0				0	T13	0	
- Short & Long-term Disability	H13	0		0				0	T13	0	
- Accumulated Sick Leave	H13	0		0				0	T13	0	
- Termination Cost	H13	0		0				0	T13	0	
- Other Post-Employment Benefits	H13	0		0				0	T13	0	
Provision for Environmental Costs	H13	0		0				0	T13	0	
Restructuring Costs	H13	0		0				0	T13	0	
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0	
Accrued Self-Insurance Costs	H13	0		0				0	T13	0	
Other Contingent Liabilities	H13	0		0				0	T13	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0	
Other	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		0	0	0	B1	0	0	0	B1	0	0

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income						T1	-$ 156,074	A
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				
Ontario (Max 11.5%)	11.5%	3.2%	-$ 4,994	3.2%	B			
Federal (Max 15%)	15.0%	9.0%	-$ 14,047	9.0%	C			
Combined effective tax rate (Max 26.5%)							12.20%	D = B + C
Total Income Taxes							**-$ 19,041**	E = A * D
Investment Tax Credits								F
Miscellaneous Tax Credits								G
Total Tax Credits							$ -	H = F + G
Corporate PILs/Income Tax Provision for Test Year							$ -	I = E - H
Corporate PILs/Income Tax Provision Gross Up [1]					87.80%	J = 1-D	$ -	K = I/J-I
Income Tax (grossed-up)							$ -	L = K + I

S. Summary (I = E - H)

S. Summary (L = K + I)

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	253,504
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		229,389
Recapture of capital cost allowance from Schedule 8	107	T8	0
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	0
Reserves from financial statements - balance at end of year	126	T13	0
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
	295		
	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			229,389

Deductions:				
Gain on disposal of assets per financial statements	401			
Dividends not taxable under section 83	402			
Capital cost allowance from Schedule 8	403	T8	638,968	
Terminal loss from Schedule 8	404	T8	0	
Allowable business investment loss	406			
Deferred and prepaid expenses	409			
Scientific research expenses claimed in year	411			
Tax reserves end of year	413	T13	0	
Reserves from financial statements - balance at beginning of year	414	T13	0	
Contributions to deferred income plans	416			
Book income of joint venture or partnership	305			
Equity in income from subsidiary or affiliates	306			
Other deductions				
Interest capitalized for accounting deducted for tax	395			
Capital Lease Payments	395			
Non-taxable imputed interest income on deferral and variance accounts	395			
	395			
	395			
	395			
	395			
	395			
ARO Payments - Deductible for Tax when Paid				
ITA 13(7.4) Election - Capital Contributions Received				
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				
Deferred Revenue - ITA 20(1)(m) reserve				
Principal portion of lease payments				
Lease Inducement Book Amortization credit to income				
Financing fees for tax ITA 20(1)(e) and (e.1)				
Total Deductions		calculated	**638,968**	
NET INCOME FOR TAX PURPOSES		calculated	**-156,074**	
Charitable donations	311			
Taxable dividends received under section 112 or 113	320			
Non-capital losses of previous tax years from Schedule 4	331	T4	0	
Net capital losses of previous tax years from Schedule 4	332	T4	0	
Limited partnership losses of previous tax years from Schedule 4	335			
REGULATORY TAXABLE INCOME		calculated	**-156,074**	T0

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 4 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Working Paper Reference	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	1,101,774		1,101,774
Amount to be used in Test Year and Price Cap Years	T1	0		0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	calculated	0		0
Loss Carry Forward Generated in Test Year (if any)	T1	156,074		156,074
Other Adjustments				0
Balance available for use in Future Years	calculated	1,257,849		1,257,849

Net Capital Loss Carry Forward Deduction		Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	23,996		23,996
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		23,996		23,996

