EXHIBIT 1:

ADMINISTRATIVE DOCUMENTS

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Application

2.1 Exhibit 1: Administrative Documents

2.1.1 Table of Contents

Please see Appendix 1-A for a Table of Contents that lists the major sections and subsections of the whole application.

2.1.2 Executive Summary and Business Plan

The Applicant is Espanola Regional Hydro Distribution Corporation referred to in this Application as the "Applicant" or "ERHDC". The Applicant is an Ontario corporation with its office in the town of Espanola. The Applicant carries on the business of distributing electricity in its service territory which includes the Town of Espanola and the Township of Sables Spanish River. The Applicant distributes electricity to approximately 3,300 customers within a service territory that covers 102 square kilometers. Of that service territory, 76 square kilometers are rural and 26 square kilometers are urban. The total population is 8,236. ERHDC is embedded within Hydro One and does not host any utilities within its service area.

ERHDC was recently purchased by North Bay Hydro Holdings Ltd. as detailed below.

The Applicant hereby applies to the Ontario Energy Board (the "OEB" or the "Board") pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2021 (the "Application"). ERHDC last had its rates rebased effective May 1, 2012 and its last IRM increase was effective May 1, 2015.

The Application has been prepared pursuant to the Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach issued October 18, 2012 (the "RRFE").

The Applicant followed Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications last revised on May 14, 2020 in preparing the Application except for the adjustments as detailed in Section 2.1.2.1 - 2021 Cost of Service Application Modified Filing below.

In accordance with Chapter 5 of the OEB's *Filing Requirements for Electricity Transmission and Distribution Applications* ERHDC has prepared a Distribution System Plan ("DSP"), which has been modified as detailed in Section 2.1.2.1 - 2021 Cost of Service Application Modified Filing below.

ERHDC has prepared the revenue requirement in accordance with the Board's Cost of Capital Parameter Updates for Rates Effective in 2021 released November 9, 2020.

The Applicant submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

(i) the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;

(ii) the proposed adjusted rates are necessary to meet the Applicant's market based rate of return and PILs (Payments in Lieu of Taxes) requirements;

(iii) Included in Exhibit 8, Rate Design, is a rate mitigation plan to reduce the impact of the rate increase to the residential class. As a result of the rate mitigation plan, there are no impacts to any of the customer classes that are so significant as to warrant any deferral of any adjustments being requested by the Applicant except as noted in Exhibit 8;

(iv) the other service charges proposed by the Applicant are the same as those previously approved by the Board, and

(v) Such other and further grounds and material as counsel may advise and this tribunal may permit.

The Application will address a number of ERHDC's regulatory issues since its last rebasing in 2012, including:

- Bringing ERHDC back into compliance with OEB regulatory requirements by allowing ERHDC to begin the transition of residential consumers towards fully-fixed rates.

- Ending the ICM rate rider, and rolling the substation properly into rates, which will help reduce rates to the benefit of customers (the actual costs of the substation were less than what was previously forecasted).

- Filing a modified one year distribution system plan (DSP) leading into the amalgamation with North Bay Hydro.

- Disposing of Group 1 DVAs, which were last disposed of for December 31, 2013 balances, and LRAMVA which was last approved for 2014 rates for pre-2012 programs in 2011 until April 2012.

- Updating ERHDC's load forecast, cost allocation and rate design to reflect more current information.

ERHDC has put a business plan in place in order to maintain the targets as set out in the OEB Renewed Regulatory Framework for Electricity (RRFE) targets and meet ERHDC's Corporate Goals as outlined below:

<u>ERHDC Corporate Targets</u>

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.
2) Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations, and ensure regulatory compliance.
3) Maintain current staffing requirements, including training and preparing for succession planning.
4) To provide a reasonable rate of return to the Shareholder.

<u>Renewed Regulatory Framework for Electricity (RRFE) Targets</u>

The Board introduced a new approach to rate setting at the end of 2012 with the Renewed Regulatory Framework. The Renewed Regulatory Framework is a performance based approach to regulation that focuses on the achievement of outcomes such as efficiency, reliability, sustainability, and financial viability. The Performance Measurement for Electricity Distributors: A Scorecard Approach, Board File EB-2010-0379 was published on March 5, 2014. The report details the scorecard measures approach which the Board expects to use in order to monitor and assess a distributor's effectiveness and improvements in achieving the four performance outcomes of:

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

ERHDC's Business Plan is attached in Appendix 1-I. The principles of the Business Plan form the basis of this application.

2.1.2.1 2021 Cost of Service Application Modified Filing

ERHDC filed a letter with the Ontario Energy Board (the "OEB") on July 24, 2020[1] proposing several adjustments to the OEB's Chapter 2 and Chapter 5 Filing Requirements applicable to this

[1] EB-2020-0020 Letter from ERHDC to OEB Re Espanola Regional Hydro Distribution Corporation 2021 Cost of Service Application – Requested Adjustments dated July 24, 2020.

Application. The intervenors in ERHDC's previous COS application and MAADs Application were copied on the letter. In summary, the adjustments requested included:

1. Limited scope of variance analysis
   - limiting all variance analysis obligations for the Application to only the test year, the bridge year and no more than the last three (3) actual historical years

2. Scaling back certain discrete requirements
   - Exhibit 1
     - Filing a simplified business plan for ERHDC covering a future time horizon of one (1) year
     - Minimizing customer engagement obligations and keeping work in-house with online survey
     - Limiting the time for the scorecard performance analysis (over the last three (3) historical years)
   - Exhibit 2
     - Distribution System Plan limited to one (1) year forward test year plan

In the OEB's response dated September 8, 2020[2] it accepted ERHDC's proposed approach and provided the following comments:

- The details needed to decide on ERHDC's rates will ultimately be determined by the OEB panel hearing the application.
- ERHDC may file a one-year DSP that will only cover the 2021 forward test year, however the OEB expects that the Advanced Capital Module/Incremental Capital Module will not be available to ERHDC until a five-year DSP is filed.
- The variance analysis and information in the Chapter 2 Appendices will include the test year, bridge year, the last three historical years and the last rebasing test year (2012).

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

- It will be up to ERHDC to determine the appropriate scope of customer engagement which is expected to be commensurate with its requests in the application.
- ERHDC will bring forward its Group 1 and Group2 DVA balances for review and disposition.

ERHDC has complied in this application with its adjustment requests and OEB comments.

2.1.2.2 Summary of Issues

The following items are discussed briefly in this summary. Certain items are discussed in more detail in other sections of the Application and are referenced to the more detailed discussion.

(a) Return on Equity and Rate History

Table 1-1 below provides the history of ROE from 2012, 2017 to 2019, and 2020 Bridge and 2021 Test years.

Table 1 - 1: Return History

	2012 Approved	2017	2018	2019	2020 Bridge	2021 Test
Return	9.12%	2.45%	4.12%	-9.46%	-5.21%	3.06%*

*Rebased rates to be effective May 1, 2021 therefore regulated return of 8.34% won't be attained in 2021

Rates were declared interim as of May 1, 2016 due to ERHDC's earnings in 2013, 2014 and 2015 being over the 3% deadband. As can be seen in Table 1-1 above, the actual achieved ROE for the Applicant was significantly less than the Board's approved ROE of 9.12% for each year after 2016, specifically, 6.67%, 5% and 18.58% less in 2017, 2018 and 2019 respectively. There has not been any overearnings in the historical period since the commencement of interim rates. As a consequence, the Applicant is seeking a declaration that the interim rate order made effective May 1, 2016 and applied in each subsequent year be declared final for the entire historical period (e.g. May 1, 2016 to April 30, 2021).

Table 1 - 2: Rate History

	2013	2014	2015	2016	2017	2018	2019	2020 Bridge
Rate Increases since last CoS	0.48%	1.55%	1.45%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 1-2 above provides ERHDC's rate increases for the period 2013 to 2020. ERHDC's last Cost of Service rate increase was in 2012. Inflationary increases to distribution rates since then were 0.48% in 2013, 1.55% in 2014, and 1.45% in 2015, for a total of 3.48%. An ICM rate rider was also implemented in 2014 for a new distribution station. Distribution rates have not increased since May 1, 2015. ERHDC's revenue requirement request (which now includes the new distribution station in the rate base) in this Cost of Service application results in an increase of approximately 7% to a monthly residential bill of 750kWhs.

(b) **Line Clearing expense history**

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 has been removed from the 2021 Test Year. and the annual contractor amount has been reduced in the 2021 Test Year. ERHHDC 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. See Exhibit 4 for more discussion.

(c) **Divestiture to North Bay Hydro**

ERHDC was sold to North Bay Hydro in 2019. Details are below.

(d) **Station 4 – Incremental Capital Module (ICM)**

ERHDC applied for and received an ICM adjustment as part of its 2014 IRM application (EB-2013-0127). In this application, ERHDC is requesting approval from the Board to move the Incremental Capital Expenditures currently recorded in Account 1508 to its capital assets as of the date of the approved rate order using the net book value of these assets at December 31, 2020. A reconciliation between the amounts included in the ICM application and actual costs is included in Exhibit 2.

(e) Contract with PUC Services Inc.

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.

Included in Exhibit 4 is a discussion of the contact and comparisons of ERHDC's costs to its peer groups. ERHDC submits that the comparisons demonstrate that the service contract with PUC Services results in prudent and reasonable costs to its customers while providing a service satisfaction level of 91% as per its latest customer satisfaction survey.

(f) Rate Application Costs

ERHDC's expenses have been consistent since its last Cost of Service application with two notable exceptions. The expenses in 2019 showed an increase because of divestiture costs incurred in conjunction with the LDC being sold to North Bay Hydro. These costs have not been requested for recovery. The second exception is the 2021 Test year which has an increase of approximately $100,000 for the one-time costs associated with the Cost of Service rate application. Table 1-3 below shows the costs associated with the Rate Application. The estimated cost of $582,539, as calculated below in Table 1-3 has been included in the 2021 Test Year expenses in the amount of $116,508.

Table 1 - 3: Rate Application 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

(g) Rate Mitigation

ERHDC has not rebased rates since 2012, has had minimal IRM increases in the last 9 years and is required to transition to a fully fixed residential rates. Without a rate mitigation plan the monthly increase to a 750kWh residential customer would be 13.76%. Therefore ERHDC is proposing a rate mitigation plan that includes:

1. Adjusting the revenue to cost ratios of the Sentinel Light rate class.

2. Recovering Group 1 regulatory variance and LRAMVA variance over 5 years. Recovering the 1589 – Global Adjustment and Group 2 variance accounts over 1 year.

3. Moving to fully fixed residential rates over the next five years;

The rate mitigation plan is detailed in Exhibit 8.

(h) Effects of Covid-19

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

An area of concern is the level of bad debts. At this time, it is difficult to predict the level of future bad debts but ERHDC will monitor customer payment patterns and follow all legislated mandates in this matter.

Due to the uncertainty with the COVID-19 crisis, ERHDC is unable to predict its effect on future consumption levels, therefore the load forecast (Exhibit 3) has not been modified to account for COVID-19.

After review of the best information available, ERHDC has not made any COVID-19 related adjustments to the Application. ERHDC will utilize the new Account 1509 - Impacts Arising from the COVID-19 Emergency deferral account to record increases in the bad debt expense, variances in consumption levels from the load forecast or other expenses as necessary. There is an ongoing OEB consultation on the Deferral Account – Impacts Arising from the COVID-19 Emergency (EB-2020-0133). ERHDC notes that the outcome of this consultation would impact how ERHDC uses the deferral account and ERHDC plans to follow OEB guidelines that result from this consultation.

2.1.2.3 Renewed Regulatory Framework for Electricity Distributors

The Board's Renewed Regulatory Framework for Electricity ("RRFE") takes a performance-based approach to planning with the four RRFE outcomes of:

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

ERHDC's corporate goals as outlined below align well with the objectives of the RRFE. Customer focus and engagement is a key component of ERHDC's current and future plans.

5) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.
6) Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations and ensure regulatory compliance.
7) Maintain current staffing requirements, including training and preparing for succession planning.
8) To provide a reasonable rate of return to the Shareholder.

Performance outcomes outlined in the Renewed Regulatory Framework for Electricity (RRFE) are measured on the LDCs scorecard which is published annually. In the most recently published scorecard (2019 results), ERHDC met or exceeded all prescribed targets for scorecard measures except for telephone calls answered and the Return on Equity (ROE) metric.

Telephone calls answered - The main contributing factor to the missed target was staff turnover which resulted in new staff having longer average talk times with customers. The extra time on the phones with customers then lead to calls waiting in the queue. ERHDC has a fully trained team in place and has seen significant improvement for 2020. ERHDC will continue to monitor this performance measure to identify opportunities for improvement.

Return on Equity- Table 1-4 below demonstrates the ROE Performance from 2014 to 2019

Table 1 - 4: ROE Performance Deemed vs. Achieved

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
% Deemed	9.12	9.12	9.12	9.12	9.12	9.12
% Achieved	28.00	15.91	6.29	2.45	4.12	-9.46

ERHDC's return on equity in 2014 and 2015 was more than 3% points higher than the expected return due to rate mitigation measures implemented as a result of the last Cost of Service approval for 2012. Returns for the years prior to 2014 were below deemed. The return on equity in 2016 was within 3% points of deemed. Returns in 2017 and 2018 were more than 3% points lower than the expected return, as are those for 2019 and projected for 2020. The low achieved regulatory return on equity is primarily due to unfavourable distribution revenue as ERHDC has not rebased its rates since 2012 and has not reached the consumption levels projected in the 2012 Cost of Service rate application. Since 2014 and 2015 rates were declared final, any changes at this time would be retroactive rate making. The changes were largely driven by the smart meter recovery and the foregone revenue rate rider from the 2012 Cost of Service rate application.

ERHDC is applying for revised rates effective May 1, 2021 to address its poor performance on profitability; this cost of service application will assist ERHDC in realigning rates to recover its costs.

ERHDC's Business Plan for 2020-2021 is attached at Appendix 1-I.

2.1.3 Customer Summary

ERHDC is an electricity distributor that services the Town of Espanola and the Township of Sables Spanish River. ERHDC distributes electricity to approximately 3,300 customers within a service territory that covers 102 square kilometers. Of that service territory, 76 square kilometers are rural and 26 square kilometers are urban. The total population is 8,236. ERHDC is embedded within Hydro One and does not host any utilities within its service area.

Every charge on your hydro bill is either mandated by the provincial government or regulated by the Ontario Energy Board (OEB). ERHDC only retains approximately 25 cents of every dollar from your bill. This amount funds our ability to provide a safe and reliable network of power to our entire Community. It also covers the cost of our building, vehicles, equipment, staffing and every other cost associated with the business. The remaining 75 cents is collected by ERHDC and goes to provincial entities to fund upstream transmission costs as well as the cost to generate electricity (including renewable and non-renewable generators) and various regulatory costs including those required to run the provincial electricity market.

The OEB's Cost of Service application typically occurs every five years and determines what each LDC can charge for its distribution rate. ERHDC is currently applying to the OEB for approval to increase the distribution rates for ERHDC Customers. The last Cost of Service rate application to increase distribution rates was in 2012. The last time ERHDC's rates increased was 2015 to account for inflationary increases. As part of the decision of an OEB MAADs application (EB-2019-0015), ERHDC was ordered to file a Cost of Service application for rates effective in 2021.

ERHDC conducts a customer satisfaction survey on a biannual basis to obtain feedback on the value of service provided to customers. The information from the surveys is used to help inform future investment planning to meet customers needs. Results of previous customer satisfaction surveys are in Table 1-5 below:

Table 1 - 5: Customer Satisfaction Survey Results

	2015	2016	2017	2018	2019
Customer Satisfaction Survey	89%	87%	87%	87%	91%

For additional details on ERHDC's customer engagement see Exhibit 1, Section 2.1.7.

This application sets out ERHDC's capital and operational plans and the funding required to support those plans. Details of ERHDC's plans can be found in its Distribution System Plan in Exhibit 2 of this application.

Since 2012, ERHDC has experienced increases in Operations, Maintenance, and Administrative ("OM&A") costs due to inflation as well as the investment in a number of infrastructure renewal projects. ERHDC requirements for distribution rates in 2021 include increases in OM&A costs and $198,000 driven by the impact of investments in capital infrastructure that ERHDC has made since 2012, including those proposed in 2021. 2021 investments include the replacement of aging poles, transformers and conductors. The 2 major programs for 2021 include the pole replacement program based on third party testing and the replacement of the primary voltage feed on highway 17.

The main contributors to the increases in OM&A are increased regulatory costs and inflationary increases over the past 9 years. The total OM&A increase requested is approximately $265,000. OM&A costs are discussed in Exhibit 4 of ERHDC's Cost of Service rate application.

ERHDC needs to make continued investment in capital assets to maintain the reliability of the distribution system. Over time the assets of the distribution system such as poles, conductors, distribution stations and transformers deteriorate and need to be replaced. Some of these components in ERHDC's distribution system are over 50 years old. The total increase in revenue requirement driven by these capital projects is approximately $198,000. Capital Expenditures are discussed in Exhibit 2 of ERHDC's Cost of Service rate application.

ERHDC is requesting approval from the OEB to charge electricity distribution rates effective May 1, 2021 to recover its base revenue requirement of $2,071,003. If approved, a typical residential customer using 750kWH would see a $8.73 per month increase. Table 1-6 below provides the effects on monthly bills for a 750 kWh residential customer, an ERHDC average residential customer and a 2,000 kWh general service < 50 kW customer.

Table 1 - 6: Bill Impacts (Residential 750kWh, Average Residential and and GS<50)

Customer Class	Consumption	$ Increase	% Increase
Residential	750 kWhs	$8.73	7.25%
Residential	848 kWhs	$9.29	6.91%
General Service < 50 kw	2,386 kWhs	$22.80	6.16%

For the specific approvals ERHDC is requesting in addition to the change in electricity distribution rates, see Section 2.1.4.13 in this Exhibit 1.

In 2019, ERHDC exceeded most of the mandatory OEB industry targets. Table 1-7 below summarizes 2019 performance. ERHDC has implemented plans to exceed all targets in 2020 and beyond. For additional details on performance measurement see section 2.1.8 in this Exhibit 1.

Table 1 - 7: Performance Results

Description	ERHDC	Target
New Residential/Small Business Services Connected on Time	100.00%	90.00%
Scheduled Appointments Met on Time	98.55%	90.00%
Telephone Calls Answered on Time	63.04%	65.00%
First Contact Resolution	99.23%	
Billing Accuracy	99.98%	98.00%
Customer Satisfaction Survey Results	91.00%	
Level of Public Awareness	85.00%	
Level of Compliance with Ontario Regulation 22/04	C	C
Number of General Public Incidents	0	0
Rate per 10, 100, 1000 km of line	0.000	0
Average Number of Hours Power to Customer is Interrupted	0.35	0.67
Average Number of Times Power to Customer is Interrupted	0.17	0.33
Distribution System Plan Implementation on Progress	On Track	
Efficiency Assessment (1 = most efficient 5 = least efficient)	2	
Total Cost ($) per Customer	$758	
Total Cost ($) per Km of Line	$17,789	
Net Cumulative Energy Savings (Percent of Target Achieved)	131.00%	
Renewable Generation Connection Impact Assessments Completed on Time	N/A	
New Micro-Embedded Generation Facilities Connected on Time	N/A	90.00%
Liquidity: Current Ratio (>1)	0.83	
Leverage: Total Debt to Equity Ratio (1.5=60/40)	-22.35	
Profitability: Regulatory Return on Equity - Deemed	9.12%	
Profitability: Regulatory Return on Equity - Achieved	-9.46%	

2.1.4 Administration

2.1.4.1 Certificate of Evidence

Attached as Appendix 1-K is ERHDC's Certificate of Evidence.

2.1.4.2 Primary Contact and Representatives

<u>The Applicant:</u>

Espanola Regional Hydro Distribution Corporation
598 Second Avenue

Espanola, Ontario
P5E 1C4

Primary Application Contact:

Mr. Tyler Kasubeck
Rates and Regulatory Affairs Officer
Telephone: 705-759-3009
Fax: 705-759-6553
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The Applicant's Legal Representation:

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide Street West
Toronto, ON M5H 4E3

Primary Contact:

John A.D. Vellone
Partner
Telephone: 416-367-6730
Fax: 416-367-6749
Email: jvellone@blg.com

2.1.4.3 Website and Social Media

The Application and related materials will be posted on ERHDC's website and will be available for viewing at the following internet address:

http://www.erhydro.com

(a) **Impacted Customers**

Residents, businesses and institutions in the Town of Espanola and the Township of Sables-Spanish Rivers who receive electricity distribution services from ERHDC will be affected by the Application. This includes customers within the following rate classes:

- Residential
- General Service Less Than 50 kW
- General Service 50 to 4999 kW
- Unmetered Scattered Load
- Sentinel Lighting
- Street Lighting

A summary of bill impacts is provided in Table 1-8 later in this section.

2.1.4.4 Publication of Notice of Hearing

ERHDC proposes to publish the Application and related materials on the following website, http://www.erhydro.com. Publishing the Application on the ERHDC website will provide easy access to interested parties and potentially reach a broader audience. If the OEB decides that publication in a paper is necessary then we recommend the Mid-North Monitor. The Mid-North Monitor is a weekly paid circulation issuing 2000 copies and covers ERHDC's entire service territory. The Mid-North monitor has the highest readership and circulation numbers in the area.

2.1.4.5 Bill Impacts

In Table 1-8 below, in addition to the 750kWh per month ERHDC has included the consumption profile of 848 kWh per month, representing the average residential customer in ERHDC's service territory and 318 kWh per month, representing the lowest 10% of users in terms of consumption. ERHDC's colder winters and use of electric heat in homes contributes to the higher average consumption profile. The electric heat is difficult to replace with forced air systems due to the cost and construction difficulties associated with installing the necessary duct work.

Table 1 - 8: Bill Impacts

Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/ Decrease	Total Bill Impact %
Residential	750	0	$8.73	7.25%
Residential	318	0	$6.29	10.74%
Residential	848	0	$9.29	6.91%
GS<50	2,386	0	$22.80	6.16%
GS>50	44,361	115	$538.50	5.98%
USL	456	0	$4.14	5.50%
Sentinel Light	81	0.22	$2.37	15.22%
Street Light	14238	41.8	-$67.37	-1.65%

2.1.4.6 Form of Hearing Requested

ERHDC requests that this Application be disposed of by way of a written hearing. A written hearing will be the most efficient, prudent and cost effective means to process the Application.

2.1.4.7 Requested Effective Date

The requested effective date for the application is May 1, 2021.

In the event that the Board is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2021, the Application requests that its current rates remain interim, pending the implementation of the Board's Rate Order for the 2021 rate year.

2.1.4.8 Statement of Deviations

ERHDC has adhered to Board's filing documents listed below in preparing this application accept as detailed in Section 2.1.2.1 - 2021 Cost of Service Application Modified Filing_above:

- Chapter 2 of the Board's "Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Applications – Chapter 2: Cost of Service", issued May 14, 2020;
- The Board's "Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5: Consolidated Distribution System Plan Filing Requirements", issued May 14, 2020; and

- The Board's Cost of Capital Parameter Updates for Rates Effective in 2021 released November 9, 2020.