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 8 CCA - Test Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the test year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")
1	Buildings, Distribution System (acq'd post 1987)	B8	$ 1,184,730							$ 1,184,730	$ -	$ -	0.50	$ -	$ -
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -
2	Distribution System (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -
3	Buildings (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -
6	Certain Buildings; Fences	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -
8	General Office Equipment, Furniture, Fixtures	B8	$ 20,300							$ 20,300	$ -	$ -	0.50	$ -	$ -
10	Motor Vehicles, Fleet	B8	$ 60,543	8,000	8,000					$ 68,543	$ -	$ 8,000	0.50	$ 4,000	$ -
10.1	Certain Automobiles	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -
12	Computer Application Software (Non-Systems)	B8	$ 5,000							$ 5,000	$ -	$ -	0.00	$ -	$ -
13_1	Lease # 1	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -
13_2	Lease # 2	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -
13_3	Lease # 3	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -
13_4	Lease # 4	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -
14	Limited Period Patents, Franchises, Concessions or Licences	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	B8	$ -							$ -	$ -	$ -		$ -	$ -
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -
42	Fibre Optic Cable	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	2.33	$ -	$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	1.00	$ -	$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	B8	$ 3							$ 3	$ -	$ -		$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -
47	Distribution System (acq'd post Feb 22/05)	B8	$ 6,278,317	480,429	480,429					$ 6,758,746	$ -	$ 480,429	0.50	$ 240,215	$ -
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	B8	$ 1,523							$ 1,523	$ -	$ -	0.50	$ -	$ -
95	CWIP	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -
	TOTALS		$ 7,550,416	$ 488,429	$ 488,429	$ -	$ -	$ -	$ -	$ 8,038,845	$ -	$ 488,429		$ 244,215	$ -

Only if election under ONTARIO REGULATION 162/01 ss. 5 or 7 filed in

(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the test year (column 9 minus column 17)
4%			$ 47,389		$ 1,137,341
6%			$ -		$ -
6%			$ -		$ -
5%			$ -		$ -
10%			$ -		$ -
20%			$ 4,060		$ 16,240
30%			$ 21,763		$ 46,780
30%			$ -		$ -
100%			$ 5,000		$ -
NA					$ -
NA					$ -
NA					$ -
NA					$ -
NA					$ -
7%			$ -		$ -
5%			$ -		$ -
8%			$ -		$ -
12%			$ -		$ -
30%			$ -		$ -
50%			$ -		$ -
45%			$ 1		$ 2
30%			$ -		$ -
8%			$ 559,917		$ 6,198,829
55%			$ 838		$ 685
0%			$ -		$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
	$ -	**$ -**	**$ 638,968**	T1	**$ 7,399,877**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Test Year	Adjusted Utility Balance		Test Year Adjustments		Balance for Test Year		Change During the Year	Disallowed Expenses
						Additions	Disposals				
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	0		0				0		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	0		0				0		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		0	0	0	T1	0	0	0	T1	0	0
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	0		0				0		0	
Accrued Employee Future Benefits:	B13	0		0				0		0	
- Medical and Life Insurance	B13	0		0				0		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	0		0				0		0	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		0	0	0	T1	0	0	0	T1	0	0

Appendix 4 – K

Espanola Regional Hydro Distribtuon Corporation 2011-2021 LRAMVA Report

IndEco

Strategic Solutions for a Changing World™

Espanola Regional Hydro Distribution Corporation 2011-2021 LRAMVA

Espanola Regional Hydro Distribution Corporation lost revenue related to Conservation and Demand Management

2011-2021

IndEco

This document was prepared for Espanola Regional Hydro Distribution Corporation by IndEco Strategic Consulting Inc.

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IndEco report C0176-2
8 September 2020

Contents

Introduction

The Lost Revenue Adjustment Mechanism (LRAM) was developed to remove a disincentive electricity local distribution companies (LDCs) may have to promote conservation and demand management (CDM) programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of LDCs. These savings and reductions directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for lost revenue that results from CDM programs the LDC offers to its customers.

Starting in 2011, the Ontario Energy Board (OEB) authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts an LDC included in the LDC's load forecast.[1]

Espanola Regional Hydro Distribution Corporation (ERHD) contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of CDM programs to customers in a variety of rate classes for the 2011-2014 period and subsequently with the IESO for the 2015-2020 period.

ERHD is requesting disposition of the LRAMVA for programs offered between 2011 and 2019, with persistence until April 30, 2021 when new rates, based on a new load forecast will come into effect. Given that ERHD is no longer offering customers new CDM programs, disposing of the LRAMVA balance that will exist as of April 30, 2021 completes ERHD's LRAMVA claims for the Conservation First Framework (CFF), and is consistent with the recommendation in the most recent filing requirements from May 2020:

"Distributors should strive to dispose of all CFF-related LRAMVA balances as part of its 2021 rate application. The OEB will rely on the Participation and Cost Reports and detailed project level savings files as supporting documentation when assessing applications for lost revenues in relation to energy and demand savings from programs delivered under the CFF where final verified results from the IESO are not available."[2]

LRAM persisting in 2011 and January to April 2012 for 2006 to 2010 programs was claimed in Ontario Energy Board rate case EB-2013-0127. ERHD has made a claim for LRAMVA since then.

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[1] *Guidelines for Electricity Distributor Conservation and Demand Management*. Ontario Energy Board. April 26, 2012 (EB-2012-0003).

[2] Ontario Energy Board, 2020. *Filing Requirements for Electricity Distribution Rate Applications*

- *2020 Edition for 2021RateApplications*. Chapter 2 Cost of Service

As required, ERHD has used the most recent input assumptions available at the time of program evaluation in support of its lost revenue calculation. The final 2014 annual verified results report provided by the IESO includes final results and adjustments for 2011 through 2014. The final 2017 annual verified results report is the most recent final CDM evaluation report available from the IESO and includes final results for 2015 through 2017 and adjustments for 2015 and 2016 programs.

Normally, the IESO releases adjustments to previous year values with each annual report. Due to direction from the Province, IESO announced that it would not be providing an annual verified report for 2018. Chapter 3 of the 2021 rate filing instructions advise LDCs to base savings subsequent to the 2017 final verified report on the IESO Participation and Cost Reports.[3] These are used to determine the 2018 savings, and adjustments made subsequent to the release of the 2017 final savings values. In addition, they provide persistence of the unverified results in 2020.

Prior to 2012, ERHD did not account for CDM in its load forecasts. ERHD included the impacts of CDM in the load forecast for ERHD's 2012 cost of service rate case and estimated the CDM savings in 2012 (EB-2011-0319). In 2011, the full savings realized resulted in lost revenues by the amount realized. For 2012 to 2021, LRAMVA threshold estimated from 2012 CDM programs is compared to the calculated lost revenue from verified final CDM results. The difference between these two is the LRAMVA value ERHD is claiming for 2012 through April 30, 2021. This report determines the variance account balance for the following revenue losses:

- Lost revenues in 2011 related to programs offered in 2011 and their persistence through 2018
- Lost revenues in 2012 through 2017 related to programs offered in those years and their persistence through 2018
- Lost revenues in 2018 related to programs offered in that year
- Lost revenues in 2019 related to programs offered in that year, as well as persistence of programs offered from 2011 to 2018
- Lost revenues from the persistence of programs offered between 2011 and 2019 in 2020 and January through April of 2021.

The carrying charges on the above variances through April 2021 are also reported.

[3] Ontario Energy Board, 2020. *Filing Requirements for Electricity Distribution Rate Applications - 2020 Edition for 2021 Rate Applications*. Chapter 2 Cost of Service

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM results – CDM results in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM results, the different time periods of results data and the rate year, and the need to determine carrying charges on the lost revenues.

The most recent input parameters available have been used to calculate the lost revenue values.

CDM RESULTS

For programs offered through 2017, the IESO performed evaluations of all programs, which examined gross energy savings from the programs, and the net-to-gross ratio (NTG), and then from those calculated net energy savings for each initiative or program. Peak load reductions were also calculated and reported in the same way. For some programs the IESO calculated gross and net energy at the project level.

Provincial results were allocated to individual LDCs based on each LDC's individual performance where possible, or through an allocation process.

The IESO reported energy savings and peak demand reductions, by program in the current year, adjustments to the previous years based on updated validation, and contribution to total savings or reductions to the end of the 2011 to 2014 period and the 2015 to 2017 period. The savings and demand reductions for a particular year for most programs persist for a number of years. The savings and demand reductions for demand response programs do not persist beyond the year in which those particular savings and demand reductions occur. The IESO was requested to provide the persistence into future years of savings and reductions for each program in each year.

Before final evaluation results were available, the IESO published monthly Participation and Cost reports that reported both verified and unverified savings. With the ending of the Conservation First Framework by the Ontario government on April 1, 2019, the IESO stopped producing reports of verified results. Unverified net energy savings for 2018, Q1 2019 and program results for earlier years that came in after the 2017 final verified results report are in the April 2019 Participation and Cost reports.