2.1.4.9 Statement of Changes to Methodologies

ERHDC confirms that it implemented the regulatory accounting changes for depreciation and overhead capitalization as part of its 2012 Cost of Service application and has prepared this Application on the IFRS basis, as required. The following issues were addressed in the 2012 Cost of Service application (EB-2011-0319):

IAS 16 – Property, Plant & Equipment – Componentization and Depreciation

IAS 16 – Property, Plant & Equipment – Capitalization of Burdens

ERHDC adopted International Financial Reporting Standards on January 1, 2015 with a transition date of January 1, 2014.

2.1.4.10 Identification of Board Directives from Previous Board Decisions

ERHDC has received two utility specific directions from the Board since submitting its last Cost of Service Application (EB-2011-0319) for the May 1, 2012 distribution rates:

<u>1. MAADs Application – Material Accounting Policies Differences Between North Bay Hydro and Espanola Regional Hydro Distribution</u>

In the OEB's MAADs Decision and Order dated August 22, 2019 (EB-2019-0015), the OEB made the following finding as it relates to the accounting policies of the Applicant:

"The OEB finds the proposal provided by the Applicant in its reply submission reasonable. The Applicant's preliminary review has not identified material differences in the underlying accounting policies between North Bay Hydro and Espanola Hydro. The Applicant is ordered to complete its analysis of accounting policies and bring forward a detailed proposal as part of its cost of service rate application."

The Applicant has completed a detailed analysis of its accounting policies in comparison to those used by North Bay Hydro. The results of that detailed analysis, in terms of similarities and differences in accounting policies are summarized in the Table 1-9 below.

<u>Table 1 - 9: Analysis of Accounting Policies Differences</u>

Accounting Policies	Comparison to NBHDL	Impact	Explanation
Capitalization Policy:			
Limit	Differs	Not material	NBHDL's policy is $500 / ERHDC is $1,000 - given ERHDC's capital spending levels, this variance has been deemed immaterial Potential impact to general asset capitalization, however, budget levels are minimal spend - 2021 Test Year general asset budget is $33k which is under ERHDC's materiality threshold of $50k
Overheads			Overall aligned with NBHDL with a few exceptions listed below that are not applicable
Engineering	Not applicable	Not material	ERHDC does not have an Engineering department - all 3rd party costs are coded to capital work directly as applicable
Ops Admin	Similar		ERHDC charges a portion of the Lines Supervisor's time to capital projects in the same proportion as the line crew charges time to the capital projects
Fleet	Similar		Hourly truck rate - charged to capital as applicable
Stores (Materials)	Not applicable	Not material	ERH codes material directly to capital projects - there is not a substantial warehouse / dedicated staff to this function
Labour	Similar		Direct labour costs based on an hourly rate - charged based on number of hours that an employee works on a specific project Includes burden costs (health benefits, employer payroll expenses, etc. - charged to capital based on percentage of total labour dollars
Depreciation	Differs	Not material	Overall aligned with NBHDL - ERHDC follows Kinetric report and is within Typical Useful Life (TUL) - ERHDC TUL aligns with NBHDL TUL with exceptions listed below, deemed immaterial
1/2 year rule - accounting purposes	Differs	Not material	ERHDC applies full year depreciation in the year of acquisition and none in the final year of life - NBHDL utilizes 1/2 year rule Deemed immaterial - ex; 2021 Test Year additions for Poles (largest component) $175,195 - over 40 years, 1/2 year rule impact = $2,190 variance (ie; reduction to dep'n in year of installation - deemed immaterial)
TUL - Poles	Differs	Not material	ERHDC utilizes a 40YR TUL (NBHDL=45YR TUL) - based on 2021 Test Year additions of $175,195 - dep'n at 40YR = $4,380 dep'n expense / dep'n at 45YR = $3,893 - an annual variance $487 (ie; dep'n would be $487 lower - deemed immaterial)
TUL - Station Transformers	Differs	Not material	ERHDC utilizes a 50YR TUL (NBHDL=45YR TUL) - based on cost of $200,000 (avg. cost of last 6 station transformers purchased by NBHDL) - dep'n at 50YR = $4,000 dep'n expense / dep'n at 45YR = $4,444 - an annual variance $444 (ie; dep'n would be $444 higher - deemed immaterial)
TUL - Station Equipment - Switchgear	Differs	Not material	ERHDC utilizes a 50YR TUL (NBHDL=45YR TUL) - based on cost of $100,000 (used for illustrative purposes as ERHDC's total CapEx spend in 2021 is $455k) - dep'n at 50YR = $2,000 dep'n expense / dep'n at 45YR = $2,500 - an annual variance $500 (ie; dep'n would be $500 higher - deemed immaterial)
CWIP	Similar		ERHDC does not capitalize an asset until it is deemed in-service
Other Accounting Policies:			
Purchasing Policy	Differs	No impact on COS	ERHDC's purchasing policy differs from NBHDL, however, appropriate controls are in place that satisfy both NBHDL and the external auditor
Employee Future Benefits	Similar		Based on actuarial reports and on accrual basis
Provision for Uncollectible Accounts	Similar		Based on accounts aged >90 days
Revenue Recognition	Similar		ERHDC recognizes revenue when earned and utilizes the accrual method
Deferral and Variance Accounts	Similar		ERHDC follows settlement guidelines and related OEB accounting guidelines
All other	Similar		All significant accounting policies are aligned with IFRS and no material discrepancies were found upon the first New ERHDC financial statement compilation Inventory valuation, use of estimates, impairment testing, OMERs, measurement/impairment of financial instruments

The accounting policies that would primarily impact rate setting are the capitalization of overheads and depreciation. A review of these policies, the types of transactions that would be processed, and how costs are allocated to capital and OM&A has been completed. It is the assessment of management that ERHDC's capitalization of overheads and depreciation policies align with NBHDL's accounting policy in all material aspects. It is important to note that there were no material deviations of accounting policies identified during the 2019 year-end processes that occurred after acquisition.

Based on this assessment ERHDC submits that underlying cost structures included in this rate application, supported by ERHDC's accounting policies, are appropriate, align with NBHDL's, and that there are no material differences. Further to this, ERHCD submits that there is no requirement to establish a deferral account to track differences in revenue requirement as a result of future amalgamation.

ICM application

ERHDC submitted an ICM application (EB-2013-0127) for the recovery of $2,062,500 associated with the construction of a new municipal substation and 44 kV line. The Board approved the related rates effective from May 1, 2014 to its next cost of service application. ERHDC established Account 1508 sub-accounts to track the costs of the new substation and the related revenues. The reconciliation of Account 1508 is addressed in Exhibit 2 of this application

2.1.4.11 Information on Conditions of Service

ERHDC's current conditions of service are found at: http://www.erhydro.com. The Conditions of Service have not changed since the last of CoS application.

2.1.4.12 Conditions of Service & Tariff of Rates and Charges

ERHDC confirms that there are no rates or charges listed in the Conditions of Service that are not on the Tariff of Rates and Charges.

2.1.4.13 Corporate and Utility Organizational Structure

ERHDC is a licenced electricity distributor that is 100% owned by its shareholder, North Bay Hydro Holdings Ltd. ("NBHHL") which is 100% owned by the Corporation of the City of North Bay. The Board of Directors of ERHDC consists of five members, two of which are independent of any related entities. Audited financial statements are formally reported to NBHHL within 90 days following the end of each fiscal year and the CEO of NBHHL is invited to all board of director meetings throughout the year. NBHHL's reporting relationship to the City of North Bay is outside the scope of ERHDC's control or involvement. Figure 1-1 below outlines the current ownership structure of Espanola Regional Hydro Distribution Corporation, and Figure 1-2 below outlines the reporting structure of Espanola Regional Hydro Distribution Corporation:

Figure 1 - 1: Current Ownership Structure of Espanola Regional Hydro Distribution Corporation

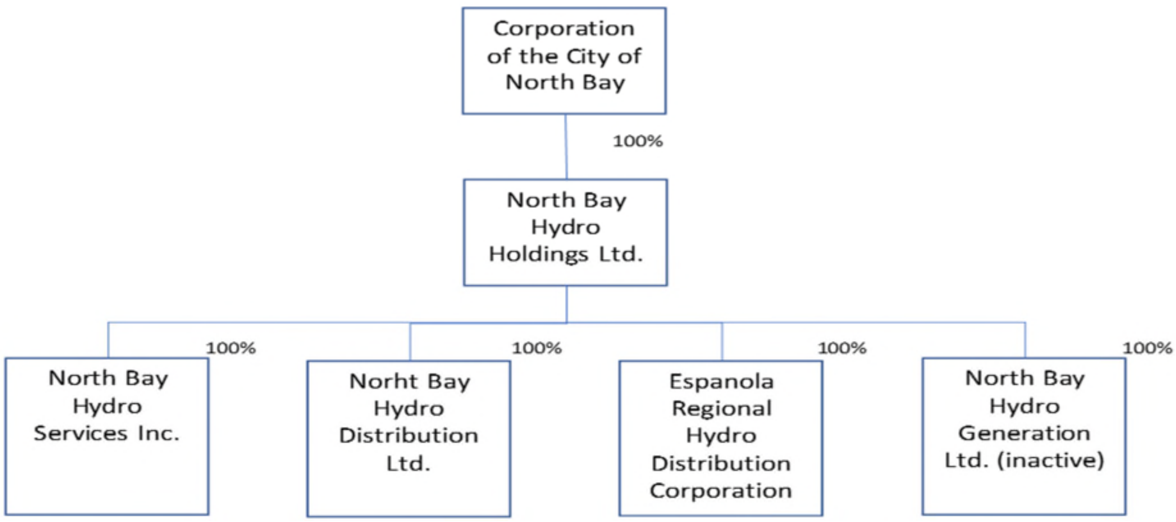
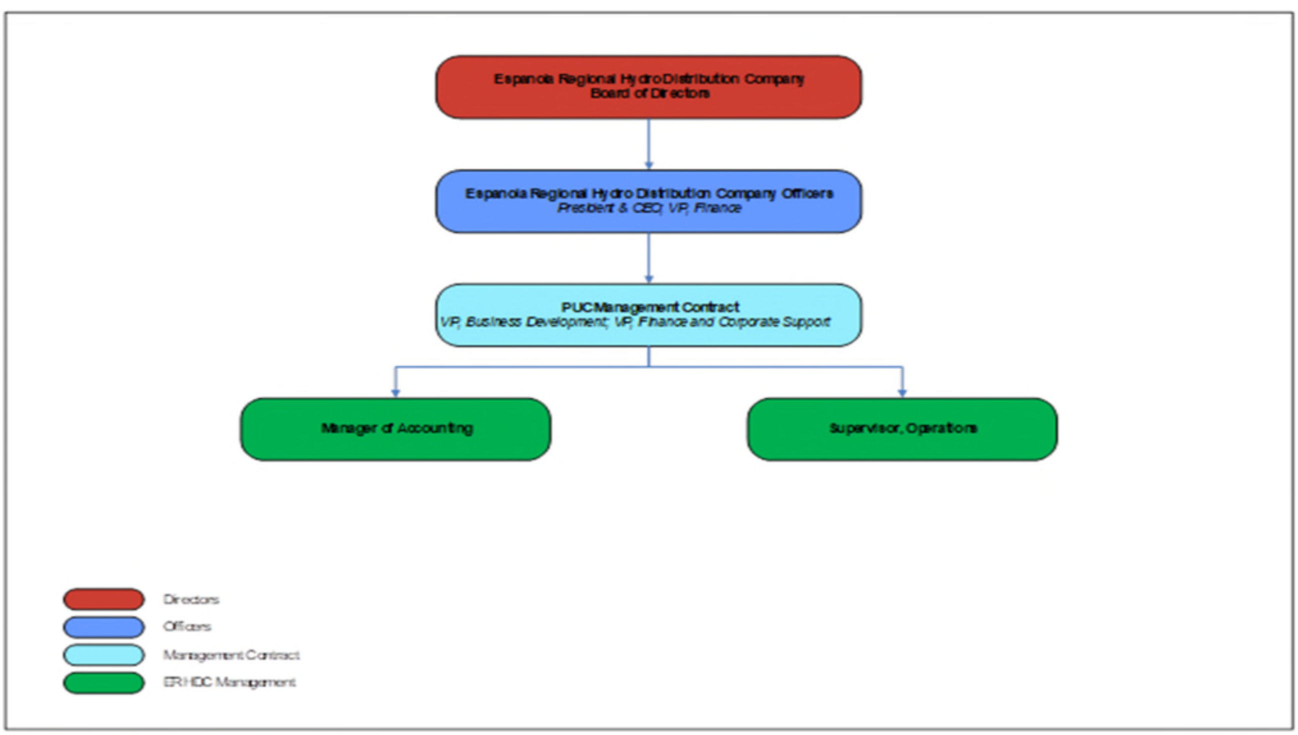


Figure 1 - 2: High-level Reporting Structure of Espanola Regional Hydro Distribution Corporation



North Bay (Espanola) Acquisition Inc. (NBEAI) received approval from the Board (EB-2019-0015) to:

1. acquire 100% of the issued and outstanding common shares of Espanola Regional Hydro Holdings Corporation ("ERHHC") and 100% of the special shares of Espanola Regional Hydro Distribution Corporation ("ERHDC") from The Corporation of the Town of Espanola and The Corporation of the Township of Sables-Spanish Rivers, pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998*; and

2. amalgamate NBEAI, ERHHC and ERHDC to create a new company operating under the name Espanola Regional Hydro Distribution Corporation, made pursuant to section 86(1)(c) of the *Ontario Energy Board Act, 1998*; and

3. to proceed with the proposed (described below) rate making framework under section 78 of the *Ontario Energy Board Act, 1998*.

The amalgamation was completed as of September 30, 2019. NBHDL and ERHDC will continue to operate as independent utilities until 2022 (i.e. after the PUC Services Agreement expires). NBHDL and ERHDC are filing separate rebasing applications. Operational synergies are not yet possible because of ERHDC's obligations under, and PUC's rights under, the PUC Services Agreement. For this reason, PUC will continue to provide services to ERHDC pursuant to the PUC Services Agreement until its expiry in 2022.

List of Specific Approvals Requested

In this Application ERHDC is requesting the following approvals:

- Approval to charge rates effective May 1, 2021 to recover a revenue requirement of $2,272,419 which includes a revenue deficiency of $449,736 as set out in Exhibit 6;

- Approval to transition to fully-fixed rates for residential customers;

- Approval of the proposed total loss factor (including transmission and distribution) of 1.0673 as set out in Exhibit 8;

- Approval to charge a Retail Transmission Network Service rate as proposed and described in Exhibit 8;
- Approval to continue to charge Wholesale Market Service Charge;
- Approval to continue the Specific Service Charges and Transformer Allowance;
- Approval to dispose of Account 1508, Other Regulatory Assets, sub-accounts for Distribution Station 4 which was subject of an ICM application (EB-2013-0127);
- Approval of the updated province-wide fixed monthly charge of $4.55 for MicroFIT Generator Service Classification;
- Approval of the rate riders for disposition of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") and Lost Revenue Adjustment Mechanism ("LRAM") for lost revenue for the 2011-2019 program years, with persistence until April 30, 2021. For additional information, please refer to Exhibit 4;
- Approval of the rate riders for disposition of the Group 1 and Group 2 and Other Deferral and Variance Accounts as detailed in Exhibit 9;
- Approval to continue to use Account 1509 – Impacts Arising from the COVID-19 Emergency;
- May 1, 2016 interim rates to be declared final rates; and
- Such other approvals as ERHDC may advise and the OEB may deem as just and reasonable.

ERHDC has completed OEB Appendix 2-A List of Requested Approvals, which is included at Appendix 1-J.

2.1.4.14 Materiality Threshold

Chapter 2 of the Filing Requirements issued by the Board on May 14, 2020 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.

2.1.5 Distribution System Overview

2.1.5.1 Description of Service Area

ERHDC is a local distribution company serving more than 3,300 customers in the Town of Espanola and the Township of Sables-Spanish Rivers as outlined in Table 1-10 below. ERHDC is bounded by Hydro One and is embedded within Hydro One. ERHDC does not have any utilities embedded within its service territory.

Table 1 - 10: Espanola Regional Hydro Distribution Corporation Distribution Service Area

Service Area:	**Description of the Applicant:**
COMMUNITY SERVED:	a) The former Town of Massey and the former Town of Webbwood now within the Township of Sables-Spanish Rivers excluding two customers b) The Town of Espanola excluding nine customers within its municipal boundaries c) 19 customers in the Township of Sables-Spanish Rivers not in the former Towns of Massey and Webbwood
TOTAL SERVICE AREA:	102 square kilometers
RURAL SERVICE AREA	76 square kilometers
URBAN SERVICE AREA	26 square kilometers
DISTRIBUTION TYPE:	Electricity Distribution
MUNICIPAL POPULATION:	8,236

A map of ERHDC's service territory is provided in Appendix 1-E.

ERHDC owns and operates systems at two distribution voltages – 4.16 kV and 12.47 kV. The 4.16 kV system primarily services the town of Espanola while the 12.47 kV services the Massey and Webbwood area. The 4.16 kV feeders in Espanola are supplied from four municipal substations fed from a single 44 kV overhead feeder. Distribution feeders include both overhead and underground lines. In Massey and Webbwood, ERHDC does not own any substations as the 12.47 kV feeders are embedded into Hydro One distribution system.

As of the end of 2019, the major asset classes which ERHDC owns, operates, and maintains are summarized in Table 1-11 below.

Table 1 - 11: Major Asset Classes of ERHDC

Asset Class	Quantity
Overhead lines 3 phase 44 kV (km)	5.8
Overhead lines 3 phase 12.47 kV (km)	9.4
Overhead lines 3 phase 4.16 kV (km)	21.7
Overhead lines 2 phase 12.47 kV (km)	1.1
Overhead lines 2 phase 4.16 kV (km)	1
Overhead lines 1 phase 7.2 kV (km)	35.24
Overhead lines 1 phase 2.4 kV (km)	16
Total of Overhead Lines (km)	90.24
Underground 3 phase cables 4.16 kV (km)	1.3
Underground 1 phase cables 2.4 kV (km)	7.6
Total of Underground Cables (km)	8.9
Submarine 1 phase cable 7.2Kv (km)	3
Pole mounted transformer,1-ph	694
1 phase cutouts	694
3 phase load break switches	4
Padmount 50 kVA, 3-ph	3
Padmount 75 kVA, 3-ph	1
Padmount 150 kVA, 3-ph	1
Padmount 500 kVA, 3-ph	3
Transclosures, 1-ph	49
Revenue Meters	3283
Substations	4

Peak loading occurring during the winter months – due to the extreme winters in the remote area of northern Ontario coupled with the fact that much of the heating is electrical in the town, the peak loading period occurs in the winter months.

Massey and Webbwood service areas are supplied via a dedicated Hydro One 44kV feeder. ERHDC also owns and operates a 44kV line which branches off the Hydro One line and enters the Town of Espanola to feed all four municipal stations. As a result of only being supplied by one feeder, in instances where Hydro One experiences an outage, ERHDC experiences loss of supply to the entire Town of Espanola. This is the major factor affecting reliability performance.

2.1.5.2 Host/Embedded Distributor

ERHDC is embedded within Hydro One. ERHDC does not have any utilities embedded within its service territory.

2.1.5.3 Transmission or High Voltage Assets

ERHDC has no transmission assets (>50kV) deemed by the Board to be distribution assets.

ERHDC is not asking the OEB to deem any new transmission assets as distribution assets in this Application.

2.1.6 Application Summary

2.1.6.1 Revenue Requirement

ERHDC requests a service revenue requirement for 2021 in the amount of $2,272,419. Based on the projected load forecast and customer growth for the 2021 Test Year, ERHDC has estimated a revenue deficiency of $449,736 based on its current rates. The computation of the revenue deficiency is shown in Exhibit 6. Therefore, ERHDC seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 8.

The 2021 service revenue requirement represents an increase of $483,716 or 27.04% over the 2012 Board-approved amount of $1,788,703. Included in the revenue deficiency is approximately $159,000 of "ICM revenue" for Distribution Station 4 which is currently in a rate rider. Excluding the rate rider revenue from the revenue deficiency results in an increase in revenue requirement of $324,716 or 18.15% over the Board Approved.

The main drivers of the revenue requirement changes from the 2012 Board-approved amount are:

- To provide a reasonable rate of return to the shareholder;
- Recovery of ERHDC costs to provide distribution services. Cost recovery is necessary to account for:
    - Increased depreciation as a result of capital expenditures since last Cost of Service (“COS”) application; and
    - Increased rate base, therefore, increased return as a result of capital expenditures since last COS application.
- The funds necessary to service ERHDC’s debt;
- Maintain capital investment levels in infrastructure to ensure a safe, reliable distribution system – connect new customers, replace aging poles, transformers, wires and tools;
- Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations, and ensure regulatory compliance. These include increased costs since last rebasing in 2012:
    - Addition of MIST metering for general service customers;
    - Increased OEB fees;
    - Increased bad debt expense;
    - Increased TOU billing expenses;
    - Increased regulatory rate filing costs;
    - Additional transformer PCB testing.
- Increased staffing requirements to meet regulatory requirements.

2.1.6.2 Budgeting and Accounting Assumptions

(a) Statement of Accounting Standard Used

ERHDC transitioned depreciation and capitalization policies to IFRS on January 1, 2012 and transitioned remaining policies to International Financial Reporting Standards on January 1, 2015 with a transition date of January 1, 2014. The standards were applied retrospectively to the comparative 2014 information. This Application is being filed using MIFRS Accounting Standards. There are no impacts resulting from changes in accounting standards.

The budget forecast for the 2021 Test year was approved by the Board of Directors of ERHDC.

ERHDC compiles budget information for the three major components of the budgeting process: revenue forecasts, operating, maintenance and administrative expense forecast, and capital budget forecast. This budget information is compiled for the Test Year. Table 1-12 below details the number of customers per year along with the inflation rate.

Table 1 - 12: Inflation and Customer Growth

	2013	2014	2015	2016	2017	2018	2019	2020	2021
# of Customers	3,338	3,337	3,340	3,332	3,336	3,351	3,357	3,357	3,357
Inflation (IPI)	1.6%	1.7%	1.6%	2.1%	1.9%	1.2%	1.5%	2.2%	1.5%

The inflation rate assumed for labour is 1.75% and 1.5% for non-labour for the 2021 Test Year budget.

2.1.6.3 Load Forecast Summary

ERHDC's load forecast is weather normalized and considers factors such as historical power purchased load, weather, calendar related factors, number of customers and spring fall flag. As outlined in Exhibit 3, ERHDC has used the same regression analysis methodology approved by the OEB in its 2012 Cost of Service application (EB-2011-0319). The regression analysis was conducted on historical electricity purchases to produce an equation that will predict weather normalized power purchases in 2021. The weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast which is allocated to rate class using historical billing data by rate class.

Based on the load forecast methodology, the total billed 2021 Test Year kWh forecast is 58,677,605 which is a 5.7% decrease over the ERHDC's 2012 OEB Approved kWh billed forecast of 62,249,997. The 2012 forecast of 62,249,997 was never achieved from 2013 to 2019. As a result, the 2021 forecast has been developed to be more in line with the results from 2013 to 2019.

The 2021 forecast of customers/connections by rate class was determined using a geometric mean analysis for all rates classes. The expected number of customers for the 2021 Test Year is 3,357 which is a 0.06% decrease compared to the 2012 OEB Approved customers of 3,359. The street light customers/connections has been updated from 1,062 devices to 799 connections.

2.1.6.4 Rate Base and DSP

The capital budget forecast for 2021 is influenced, among other factors, by ERHDC's priority to maintain adequate security of supply to meet customer needs, as well as to replace end-of-life assets. Major cost drivers for the DSP in 2021 are:

- System renewal; and
- Customer connections and regulatory requirements.

The rate base used for the purpose of calculating the revenue requirement used in this application is $7,599,049 and is comprised of the average of the balances at the beginning and the end of the 2021 Test Year, plus a working capital allowance, which is 7.5% of the sum of the cost of power and controllable expenses.

ERHDC has provided its rate base calculations for the years 2012 Board Approved, 2017 to 2019 Actual, 2020 Bridge and 2021 Test Year below in Table 1-13. ERHDC has calculated its 2021 rate base as $7,599,049 (Exhibit 2).

The 2012 Board approved rate base for the 2012 Test Year was $4,244,736. The cumulative change in rate base was $3,354,313 which is a 79% increase.

Table 1 - 13: Rate Base Summary

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

Table 1-14 below summarizes the planned capital expenditures for the 2020 Bridge Year and 2021 Test Year.

Table 1 - 14: Planned Capital Expenditures

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

All proposed capital projects are assessed within the framework of its capital budget priority and are outlined in Exhibit 2.

The Board-approved net capital expenditures were $1,025,592 for the 2012 Test Year which included $637,000 for smart meters. The change in capital expenditures to the 2021 Test Year is a reduction of $562,163 or -55%. Excluding the smart meters, the increase over the 2012 Approved is $74,625.

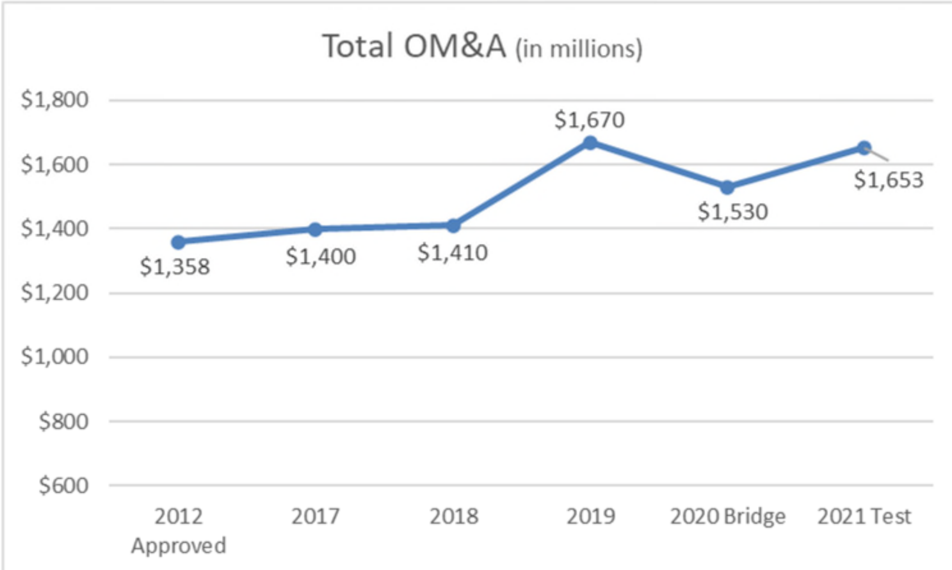
ERHDC is not requesting any costs for renewable energy connections/expansions, smart grid, and regional planning initiatives. There are no applications in hand and ERHDC is not currently aware of any customers wishing to connect renewable generation plant to the grid.

2.1.6.5 Operations, Maintenance and Administration Expense

ERHDC is proposing recovery through distribution rates of $1,653,431 in Operating, Maintenance and Administration ("**OM&A**") costs for the 2021 Test Year. The 2012 Board Approved OM&A was $1,358,127, accordingly the 2021 request represents an increase of $295,304 or 21.74% over the 2012 Board-approved expenditures, or an annual average increase of 2.41%. The test year 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 2021 is 2.2%.

These costs were necessary for ERHDC to safely operate and maintain the distribution system and to meet all incremental regulatory requirements. Figure 1-3 below illustrates ERHDC's OM&A expenses for the 2012 approved, 2017 to 2019 historical, 2020 Bridge and 2021 Test years.

<u>Figure 1 - 3: 2012 Approved, 2017 to 2021 OM&A</u>



The increase from the 2012 Approved to the 2020 Bridge year amount of $1,530,356 is $172,233, an average annual increase of 1.59%. During the period 2013 to 2019 average annual inflation has been 1.66% and using a 1% inflation rate for 2020, the average from 2013 to 2020 is 1.58%. ERHDC OM&A expenses have tracked inflation for the period 2013 to 2020.

As can be seen from Figure 1-3 above, ERDHC's OM&A expenses have had two spikes in the period 2017 to 2021; those being 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 $123,704 increase in 2021, the main driver is $100,000 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.

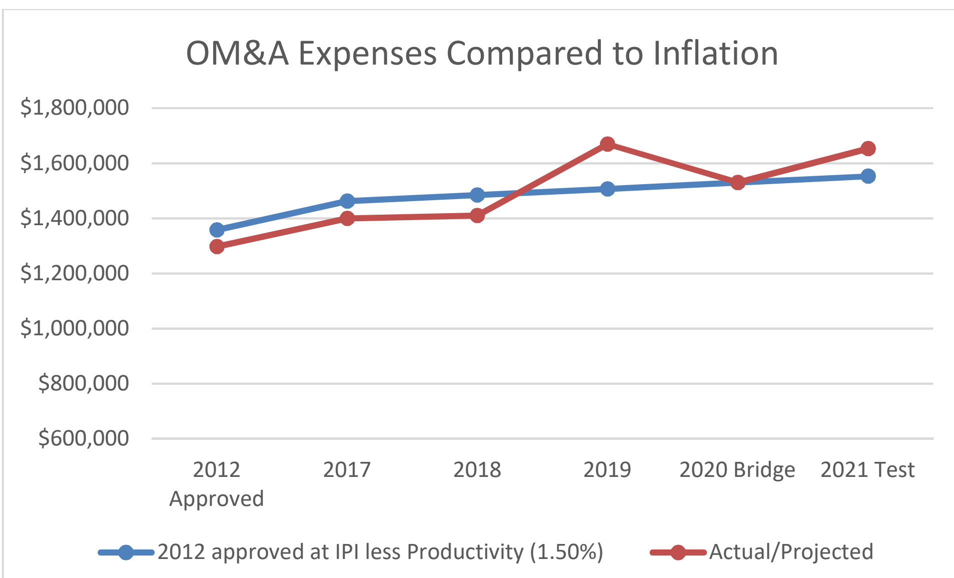
ERHDC is requesting the following items in its Cost of Service rate application which are not currently in expenses being recovered in rates:

- Increased cost for the mandated PCB transformer testing;
- Increased cost for the mandated MIST meter conversion;

- Increased annual OEB fees since 2012
- Increased costs for mandated Customer Satisfaction Surveys
- Increased costs for mandated Electrical Safety Surveys
- Rate application intervenor costs
- Rate application consultant costs
- Rate application OEB costs
- Increased administrative salaries due to increased reporting requirements since 2012

The following Figure 1-4 indicates that the 2021 test year request is in line with the average inflationary increase over the period excluding the additional costs for a cost of service rate application.

<u>Figure 1 - 4: 2012 Approved, 2017 to 2021 OM&A Costs Compared to Inflation</u>



ERHDC's workforce planning is discussed in more detail in Exhibit 4, however Table 1-15 below summarizes number of employees and compensation for 2012 Board Approved, 2017 to 2019 Actual, 2020 Bridge and 2021 Test Years. All compensation is included, whether expensed or capitalized. Total compensation increased from the 2012 approved of $564,719 to the 2021 Test year amount of $831,227, an increase of 47.19%. FTEs increased from 5.42 to 7.31 mainly due to the addition of a lines supervisor which had previously been included in the service contract with PUC Services and the increasing of part-time office staff to full time. The increase in compensation for the lines supervisor was more than offset by the cost reduction in the service contract. The cost per FTE increased 9.14% from the 2012 Approved to the 2021 Test Year, an average increase of 1.02% per year.

Table 1 - 15: 2012, 2017 to 2021 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

2.1.6.6 Cost of Capital

ERHDC has used the Board's Cost of Capital Parameter Updates for Rates Effective in 2021 released November 9, 2020 and there are no deviations from the Board's cost of capital methodology in this Application. Table 1 -16 below describes the capital structure and cost of capital for the 2021 Test year.

Table 1 - 16: Capital Structure and Cost of Capital (Appendix 2-OA)

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last OEB-approved year and the test year.

Test Year: 2021

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$4,255,467	3.03%	$128,776
2	Short-term Debt	4.00%	(1)	$303,962	1.75%	$5,319
3	**Total Debt**	60.0%		$4,559,429	2.94%	$134,095
	Equity					
4	Common Equity	40.00%		$3,039,620	8.34%	$253,504
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$3,039,620	8.34%	$253,504
7	**Total**	100.0%		$7,599,049	5.10%	$387,599

2.1.6.7 Cost Allocation and Rate Design

ERHDC has not deviated from the Board's cost allocation and rate design methodology.

(a) Cost Allocation

The data used in the updated 2021 cost allocation study is consistent with ERHDC's cost data that supports the proposed 2021 revenue requirement outlined in this Application. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to ERHDC from its engineering records, and its customer and financial information systems.

As shown in Table 1-17 below, the 2021 cost allocation study indicates the revenue to cost ratios for the General Service < 50 kW, General Service > 50 kW, Sentinel Lighting and Street Lighting rate classes are outside the OEB's range. For 2021 and onward, it is proposed the ratios for these rate classes be brought within the OEB's range as outlined in ERHDC's rate mitigation plan (Exhibit 8). The Residential class will be adjusted upward to maintain revenue neutrality.

Table 1 - 17: Revenue to Cost Ratios

Rate Class	2021 Updated Cost Allocation Study	2021 Proposed Ratios	Board Targets Min to Max	
Residential	89.9%	92.6%	85.0%	115.0%
General Service < 50 kW	119.6%	119.6%	80.0%	120.0%
General Service ≥ 50 to 4999 kW	130.5%	120.0%	80.0%	120.0%
Street Lights	203.9%	120.0%	80.0%	120.0%
Sentinel Lights	66.3%	80.0%	80.0%	120.0%
Unmetered Scattered Load	106.9%	106.9%	80.0%	120.0%

(b) **Rate Design**

Except for the Residential class, ERHDC proposes to maintain the fixed/variable proportions assumed in the current rates to design the proposed monthly service charges.

On April 2, 2015, the OEB released its Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. Typically, this transition would be implemented over a period of four years, beginning in 2016. However, ERHDC has not had a rate application before the Board since 2015 and has not implemented the transition to fully fixed rates for residential customers. The implementation period for ERHDC will commence in 2021 and extend to 5 years in order to address mitigation expectations outlined in a letter from the OEB published on July 16, 2015. With a 5 year implementation, the last year of transition will be 2025.

Table 1-18 below outlines a comparison between the 2020 current and the 2021 proposed distribution rates based on ERHDC's proposed rate mitigation plan which is outlined in Exhibit 8.

Table 1 - 18: Distribution Charges

	Monthly Service Charge			Volumetric Charge			
Rate Class	2020 Current	2021 Proposed	% Difference	Unit of Measure	2020 Current	2021 Proposed	% Difference
Residential	$14.07	$22.77	62%	kwh	$0.0170	$0.0180	6%
General Service < 50 kW	$25.22	$32.22	28%	kwh	$0.0207	$0.0264	28%
General Service 50 to 4,999 kW	$196.43	$229.37	17%	kW	$3.7949	$4.4011	16%
Street Lighting	$1.99	$1.29	-35%	kW	$25.0801	$16.2041	-35%
Unmetered Scattered Load	$12.26	$15.66	28%	kwh	$0.0157	$0.0201	28%
Senitnel Lighting	$2.14	$3.40	59%	kW	$17.2571	$27.4341	59%

2.1.6.8 Deferral and Variance Accounts

As outlined in Exhibit 9, ERHDC is requesting approval for the disposition of Group 1, Group 2 and Other Accounts in the amount of $1,053,340 receivable from customers. This includes Group 1 Accounts excluding account 1589 of $760,292 owed to ERHDC by customers and an amount of $55,746 being owed to ERHDC by Non RPP customers only for account 1589 - RSVA - Global Adjustment. It also includes Group 2 accounts of $91,968 owed to customers and other account amounts of $329,270 owed to ERHDC by all customers. Also included is the LRAM Variance Account (1568). ERHDC proposes a 5 year disposition period for the Group 1 Account and LRAMVA Varaiance Account. ERHDC proposes a 1 year disposition period for Account 1589-RSVA-Global Adjustment and the Group 2 Variance Accounts. ERHDC is not requesting any New Deferral and Variance Accounts.

2.1.6.9 Bill Impacts

ERHDC acknowledges that the bill impacts of its proposed electricity distribution rates required rate mitigation. Table 1-19 below highlights the bill impacts on various rate classes. The following measures have been taken to mitigate rate impacts:

1. Adjusting the revenue to cost ratios of the Sentinel Light rate class.
2. Recovering Group 1 regulatory variance and LRAMVA variance over 5 years.
Recovering the 1589 – Global Adjustment and Group 2 variance accounts over 1 year.
3. Moving to fully fixed residential rates over the next five years.

<u>Table 1 - 19: Bill Impacts</u>

Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/ Decrease	Total Bill Impact %
Residential	750	0	$8.73	7.25%
Residential	318	0	$6.29	10.74%
Residential	848	0	$9.29	6.91%
GS<50	2,386	0	$22.80	6.16%
GS>50	44,361	115	$538.50	5.98%
USL	456	0	$4.14	5.50%
Sentinel Light	81	0.22	$2.37	15.22%
Street Light	14238	41.8	-$67.37	-1.65%

Table 1-19 above indicates that the bill impacts for all rate classes are under a 10% increase except for the Residential Class low 10th percentile consumers, and the Sentinel Light Class.

The total bill impacts for an ERHDC Residential RPP customer at the 10th consumption percentile is 10.74%. This impact which is slightly above 10% mainly results from a change in the cost allocation model for the Street Lighting class and the fixed/variable transition. The current cost allocation model allocates fewer costs to the Street Lighting class than was done in the previous cost allocation study. This results from the issuance of new cost allocation policy for the Street Lighting class by the Board on June 12, 2015. In order to maintain revenue neutrality the reduced Street Lighting revenue is being assigned to the Residential class resulting in the total bill impact referenced above. Similarly, there are fewer costs allocated to the GS>50 class and this has also been shifted to the residential class. The low consumption customers are also impacted by the transition to fully fixed distribution rates. Without the effects of the fixed/variable transition the increase to the low volume residential customers would be 7.01%. Since ERHDC has extended the implementation to a fully fixed Residential monthly service charge from four to five years it is ERHDC position that a further extension would not be reasonable to address an issue that is mainly caused by a revised cost allocation methodology.

The Sentinel Light class has undergone an increase of 15.22% which is the result of cost allocation.

Incorporated in the overall monthly bill impact is the effect of the following major components of the electricity bill:

- Distribution rates (monthly service charge and volumetric rates);
- Transition to a fully-fixed rate for distribution rates
- Disposition of deferral and variance accounts:
- Revised Retail Transmission rates;
- Increased low voltage charges
- Regulatory Charges; and
- Loss Factors.

2.1.7 Customer Engagement

As of the date of filing this Application, no letters of comment have been received. ERHDC will file all responses to matters raised in letters of comment filed with the Board during the course of the proceeding in this Exhibit 1, in accordance with Section 2.4.9 of the Filing Requirement. Appendix 2-AC has been attached to this Exhibit as Appendix 1-F.

ERHDC is constantly striving for a higher customer service standard. With a priority of ensuring ERHDC follows an ‘easy to do business with’ strategy, ERHDC has invested in the customer experience by making a number of changes internally. For example, a ‘one-stop shop’ approach to the customer service department was implemented to better serve customers at first point of contact. Other improvements included enhancing our communications portfolio to include social media and upgrading our website, developing online forms and promoting an e-billing campaign.

ERHDC uses a number of traditional and digital communication tactics and initiatives to provide information to its customers in a relevant and timely fashion. An effective communications strategy allows ERHDC to build greater trust with our customers and create opportunities for education.

ERHDC uses press releases, media interviews, social media advertising, digital, print and radio advertising, attendance at community events, website updates, bill inserts, and the ATLAS phone notification system to inform customers of important information relating to power outages, vegetation management, and conservation program initiatives.

(a) Formal Customer Engagement

ERHDC informed its customers of the proposals being considered for inclusion in the Application through a formal engagement. The formal customer engagement was accomplished through the use of a customer survey, which gauged customers' understanding of their electricity bill, the electrical distribution system, ERHDC operations, and solicited feedback on public perception and customer satisfaction. The customer engagement survey was performed as part of the Application and is included at Appendix 1-G. The customer engagement survey was developed to inform customers of the proposed rate increase associated with the Application. It provided a short overview of ERHDC's operations, cost drivers, bill breakdown, and capital projects needed to be completed. It allowed customers to comment, and open two-way communication between ERHDC and its customer base, in order to move forward with efficient customer engagement strategies. There were 67 completed surveys. The survey included information explaining pertinent information related to the Application, such as the cost drivers associated with operations, and planned capital projects.

Another set of three surveys was run by Utility Pulse Division Simul Corporation. These surveys were intended to gauge customer satisfaction, the utility's performance, and the perception of the utility. The latest survey which was performed in 2019 is included as Appendix 1-G in this Exhibit.

In 2020 ERHDC participated in its third public electrical safety awareness survey since 2016 to provide a benchmark level concerning the public's electrical safety awareness and identify opportunities where additional education and outreach may be required. The survey gauged the public's awareness level of key electrical safety concepts related to distribution assets ("Public Awareness Safety Survey").

(b) Other Customer Engagement

ERHDC also engages with customers regarding specific projects.

For example, a letter was sent to Spanish River Drive customers regarding the capital work that was being performed on Spanish River Drive which asked if there were questions or concerns. A mid-project letter was also sent to these residents to inform them of the project status. Although no formal written responses were received, positive comments were expressed to the line crew while working on site.

In a similar manner, in the case of the relocation of cross-lot conduit, customers were informed of the work to be completed and questions or concerns were solicited. Again, no formal responses were received.

Customers transferred to Hydro One due to the previous long term loan transfer agreement received two letters explaining the transfer and offering to answer any questions.

ERHDC's objective was to inform and engage with customers before work began. Due to the nature of the service territory, face to face conversations are also a method used to engage customers.

(c) Informal Customer Engagement

The following customer engagement has also carried out:

Community event - ERHDC participated in the Pumpkin Fest community event over the last three years which was used to promote conservation programs. Events like these provide an opportunity for customers to ask questions to staff in an informal setting and receive information on a variety of topics relating to the utility. Involvement in the community also extends to conservation campaigns, including the Save on Energy Program and AffordAbility Fund.

Digital/Online Communications – regarding COVID-19 updates, conservation programs, online services available, electricity industry changes and requirements.

Public Notices/Online Broadcasting System (Tele-Works) – regarding delays for appliances/in-home assessments due to COVID, conservation program updates.

Public Relations/Media Relations – Press releases and radio ads regarding: conservation programs, industry changes, TOU changes, Government programs (CEAP, CEAP-SB), rate changes.

Bill Inserts – regarding TOU changes, conservation programs, E-Billing, bill/rate changes, government initiatives.

Customer Connect – 24/7 access to online monthly bills and daily usage.

ERHDC is focussed on improving its customer engagement through various communication methods. ERHDC used bill inserts and press releases to provide information to customers about changes that could affect their bill, as well as information about bills, regulation/legislation changes, and current energy industry events. ERHDC advertised through online and radio to promote the community brand, and to build awareness with conservation tips. The bill inserts provided information around legislation, regulations, service changes, and conservation program initiatives. This method provides a direct line of communication to the customer. ERHDC has implemented a Customer Care department with a greater focus on caring for the customer as opposed to just serving the customer.

(d) Themes Arising from Customer Engagement Survey (Fall 2020)

- **Price** – 73.4% of respondents selected ‘Delivering reasonable electricity prices’ as their top priority for ERHDC to focus on. (Slide 28 Customer Engagement Summary at Appendix 1-G).

- **Bill Breakdown** – 60% of respondents thought that the ‘amount retained by ERH, e.g. $29 on a $119 estimated average residential bill is reasonable to operate and maintain a safe, local electricity service.’ (Slide 40 Customer Engagement Summary at Appendix 1-G).

- **Infrastructure Renewal** – 92% of respondents stated ERHDC should be pro-active in maintaining and upgrading equipment to ensure electricity is supplied reliably and safely in the network (Slide 29 Customer Engagement Summary at Appendix 1-G).

- Infrasture Renewal - 61% of respondents stated, ‘I would be willing to pay any rate increase (e.g. 15%) that allowed ERH to invest as much as possible to improve the reliability and overall performance of the system’ or ‘While I don’t want a rate increase, I would be willing to pay the proposed increase of my bill to maintain reliability and service through a dedicated workforce and well-planned infrastructure renewal.’ (Slide 48 Customer Engagement Summary at Appendix 1-G).

- **Reliability –** 89% of respondents replied Very good or Good when asked about ERH’s reliability specific to power outages . (Slide 60 Customer Engagement Summary at Appendix 1-G). When asked ‘what was the longest power outage that you had in the past year?’, 50% answered less than 30 minutes. (Slide 54 Customer Engagement Summary at Appendix 1-G).

- **Communications –** 80% of respondents stated they would like to see more updates or communication surrounding future plans on upgrades and/or maintenance (Slide 32 Customer Engagement Summary at Appendix 1-G).

(e) **Themes Arising from Customer Satisfaction Survey (Fall 2019)**

This survey was conducted by UtilityPulse via telephone in 2019 using random sample approach. The survey received 201 responses. A copy of the Customer Satisfaction Survey is attached at Appendix 1-H. Overall, ERHDC’s customer satisfaction rating (post survey completion) was 93%, compared to 92% province wide.

- **Cost –** Customers continue to be concerned about costs, but nowhere near where they were in 2016 and the early part of 2017. 43% still identified better prices and lower rates however as ‘an important thing ERHDC could do to improve service’.

- **Credibility and Trust –** 92% of ERHDC customers say that the utility is a trusted and trustworthy company. The utility is seen as knowledgeable about the services it provides, about what is happening in the industry, and how customers can reduce costs or create more value.

- **Communications** – 76% of ERHDC customers find that they are satisfied or fairly satisfied with the quality of information available when outages occur. 85% are satisfied or fairly satisfied with the timelines and relevance of information for things such as planned outages, construction activity and tree trimming. 10% of respondents identified better communications as ‘‘an important thing ERHDC could do to improve service’.

- **Convenience of Services –** While most customers are satisfied with access to services, only 43% and 45% were satisfied or very satisfied with the online self-serve options for managing their accounts and the online self-serve options for requesting services respectively. Overall, ERHDC received a score of 77% for convenience of services.