These are the best, most definitive, and defensible estimates of results associated with these programs and incorporate the most appropriate estimates of results from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Allocating results to rate classes

The IESO reports results by program or initiative. These only partially map onto rate classes. The IESO provided net results by project for projects in programs that span multiple rate classes in 2015, 2016 and 2017 and Espanola Regional Hydro identified the rate classes for these projects to calculate the allocation across rate classes. In 2011 to 2014, and 2018 and 2019, Espanola Regional Hydro reported information on projects to the IESO and again the rate classes were identified for individual projects to calculate the allocation. Where available, the allocation was calculated according to the billing unit of the relevant rate class. That is, for GS<50 projects, their allocation is the percentage of total kWh for projects in that rate class; for GS>50, their allocation is the percentage of total kW for projects in that rate class.

Application of reported results

Through 2017, the IESO reported both energy savings and reductions in demand. Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. For rate classes where the customer is charged for distribution by energy use (kWh), the IESO reported net energy savings are used to calculate lost revenues related to CDM results. For customer classes where the LDC charges for distribution based on the customer's peak monthly demand (kW), the IESO reported net demand reductions are used to calculate lost revenues related to CDM results.[4] The demand reductions in the IESO reports are multiplied by the number of months a specific program impacts a customer's peak demand. "The IESO indicated that the demand savings from energy efficiency programs shown in the Final CDM Results should generally be multiplied by twelve (12) months to represent the demand savings the distributor has experienced over the entire year…In the case of the Building Commissioning initiative, the demand savings provided in the Final CDM Results should only be multiplied by three (3) as these savings are related to space cooling and do not occur throughout the full year, but only during the summer months, typically."[5]

The OEB has decided that lost revenue cannot be claimed for the kW values reported by the IESO for the Demand Response 3 (DR3) program. "The monthly peak demand of a demand-billed customer used for billing purposes may not correspond with the demand response event; even if it did, the lost revenues would only be related to a difference between the customer's peak demand absent the demand response event and the next highest peak demand for the customer in that month… Since the IESO's evaluations cannot confirm

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[4] The exception is street lighting projects, for which the system peak reduction (reported by the IESO) and the customer peak demand reduction diverge. The ERHD street light project is discussed below.

[5] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2017-0182, May 19, 2017, p. 4.

the nature of the demand savings relative to the billing period for demand-billed customers, it is not appropriate that distributors be credited with lost revenues from demand response programs, except for those situations where the distributor can explicitly demonstrate revenue impacts."[6]

For 2018 and adjustments to 2017 made after the 2017 final results were available, the IESO did not report demand reductions. Demand reductions were estimated based on the relationship between energy and demand for each program in the verified results for that year where available, or in the previous year within ERHD.

Load reductions accounted for in the load forecast

In recent years, LDCs have incorporated projected load losses that will result from CDM programs in their load forecasts, submitted as part of their Cost of Service applications. When determining actual lost revenues, these forecasted reductions in a particular year need to be deducted from load losses attributable to CDM programs in that year to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the results accounted for in the load forecast and the results attributable to the programs.

Persistence

Persistence of energy and demand savings for programs offered between 2011 and 2014 was requested from the IESO, and these were provided for most programs.

Persistence of energy and demand savings for programs offered in 2015 to 2017 was provided with the 2017 final verified results report.

The April 2019 Participation and Costs report provided estimated net energy persistence in 2020 for all verified and unverified results.

Where persistence data were not provided, persistence is estimated using the following methods:

- For programs in 2011 – 2014 where persistence was not provided persistence was estimated using the same rate of persistence loss seen in that program in the previous year
- For unverified results in 2017 and 2018, persistence to 2020 was estimated using linear interpolation between the program year and 2020
- For unverified results, persistence in 2021 was estimated using the same rate of lost persistence seen in the verified results for that year, if available, or for 2017.

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[6] Ibid. p. 7.

Overall impact of CDM on load, by rate class

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by rate class. Finally, the difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

DISTRIBUTION RATES

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges or pass-throughs for the utility that do not affect the LDC's revenues. An exception is for certain rate riders related to taxes, and these are added to the distribution volumetric rates for lost revenue calculations, where applicable.

For most electricity distribution utilities in Ontario, including ERHD, distribution rates are set for the period from 1 May to 30 April of the next year. CDM results are reported as first-year savings for programs by calendar year, so average rates for the calendar year need to be calculated. For simplicity, the average rate is estimated based on the rate being four-twelfths of the previous year's rate (for January through April), and eight-twelfths of the current year's rate (for May through December).

CARRYING CHARGES

Because these revenues are lost throughout the year and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB and published on the Board's website. The carrying charges are simple interest, not compounded, and are calculated on the monthly lost revenue balance. Because the IESO final results estimates are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. Thus, 1/12 of the annual results are allocated to each month of the year.