- **Billing Problems –** In 2019, 12% of customer respondents had a billing problem in the past 12 months, compared to 20% in 2017 ad 17% in 2015. This reflects positive changes in customer service. 90% stated ERHDC provides accurate billing.

Customer Service – 83% of customers stated that ERHDC deals professionally with customers’ problems. Overall, 70% of customers were satisfied with their most recent experience with ERHDC, compared to 79% province wide.

(f) **Effect on Application**

As a result of the feedback on price, the DSP was assembled to ensure that the rate increases were minimized, while considering the need for necessary system renewal projects in order to maintain reliability. Also, as a result of the feedback on price, ERHDC has strictly managed any increases to its OM&A budget in the test year.

Despite the fact that a large percentage of ERHDC’s assets are part of an aging electrical distribution system, ERHDC has held off on capital investments for large-scale infrastructure such as the transformer stations, based on customer concern for increasing costs. ERHDC has designed its DSP to ensure that asset renewal proceeds at a gradual, steady pace rather than by sudden or significant increases. The DSP focuses on equipment in poor or very poor condition, or near the end of its service life. The projects included in the DSP are driven in part by safety.

ERHDC has worked to balance the infrastructure and affordability drivers with a proposed rate increase that will affect the total average (using 750kWh) residential electricity bill by less than $9.00/month despite the fact that there has been no distribution rate increase since May 1, 2015.

2.1.7.2 Operational Effectiveness

ERHDC has completed the 2021 Benchmarking Spreadsheet Forecast model based on the 2020 Bridge Year projection and 2021 Test Year request and has included a summary of the outcome in Table 1-20 below. ERHDC is mindful of its stretch factor cohort and will continue to exceed all scorecard performance targets in the areas of Customer Focus, Operational Effectiveness and Public Policy Responsiveness while maintaining its cost efficiency factor of 2 over the period leading up to the amalgamation with North Bay Hydro.

Table 1 - 20: Benchmarking Summary

	2017 Historical	2018 Historical	2019 Historical	2020 Bridge	2021 Test
Actual Total Cost	$2,174,399	$2,256,379	$2,517,554	$2,475,036	$2,716,071
Predicted Total Cost	$2,738,909	$2,890,756	$2,995,788	$3,238,682	$3,452,204
Difference	-$564,510	-$634,377	-$478,234	-$763,646	-$736,132
% Difference (Cost Performance)	-20.61%	-21.95%	-15.96%	-23.58%	-21.32%
Stretch Factor Cohort (Annual)	2	2	2	2	2

Table 1-21 below is the comparison of LDCs with a similar density profile as ERHDC. The table compares ERHDC's proposed 2021 rates to the 2019 rates data base information which is the latest data base available. The table indicates ERHDC is below average for the residential class and above the average for the general service classes.

Residential class - 23% below average.

General Service < 50kW - 12% above average.

General Service > 50kW - 15% above average.

<u>Table 1 - 21: Comparison of Residential 750 kWh Monthly Bill –Service Territory Customer Density</u>

Residential

		kWhs	750										
LDC	Service Charge	Smart Meter Entity Ch	Dist Volumetric	Trans Network	Trans Conn	Low Voltage	Loss Factor	Service Charge	Smart Meter Entity Ch	Dist Volumetric	Trans Network & Conn	Low Voltage	Total
Hearst	24.28	0.57		0.0063	0.0057	0.0007	1.0414	$24.28	$0.57	$0.00	$9.37	$0.53	$34.75
ERTH Power Corporation	31.51	0.57		0.0063	0.0059	0.0034	1.0325	$31.51	$0.57	$0.00	$9.45	$2.55	$44.08
Espanola proposed rates	22.79	0.57	0.018	0.0067	0.005	0.007	1.0673	$22.79	$0.57	$13.50	$9.37	$5.25	$51.48
Atikokan Hydro	47.59	0.57		0.0068	0.0048		1.0945	$47.59	$0.57	$0.00	$9.52	$0.00	$57.68
Sioux Lookout (DRP)	47.88	0.57		0.0068	0.0018	0.005	1.0565	$47.88	$0.57	$0.00	$6.81	$3.75	$59.01
Algoma Power (DRP)	42.23	0.57	0.0172	0.0066	0.006		1.0917	$42.23	$0.57	$12.90	$10.32	$0.00	$66.02
Hydro One R1 (DRP)	40.45	0.57	0.0231	0.0078	0.007		1.076	$40.45	$0.57	$17.33	$11.94	$0.00	$70.29
Hydro One R2 (DRP)	96.22	0.57	0.0367	0.0073	0.0066		1.105	$96.22	$0.57	$27.53	$11.52	$0.00	$135.83
DRP - receiving Distribution Rate Proctection													
							750 kWh average	$64.89			ERHDC	-21%	below average

General Service less than 50 kWs

		kWhs	2,027										
LDC	Service Charge	Smart Meter Entity Ch	Dist Volumetric	Trans Network	Trans Conn	Low Voltage	Loss Factor	Service Charge	Smart Meter Entity Ch	Dist Volumetric	Trans Network & Conn	Low Voltage	Total
Hearst	19.07	0.57	0.0065	0.0059	0.005	0.0006	1.0414	$19.07	$0.57	$13.18	$23.01	$1.22	$57.04
ERTH Power Corporation	22.49	0.57	0.0143	0.0059	0.0056	0.0031	1.0325	$22.49	$0.57	$28.99	$24.07	$6.28	$82.40
Sioux Lookout	46.36	0.57	0.0102	0.0061	0.0013	0.0035	1.0565	$46.36	$0.57	$20.68	$15.85	$7.09	$90.55
Atikokan Hydro	77.73	0.57	0.0047	0.006	0.0041		1.0945	$77.73	$0.57	$9.53	$22.41	$0.00	$110.23
Hydro One Uurban GS	25.05	0.57	0.0301	0.0066	0.0055		1.067	$25.05	$0.57	$61.01	$26.17	$0.00	$112.80
Espanola proposed rates	32.24	0.57	0.0265	0.0063	0.0045	0.0063	1.0673	$32.24	$0.57	$53.72	$23.36	$12.77	$122.66
Algoma Power	25.64	0.57	0.0361	0.0066	0.006		1.0917	$25.64	$0.57	$73.17	$27.88	$0.00	$127.27
Hydro One GS	33.48	0.57	0.0622	0.0061	0.0054		1.096	$33.48	$0.57	$126.08	$25.55	$0.00	$185.68
							2,027 kWh average	$109.42			ERHDC	12%	above average

General Service greater than 50 kWs

		kWhs	37361										
		kWs	93										
LDC	Service Charge	Smart Meter Entity Ch	Dist Volumetric	Trans Network - Interval	Trans Conn - Interval	Low Voltage	Loss Factor	Service Charge	Smart Meter Entity Ch	Dist Volumetric	Trans Network & Conn	Low Voltage	Total
Hearst 50 to 1,499 kW	57.13		1.7977	2.4242	2.0248	0.2296	1.0414	$57.13	$0.00	$167.19	$430.89	$21.35	$676.56
Hearst Intermediate	232.39		1.1943	2.7114	2.3883	0.2708	1.0414	$232.39	$0.00	$111.07	$493.91	$25.18	$862.55
ERTH Power Corporation	125.08		3.0253	2.6473	2.0015	1.1189	1.0325	$125.08	$0.00	$281.35	$446.39	$104.06	$956.88
Sioux Lookout	377.21		1.3165	2.4593	0.5659	1.5996	1.0565	$377.21	$0.00	$122.43	$297.24	$148.76	$945.65
Espanola proposed rates	229.63		4.4059	2.8435	2.4072	2.4327	1.0673	$229.63	$0.00	$409.75	$521.18	$226.24	$1,386.80
Hydro One Uurban GS	98.94		10.3954	2.3591	1.9892		1.061	$98.94	$0.00	$966.77	$429.06	$0.00	$1,494.77
Atikokan Hydro	574.73		3.8202	2.5918	1.8283		1.0945	$574.73	$0.00	$355.28	$449.92	$0.00	$1,379.92
Hydro One GS	114.96		17.9552	1.8216	1.5492		1.096	$114.96	$0.00	$1,669.83	$343.58	$0.00	$2,128.37
							93 kW average	$1,228.94			ERHDC	13%	above average

2.1.7.3 Public Policy Responsiveness

In addition to the three Public Policy Responsiveness metrics in the Scorecard, ERHDC has successfully and on a timely basis complied with the following changes in law, regulation, policies or guidelines that have affected its business. The quantity of public policy initiatives has increased and the time frame for compliance has decreased. Included in the following list are some of the mandated programs that ERHDC has implemented or are in the process of implementing:

1. Smart Meter Deployment

2. Time of Use (TOU) Pricing and Billing
3. Adoption of International Financial Reporting Standards (IFRS)
4. Implementation of the Low-income Energy Assistance Program (LEAP)
5. Implementation of the Ontario Clean Energy Benefit (OCEB)
6. Implementation of Ontario Energy Support Program (OESP)
7. Information on Invoices to Low-Volume Consumers of Electricity
8. Global Adjustment Bill Print Modifications
9. Industrial Conservation Initiative (Class A Global Adj)
10. Distribution System Code Amendments (bill issuance, payment procedures, disconnects, arears payment plans, deposits, low income customers)
11. Revised Electricity Reporting and Record Keeping Requirements
12. Renewed Regulatory Framework (RRFE) (scorecard, etc.)
13. Accessibility for Ontarians with Disabilities Act, 2005
14. Employment Standards Act Changes
15. Ontario One Call
16. Customer Engagement
17. Distribution System Plan (DSP) Requirements
18. Public Safety Awareness Survey
19. Ontario Fair Hydro Plan (OFHP) Dynamic Messaging
20. Ontario Fair Hydro Plan (OFHP) Bill Messaging
21. First Nations Delivery Credit
22. Retailer Bill Presentment Changes
23. Written Notice of Switch to Retailer
24. Ontario Rebate to Electricity Customers
25. Smart Meter Entity (SME) Additional Reporting and Synchronization
26. Debt Retirement Exemption and Bill Presentation
27. Overhead Transformer PCB Testing
28. The Ontario Electricity Support Program (OESP)
29. The cancellation and centralization of Conservation and Demand Management
30. (CDM)

31. Implementation of the Ontario Electricity Rebate
32. Implementation of changes to Customer Service Rules
33. Installation of Metering Inside the Settlement Timeframe (MIST) meters for > 50
34. kW customers
35. Continued connection of Renewable Generation
36. Implementation of the OEB's standardized accounting process for RPP settlement
37. Implementation of the OEB Cyber Security Framework
38. Implementation of COVID-19 Billing Changes
39. Implementation of Time of Use Opt-Out

2.1.8 Performance Measurement

(a) Performance Evaluation

In this Application, ERHDC has presented its performance for each of the Board's performance outcomes over the last three historical years, its current performance, and its projections for continuous improvements over the term of the Application.

(b) Renewed Regulatory Framework for Electricity Distributors (RRFE)

The Board introduced a new approach to rate setting at the end of 2012 with the Renewed Regulatory Framework. The Renewed Regulatory Framework is a performance based approach to regulation that focuses on the achievement of outcomes such as efficiency, reliability, sustainability, and financial viability. The Performance Measurement for Electricity Distributors: A Scorecard Approach, Board File EB-2010-0379 was published on March 5, 2014. The report details the scorecard measures approach which the Board expects to use in order to monitor and assess a distributor's effectiveness and improvements in achieving the four performance outcomes of:

- **Customer Focus**: services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness**: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

- **Public Policy Responsiveness**: utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board), and

- **Financial Performance**: financial viability is maintained; and savings from operational effectiveness are sustainable.

(l) Scorecard

The Scorecard Approach, issued on March 5, 2014 details the scorecard measures approach which the Board expects to use in order to monitor and assess a distributor's effectiveness and improvement in achieving the four performance outcomes mentioned above, and to facilitate distributor benchmarking.

ERHDC has published its most recent scorecard for public viewing on its website at http://www.erhydro.com/document/2018%20Scorecard%20-%20Espanola%20Regional%20Hydro%20Distribution%20Corporation%20Final.pdf

ERHDC's scorecard for 2019 is presented in Table 1-22 below and in Appendix 1-B in full.

Table 1 - 22: ERHDC's scorecard for 2019

Scorecard - Espanola Regional Hydro Distribution Corporation 9/23/2020

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

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

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

2.1.8.1 RRFE Performance Outcomes

Scorecard Highlights:

1. Exceeded the 5-year rolling average distributor target in reliability performance.
2. Fifth consecutive year with zero public safety incidences.
3. Eighth consecutive year maintaining an efficiency assessment rating of Group 2 which is defined as having actual costs between 10% and 25% below predicted costs under the PEG model.

ERHDC will continue working towards maintaining its high level of customer satisfaction and operational effectiveness in this cost of service period and beyond.

2.1.8.2 ERHDC's target is to attain all scorecard targets.

This Section details the steps ERHDC has taken in respect of each of the Board's four RRFE outcomes in accordance with benchmarking of electricity distributor cost performance.

(a) Customer Focus

(i) Service Quality

As detailed in Table 1-23 below, ERHDC met all the following Service Quality targets for the period 2017 to 2019 except for the 2019 Telephone Calls Answered on Time. The main contributing factor to the missed target was staff turnover which resulted in new staff having longer average talk times with customers. The extra time on the phones with customers then lead to calls waiting in the queue. ERHDC has a fully trained team in place and has seen significant improvement for 2020. ERHDC will continue to monitor this performance measure to identify opportunities for improvement.

Table 1 - 23: Service Quality Measures

YEAR	New Residential/Small Business Services Connected on Time (Target: 90%)	Scheduled Appointments Met on Time (Target: 90%)	Telephone Calls Answered on Time (Target: 65%)
2017	100.00%	98.18%	72.62%
2018	100.00%	100.00%	70.67%
2019	100.00%	98.55%	63.04%
Target 2020	100.00%	100.00%	65.00%
Target 2021	100.00%	100.00%	65.00%

(ii) Customer Satisfaction

As detailed in the scorecard above, ERHDC met all the Customer Satisfaction targets for the period 2017 to 2019 as shown in **Table 1-24** below:.

Table 1 - 24: Customer Satisfaction Measures

YEAR	First Contact Resolution	Billing Accuracy (Target: 98%)	Customer Satisfaction Survey Results
2017	99.60%	99.95%	87.00%
2018	99.73%	99.89%	87.00%
2019	99.23%	99.98%	91.00%
Target 2020	100.00%	100.00%	91.00%
Target 2021	100.00%	100.00%	92.00%

Customer Satisfaction Survey Results

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

(b) **Operational Effectiveness - Safety**

As detailed in Table 1-25 below, ERHDC met all the following Customer Satisfaction targets for the period 2017 to 2019:

- Level of Compliance with Regulation 22/04
- Serious Electrical Incident Index - Number of General Public Incidences
- Serious Electrical Incident Index – Rate per 10, 100, 1000 km of line

Table 1 - 25: Safety Measures

YEAR	Level of Public Awareness	Level of Compliance with Ontario Regulation 22/04 (Target: substantially compliant)	Number of General Public Incidents	Rate per 10, 100, 1000 km of line
2017	84.00%	C	0	0.000
2018	84.00%	C	0	0.000
2019	85.00%	C	0	0.000
Target 2020	85.00%	C	0	0.000
Target 2021	86.00%	C	0	0.000

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

Safety - Component A – Public Awareness of Electrical Safety

ERHDC's third safety awareness survey was conducted in early 2020. A representative sample of ERHDC's service territory population was surveyed to gauge the public's awareness level of key electrical safety concepts related to distribution assets. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness and identify opportunities where additional education and outreach may be required. ERHDC's score for 2019 was 85% (2017 84%). ERHDC's target for this metric is to improve each year the survey is undertaken.

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

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

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

Safety - Component C – Serious Electrical Incident Index

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

(ii) System Reliability

As detailed in Table 1-26 below, ERHDC met all the following System Reliability targets for the period 2017 to 2019:

- Average Number of Hours that Power to a Customer is Interrupted
- Average Number of Times that Power to a Customer is Interrupted

Table 1 - 26: System Reliability Measures

YEAR	Average Number of Hours Power to Customer is Interrupted	Average Number of Times Power to Customer is Interrupted
2017	0.35	0.10
2018	0.16	0.06
2019	0.35	0.17
Target 2020	0.35	0.35
Target 2021	0.33	0.33

Average Number of Hours that Power to a Customer is Interrupted

The System Average Interruption Duration Index (SAIDI) of 0.35 in 2019 was below the target of 0.67. There are ongoing efforts to improve reliability including replacing aging infrastructure and ongoing vegetation management.

Average Number of Times that Power to a Customer is Interrupted

The System Average Interruption Frequency Index (SAIFI) of 0.17 in 2019 was substantially below the target of 0.33. Consistent with SAIDI, there are ongoing efforts to improve reliability including replacing aging infrastructure and ongoing vegetation management.

(iii) Asset Management

Distribution System Plan Implementation Progress

Although ERHDC has employed some degree of distribution system planning for several years, it began drafting its first formal Distribution System Plan (DSP), meeting all OEB Chapter 5 Filing Requirements, in 2015-2016 with the intention of filing the DSP with the OEB as part of a 2017 Cost of Service Application. Activity was halted however in 2017 with the announcement of the pending sale of ERHDC to North Bay Hydro. Now that the acquisition is complete, ERHDC has updated its DSP in preparation for this Application. Due to future amalgamation in 2022, the OEB has accepted that the DSP will only cover 2021, rather than a full five-year DSP. The DSP will outline how ERHDC will develop, manage, and maintain its distribution system equipment to provide a safe, reliable, efficient, and cost-effective distribution system.

(iv) Cost Control

Table 1 - 27: Cost Control Measures

YEAR	Efficiency Assessment (1 = most efficient 5 = least efficient)	Total Cost ($) per Customer	Total Cost ($) per Km of Line
2017	2	$ 661	$ 15,421
2018	2	$ 683	$ 16,003
2019	2	$ 758	$ 17,789
Target 2020	2	$ 761	$ 17,855
Target 2021	2	$ 818	$ 19,205

Efficiency Assessment

Table 1-27 above is ERHDC's scorecard on cost control measures. 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.

The following Table 1-28 summarizes the distribution of all distributors across the 5 groupings for 2019:

Table 1 - 28: Groupings of All Ontario LDCs for 2019

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	6
2	Actual costs are 10% to 25% below predicted costs	More Efficient	19
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	26
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	9
5	Actual costs are 25% or more above predicted costs	Least Efficient	3

In 2019, for the eighth consecutive year, ERDHC was placed in Group 2. ERHDC's efficiency performance based on the PEG model was below the predicted costs by an average of 21.68% over the last three years. ERHDC considers one of the main drivers in controlling costs is the third party billing and management contract. ERHDC monitors its performance and expenses on an ongoing basis in order to budget with the goal of remaining in Group 2. ERHDC is projected to remain in Group 2 (between 10% and 25% below predicted costs) based on the 2020 bridge year budget and 2021 test year estimates.

Total Cost per Customer

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

Total Cost per Km of Line

This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. ERHDC's 2019 rate is $17,789 per Km of line, a 11% increase over 2018. As mentioned above, this increase is due to increased administrative expenses related to the sale. ERHDC continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. Table 1-29 below, is a summary of the public policy and responsiveness measure for 2017, 2018, and 2019, as well as targets for 2020 and 2021.

(c) Public Policy Responsiveness

Table 1 - 29: Public Policies and Responsiveness Measures

YEAR	Net Cumulative Energy Savings (Percent of Target Achieved)	Renewable Generation Connection Impact Assessments Completed on Time	New Micro-Embedded Generation Facilities Connected on Time (Target: 90%)
2017	80.32%		100.00%
2018	99.00%		
2019	131.00%		
Target 2020	N/A		
Target 2021	N/A	N/A	N/A

(i) Net Cumulative Energy Savings

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

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

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

(ii) Connection of Renewal Generation

Renewable Generation Connection Impact Assessments Completed on Time

Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. For the year 2019 no CIA requests were received. ERHDC maintains internal processes to ensure all applications are processed within the prescribed timelines when they are received.

New Micro-embedded Generation Facilities Connected On Time

ERHDC received no applications for Micro-embedded Generation Facilities in 2019.

(d) Financial Performance

(i) Financial Ratios

Table 1 - 30: Financial Ratios Measures

YEAR	Liquidity: Current Ratio (>1)	Leverage: Total Debt to Equity Ratio (1.5=60/40)	Profitability: Regulatory Return on Equity - Deemed	Profitability: Regulatory Return on Equity - Achieved	Variance ROE
2017	1.17	1.17	9.12%	2.45%	-6.67%
2018	1.22	1.12	9.12%	4.12%	-5.00%
2019	0.83	- 22.35	9.12%	-9.46%	-18.58%
Target 2020	1.00	- 22.35	9.12%	-5.21%	-14.33%
Target 2021	1.00	- 22.35	8.52%	3.06%	-5.46%

Liquidity: Current Ratio (Current Assets/Current Liabilities)

Table 1-30 above shows ERHDC's financial ratios. As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

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

Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt to equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring. ERHDC has a debt to equity ratio of -22.35 in 2019 which is below the deemed capital structure. As noted above, the financing structure is temporary and the leverage ratio tied to liquidity will continue to be low until the amalgamation occurs.

Profitability: Regulatory Return on Equity – Deemed (included in rates)

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

Profitability: Regulatory Return on Equity – Achieved

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

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

2.1.8.3 2020 Benchmarking Spreadsheet Forecast Model

ERHDC has completed the 2021 Benchmarking Spreadsheet Forecast model based on the 2020 Bridge Year projection and 2021 Test Year request and has included a summary of the outcome in Table 1-27 below. ERHDC is mindful of its stretch factor cohort and will continue to exceed all scorecard performance targets in the areas of Customer Focus, Operational Effectiveness and Public Policy Responsiveness while maintaining its cost efficiency factor of 2 over the period leading up to the amalgamation with North Bay Hydro. Table 1-31 below outlines the hisotical results of the benchmarking forecast for 2017, 2018, and 2019, as well as the 2020 Bridge and 2021 Test years.

Table 1 - 31: Results of Benchmarking Forecast

	2017 Historical	2018 Historical	2019 Historical	2020 Bridge	2021 Test
Actual Total Cost	$2,174,399	$2,256,379	$2,517,554	$2,475,036	$2,716,071
Predicted Total Cost	$2,738,909	$2,890,756	$2,995,788	$3,238,682	$3,452,204
Difference	-$564,510	-$634,377	-$478,234	-$763,646	-$736,132
% Difference (Cost Performance)	-20.61%	-21.95%	-15.96%	-23.58%	-21.32%
Stretch Factor Cohort (Annual)	2	2	2	2	2

2.1.9 Financial Information

2.1.9.1 Non-Consolidated Audited Financial Statements

Copies of ERHDC's 2018 and 2019 Audited Financial Statements which include 3 years historical data are provided in Appendix 1-C.

(a) **Reconciliation between Audited Financial Statements and Regulatory Accounting**

Reconciliations of ERHDC's Audited Financial Statements to the annual Regulatory Reporting Requirement ("RRR") Trial Balance for 2017, 2018 and 2019 are provided in Appendix 1-D.

(b) Annual Report and MD&A for Parent Company

ERHDC does not have any annual reports.

(c) Rating Agency Reports

ERHDC does not hold public debt, therefore, does not require a rating agency report.

(d) Prospectus, Information Circulars for Recent and Planned Issuances

ERHDC has no past or planned prospectuses, information circulars, or other similar documents.

(e) Changes in Tax Status

ERHDC has not had a change in Tax Status since its last Cost of Service Application.

(f) Accounting Orders

ERHDC confirms that it implemented the regulatory accounting changes for depreciation and overhead capitalization in 2012. ERHDC has prepared this Application on the MIFRS basis, as required.

ERHDC submitted an ICM application (EB-2013-0127) for the recovery of $2,062,500 associated with the construction of a new municipal substation and 44 kV line. The Board approved the related rates effective from May 1, 2014 to its next cost of service application. ERHDC established Account 1508 sub-accounts to track the costs of the new substation and the related revenues. The reconciliation of Account 1508 is addressed in Exhibit 2 of this application.

(g) Uniform System of Accounts

ERHDC confirms there are no departures from the Uniform System of Accounts.

(h) **Accounting Standards**

ERHDC confirms that it implemented the regulatory accounting changes for depreciation and overhead capitalization in 2012. ERHDC adopted International Financial Reporting Standards on January 1, 2015 with a transition date of January 1, 2014. The standards were applied retrospectively to the comparative 2014 information. This Application is being filed using MIFRS Accounting Standards. Historical years are represented under the following Accounting Standards: 2012 and 2013 using CGAAP and MIFRS 2014 through to 2021.

(i) **Accounting Treatment of Non-Utility Businesses**

ERHDC does not have any non-utility business activities.

2.1.10 Distributor Consolidation

On January 16, 2019, North Bay (Espanola) Acquisition Inc. (“NBEAI”) (an affiliate of NBHDL) filed a Mergers, Amalgamations, Acquisitions and Divestitures application (EB-2019-0015) (“MAADs Application”) which sought approval for the acquisition of Espanola Hydro Holdings Corporation (“ERHHC”) and Espanola Regional Hydro Distribution Corporation (“Espanola Hydro”) by NBEAI and the amalgamation of NBEAI, ERHHC and Espanola Hydro to form Espanola Regional Hydro Distribution Corporation (“ERHDC”). These approvals formed Phase 1 of a two-phase transaction.

In its August 22, 2019 Decision and Order[3], the Ontario Energy Board (“OEB” or “Board”) approved Phase 1 of the two-phase transaction. Effective October 1, 2019, the former entities amalgamated pursuant to the provisions of the *Business Corporations Act, 1990* (Ontario), to continue as one corporation under the name of Espanola Regional Hydro Distribution Corporation.

In this context, ERHDC confirms that:

[3] EB-2019-0015 – North Bay (Espanola) Acquisition Inc. MAADs Application, Decision and Order [*MAADs Decision*] dated August 22, 2019

- Due to the continued operation of the Services Agreement between PUC Services Inc. and ERHDC ("PUC Services Agreement"), which expires on February 28, 2022 and includes cost prohibitive provisions associated early termination that would not create value for ratepayers, NBHDL and ERHDC continue to be operated on a stand-alone basis.
- ERHDC confirms that there are no incentives that formed part of the acquisition and amalgamation that represent costs that are included or are being proposed to be included in ERHDC's rate base and/or revenue requirement.
- ERHDC confirms that there are no commitments were made to shareholders that are to be funded through ERHDC rates.
- As was outlined in the MAADs Application,[4] NBHDL and ERHDC continue to operate as separate entities subsequent to Phase 1 and consequently there has been no impact with respect to price or underlying costs. Operational synergies are not yet possible because of ERHDC's obligations and PUC's rights under the PUC Services Agreement. This expectation was acknowledged by the OEB in the MAADs Decision and Order[5].
- ERHDC confirms that it does have a prior approval of an ACM or ICM that is now seeking to incorporate into rate base for the first time.

NBEAI included a Proposed Rate Framework as part of the MAADs Application[6]. NBEAI proposed that following the Phase 1 Transaction, NBHDL and ERHDC be permitted to continue to operate as independent utilities until 2022 (i.e. after the PUC Services Agreement expires). NBHDL would file its cost of service rebasing application prior to Phase 2 of the two-phase transaction and it would also ensure that ERHDC file a cost of service rebasing application at that time as well. NBHDL and ERHDC's rebasing applications would be heard independently.

As part of the Proposed Rate Framework, ERHDC's cost of service application will help maintain the ongoing financial viability of the utility as well as address regulatory matters, which include[7]:

[4] EB-2019-0015 – North Bay (Espanola) Acquisition Inc. MAADs Application [*MAADs Application]*, January 16, 2019, page 11.
[5] MAADs Decision, page 14.
[6] MAADs Application, page 11.
[7] MAADs Application, page 12.

- ERHDC to begin the transition of residential customers towards fully-fixed rates;
- Ending a current Incremental Capital Module (ICM) rate rider, and rolling the substation properly into base rates, which will help reduce rates to the benefit of customers (the actual costs of the substation were less than what was previously forecasted);
- Filing a comprehensive five-year consolidated distribution system plan in accordance with the OEB's requirements;
- Disposing of Group 1 Deferral and Variance Accounts, which were last disposed of for December 31, 2013 balances, and the Lost Revenue Adjustment Mechanism last cleared for programs ending April 2012; and
- Updating ERHDC's load forecast, cost allocation and rate design to reflect more current information.

Regarding the Proposed Rate Framework, the OEB found that it was consistent with the OEB's policies for one utility to acquire another utility and operate it on a stand-alone basis and by remaining as stand-alone utilities, it would include filing separate rate applications[8]. The OEB found that NBEAI's Proposed Rate Framework to file separate cost of service rate applications for 2021 rates for NBHDL and ERHDC reasonable.[9]

[8] MAADs Decision, page 25.
[9] Ibid.

APPENDIX 1-A
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Appendix 1-B
2019 Scorecard – ERHDC Inc.

Scorecard - Espanola Regional Hydro Distribution Corporation 9/23/2020

Performance Outcomes	Performance Categories	Measures	2015	2016	2017	2018	2019	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time	100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time	100.00%	100.00%	98.18%	100.00%	98.55%		90.00%	
		Telephone Calls Answered On Time	76.10%	76.20%	72.62%	70.67%	63.04%		65.00%	
	Customer Satisfaction	First Contact Resolution	99.6%	99.17 %	99.60%	99.73%	99.23%			
		Billing Accuracy	99.93%	99.95%	99.95%	99.89%	99.98%		98.00%	
		Customer Satisfaction Survey Results	89%	87 %	87 %	87%	91.00			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness	85.00%	85.00%	84.00%	84.00%	85.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]	C	C	C	C	C			C
		Serious Electrical Incident Index: Number of General Public Incidents	0	0	0	0	0			0
		Serious Electrical Incident Index: Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]	0.27	0.55	0.35	0.16	0.35			0.67
		Average Number of Times that Power to a Customer is Interrupted [2]	0.07	1.10	0.10	0.06	0.17			0.33
	Asset Management	Distribution System Plan Implementation Progress	On Track	On Track	On Track	On Track	On Track			
	Cost Control	Efficiency Assessment	2	2	2	2	2			
		Total Cost per Customer [3]	$658	$670	$661	$683	$758			
		Total Cost per Km of Line [3]	$15,465	$15,702	$15,421	$16,003	$17,789			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]	20.83%	35.54%	80.32%	99.00%	131.00%			2.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time	0.00%	0.00%						
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%				90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)	1.47	1.34	1.17	1.22	0.83			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.30	1.22	1.17	1.12	-22.35			
		Profitability: Regulatory Return on Equity: Deemed (included in rates)	9.12%	9.12%	9.12%	9.12%	9.12%			
		Profitability: Regulatory Return on Equity: Achieved	15.91%	6.29%	2.45%	4.12%	-9.46%			

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

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

APPENDIX 1-C
ERHDC Inc Audited Financial Statements 2018-2019

Espanola Regional Hydro Distribution Corporation

Financial Statements

Year ended December 31, 2018

INDEPENDENT AUDITOR'S REPORT

To: The Shareholders of
Espanola Regional Hydro Distribution Corporation

Report on the Audit of the Financial Statements

Opinion

We have audited the financial statements of **Espanola Regional Hydro Distribution Corporation**, which comprise the statement of financial position as at **December 31, 2018**, and the statements of comprehensive earnings, retained earnings and accumulated other comprehensive earnings, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the corporation as at **December 31, 2018**, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the corporation's financial reporting process.

Edwin P. Reilly • Sam P. Lolas • Kirby W. Houle • Ian L. FitzPatrick • Joel A. Humphrey • Cleo L. Melanson

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INDEPENDENT AUDITOR'S REPORT, continued

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements. As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

INDEPENDENT AUDITOR'S REPORT, continued

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Freelandt Caldwell Reilly LLP

FREELANDT CALDWELL REILLY LLP

Chartered Professional Accountants
Licensed Public Accountants

Sudbury, Ontario
April 10, 2019

Espanola Regional Hydro Distribution Corporation

Statement of Financial Position
December 31, 2018 with comparative figures for 2017

	2018	2017
Assets		
Current		
Cash	$ 767,496	$ 1,483,510
Accounts receivable (note 4)	1,151,782	1,027,266
Unbilled revenue - energy sales	532,037	570,747
Unbilled revenue - distribution	152,114	162,262
Inventory	50,383	71,199
Prepaid expenses	159,865	28,742
Payment in lieu of taxes	79,202	63,196
	2,892,879	3,406,922
Payment in lieu of deferred taxes (note 8)	11,392	10,510
Property, plant and equipment (note 5)	4,880,215	4,640,045
Total assets	7,784,486	8,057,477
Regulatory assets (note 6)	2,543,512	2,680,471
Payment in lieu of deferred tax regulatory assets (note 6)	102,932	70,916
Total assets and regulatory assets	$ 10,430,930	$ 10,808,864

Approved on behalf of the Board of Directors:

Director ____________________

Director ____________________

See accompanying notes to financial statements

Espanola Regional Hydro Distribution Corporation
Statement of Financial Position
December 31, 2018 with comparative figures for 2017

	2018	2017
Liabilities and shareholders' equity		
Current		
Accounts payable and accrued liabilities	$ 655,886	$ 606,029
Payable for energy purchases	1,454,594	2,140,288
Current portion of long-term debt	86,359	83,452
	2,196,839	2,829,769
Customer deposits	210,362	222,090
Deferred revenue	137,257	-
Payment in lieu of deferred taxes (note 8)	114,324	70,560
Contributions in aid of construction (note 9)	316,758	286,384
Employee future benefits (note 10)	84,387	70,067
Long-term obligations (note 11)	2,071,612	2,157,971
Notes payable (note 12)	1,524,511	1,524,511
	6,656,050	7,161,352
Shareholders' equity		
Share capital (note 13)	2,281,000	2,281,000
Retained earnings	1,003,493	923,799
Accumulated other comprehensive earnings	998	14,954
	3,285,491	3,219,753
Total liabilities and shareholders' equity	9,941,541	10,381,105
Regulatory liabilities (note 6)	489,389	416,893
Payment in lieu of deferred tax regulatory liabilities (note 6)	-	10,866
Total liabilities, shareholders' equity and regulatory liabilities	$ 10,430,930	$ 10,808,864

Commitments (note 16)

Espanola Regional Hydro Distribution Corporation
Statement of Comprehensive Earnings
Year ended December 31, 2018 with comparative figures for 2017

	2018	2017 (restated) (note 20)
Revenue		
Energy sales	$ 6,729,611	$ 7,152,542
Distribution	1,630,447	1,593,631
	8,360,058	8,746,173
Cost of Energy	6,520,156	7,315,286
Gross Profit	1,839,902	1,430,887
Operating expenses (note 14)		
General and administration	329,323	376,015
Billing and collecting	429,732	433,424
Distribution - operations	374,289	303,433
Distribution - maintenance	267,091	285,370
Depreciation	161,273	153,005
Interest on long-term obligations and notes payable	148,067	150,875
	1,709,775	1,702,122
Earnings (loss) before other income and payment in lieu of taxes	130,127	(271,235)
Other income		
Interest	20,896	18,732
Labour, rental and other charges	112,275	99,528
Amortization of contributions in aid of construction	9,845	8,103
	143,016	126,363
Earnings (loss) before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)	273,143	(144,872)
Payments in lieu of taxes (recovery) (note 8)		
Current	(16,006)	(63,196)
Deferred	42,882	38,778
	26,876	(24,418)
Net earnings (loss) before change in regulatory asset and liability balances and other comprehensive earnings (loss)	246,267	(120,454)
Change in regulatory assets and liabilities (note 6)		
Change in regulatory asset and liability account balances related to profit and loss	(209,455)	162,744
Change in payment in lieu of deferred tax balances related to regulatory assets and liabilities	42,882	38,778
	(166,573)	201,522
Net earnings before other comprehensive loss	79,694	81,068
Other comprehensive loss		
Remeasurement of employee future benefits liability, net of tax	(13,956)	(4,327)
Net earnings	$ 65,738	$ 76,741

See accompanying notes to financial statements

Espanola Regional Hydro Distribution Corporation

Statement of Retained Earnings and Accumulated Other Comprehensive Earnings
Year ended December 31, 2018 with comparative figures for 2017

	Share capital	Retained earnings	Accumulated other comprehensive earnings (loss)	Total
Balance, December 31, 2017	$ 2,281,000	$ 923,799	$ 14,954	$ 3,219,753
Net earnings before other comprehensive loss	-	79,694	-	79,694
Other comprehensive loss	-	-	(13,956)	(13,956)
Balance, December 31, 2018	2,281,000	1,003,493	998	3,285,491
Balance, December 31, 2016	2,281,000	842,731	19,281	3,143,012
Net earnings before other comprehensive loss	-	81,068	-	81,068
Other comprehensive loss	-	-	(4,327)	(4,327)
Balance, December 31, 2017	$ 2,281,000	$ 923,799	$ 14,954	$ 3,219,753

Espanola Regional Hydro Distribution Corporation
Cash Flows Statement
Year ended December 31, 2018 with comparative figures for 2017

	2018	2017
Cash flows from operating activities		
Net earnings before other comprehensive loss	$ 79,694	$ 81,068
Adjustments to reconcile earnings to cash provided by (used in) operations:		
Depreciation	183,915	175,597
Amortization of contributions in aid of construction	(9,895)	(8,103)
Provision for payment in lieu of deferred taxes	42,882	38,778
Provision for payment in lieu of taxes	(16,006)	(63,196)
Interest charges on long-term obligations and notes payable	148,067	150,875
	428,657	375,019
Change in non-cash working capital items		
Accounts receivable	(124,516)	183,336
Unbilled revenue - energy sales	38,710	91,155
Unbilled revenue - distribution	10,148	(8,434)
Inventory	20,816	4,647
Prepaid expenses	(131,123)	118
Payment in lieu of taxes paid	-	144,571
Accounts payable and accrued liabilities	49,857	(71,030)
Payable for energy purchases	(685,694)	(469,081)
Interest on long-term obligations and notes payable paid	(148,067)	(150,875)
	(541,212)	99,426
Cash flows from investing activities		
Proceeds on disposal of property, plant and equipment	-	32,008
Purchase of property, plant and equipment	(424,085)	(694,191)
Regulatory assets	104,943	(278,373)
	(319,142)	(940,556)
Cash flows from financing activities		
Customer deposits	(11,728)	41,540
Deferred revenue	137,257	-
Regulatory liabilities	61,630	76,851
Contributions in aid of construction received	40,269	3,293
Employee future benefits	364	233
Repayment of long-term debt	(83,452)	(80,644)
	144,340	41,273
Decrease in cash	(716,014)	(799,857)
Cash, beginning of year	1,483,510	2,283,367
Cash, end of year	$ 767,496	$ 1,483,510

See accompanying notes to financial statements

1. Nature of operations

Espanola Regional Hydro Distribution Corporation was incorporated on November 1. 2000 under the laws of the province of Ontario, Canada. The incorporation was required in accordance with the Electricity Act. 1998, Ontario (the EA). The Corporation is a wholly owned subsidiary of Espanola Regional Hydro Holdings Corporation and was incorporated for the purpose of providing regulated electricity distribution services to customers in the Town of Espanola and the Township of Sables-Spanish Rivers from its head office located at 598 Second Street. Espanola Ontario, Canada.

The Corporation and other electricity distributors purchase their electricity from the wholesale market administered by the Independent Electricity System Operator (IESO) and recover the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board (the OEB).

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The Ontario Energy Board Act, 1998 sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and the filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity and the responsibility for ensuring that electricity distribution companies fulfil their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry may affect distribution rates and the permitted recovery or settlement or the timing of recovery or settlement of certain regulatory assets and liabilities.

2. Significant accounting policies

These financial statements are prepared using International Financial Reporting Standards applying the accounting policies set out below on a consistent basis in all years presented in these financial statement. The significant policies are detailed as follows:

(a) Statement of compliance and basis of measurement

These financial statements are the representation of the Corporation's management and are prepared in accordance with International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB). The Corporation adopted IFRS as of January 1, 2015 with a transition date of January 1, 2014. The Corporation's accounting policies are based on IFRS applicable as at December 31, 2018. The Corporation has adopted the requirements of IFRS 14 - Regulatory Deferral Accounts, which permits the Corporation to account for regulatory deferral account balances using its previous GAAP when it adopted IFRS. Previously, the financial statements of the Corporation were prepared using Canadian generally accepted accounting principles.

These financial statements have been prepared on a historical cost basis, except for financial instruments classified as "fair value through profit or loss" and "available for sale" financial assets which have been measured at fair value.

These financial statements are presented in Canadian dollars and were approved by the Corporation's Board of Directors on April 10, 2019.

(b) Effects of rate regulation

The Ontario Energy Board (OEB) is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in a non rate regulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting and approval process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting and approval process.

(c) Cash and cash equivalents

Cash and cash equivalents are defined as cash and highly liquid investments, consisting primarily of term deposits, with terms to maturity of three months or less at the date of purchase.

(d) Inventory

Inventory is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

2. **Significant accounting policies, continued**

(e) **Property, plant and equipment**

Property, plant and equipment are measured at historical cost or deemed cost less accumulated depreciation and impairment losses, if any. The Corporation elected to use the carrying amount, as previously determined under Canadian GAAP, as the deemed cost at January 1, 2014, the transition date to IFRS. In circumstances where parts of an item of property, plant and equipment have different useful lives they are accounted for as separate components of property, plant and equipment. The Corporation provides for depreciation using the straight-line method at rates designed to depreciate the cost of the property, plant and equipment over their estimated useful lives. A full year's depreciation is recorded in the year of acquisition. No depreciation is recorded in the year of disposal. The carrying amount of an item of property, plant and equipment is derecognized on disposal. The annual depreciation rates and useful lives are reviewed annually and are as follows:

Buildings	50 years
Furniture and equipment	5-10 years
Vehicles	15 years
Transmission and distribution equipment	40-60 years

Construction in progress includes assets not currently in use and therefore not yet subject to depreciation.

In certain cases, non-refundable contributions are received in aid of construction or acquisition of property, plant and equipment. Contributions in aid of construction are classified as liabilities and are amortized at the same rate as the assets to which they relate.

2. **Significant accounting policies, continued**

(f) Impairment of non-financial assets

At the end of each reporting period, the Corporation reviews the carrying amounts of its property, plant and equipment to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Corporation estimates the recoverable amount of the cash-generating unit ("CGU") to which the asset belongs. Where a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual CGUs, or otherwise they are allocated to the smallest group of CGUs for which a reasonable and consistent allocation basis can be identified.

Recoverable amount is the higher of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset or CGU is estimated to be less than its carrying amount, the carrying amount of the asset or CGU is reduced to its recoverable amount. An impairment loss is recognized immediately in operations.

Where an impairment loss subsequently reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset or CGU in prior years. A reversal of an impairment loss is recognized immediately in operations.

(g) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a rate, net of tax, that reflects current market assessments of the time value of money and the risks specific to the liability.

(h) Borrowing costs

Borrowing costs directly attributable to the acquisition or construction of property, plant and equipment, which take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use. All other borrowing costs are recognized in operations in the period in which they are incurred.

2. **Significant accounting policies, continued**

(i) Asset retirement obligations

Accounting standards require the Corporation to determine the fair value of future expenditures required to settle legal obligations to remove property, plant and equipment. If reasonably estimable, the Corporation recognizes a liability for the estimated current value of future expenditures required to settle obligations for the retirement of property, plant and equipment. Decommissioning liabilities are recorded at fair value, with a corresponding increase to the recorded amount of property, plant and equipment. Accretion of decommissioning liabilities is included in operations. Differences between the recorded amount of decommissioning liabilities and the actual decommissioning costs incurred are recorded as a gain or loss in the period of settlement.

Some of the Corporation's distribution system assets may have asset retirement obligations. As the Corporation expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of the related asset retirement obligation cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Corporation is legally required to remove, an asset retirement obligation will be recognized at that time.

(j) Pension plan

The Corporation provides a pension plan for all its full-time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multiemployer pension plan that provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund.

OMERS is a defined benefit plan, however it does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. Obligations for contributions to defined contribution pension plans are recognized as an expense in net operations when they are due.

2. **Significant accounting policies, continued**

(k) **Revenue recognition**

Distribution and energy related revenues attributable to the supply and distribution of electricity are based on OEB approved rates and revenue is recognized as electricity is delivered to customers based on periodic meter readings. At the end of an accounting cycle, there is energy used by consumers for which meter readings are not available and no bills have been issued. This unbilled revenue is estimated and recorded in current assets on the statement of financial position at the end of each fiscal year. The related cost of energy is recorded on the basis of energy used.

The difference between the amount paid by the Corporation to Hydro One for the purchase of energy and related service costs and the amount billed by the Corporation to its customers for energy sales based on regulated rates are recorded on the statement of financial position as regulatory assets and liabilities until their final disposition is decided by the OEB. In accordance with IFRS 14, the change in these regulatory assets and liabilities are reported, net of tax, with regulatory balances in the statement of comprehensive earnings.

Labour, rental and other charges revenue is recognized in the period in which these services are provided.

(l) **Payment in lieu of taxes**

Pursuant to the EA, the Corporation is required to compute taxes under the Income Tax Act (Canada) (ITA) and remit such amounts computed there under to the Ontario Electricity Financial Corporation (OEFC). These amounts, referred to as payments in lieu of taxes (PILs) under the EA, are applied to reduce certain debt obligations of the former Ontario Hydro now owing by the OEFC.

Payment in lieu of deferred income tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the financial statement carrying amount of assets and liabilities and their tax bases. Payment in lieu of deferred tax assets are also recognized for the benefit of any deductions or losses available to be carried forward to future periods for tax purposes that are likely to be realized. These amounts are measured using enacted or substantively enacted tax rates and are re-measured annually for changes in these rates. Any payment in lieu of deferred income tax assets are reassessed each year to determine if a valuation allowance is required. Any effect of the re-measurement or reassessment is recognized in operations in the period of the change.

As prescribed by regulatory rate order, payment in lieu of taxes are recovered through customer rates based on the taxes payable method. Therefore, rates do not include the recovery of payment in lieu of deferred taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, payment in lieu of deferred tax regulatory assets or liabilities are recognized for the amount of payment in lieu of deferred taxes which are expected to be included in future rates and recovered from or refunded to customers in future periods through the rate setting and approval process.