Carrying charges accrue from the time of the results, until disposition.

CDM LOST REVENUES IN 2021

CDM results and the threshold are reported on an annual basis. Since LRAMVA is only being claimed for one-third of the year, the formula for LRAMVA becomes:

Annual savings/3 * Rate – Annual Threshold/3 * Rate

For simplicity of reporting, the LRAMVA workform using the annual savings and threshold amounts and instead uses rate/3:

(Annual Savings – Annual Threshold) * Rate/3

Conveniently, because of the way the workform calculates the average annual rate, the Rate/3 is automatically calculated on the workform by not including 2021 rates (which come into effect in May) but showing that Period 1 of 4 months (Jan-Apr) uses 2020 rates.

REPORTING OF LOST REVENUE

The LDC reports these lost revenues on its financial statements in Account 1568, and the associated rate class-specific sub-accounts.

Results

Following the methodology described above, lost revenues were calculated for ERHD. The results reference tables provided in the work form.

CDM RESULTS

IESO evaluation results

The most recent and appropriate final CDM evaluation reports from the IESO were used in support of the lost revenue calculations for all savings through 2017, except for a street lighting project completed in 2015.

The April 2019 IESO Participation and Cost report was used to determine savings for 2018 and 2019, and 2017 adjustments. Since demand savings estimates are not provided in the Participation and Cost report, for programs in rate classes billed by demand, these were estimated based on the kW/kWh for the same program realized by Espanola Regional Hydro in the most recent year.

The IESO provided ERHD with persistence data for savings at the program level for programs through 2017.

The IESO Participation and Cost report includes 2020 persistence of 2018 and 2019 programs and 2017 adjustments made after the release of the final 2017 verified results. These values are used in the workform, with intermediate years estimated via linear interpolation. 2021 persistence of unverified results is based on the persistence rate of verified results in the same year, where available, or in 2017.

The data provided are presented in Table 4a through 4d on Tab 4, and Tables 5a to 5e on Tab 5 of the LRAMVA work form.

Streetlighting project

In 2014, Espanola Regional Hydro began a project to retrofit streetlights in the municipality. The project was completed in early 2015, and changes in billing were instituted in January 2015.

Energy savings from this project were reported within the Retrofit program results for 2015. Because streetlighting is not used during peak periods, the IESO reports zero peak demand savings from streetlighting projects. However, the streetlight retrofit project did impact ERHD's revenues so a special calculation is done to calculate demand reductions of the project and its impact on revenues, drawing on actual bill reductions, and characteristics of the bulbs that are replaced or retrofitted.

Details are shown on Tab 8 of the LRAMVA work forms. A net-to-gross adjustment is applied to the calculated gross reductions. As a project-specific NTG ratio is not available, the NTG ratio for the Retrofit program in 2015 is used. The calculated net demand reduction of the streetlight retrofit project is shown on Tab 8 of the LRAMVA work forms.

As the streetlighting rate class is billed by kW, the calculated net kWh savings from the Retrofit LED upgrade project do not impact ERHD's revenue. Thus, the calculated kilowatt-hours of savings have been manually removed from the reported Retrofit program savings in 2015. The actual lost revenue from the streetlighting retrofit project has been calculated directly by multiplying the reduction in the demand billed by the appropriate rate.

As requested by the Ontario Energy Board, the work form shows the quantities and wattage of bulbs that were changed for the project. Where applicable, ERHD confirms it has used the OEB streetlighting load shape in estimating the demand reductions.

ERHD confirms that the streetlight upgrade reported represents incremental savings attributable to participation in the IESO program. ERHD did not include any savings not attributable to the IESO program.

As discussed, the associated energy savings for the streetlighting project under the Retrofit program have been removed from the energy savings associated with this program so as not to double count savings.

ERHD has received a report from the municipality that validates the number and type of bulbs replaced or retrofitted through the IESO program.

Allocating results to rate classes

ERHD provided information on the allocation of results to rate classes, drawing on project specific information provided by the IESO. In most cases, the allocation is straightforward. Only the Retrofit Program, and its predecessor the Energy Efficiency Retrofit Initiative (EERI) spanned more than one rate class. No allocation was provided for programs for which ERHD has no program results.

ERHD bills customers in different rate classes using different volumetric units, either kilowatt hours (kWh), or customer peak monthly kilowatts (kW). The rate classes (and billing units) for ERHD are:

- Residential (kWh)
- GS <50 kW (kWh)
- GS 50 to 4,999 kW (kW)
- Unmetered Scattered Load (kWh)
- Sentinel Lighting (kW)
- Street Lighting (kW)

Tables 4a, 4b, 4c and 4d of the OEB LRAMVA work form show the percentage allocation by rate class for 2011 to 2014 results. Tables 5-a, b, c, d and e of the OEB LRAMVA work form show the percentage allocation by rate class for 2015, 2016, 2017, 2018 and 2019 results respectively. In each year the rate class allocation percentage totals for each program may not add up to exactly 100% in cases were kWh savings are allocated to rate classes billed by kWh and kW demand reductions are allocated to rate classes billed by kW.

Load reductions accounted for in the load forecast

The cost of service application affecting 2012 through 2021 results was filed for the 2012 rate year (EB-2011-0319). The load forecast associated with that application included a CDM adjustment to account for estimated load losses from 2011 and 2012 CDM programs. Related to the specific adjustment made to the forecast for CDM, is the LRAMVA threshold value.

"The LRAMVA threshold value is the anticipated lost revenue amount (based on anticipated CDM savings) based on what is reflected in the underlying load forecast (i.e., used for billing determinants, as applicable) when the distributor has rebased rates through a cost of service (or Custom IR) application."[7]

As stated in the quoted guideline, this value is compared with actual lost revenues (based on actual CDM savings) to generate the final LRAMVA amount.

Overall impact of CDM on load, by rate class

Multiplying the adjusted energy savings or demand reduction reported for ERHD for each program by the allocation by rate class provides the impact on load of that CDM program within the appropriate rate class. The sum of the energy savings and demand reductions for all of the programs for each rate class provides the overall impact of CDM on load by rate class. The overall load impact for each calendar year includes the results for the CDM programs and any adjustments to the results in that year.

The bottom of Tables 4a, 4b, 4c and 4d of the work form shows the overall impact of CDM on load by rate class for 2011, 2012, 2013 and 2014, respectively. The bottom of Tables 5-a, 5-b and 5-c, 5-d and 5-e of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2015, 2016, 2017, 2018 and 2019.

DISTRIBUTION RATES

The distribution rates that are used to calculate the CDM impact on distributor revenue for each rate class for ERHD are shown in Table 3

[7] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2017-0182, May 19, 2017, p.8.

of the OEB LRAMVA work form. The distribution rates are pro-rated from the rate year to the calendar year, as needed, using the number of months of each rate year in each calendar year. Table 3-a of the OEB LRAMVA work form shows the pro-rated rates used for 2011 through 2021. As discussed on p.6, the rates shown for 2021 are one-third of the 2020 rates to account for lost revenues only being related to one-third of the year.

LOST REVENUES

The lost revenues for each year by rate class for ERHD calculated from final CDM program results are shown in Table 1-b of the OEB LRAMVA work form. The lost revenue for 2011 through 2021 is based on the load impact for each rate class in 2011-2021 multiplied by the rate for that rate class in that year. The load impact includes the impact of CDM programs in 2011-2021 and the persistence of the CDM program impact from programs offered in 2011 through 2019.

Table 1-b of the OEB LRAMVA work form also shows the lost revenue in 2012 through 2021 due to CDM activities accounted for in ERHD's 2012 load forecast. The impact on ERHD's revenue is the variance between what is calculated from final CDM program results and CDM results already accounted for in the load forecast.

CARRYING CHARGES

The monthly carrying charges by rate class on ERHD's lost revenue variance are shown in Table 6 of the OEB LRAMVA work form. The carrying charges are reported monthly, from the time the lost revenues resulted (January 2011), through to April 30, 2021.

Conclusions

The LRAMVA balance at April 30, 2021 for ERHD that includes results from 2011 – 2019 CDM programs, adjustments to 2011 to 2017 results and persistence to April 30, 2021 is $329,270. The total carrying charges on this LRAMVA balance accumulated to April 30, 2021 are $15,082. These balances are attributable to individual rate classes according to the following table:

Customer Class	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	$93,764	$3,421	$97,185
GS < 50 kW	$71,525	$5,495	$77,019
GS 50 to 4,999 kW	$46,194	$1,879	$48,073
Unmetered scattered load	-$312	-$20	-$332
Sentinel lighting	-$169	-$11	-$180
Street light service	$103,186	$4,317	$107,503
Total	$314,188	$15,082	$329,270

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