2. Significant accounting policies, continued

(m) Employee future benefits

The Corporation's net obligation in respect of its employee future benefit plan is calculated by estimating the amount of future benefits that employees have earned in return for their service in the current and prior periods, that benefit is discounted to determine its present value. Any unrecognised past service costs are deducted. The discount rate is the interest rate at the reporting date on high quality debt instruments with duration similar to the duration of the plan.

The cost of these employee future benefits is expensed as earned by employees through employment service. The accrued benefit obligation and the current service costs are actuarially determined by applying the projected unit credit method and incorporate management's best estimate of certain underlying assumptions. Re-measurements arising from employee benefit plans are recognized immediately in operations. When the benefits of a plan are improved, these increases are recognized immediately in operations.

2. **Significant accounting policies, continued**

(n) **Financial instruments**

(i) **Measurement of financial instruments**

Financial assets and financial liabilities are initially measured at fair value. Fair value is the amount for which an asset could be exchanged, or a liability settled, between knowledgeable, willing parties in an arm's length transaction. Transaction costs that are directly attributable to the acquisition or issue of financial assets and financial liabilities, other than financial assets and financial liabilities at fair value through profit or loss ("FVTPL"), are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at FVTPL are recognized immediately in profit or loss. Transactions to purchase or sell these items are recorded on the trade date.

Financial instruments are measured at their amortized cost subsequent to initial recognition. Amortized cost is the amount at which the financial instrument is measured at initial recognition less principal repayments, plus or minus the cumulative amortization using the effective interest method of any difference between that initial amount and the maturity amount. Net gains and losses arising from changes in fair value are recognized in operations upon de-recognition or impairment.

The Corporation has classified its cash equivalents, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, payable for energy purchases, long-term obligations, and notes payable as financial instruments measured at amortized cost.

(ii) **Impairment**

A financial asset measure at amortized cost is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount, and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount.

All impairment losses are recognized in operations. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in operations.

2. **Significant accounting policies, continued**

(o) **Measurement uncertainty**

The preparation of financial statements in conformity with International Financial Reporting Standards requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. By their nature, these estimates are subject to measurement uncertainty. The effect of changes in such estimates on the financial statements in future periods could be significant, including changes as a result of future decisions made by the Ontario Energy Board (OEB). All estimates are reviewed periodically and adjustments are made and recognized in operations, as appropriate, in the year they become known. Accounts specifically affected by estimates and assumptions in these financial statements are as follows:

(i) **Property, plant and equipment**

Amounts recorded in the financial statements for depreciation are based on the estimated useful lives of the Corporation's property, plant and equipment. These useful lives are management's best estimate of the service lives of these assets and are reviewed annually. Changes to these estimated useful lives could materially affect the amount of depreciation recorded in the financial statements.

The Corporation's policy relating to property, plant and equipment is described in note 2(e). In applying this policy, management uses judgment in determining whether certain costs are additions to the carrying amount of property, plant and equipment or expensed in operations as repairs and maintenance. Judgment is also necessary in determining the appropriate componentization structure of the Corporation's property, plant and equipment.

(ii) **Decommissioning liabilities**

The Corporation recognizes a liability for the estimated current value of future expenditures required to settle obligations for the retirement of property, plant and equipment. Decommissioning liabilities are recorded at fair value, with a corresponding increase to the recorded amount of property, plant and equipment. Accretion of decommissioning liabilities is included in operations. Differences between the recorded amount of decommissioning liabilities and the actual decommissioning costs incurred are recorded as a gain or loss in the period of settlement.

(iii) **Employee future benefits**

The Corporation provides certain health and dental benefits to retired employees. The estimated cost of providing these benefits is accounted for on an accrual basis in the period in which employees render their services and are actuarially determined using the projected benefit method pro-rated on service and include management's best estimate of salary escalations, retirement ages and expected health care cost escalations.

2. **Significant accounting policies, continued**

(o) **Measurement uncertainty, continued**

(iv) **Regulatory assets and liabilities**

When recognizing regulatory assets and liabilities management assumes that such credits or costs will be recovered from customers or refunded to customers in future years through the rate setting and approval process. Refund or recovery of these regulatory assets and liabilities are subject to the review and approval of the OEB. Consequently, there is risk that some or all of the regulatory assets and liabilities will not be approved by the OEB which could have a material affect on the Corporation's comprehensive income in the year of the OEB decision.

3. **Future changes to significant accounting policies**

The Corporation has not yet adopted the following new and revised International Financial Reporting Standards that have been issued but are not yet effective:

Leases IFRS 16

In January 2016, IFRS 16 - Leases was issued. IFRS 16 establishes principles for the recognition, measurement, presentation and disclosure of leases with the objective of ensuring that lessees and lessors provide relevant information that faithfully represents those transactions. IFRS 16 replaces IAS 17 and is effective for periods beginning on or after January 1, 2019. The Corporation is assessing the impact of IFRS 16 on its results of operations, financial position and disclosures.

Uncertainty Over Income Tax Treatments IFRIC 23

In June 2017, IFRIC 23 - Uncertainty Over Income Tax Treatments was issued. IFRIC 23 provides guidance on the accounting for current and deferred tax assets and liabilities in situations in which there is uncertainty over income tax treatments and is effective for periods beginning on or after January 1, 2019. The Corporation is assessing the impact of IFRIC 23 on its results of operations, financial position and disclosures.

4. **Accounts receivable**

	2018	2017
Electrical energy receivables	$ 748,997	$ 720,775
Water and sewer receivables	206,397	213,578
Other receivables	196,388	92,913
	$ 1,151,782	$ 1,027,266

	2018	2017
Aging of accounts receivable		
Current	$ 1,109,920	$ 964,371
30 days	15,764	13,904
60 days	8,018	10,950
Over 90 days	18,080	38,041
	$ 1,151,782	$ 1,027,266

5. Property, plant and equipment

2018

	Land	Buildings	Transmission & Distribution Equipment	Vehicles	Furniture and Equipment	Construction In Progress	Total
Cost							
Balance, beginning of year	$ 88,880	183,831	4,509,168	315,642	31,451	106,501	$ 5,235,473
Additions	-	-	421,259	-	1,619	1,207	424,085
Transfers	-	-	56,524	-	-	(56,524)	-
Disposals	-	-	-	-	-	-	-
Balance, end of year	88,880	183,831	4,986,951	315,642	33,070	51,184	5,659,558
Accumulated Amortization							
Balance, beginning of year	-	18,087	474,275	83,596	19,470	-	595,428
Depreciation	-	4,572	153,163	22,592	3,588	-	183,915
Disposals	-	-	-	-	-	-	-
Balance, end of year	-	22,659	627,438	106,188	23,058	-	779,343
Net book value	$ 88,880	161,172	4,359,513	209,454	10,012	51,184	$ 4,880,215

2017

	Land	Buildings	Transmission & Distribution Equipment	Vehicles	Furniture and Equipment	Construction In Progress	Total
Cost							
Balance, beginning of year	$ 88,880	183,831	3,929,058	315,642	31,451	54,100	$ 4,602,962
Additions	-	-	635,376	-	-	58,815	694,191
Transfers	-	-	6,414	-	-	(6,414)	-
Disposals	-	-	(61,680)	-	-	-	(61,680)
Balance, end of year	88,880	183,831	4,509,168	315,642	31,451	106,501	5,235,473
Accumulated Amortization							
Balance, beginning of year	-	13,515	359,120	61,004	15,864	-	449,503
Depreciation	-	4,572	144,827	22,592	3,606	-	175,597
Disposals	-	-	(29,672)	-	-	-	(29,672)
Balance, end of year	-	18,087	474,275	83,596	19,470	-	595,428
Net book value	$ 88,880	165,744	4,034,893	232,046	11,981	106,501	$ 4,640,045

6. Regulatory assets and liabilities

	January 1, 2018	Regulatory activity	December 31, 2018
Settlement variances (a)	$ 1,212,814	$ (2,226)	$ 1,210,588
Stranded meters (b)	11,501	(2,197)	9,304
Substation (c)	1,456,156	(132,536)	1,323,620
Payment in lieu of deferred tax regulatory assets (d)	70,916	32,016	102,932
Total regulatory assets	2,751,387	(104,943)	2,646,444
Settlement variances (a)	416,893	72,496	489,389
Payment in lieu of deferred tax regulatory liabilities (d)	10,866	(10,866)	-
Total regulatory liabilities	427,759	61,630	489,389
Net regulatory assets	$ 2,323,628	$ (166,573)	$ 2,157,055

	January 1, 2017	Regulatory activity	December 31, 2017
Settlement variances (a)	$ 846,342	$ 366,472	$ 1,212,814
Stranded meters (b)	11,460	41	11,501
Substation (c)	1,590,515	(134,359)	1,456,156
Payment in lieu of deferred tax regulatory assets (d)	24,697	46,219	70,916
Total regulatory assets	2,473,014	278,373	2,751,387
Settlement variances (a)	347,483	69,410	416,893
Payment in lieu of deferred tax regulatory liabilities (d)	3,425	7,441	10,866
Total regulatory liabilities	350,908	76,851	427,759
Net regulatory assets	$ 2,122,106	$ 201,522	$ 2,323,628

6. **Regulatory assets and liabilities, continued**

Regulatory assets and liabilities arise as a result of the rate setting and approval process through the OEB.

(a) The difference between the amount paid by the Corporation to Hydro One for the purchase of energy and related service costs and the amount billed by the Corporation to its customers as energy sales based on regulated rates are recorded on the statement of financial position as settlement variances until their final disposition is decided by the OEB. The Corporation recognizes settlement variances as an asset or liability based on the expectation that these amounts will be approved by the OEB for future collection from, or refund to, customers through the rate setting and approval process. The settlement variance asset (liability) represents the excess (deficiency) of amounts billed to the Corporation by Hydro One for the purchase of energy over the amounts charged by the Corporation to its customers as energy sales.

Recovery or refund of the settlement variances is done on an annual basis through application to the OEB. Currently, no amount has been approved for recovery or refund. Accordingly, the timing of the recovery or refund is unknown.

(b) The stranded meter regulatory assets represent the unrecovered net book value of decommissioned analog meters. The net book value of the stranded meters was reclassified to the regulatory asset account for recovery to the end of March 2017.

(c) The substation asset represents the cost of construction of a new substation in the Town of Espanola. The OEB approved the recovery of $168,193 per year in the Corporation's rates until their next cost of service rate order.

(d) The payment in lieu of deferred tax regulatory asset and liability relate to the expected increase in or reduction of distribution rates for customers arising from temporary differences which give rise to payment in lieu of deferred tax assets and liabilities.

For certain of the regulatory assets and liabilities, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the OEB in determining the item's treatment for rate-setting purposes. The Corporation continually assesses the likelihood of recovery of each of its regulatory assets and refund of each of its regulatory liabilities and continues to believe that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If at some future date the Corporation determines that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be charged to operations in the period the determination is made.

7. **Bank credit facilities**

A revolving demand credit facility has been granted by the Royal Bank of Canada to a maximum of $500,000 bearing interest at the bank's prime rate plus 0.8% per annum.

A reducing facility by way of leases has also been granted by the Royal Bank of Canada to a maximum of $200,000, terms of which are governed by separate lease agreements.

The above credit facilities are secured by a first ranking general security agreement.

At the year-end date, no amount has been drawn on these credit facilities.

8. **Payment in lieu of taxes**

(a) The components of payment in lieu of deferred tax balances are as follows:

		2018	2017
Payment in lieu of deferred tax assets:			
Difference between tax basis of employee future benefits obligation and carrying amount	$	11,392 $	10,510
Payment in lieu of deferred tax liabilities:			
Difference between tax basis of property, plant and equipment and carrying amount		(114,324)	(70,560)
	$	(102,932) $	(60,050)

(b) The provision for payment in lieu of taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 13.5% (2017 - 15.0%) to the earnings for the years as follows:

		2018	2017
Earnings (loss) for the year before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)	$	273,143 $	(144,872)
Change in regulatory asset and liability account balances related to profit and loss		(209,455)	162,744
Remeasurement of employee future benefits liability included in other comprehensive income		(13,956)	(4,327)
	$	49,732 $	13,545
Anticipated income tax	$	6,714 $	2,032
Tax effect of the following:			
Tax effect of change in regulatory assets		27,253	(35,562)
Tax effect of change in payment in lieu of deferred tax regulatory asset		2,110	11,151
Adjustment due to change in tax rate		(9,201)	(2,039)
Provision for (recovery of) payment in lieu of taxes	$	26,876 $	(24,418)

9. **Contributions in aid of construction**

In certain cases, non-refundable contributions are received in aid of construction or acquisition of property, plant and equipment. Contributions in aid of construction are deferred and amortized to other revenue at the same rate as the assets to which they relate.

		2018	2017
Balance, beginning of year	$	286,384 $	291,194
Contributions received in the year		40,269	3,293
Amortization of contributions in aid of construction		(9,895)	(8,103)
Balance, end of year	$	316,758 $	286,384

10. **Employee future benefits**

The Corporation pays certain post-employment health and dental benefits on behalf of its retired employees. Accounting standards for employee future benefits require that these post-retirement costs be recognized in the period in which the employees rendered their services. Information about the Corporation's accrued benefit liability and the related expense are based on results and assumptions by actuarial valuation at December 31, 2018 and are as follows:

		2018	2017
Accrued benefit liability, beginning of year	$	70,067 $	65,507
Current service cost recognized in operations		500	530
Interest cost recognized in operations		2,415	2,531
Benefits paid by employer		(2,591)	(2,828)
Net actuarial loss recognized in other comprehensive income		13,956	4,327
Accrued benefit liability, end of year	$	84,347 $	70,067

The main assumptions employed for the valuations are as follows:

The health benefit cost is estimated to increase at rates ranging from 4.0% to 5.3% per annum. The dental benefit cost is estimated to increase at rates ranging from 4.0% to 5.4% per annum.

The obligation at year-end and the present value of future liabilities and the related expense, were determined using an annual discount rate of 4.0% per annum (2017 - 3.50%) representing an estimate of the yield on high quality corporate bonds with a duration similar to the duration of the plan.

Future general salary and wage levels were assumed to increase at 2.5% per annum (2017 - 2.6%).

11. Long-term obligations

	2018	2017
Infrastructure Ontario non-revolving term loan, repayable in blended monthly installments of $2,860 including interest at 2.73% per annum, secured by a general security agreement ranking behind the first ranking general security agreement registered by the Royal Bank of Canada and maturing December 2025	$ 218,423	$ 246,360
Infrastructure Ontario non-revolving term loan, repayable in blended monthly installments of $10,831 including interest at 3.78% per annum, secured by a general security agreement ranking behind the first ranking general security agreement registered by the Royal Bank of Canada and maturing December 2040	1,939,548	1,995,063
	2,157,971	2,241,423
Less current portion	86,359	83,452
	$ 2,071,612	$ 2,157,971

The Ontario Infrastructure loans require the Corporation to meet a debt service coverage ratio of a minimum of 1:25 to 1 and a debt to total assets ratio of less than 60%. At December 31, 2018 the corporation is in compliance with these covenants.

Estimated principal repayments are as follows:

2019	$ 86,359
2020	89,370
2021	92,489
2022	95,718
2023	99,062
Subsequent years	1,694,973
	$ 2,157,971

12. **Notes payable**

	2018	2017
Note payable to the Town of Espanola	$ 1,185,416	$ 1,185,416
Note payable to the Township of Sables-Spanish Rivers	339,095	339,095
	$ 1,524,511	$ 1,524,511

Notes payable to the Town of Espanola and Township of Sables-Spanish Rivers are without security, are due on demand with one year's written notice, include interest at 4.41% per annum (2017 – 4.41%) and are convertible into special shares of the Corporation at a rate of $10,000 per share. During the year, the Corporation paid interest in the amount of $52,277 (2017 - $52,277) to the Town of Espanola and $14,954 (2017 - $14,954) to the Township of Sables-Spanish Rivers.

13. **Share capital**

	2018	2017
Authorized		
Unlimited number of common shares		
Unlimited discretionary non-cumulative dividend paying, redeemable at $10,000 per share, non-voting special shares		
Issued		
1,000 common shares	$ 1,000	$ 1,000
228 special shares	2,280,000	2,280,000
	$ 2,281,000	$ 2,281,000

14. Operating expenses

For internal management reporting purposes the Corporation's operating expenses are reported by function. Operating expenses reported by nature are as follows:

	2018	2017
Salaries, wages and benefits	$ 505,190	$ 421,429
Office and administration	256,809	315,933
Contracted services	452,763	421,995
Operations and maintenance	132,238	157,907
Depreciation	183,915	175,597
Interest on long-term debt and notes payable	148,067	150,875
Bad debts	30,793	58,386
	$ 1,709,775	$ 1,702,122

15. Pension plan

The Corporation provides pension benefits to its employees through the Ontario Municipal Employees Retirement System (OMERS) pension plan. The plan is a multi-employer, contributory, defined benefit pension plan with equal contributions by both employer and employees. During the year the Corporation made employer contributions of $62,624 (2017 - $63,524) to OMERS.

At December 31, 2018 the OMERS pension plan had total assets of $111.8 billion (2017 - $105.7 billion) and an accumulated deficit of $2.64 billion (2017 - $0.77 billion surplus).

16. Commitments

The Corporation has entered into a contract for management, billing, collecting, customer service, software and data hosting services and support with PUC Services Inc. for a five year period ending May 31, 2021, at an annual base cost as follows:

2019	$ 173,949
2020	177,423
2021	74,530

In addition to the above charges, a monthly charge of $5.26 to $5.75 per meter, for up to 3,700 meters for residential and general service customers, will apply.

17. Related party transactions

The Corporation is related to the Town of Espanola by virtue of the fact that the Town is an 81% owner of the Corporation's sole shareholder. Likewise, the Township of Sables-Spanish Rivers is a 19% owner of the Corporation's sole shareholder.

In the normal course of business, the Corporation provides electrical energy to the Town of Espanola and the Township of Sables-Spanish Rivers at the same regulated rates and terms approved by the OEB as other similar customers, based on the amount of electricity consumed.

The Corporation also provides water and waste water billing and collection services on behalf of the Town of Espanola. Included in other charges revenue is 18,136 (2017 - $18,136) earned with respect to these services. Also, included in accounts payable and accrued liabilities is $442,210 (2017 - $443,123) relating to amounts collected by the Corporation on behalf of the Town of Espanola for water and waste water billing. Correspondingly, included in accounts receivable is $206,397 (2017 - $213,578) relating to amounts receivable from customers for water and waste water services.

18. Capital disclosure

The Corporation's objectives when managing capital are:

(a) Ensure ongoing access to capital at a reasonable cost in order to maintain and improve the electricity distribution system of the Corporation to ensure the continued delivery of safe, reliable electricity services to customers, and to safeguard the Corporation's ability to continue as a going concern and provide a reasonable rate of return to its shareholders;

(b) Align the Corporation's capital structure with the debt to equity structure deemed appropriate by the OEB.

The Corporation's capital consists of shareholder's equity and notes payable to the Town of Espanola and Township of Sables-Spanish Rivers. There have been no changes in the Corporation's approach to managing capital during the year.

19. Financial instruments

Transactions in financial instruments may result in an entity assuming or transferring financial risks to or from another party. The Corporation is exposed to the following risks associated with financial instruments and transactions it is a party to:

(a) Fair value

The fair value of current financial assets and current financial liabilities approximates their carrying value due to their short-term maturity dates. The fair value of long-term financial liabilities approximates their carrying value based on the presumption that the Corporation is a going concern and thus expects to fully repay the outstanding amounts.

(b) Credit risk

Credit risk is the risk that one party to a financial transaction will fail to discharge a financial obligation and cause the other party to incur a financial loss. The Corporation's main credit risks are associated with its cash and accounts receivable.

The Corporation minimizes credit risk associated with its cash balances by ensuring that these financial assets are held with large reputable financial institutions with high credit ratings.

The Corporation incurs amounts due from its customers in the regular course of business and has credit risk associated with its accounts receivable balances of $1,151,782 (2017 - $1,027,266). The Corporation reduces its exposure to credit risk through management's on-going monitoring of its accounts receivable balances and collections. Credit valuations are performed on a regular basis and credit is granted upon a review of the credit history of the applicant. An allowance for bad debts is recorded when applicable.

(c) Liquidity risk

Liquidity risk is the risk that the Corporation cannot repay its obligations when they become due to its creditors. The Corporation has liquidity risk associated with its accounts payable and accrued liabilities, payable for energy purchases, long-term obligations and notes payable. The Corporation reduces its exposure to liquidity risk by ensuring that it documents when authorized payments become due, and budgets to maintain adequate cash resources including a line of credit, to repay creditors including long-term obligations interest and principal as those liabilities become due.

The majority of the Corporation's accounts payable and payable for energy purchases, as reported in the consolidated statement of financial position, are due within 30 days.

20. Changes in accounting policies

IFRS 15 - Revenue From Contracts with Customers

In May 2014, the International Accounting Standards Board (IASB) issued IFRS 15 effective for annual periods beginning on or after January 1, 2018, which replaced existing revenue recognition guidance, including IAS 18 Revenue and IFRIC 18 Transfers of Assets from Customers. IFRS 15 applies to contracts with customers and specifies that revenue is recognized when or as an entity transfers control of goods or services to a customer at the amount to which the entity expects to be entitled to receive from that customer.

The adoption of IFRS 15 resulted in a $406,683 reclassification in the statement of operations between energy sales and cost of energy for the comparative year ended December 31, 2017, and had no impact to opening retained earnings as at January 1, 2018 as follows:

	December 31, 2017, as originally stated	Change in accounting policy adjustment	December 31, 2017, as restated
Energy sales	$ 6,745,859	$ 406,683	$ 7,152,542
Cost of energy	6,908,603	406,683	7,315,286

IFRS 9 Financial Instruments

In July 2014, the IASB issued the final version of IFRS 9 Financial Instruments effective for annual periods beginning on or after January 1, 2018, which replaced IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 includes revised guidance on the classification and measurement of financial instruments. It also carries forward the guidance on recognition and derecognition of financial instruments from IAS 39. The Corporation adopted IFRS 9 retrospectively on January 1, 2018. Despite the retrospective adoption of IFRS 9, the Corporation is not required, upon initial application, to restate comparative figures.

IFRS 9 eliminates the previous IAS 39 categories of held to maturity, loans and receivables and available for sale financial assets.

Under IFRS 9, on initial recognition, a financial asset is classified and measured at amortized cost, fair value through other comprehensive income, or fair value through profit or loss. The adoption of IFRS 9 has not had a significant effect on the Corporation's accounting policies related to financial instruments. The impact of IFRS 9 on the classification and measurement of financial instruments results in the Corporation's cash and cash equivalents, accounts receivable and unbilled revenue have been reclassified to the amortized cost category.

21. **Subsequent event**

On January 12, 2018 the Town of Espanola and Township of Sables-Spanish Rivers (the municipalities) announced the acceptance of a letter of intent to purchase the shares of Espanola Regional Hydro Holdings Corporation (the Corporation's shareholder) with North Bay Hydro Distribution Ltd. During the year the Municipalities and North Bay Hydro Distribution Ltd. completed the due diligence process and finalized the preparation of a definitive agreement of purchase and sale. At the balance sheet date the agreement of purchase and sale is still awaiting regulatory approval.

Espanola Regional Hydro Distribution Corporation

Financial Statements

Three Month Period from October 1, 2019 to December 31, 2019

INDEPENDENT AUDITOR'S REPORT

To: The Shareholder of
Espanola Regional Hydro Distribution Corporation

Opinion
We have audited the financial statements of **Espanola Regional Hydro Distribution Corporation**, which comprise the statement of financial position as at **December 31, 2019**, and the statements of comprehensive loss, retained earnings (deficit) and accumulated other comprehensive earnings (loss), and cash flows for the three month period from October 1, 2019 to December 31, 2019, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at **December 31, 2019**, and the results of its operations and its cash flows for the three month period then ended in accordance with International Financial Reporting Standards.

Basis for Opinion
We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter
We draw attention to note 21 to these financial statements, which describes that Espanola Regional Hydro Distribution Corporation, along with Espanola Regional Hydro Holdings Corporation, were acquired by North Bay (Espanola) Acquisition Inc. on October 1, 2019 and the three corporations were immediately amalgamated, also on October 1, 2019, with the amalgamated corporation continuing to carry on operations as Espanola Regional Hydro Distribution Corporation.

We also draw your attention to note 22 to these financial statements which describes the effect of the above noted transactions on the comparative figures presented in these financial statements.

Responsibilities of Management and Those Charged with Governance for the Financial Statements
Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Corporation’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern

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and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements
Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements. As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

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INDEPENDENT AUDITOR'S REPORT, continued

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

FREELANDT CALDWELL REILLY LLP

Chartered Professional Accountants
Licensed Public Accountants

Sudbury, Ontario
April 16, 2020

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Espanola Regional Hydro Distribution Corporation

Statement of Financial Position

December 31, 2019 with comparative figures for September 30, 2019

	December 31 2019	September 30 2019 (note 22)
Assets		
Current		
Cash	$ 317,887	$ 375,296
Accounts receivable (note 4)	1,226,204	1,250,255
Unbilled revenue - energy sales	791,739	282,042
Unbilled revenue - distribution	156,681	114,319
Inventory	48,049	44,205
Prepaid expenses	118,235	141,913
Payment in lieu of taxes	1,816	1,814
	2,660,611	2,209,844
Advances to corporate shareholder	100	-
Property, plant and equipment (note 5)	5,145,115	5,106,006
Goodwill	3,322,007	-
Total assets	11,127,833	7,315,850
Regulatory assets (note 6)	2,697,028	2,775,259
Total assets and regulatory assets	$ 13,824,861	$ 10,091,109

Approved on behalf of the Board of Directors:

Director ________________________

Director ________________________

Espanola Regional Hydro Distribution Corporation
Statement of Financial Position
December 31, 2019 with comparative figures for September 30, 2019

		December 31 2019		September 30 2019 (note 22)
Liabilities and shareholders' equity (deficiency)				
Current				
Operating loan (note 7)	$	235,000	$	-
Accounts payable and accrued liabilities		233,852		870,865
Payable for energy purchases		1,854,606		1,178,732
Advances from related company (note 8)		551,351		-
Current portion of long-term obligations		89,370		88,608
		2,964,179		2,138,205
Customer deposits		220,351		223,680
Deferred revenue		104,799		114,098
Payment in lieu of deferred taxes (note 9)		167,980		50,998
Contributions in aid of construction (note 10)		345,940		348,367
Employee future benefits (note 11)		98,543		98,197
Long-term obligations (note 12)		9,818,431		2,004,871
Notes payable (note 13)		-		1,524,511
		13,720,223		6,502,927
Shareholders' equity (deficiency)				
Share capital (note 14)		100		2,281,000
Retained earnings (deficit)		(462,820)		876,190
Accumulated other comprehensive earnings (loss)		-		(11,471)
		(462,720)		3,145,719
Total liabilities and shareholders' equity (deficiency)		13,257,503		9,648,646
Regulatory liabilities (note 6)		567,358		442,463
Total liabilities, shareholder's equity (deficiency) and regulatory liabilities	$	13,824,861	$	10,091,109

Commitments (note 18)

Espanola Regional Hydro Distribution Corporation

Statement of Comprehensive Loss
Three month period from October 1, 2019 to December 31, 2019
with comparative figures for the nine month period from January 1, 2019 to September 30, 2019

	December 31, 2019 (3 months)	September 30, 2019 (9 months) (note 22)
Revenue		
Energy sales	$ 2,363,438	$ 4,943,711
Distribution	429,486	1,212,692
	2,792,924	6,156,403
Cost of Energy	2,043,330	5,171,386
Gross Profit	749,594	985,017
Operating expenses (note 15)		
General and administration	159,978	329,278
Billing and collecting	87,360	362,763
Distribution - operations	95,436	335,519
Distribution - maintenance	68,915	223,910
Depreciation	41,801	127,061
	453,490	1,378,531
Earnings (loss) before other income (expense) and payment in lieu of taxes	296,104	(393,514)
Other income (expense)		
Interest	26,048	19,481
Labour, rental and other charges	21,702	118,597
Amortization of contributions in aid of construction	2,527	7,581
Interest on long-term obligations and notes payable	(73,810)	(109,148)
Interest rate swap mark-to-market adjustment (note 12)	(46,660)	-
	(70,193)	36,511
Earnings (loss) before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)	225,911	(357,003)
Payments in lieu of taxes (recovery) (note 9)		
Current	-	(2,025)
Deferred	116,982	(51,934)
	116,982	(53,959)
Net earnings (loss) before change in regulatory asset and liability balances and other comprehensive earnings (loss)	108,929	(303,044)
Change in regulatory assets and liabilities (note 6)		
Change in regulatory asset and liability account balances related to profit and loss	(320,108)	227,675
Change in regulatory asset account balance related to payment in lieu of deferred taxes	116,982	(51,934)
	(203,126)	175,741
Net loss before other comprehensive loss	(94,197)	(127,303)
Other comprehensive loss		
Remeasurement of employee future benefits liability, net of tax	-	(12,469)
Net comprehensive loss	$ (94,197)	$ (139,772)

Espanola Regional Hydro Distribution Corporation

Statement of Retained Earnings (deficit) and Accumulated Other Comprehensive Earnings (Loss)
Three month period from October 1, 2019 to September 30, 2019
with comparative figures for nine month period from January 1, 2019 to September 30, 2019

	Share capital	Retained earnings (deficit)	Accumulated other comprehensive earnings (loss)	Total
Balance at September 30, 2019, as originally stated (note 22)	$ 2,281,000	876,190	(11,471)	$ 3,145,719
Amalgamation adjustment (note 22)	(2,280,900)	(1,244,813)	11,471	(3,514,242)
Balance at October 1, 2019, as adjusted	100	(368,623)	-	(368,523)
Net earnings (loss) before other comprehensive loss (3 months)	-	(94,197)	-	(94,197)
Other comprehensive loss	-	-	-	-
Balance at December 31, 2019	100	(462,820)	-	(462,720)
Balance at December 31, 2018	2,281,000	1,003,493	998	3,285,491
Net earnings (loss) before other comprehensive loss (nine months)	-	(127,303)	-	(127,303)
Other comprehensive loss	-	-	(12,469)	(12,469)
Balance at September 30, 2019 (note 22)	$ 2,281,000	876,190	(11,471)	$ 3,145,719

Espanola Regional Hydro Distribution Corporation

Cash Flows Statement
Three month period from October 1, 2019 to December 31, 2019
with comparative figures for the nine month period from January 1 2019 to September 30, 2019

	December 31, 2019 (3 months)	September 30, 2019 (9 months) (note 22)
Cash flows from operating activities		
Net loss	$ (94,197)	$ (127,303)
Adjustments to reconcile earnings to cash provided by (used in) operations:		
Depreciation	48,621	147,422
Amortization of contributions in aid of construction	(2,527)	(7,581)
Provision for payment in lieu of deferred taxes	116,982	(51,934)
Provision for payment in lieu of taxes	-	(2,025)
Interest rate swap mark-to-market adjustment	46,660	-
	115,539	(41,421)
Change in non-cash working capital items (note 16)	(840,594)	231,977
	(725,055)	190,556
Cash flows from investing activities		
Purchase of property, plant and equipment	(87,730)	(373,213)
Regulatory assets	78,231	(128,815)
	(9,499)	(502,028)
Cash flows from financing activities		
Operating loan	235,000	-
Advances from related company	351,351	-
Customer deposits	(3,329)	13,318
Deferred revenue	(9,299)	(23,159)
Regulatory liabilities	124,895	(46,926)
Contributions in aid of construction	100	39,190
Employee future benefits	346	1,341
Repayment of long-term obligations	(26,317)	(64,492)
	672,747	(80,728)
Decrease in cash	(61,807)	(392,200)
Cash, beginning of period	379,694	767,496
Cash, end of period	$ 317,887	$ 375,296

1. **Nature of operations**

Espanola Regional Hydro Distribution Corporation was created on October 1, 2019 by the amalgamation of North Bay (Espanola) Acquisition Inc., Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation. The corporation is required in accordance with the Electricity Act, 1998, Ontario (the EA), is a wholly owned subsidiary of North Bay Hydro Holdings Limited, and was created for the purpose of providing regulated electricity distribution services to customers in the Town of Espanola and the Township of Sables-Spanish Rivers from its head office located at 598 Second Street, Espanola Ontario, Canada.

The Corporation and other electricity distributors purchase their electricity from the wholesale market administered by the Independent Electricity System Operator (IESO) and recover the costs of electricity and certain other costs from customers under the authority of the Ontario Energy Board (the OEB) Act, 1998.

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The Ontario Energy Board Act, 1998 sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and the filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity and the responsibility for ensuring that electricity distribution companies fulfil their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry may affect distribution rates and the permitted recovery or settlement or the timing of recovery or settlement of certain regulatory assets and liabilities.

2. **Significant accounting policies**

These financial statements are prepared using International Financial Reporting Standards applying the accounting policies set out below on a consistent basis in all periods presented in these financial statement. The significant policies are detailed as follows:

(a) **Statement of compliance and basis of measurement**

These financial statements are the representation of the Corporation`s management and are prepared in accordance with International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB). The Corporation's accounting policies are based on IFRS standards in effect on January 1, 2019. The Corporation has adopted the requirements of IFRS 14 - Regulatory Deferral Accounts, which permits the Corporation to account for regulatory deferral account balances.

These financial statements have been prepared on a historical cost basis. These financial statements are presented in Canadian dollars and were approved by the Corporation's Board of Directors on April 16, 2020.

(b) **Effects of rate regulation**

The Ontario Energy Board (OEB) is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in a non rate regulated corporation. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting and approval process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers in future periods through the rate-setting and approval process.

(c) **Cash and cash equivalents**

Cash and cash equivalents are defined as cash and highly liquid investments, consisting primarily of term deposits, with terms to maturity of three months or less at the date of purchase.

(d) **Inventory**

Inventory is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

2. **Significant accounting policies, continued**

(e) **Property, plant and equipment**

Property, plant and equipment are measured at historical cost less accumulated depreciation and impairment losses, if any. In circumstances where parts of an item of property, plant and equipment have different useful lives they are accounted for as separate components of property, plant and equipment. The Corporation provides for depreciation using the straight-line method at rates designed to depreciate the cost of the property, plant and equipment over their estimated useful lives. A full year's depreciation is recorded in the year of acquisition. No depreciation is recorded in the year of disposal. The carrying amount of an item of property, plant and equipment is derecognized on disposal. The annual depreciation rates and useful lives are reviewed annually and are as follows:

Buildings	50 years
Furniture and equipment	5-10 years
Vehicles	15 years
Transmission and distribution equipment	40-60 years

Construction in progress includes assets not currently in use and therefore not yet subject to depreciation.

In certain cases, non-refundable contributions are received in aid of construction or acquisition of property, plant and equipment. Contributions in aid of construction are classified as liabilities and are amortized at the same rate as the assets to which they relate.

2. **Significant accounting policies, continued**

(f) **Impairment of non-financial assets**

At the end of each reporting period, the Corporation reviews the carrying amounts of its property, plant and equipment to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Corporation estimates the recoverable amount of the cash-generating unit ("CGU") to which the asset belongs. Where a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual CGUs, or otherwise they are allocated to the smallest group of CGUs for which a reasonable and consistent allocation basis can be identified.

Recoverable amount is the higher of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset or CGU is estimated to be less than its carrying amount, the carrying amount of the asset or CGU is reduced to its recoverable amount. An impairment loss is recognized immediately in operations.

Where an impairment loss subsequently reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset or CGU in prior years. A reversal of an impairment loss is recognized immediately in operations.

(g) **Goodwill**

Goodwill represents the difference between the acquisition cost of the Corporation and the fair value of the net assets acquired. Goodwill is not amortized, but is subject to fair value impairment tests annually. Goodwill is allocated to reporting units and any potential goodwill impairment is identified by comparing the carrying value of the reporting unit with its fair value. If any potential impairment is identified, then the amount of the impairment is quantified by comparing the carrying value of goodwill to its fair value, based on the fair value of the assets and liabilities of the reporting unit. Any impairment of goodwill is charged to operations in the period in which the impairment is determined

(h) **Provisions**

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a rate, net of tax, that reflects current market assessments of the time value of money and the risks specific to the liability.

2. **Significant accounting policies, continued**

(i) **Borrowing costs**

Borrowing costs directly attributable to the acquisition or construction of property, plant and equipment, which take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use. All other borrowing costs are recognized in operations in the period in which they are incurred.

(j) **Asset retirement obligations**

Accounting standards require the Corporation to determine the fair value of future expenditures required to settle legal obligations to remove property, plant and equipment. If reasonably estimable, the Corporation recognizes a liability for the estimated current value of future expenditures required to settle obligations for the retirement of property, plant and equipment. Decommissioning liabilities are recorded at fair value, with a corresponding increase to the recorded amount of property, plant and equipment. Accretion of decommissioning liabilities are included in operations. Differences between the recorded amount of decommissioning liabilities and the actual decommissioning costs incurred are recorded as a gain or loss in the period of settlement.

Some of the Corporation's distribution system assets may have asset retirement obligations. As the Corporation expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of the related asset retirement obligation cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Corporation is legally required to remove, an asset retirement obligation will be recognized at that time.

(k) **Pension plan**

The Corporation provides a pension plan for all its full-time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund.

OMERS is a defined benefit plan, however it does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. Obligations for contributions to defined contribution pension plans are recognized as an expense in operations when they are due.

2. **Significant accounting policies, continued**

(l) **Revenue recognition**

Distribution and energy related revenues attributable to the supply and distribution of electricity are based on OEB approved rates and revenue is recognized as electricity is delivered to customers based on periodic meter readings. At the end of an accounting cycle, there is energy used by consumers for which meter readings are not available and no bills have been issued. This unbilled revenue is estimated and recorded in current assets on the statement of financial position at the end of each fiscal period. The related cost of energy is recorded on the basis of energy used.

The difference between the amount paid by the Corporation to Hydro One for the purchase of energy and related service costs and the amount billed by the Corporation to its customers for energy sales based on regulated rates are recorded on the statement of financial position as regulatory assets and liabilities until their final disposition is decided by the OEB. In accordance with IFRS 14, the change in these regulatory assets and liabilities are reported, net of tax, with regulatory balances in the statement of comprehensive earnings.

Labour, rental and other charges revenue are recognized in the period in which these services are provided.

(m) **Payment in lieu of taxes**

Pursuant to the EA, the Corporation is required to compute taxes under the Income Tax Act (Canada) (ITA) and remit such amounts computed there under to the Ontario Electricity Financial Corporation (OEFC). These amounts, referred to as payments in lieu of taxes (PILs) under the EA, are applied to reduce certain debt obligations of the former Ontario Hydro now owing by the OEFC.

Payment in lieu of deferred income tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the financial statement carrying amount of assets and liabilities and their tax bases. Payment in lieu of deferred tax assets are also recognized for the benefit of any deductions or losses available to be carried forward to future periods for tax purposes that are likely to be realized. These amounts are measured using enacted or substantively enacted tax rates and are re-measured annually for changes in these rates. Any payment in lieu of deferred income tax assets are reassessed each fiscal period to determine if a valuation allowance is required. Any effect of the re-measurement or reassessment is recognized in operations in the period of the change.

As prescribed by regulatory rate order, payment in lieu of taxes are recovered through customer rates based on the taxes payable method. Therefore, rates do not include the recovery of payment in lieu of deferred taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, payment in lieu of deferred tax regulatory assets or liabilities are recognized for the amount of payment in lieu of deferred taxes which are expected to be included in future rates and recovered from or refunded to customers in future periods through the rate setting and approval process.

2. **Significant accounting policies, continued**

(n) **Employee future benefits**

The Corporation’s net obligation in respect of its employee future benefit plan is calculated by estimating the amount of future benefits that employees have earned in return for their service in the current and prior periods, that benefit is discounted to determine its present value. Any unrecognised past service costs are deducted. The discount rate is the interest rate at the reporting date on high quality debt instruments with duration similar to the duration of the plan.

The cost of these employee future benefits is expensed as earned by employees through employment service. The accrued benefit obligation and the current service costs are actuarially determined by applying the projected unit credit method and incorporate management’s best estimate of certain underlying assumptions. Re-measurements arising from employee benefit plans are recognized immediately in operations. When the benefits of a plan are improved, these increases are recognized immediately in operations.

(o) **Financial instruments**

(i) **Measurement of financial instruments**

All of the Corporation's financial assets and financial liabilities are initially measured at fair value. Fair value is the amount for which an asset could be exchanged, or a liability settled, between knowledgeable, willing parties in an arm's length transaction. Transaction costs, that are directly attributable to the acquisition or issue of financial assets and financial liabilities, are added to the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition.

Subsequent to initial recognition these financial assets and financial liabilities are measured at their amortized cost. Amortized cost is the amount at which the financial instrument is measured at initial recognition less principal repayments, plus or minus the cumulative amortization using the effective interest method of any difference between that initial amount and the maturity amount. Interest rate swaps that are not hedging items are measured at fair value and changes in fair value are recognized in operations in the period they occur.

2. **Significant accounting policies, continued**

(o) **Financial instruments, continued**

(ii) **Impairment**

A financial asset measured at amortized cost is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount, and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount.

All impairment losses are recognized in operations. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in operations.

(p) **Measurement uncertainty**

The preparation of financial statements in conformity with International Financial Reporting Standards requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. By their nature, these estimates are subject to measurement uncertainty. The effect of changes in such estimates on the financial statements in future periods could be significant, including changes as a result of future decisions made by the Ontario Energy Board (OEB). All estimates are reviewed periodically and adjustments are made and recognized in operations, as appropriate, in the period they become known. Accounts specifically affected by estimates and assumptions in these financial statements are as follows:

(i) **Property, plant and equipment**

Amounts recorded in the financial statements for depreciation are based on the estimated useful lives of the Corporation's property, plant and equipment. These useful lives are management's best estimate of the service lives of these assets and are reviewed annually. Changes to these estimated useful lives could materially affect the amount of depreciation recorded in the financial statements.

The Corporation's policy relating to property, plant and equipment is described in note 2(e). In applying this policy, management uses judgment in determining whether certain costs are additions to the carrying amount of property, plant and equipment or expensed in operations as repairs and maintenance. Judgment is also necessary in determining the appropriate componentization structure of the Corporation's property, plant and equipment.

2. **Significant accounting policies, continued**

(p) **Measurement uncertainty, continued**

(ii) **Payment in lieu of taxes**

Significant judgment is required in determining the provision for payment in lieu of taxes. There are many judgments and calculations made for which the ultimate tax determination is uncertain. The Corporation recognizes tax assets and liabilities based on the Corporation's interpretation of current tax law. Where the final outcome of these interpretations is different from the amounts that were originally recorded, these differences are recognized in the current and deferred income tax provisions in the period in which the determination is made.

(iii) **Employee future benefits**

The Corporation provides certain health and dental benefits to retired employees. The estimated cost of providing these benefits is accounted for on an accrual basis in the period in which employees render their services and are actuarially determined using the projected benefit method pro-rated on service and include management's best estimate of salary escalations, retirement ages and expected health care cost escalations.

(iv) **Regulatory assets and liabilities**

When recognizing regulatory assets and liabilities management assumes that such credits or costs will be recovered from customers or refunded to customers in future years through the rate setting and approval process. Refund or recovery of these regulatory assets and liabilities are subject to the review and approval of the OEB. Consequently, there is risk that some or all of the regulatory assets and liabilities will not be approved by the OEB which could have a material affect on the Corporation's comprehensive income in the year of the OEB decision.

3. **Future changes to significant accounting policies**

The Corporation's accounting policies are based on IFRS standards in effect on January 1, 2019. There are currently no IFRS standards that have been issued, but that are not yet effective, that would have a material affect on the Corporation's financial statements beginning on or after January 1, 2020.

4. **Accounts receivable**

	December 31, 2019	September 30, 2019
Electrical energy receivables	$ 803,305	$ 615,877
Water and sewer receivables	-	431,174
Other receivables	422,899	203,204
	$ 1,226,204	$ 1,250,255

	December 31, 2019	September 30, 2019
Aging of accounts receivable:		
Current	$ 1,210,533	$ 995,349
30 days	13,925	242,186
60 days	1,746	8,927
Over 90 days	-	3,793
	$ 1,226,204	$ 1,250,255

5. Property, plant and equipment

December 31, 2019

	Land	Buildings	Transmission & Distribution Equipment	Vehicles	Furniture and Equipment	Construction In Progress	Total
Cost							
Balance, beginning of	$ 88,880	183,831	5,276,320	385,981	41,654	56,105	$ 6,032,771
Additions	-	-	77,863	-	6,341	3,526	87,730
Transfers	-	-	-	-	-	-	-
Disposals	-	-	-	-	-	-	-
Balance, end of period	88,880	183,831	5,354,183	385,981	47,995	59,631	6,120,501
Accumulated Amortization							
Balance, beginning of	-	26,088	747,301	126,649	26,727	-	926,765
Depreciation	-	1,143	40,415	6,819	244	-	48,621
Disposals	-	-	-	-	-	-	-
Balance, end of period	-	27,231	787,716	133,468	26,971	-	975,386
Net book value	$ 88,880	156,600	4,566,467	252,513	21,024	59,631	$ 5,145,115

September 30, 2019

	Land	Buildings	Transmission & Distribution Equipment	Vehicles	Furniture and Equipment	Construction In Progress	Total
Cost							
Balance, beginning of year	$ 88,880	183,831	4,986,951	315,642	33,070	51,184	$ 5,659,558
Additions	-	-	289,369	70,339	8,584	4,921	373,213
Transfers	-	-	-	-	-	-	-
Disposals	-	-	-	-	-	-	-
Balance, end of year	88,880	183,831	5,276,320	385,981	41,654	56,105	6,032,771
Accumulated Amortization							
Balance, beginning of year	-	22,659	627,438	106,188	23,058	-	779,343
Depreciation	-	3,429	119,863	20,461	3,669	-	147,422
Disposals	-	-	-	-	-	-	-
Balance, end of year	-	26,088	747,301	126,649	26,727	-	926,765
Net book value	$ 88,880	157,743	4,529,019	259,332	14,927	56,105	$ 5,106,006

6. **Regulatory assets and liabilities**

	September 30, 2019	Regulatory activity	December 31, 2019
Settlement variances (a)	$ 1,492,061	$ (164,151)	$ 1,327,910
Stranded meters (b)	9,040	12	9,052
Substation (c)	1,223,160	(31,074)	1,192,086
Payment in lieu of deferred tax regulatory assets (d)	50,998	116,982	167,980
Total regulatory assets	2,775,259	(78,231)	2,697,028
Settlement variances (a) - liability	442,463	124,895	567,358
Total regulatory liabilities	442,463	124,895	567,358
Net regulatory assets	$ 2,332,796	$ (203,126)	$ 2,129,670

	January 1, 2019	Regulatory activity	September 30, 2019
Settlement variances (a)	$ 1,210,588	$ 281,473	$ 1,492,061
Stranded meters (b)	9,304	(264)	9,040
Substation (c)	1,323,620	(100,460)	1,223,160
Payment in lieu of deferred tax regulatory assets (d)	102,932	(51,934)	50,998
Total regulatory assets	2,646,444	128,815	2,775,259
Settlement variances (a) - liability (reduction)	489,389	(46,926)	442,463
Total regulatory liabilities	489,389	(46,926)	442,463
Net regulatory assets	$ 2,157,055	$ 175,741	$ 2,332,796

6. **Regulatory assets and liabilities, continued**

In accordance with IFRS 14 - Regulatory deferral accounts, the Corporation has continued to apply the accounting policies that it applied, in accordance with CPA Canada Handbook Part V - pre-changeover accounting standards, prior to its adoption of International Financial Reporting Standards. Regulatory assets and liabilities arise as a result of the rate setting and approval process through the OEB.

(a) The difference between the amount paid by the Corporation to Hydro One for the purchase of energy and related service costs and the amount billed by the Corporation to its customers as energy sales, based on regulated rates, are recorded on the statement of financial position as settlement variances until their final disposition is decided by the OEB. The Corporation recognizes settlement variances as an asset or liability based on the expectation that these amounts will be approved by the OEB for future collection from, or refund to, customers through the rate setting and approval process. The settlement variance asset (liability) represents the excess (deficiency) of amounts billed to the Corporation by Hydro One for the purchase of energy over the amounts charged by the Corporation to its customers as energy sales. Currently, no amounts for settlement variances have been approved by the OEB for recovery or refund. Accordingly, the timing of the recovery or refund is unknown.

In the absence of rate regulation, revenue recognized in the statement of comprehensive earnings (loss) would have decreased by $289,046 in the three month period ended December 31, 2019 ($328,399 increase for the nine month period ended September 30, 2019) related to amounts recognized for settlement variances.

(b) The stranded meter regulatory asset represents the unrecovered net book value of decommissioned analogue meters. At the direction of the OEB, the net book value of the stranded meters were reclassified to the regulatory asset account for recovery in rates to the end of March 2017. Currently, no amounts for stranded meters have been approved by the OEB for recovery. Accordingly, the timing of the recovery is unknown.

In the absence of rate regulation, revenue recognized in the statement of comprehensive earnings (loss) would have increased by $NIL in the three month period ended December 31, 2019 ($NIL for the nine month period ended September 30, 2019) related to amounts recognized for the substation.

(c) The substation asset represents the cost of construction of a new substation in the Town of Espanola. The OEB approved the recovery for substation costs of $168,193 per year in the Corporation's rates until their next cost of service rate order.

In the absence of rate regulation, revenue recognized in the statement of comprehensive earnings (loss) would have increased by $37,055 in the three month period ended December 31, 2019 ($120,341 increase for the nine month period ended September 30, 2019) related to amounts recognized for the substation.

6. Regulatory assets and liabilities, continued

(d) The payment in lieu of deferred tax regulatory asset represents the expected increase in distribution rates for customers arising from temporary differences which give rise to payment in lieu of deferred tax liabilities. Currently, no amounts for payment in lieu of deferred taxes have been approved by the OEB for recovery. Accordingly, the timing of the recovery is unknown.

For certain of the regulatory assets and liabilities, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the OEB in determining the item's treatment for rate-setting purposes. The Corporation continually assesses the likelihood of recovery of each of its regulatory assets and refund of each of its regulatory liabilities and continues to believe that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If at some future date the Corporation determines that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be charged to operations in the period the determination is made.

7. Operating loan

A revolving operating loan credit facility has been granted by The Toronto Dominion Bank to a maximum of $500,000 bearing interest at the bank's prime rate of interest per annum.

This credit facility is secured by a general security agreement representing a first charge on all of the Corporation's present and after acquired property, an inter-creditor agreement with Ontario Infrastructure and Lands Corporation and a guarantee of advances by North Bay Hydro Distribution Limited, a related company.

8. Advances from related company

The corporation is related to North Bay Hydro Distribution Limited by virtue of common controlling shareholders. The corporation is a wholly owned subsidiary of North Bay Hydro Holdings Limited.

	December 31, 2019	September 30, 2019
North Bay Hydro Distribution Limited	$ 551,351	$ -

The advances from North Bay Hydro Distribution Limited are unsecured, bear interest at the prime rate of interest on the first $200,000 of advances only, and have no specific terms of repayment.

9. **Payment in lieu of taxes**

(a) The components of payment in lieu of deferred tax balances are as follows:

	December 31, 2019	September 30, 2019
Payment in lieu of deferred tax assets:		
Difference between tax basis of long-term obligations and carrying amount	$ 12,365	$ -
Difference between tax basis of employee future benefits obligation and carrying amount	26,114	12,274
Carrying value of loss carryforward deferred tax asset	93,049	70,185
Payment in lieu of deferred tax liabilities:		
Difference between tax basis of property, plant and equipment and carrying amount	(299,508)	(133,457)
	$ (167,980)	$ (50,998)

(b) The provision for payment in lieu of taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 26.5% (September 2019 - 12.5%) to the earnings (loss) for the periods as follows:

	December 31, 2019	September 30, 2019
Earnings (loss) for the period before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)	$ 225,911	$ (357,003)
Change in regulatory asset and liability account balances related to profit and loss	(320,108)	227,675
Remeasurement of employee future benefits liability included in other comprehensive income	-	(12,469)
	$ (94,197)	$ (141,797)
Anticipated income tax recovery	$ (24,962)	$ (17,725)
Tax effect of the following:		
Tax effect of change in regulatory assets	62,258	(26,493)
Tax effect of change in payment in lieu of deferred tax regulatory asset	11,252	(3,180)
Adjustment due to change in tax rate	68,434	(6,561)
Provision for (recovery of) payment in lieu of taxes	$ 116,982	$ (53,959)

(c) For income tax purposes, the Corporation has a loss of $351,128 which can be applied to reduce future years' taxable income. This loss expires in 2038.

10. Contributions in aid of construction

In certain cases, non-refundable contributions are received in aid of construction or acquisition of property, plant and equipment. Contributions in aid of construction are deferred and amortized to other revenue at the same rate as the assets to which they relate.

	December 31, 2019	September 30, 2019
Balance, beginning of period	$ 348,367	$ 316,758
Contributions received in the period	100	39,190
Amortization of contributions in aid of construction	(2,527)	(7,581)
Balance, end of period	$ 345,940	$ 348,367

11. Employee future benefits

The Corporation pays certain post-employment health and dental benefits on behalf of its retired employees. Accounting standards for employee future benefits require that these post-retirement costs be recognized in the period in which the employees rendered their services. Information about the Corporation's accrued benefit obligation and the related expense are based on results and assumptions by actuarial valuation at September 30, 2019 and are as follows:

	December 31, 2019	September 30, 2019
Accrued benefit obligation, beginning of period	$ 98,197	$ 84,387
Current service cost recognized in operations	242	725
Interest cost recognized in operations	734	2,504
Benefits paid by employer	(630)	(1,888)
Net actuarial loss recognized in other comprehensive income	-	12,469
Accrued benefit obligation, end of period	$ 98,543	$ 98,197

11. Employee future benefits, continued

The main assumptions employed for the valuation of the employee future benefit obligation are as follows:

The health benefit cost is estimated to increase at a rate of 4.0% (September 2019 - 4.0%) per annum. The dental benefit cost is estimated to increase at a rate of 4.3% (September 2019 - 4.3%) per annum.

The obligation at period-end and the present value of future obligations and the related expense, were determined using an annual discount rate of 3.0% per annum (September 2019 - 3.0%) representing an estimate of the yield on high quality corporate bonds with a duration similar to the duration of the plan.

Future general salary and wage levels were assumed to increase at 2.5% (September 2019 - 2.5%) per annum.

12. Long-term obligations

	December 31, 2019	September 30, 2019
Ontario Infrastructure and Lands Corporation non-revolving term loan, repayable in blended monthly installments of $2,860 including interest at 2.73% per annum, maturing December 2025	$ 189,713	$ 196,964
Ontario Infrastructure and Lands Corporation non-revolving term loan, repayable in blended monthly installments of $10,831 including interest at 3.78% per annum, maturing December 2040	1,881,898	1,896,515
Toronto Dominion Bank committed reducing term facility by way of a floating rate term loan available by way of bankers acceptances, maturing October 2044 (see below for terms)	7,789,530	-
Interest rate swap mark-to-market adjustment	46,660	-
	9,907,801	2,093,479
Less current portion	89,370	88,608
	$ 9,818,431	$ 2,004,871

12. **Long-term obligations , continued**

The Ontario Infrastructure and Lands Corporation loans are secured by a general security agreement ranking behind the first ranking general security agreement registered by The Toronto Dominion Bank (note 7), an inter-creditor agreement between Ontario Infrastructure and Lands Corporation and The Toronto Dominion Bank and a guarantee provided by North Bay Hydro Distribution Limited.

The Corporation has entered into an interest rate swap derivative agreement with the Toronto Dominion Bank to manage the volatility of the interest rate on the committed reducing term facility. The loan is being repaid over 300 months with interest only repayments of $19,006 for 36 months until October 2022 then principal and interest repayments of $40,057 for 264 months until October 2044, with interest at a fixed rate of 2.928% per annum. The fair value of this loan is $7,836,190 which is estimated by obtaining mark-to-market quotes from the Toronto Dominion Bank resulting in an interest rate swap mark-to-market adjustment of $46,660. The quoted amount reflects the estimated amount that the Corporation would pay to settle the derivative agreement at the statement of financial position date.

The Toronto Dominion Bank committed reducing term facility is secured by a general security agreement representing a first charge on all of the Corporation's present and after acquired property, an inter-creditor agreement with Ontario Infrastructure and Lands Corporation and a guarantee of advances by North Bay Hydro Distribution Limited.

The Ontario Infrastructure and Lands Corporation loans require the Corporation at all times to meet a debt service coverage ratio of a minimum of 1:30 to 1 and a debt to total assets ratio of less than 60% calculated annually at December 31st beginning with the December 31, 2023 fiscal period.

The Toronto Dominion Bank loan requires the Corporation at all times to meet a debt service coverage ratio of a minimum of 1:20 to 1 and a debt to capitalization ratio of less than 60% calculated annually at December 31st beginning with the December 31, 2022 fiscal period.

Estimated principal repayments required to settle long-term obligations are as follows, (excludes interest rate swap mark-to-market adjustment):

2020	$ 89,370
2021	92,489
2022	137,871
2023	356,338
2024	367,437
Subsequent years	8,817,636
	$ 9,861,141

13. Notes payable

	December 31, 2019	September 30, 2019
Note payable to the Town of Espanola	$ -	$ 1,185,416
Note payable to the Township of Sables-Spanish Rivers	-	339,095
	$ -	$ 1,524,511

Notes payable to the Town of Espanola and Township of Sables-Spanish Rivers were without security, due on demand with one year's written notice, included interest at 4.41% per annum ,and convertible into special shares of the Corporation at a rate of $10,000 per share. During the period, the Corporation paid interest in the amount of $Nil (September 2019 - $39,208) to the Town of Espanola and $Nil (September 2019 - $11,216) to the Township of Sables-Spanish Rivers.

Upon closing of the acquisition on October 1, 2019 the promissory notes payable were cancelled (note 21).

14. Share capital

	December 31, 2019	September 30, 2019
Authorized		
Unlimited number of common shares		
Issued		
100 common shares (September 2019 - 1,000 common shares (note 21))	$ 100	$ 1,000
228 discretionary non-cumulative dividend paying, redeemable at $10,000 per share, non-voting special shares (note 21)	-	2,280,000
	$ 100	$ 2,281,000

15. Operating expenses

For internal management reporting purposes the Corporation's operating expenses are reported by function. Operating expenses reported by object are as follows:

	December 31, 2019	September 30, 2019
Salaries, wages and benefits	$ 150,617	$ 391,512
Contracted services	107,785	347,508
Office and administration	108,270	241,583
Operations and maintenance	43,108	187,408
Depreciation	48,621	147,422
Bad debts (recovery)	(4,911)	63,098
	$ 453,490	$ 1,378,531

16. Change in non-cash working capital items

	December 31, 2019	September 30, 2019
Accounts receivable	$ 24,051	$ 122,612
Unbilled revenue - energy sales	(509,697)	249,995
Unbilled revenue - distribution	(42,362)	37,795
Inventory	(3,844)	6,178
Prepaid expenses	23,678	17,952
Payment in lieu of taxes paid	(2)	79,413
Accounts payable and accrued liabilities	(1,008,292)	(6,106)
Payable for energy purchases	675,874	(275,862)
	$ (840,594)	$ 231,977

17. Pension plan

The Corporation provides pension benefits to its employees through the Ontario Municipal Employees Retirement System (OMERS) pension plan. The plan is a multi-employer, contributory, defined benefit pension plan funded by equal contributions by both employer and employees. During the period the Corporation made employer contributions of $14,908 (September 2019 - $47,047) to OMERS.

At December 31, 2019 the OMERS pension plan had total assets of $122.5 billion (2018 - $111.8 billion) and an accumulated deficit of $3.397 billion (2018 - $4.191 billion deficit).

18. Commitments

The corporation has entered into a contract for management, billing, collecting, customer service, software and data hosting services and support with PUC Services Inc. expiring February 28, 2022 at a base cost as follows:

2020	$	177,423
2021		180,958
2022		30,408

In addition to the above charges, a monthly charge of $5.53 to $5.75 per meter, for up to 3,700 meters for residential and general service customers, will also apply.

19. Capital disclosure

The Corporation's objectives when managing capital are:

(a) Ensure ongoing access to capital at a reasonable cost in order to maintain and improve the electricity distribution system of the Corporation to ensure the continued delivery of safe, reliable electricity services to customers, and to safeguard the Corporation's ability to continue as a going concern and provide a reasonable rate of return to its shareholders;

(b) Maintain the Corporation's capital structure with the financial ratios and recommended guidelines prescribed by the OEB.

The Corporation's capital consists of its common share capital, retained earnings (deficit) operating loans and long-term obligations. In order to achieve the above noted objectives the Corporation develops detailed annual operating and capital budgets and seeks to control costs to meet its working capital and capital investment requirements on both a short-term and long-term basis. There have been no changes in the Corporation's approach to managing capital during the period.

At December 31, 2019 the Corporation is party to debt agreements with Ontario Infrastructure and Lands Corporation (note 12) and The Toronto Dominion Bank (notes 7 and 12) that contain certain covenants that restrict the Corporation from incurring additional debt or making distributions to shareholders in excess of certain limits, that would cause a violation of those covenants.

20. Financial instruments

Transactions in financial instruments may result in an entity assuming or transferring financial risks to or from another party. The Corporation is exposed to the following risks associated with financial instruments and transactions it is a party to:

(a) Fair value

The fair value of current financial assets and current financial liabilities approximates their carrying value due to their short-term maturity dates. The fair value of long-term financial liabilities approximates their carrying value based on the presumption that the Corporation is a going concern and thus expects to fully repay the outstanding amounts. Fair value of derivative financial instruments is estimated by obtaining mark-to-market quotes from The Toronto Dominion Bank. The quoted amount reflects the estimated amount that the Corporation would pay to settle the derivative agreement at the statement of financial position date.

20. **Financial instruments, continued**

(b) Credit risk

Credit risk is the risk that one party to a financial transaction will fail to discharge a financial obligation and cause the other party to incur a financial loss. The Corporation's main credit risks are associated with its cash and accounts receivable.

The Corporation minimizes credit risk associated with its cash balances by ensuring that these financial assets are held with large reputable financial institutions with high credit ratings.

The Corporation incurs amounts due from its customers in the regular course of business and has credit risk associated with its accounts receivable balances of $1,226,204 (September 30, 2019 - $1,250,255). The Corporation reduces its exposure to credit risk through management's on-going monitoring of its accounts receivable balances and collections. Credit valuations are performed on a regular basis and credit is granted upon a review of the credit history of the applicant. An allowance for bad debts is recorded when applicable.

(c) Liquidity risk

Liquidity risk is the risk that the Corporation cannot repay its obligations when they become due to its creditors. The Corporation has liquidity risk associated with its operating loan, accounts payable and accrued liabilities, payable for energy purchases and long-term obligations. The Corporation reduces its exposure to liquidity risk by ensuring that it documents when authorized payments become due, and budgets to maintain adequate cash resources including an operating line of credit, to repay creditors including long-term obligations interest and principal as those liabilities become due.

The majority of the Corporation's accounts payable and payable for energy purchases, as reported in the statement of financial position, are due within 30 days.

21. Business combination

On October 1, 2019, North Bay (Espanola) Acquisition Inc., a wholly owned subsidiary of North Bay Hydro Holdings Ltd. acquired, for $7,992,237 of cash consideration, all of the outstanding shares of all classes of Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation (the "purchased securities").

This acquisition was accounted for as a business combination using the acquisition method of accounting whereby the acquired tangible and intangible assets and assumed liabilities are recorded in these financial statements at their estimated fair values at the date of acquisition.

Immediately after the acquisition North Bay (Espanola) Acquisition Inc., Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation amalgamated to form this corporation, which has continued operations under the name Espanola Regional Hydro Distribution Corporation. The results of operations are included in the accounts from the effective date of acquisition of October 1, 2019.

Details of the acquisition of the purchased securities are as follows:

		October 1, 2019
Purchased securities:		
1,000 common shares issued by Espanola Regional Hydro Holdings Corporation	$	4,187,726
228 special shares issued by Espanola Regional Hydro Distribution Corporation		2,280,000
Promissory notes payable issued by Espanola Regional Hydro Distribution Corporation		1,524,511
Total purchase price	$	7,992,237

21. **Business combination, continued**

Fair value of assets acquired:		
Current assets	$	2,209,844
Property, plant and equipment		5,106,006
Regulatory assets		2,775,259
		10,091,109
Liabilities assumed:		
Current liabilities		2,138,205
Customer deposits		223,680
Deferred revenue		114,098
Payment in lieu of deferred taxes		50,998
Contributions in aid of construction		348,367
Employee future benefits		98,197
Long-term obligations		2,004,871
Promissory notes payable		1,524,511
Regulatory liabilities		442,463
Fair value of net assets acquired	$	3,145,719

Upon closing of the acquisition the promissory notes payable were cancelled.

The total purchase price has been allocated as follows:

Fair value of net assets acquired	$	3,145,719
Goodwill recognized		3,322,007
Cancellation of promissory notes payable		1,524,511
Fair value of net assets recognized	$	7,992,237

The determination of fair values and the purchase price equation are based upon an independent valuation. The primary drivers to generate goodwill are business synergies and opportunities in another region. The goodwill is not deductible for income tax purposes. The Corporation has recognized $368,523 in acquisition related expenses. All acquisition related expenses have been expensed in the accounts of the Corporation.

See note 22 regarding the presentation of comparative figures in these financial statements.

22. Comparative figures

The objective of financial statements are to communicate information that is useful to investors, creditors and other users in making resource-allocation decisions and assessing management's stewardship. Comparative figures are required to be meaningful to the users of these financial statements.

In a vertical amalgamation the amalgamated enterprise is legally a continuation of the predecessor enterprises. However, since control changed immediately prior to the amalgamation the comparative figures cannot consist of the consolidated financial information of all of the predecessor enterprises. Accordingly, these comparative figures represent only the assets, liabilities, shareholders' equity, revenues and expenses of the former Espanola Regional Hydro Distribution Corporation because these figures represent the most meaningful and useful comparators.

The adjustment to retained earnings for pushdown accounting on amalgamation reflected in the statement of retained earnings and other comprehensive earnings (loss) consists of the following:

	October 1, 2019
Reduction for total shareholders' equity of predecessor entities (note 21)	$ 3,145,719
Adjustment for accumulated deficit of North Bay (Espanola) Acquisition Inc. at the date of acquisition	368,523
Amalgamation adjustment at October 1, 2019	$ 3,514,242

23. Subsequent events

Subsequent to year end, the impact of COVID-19 in Canada and on the global economy increased significantly. The global pandemic has disrupted economic activities and supply chains. Although the disruption from the virus is expected to be temporary, given the dynamic nature of these circumstances, the duration of the business disruption and related financial impact cannot be reasonably estimated at this time. The entity's ability to continue to service debt and meet obligations as they come due is dependent on the continued ability to generate earnings and cash flows. At this time, the full potential impact of COVID-19 on the entity is not known.

APPENDIX 1-D
Mapped Audited FS to RRR Trial Balance 2017-2019

Espanola Regional Hydro Distribution Corporation

Filing : 2.1.13
RRR Section: A distributor shall provide in the form and manner required by the Board annually the uniform system of account balances mapped and reconciled to the annual audited financial statements.

2017 Trial Balance Mapped to Audited Financial Statements

Color Legend:	Assets	Liabilities and Equity	Income Statement

Current Assets

Account Description	OEB	Amount	Category
Cash	1005	$ 1,483,309.93	1
Cash Advances and Working Funds	1010	$ 200.00	1
Interest Special Deposits	1020		
Dividend Special Deposits	1030		
Other Special Deposits	1040		
Term Deposits	1060		
Current Investments	1070		
Customer Accounts Receivable	1100	$ 720,773.78	2
Accounts Receivable - Services	1102		
Accounts Receivable - Recoverable Work	1104	$ 40,862.51	2
Accounts Receivable - Merchandise Jobbing, etc.	1105		
Other Accounts Receivable	1110	$ 265,629.29	2
Accrued Utility Revenues	1120	$ 733,009.14	REF A
Accumulated Provision for Uncollectible Accounts--Cre	1130		
Interest and Dividends Receivable	1140		
Rents Receivable	1150		
Notes Receivable	1170		
Prepayments	1180	$ 28,742.88	6
Miscellaneous Current and Accrued Assets	1190	$ 134,112.00	REF B
Accounts Receivable from Associated Companies	1200		
Notes Receivable from Associated Companies	1210		
Inventory			
Fuel Stock	1305		
Plant Materials and Operating Supplies	1330	$ 71,198.78	5
Merchandise	1340		
Non Rate-Regulated Materials and Supplies	1350		
Non-Current Assets			
Non-Current Investments in Non-Associated Companie	1405		
Finance Lease Receivable	1407		
Long Term Receivable - Street Lighting Transfer	1408		
Other Special or Collateral Funds	1410		
Sinking Funds	1415		
Unamortized Debt Expense	1425		
Unamortized Discount on Long-Term Debt--Debit	1445		
Unamortized Deferred Foreign Currency Translation Ga	1455		
Other Non-Current Assets	1460		
Portfolio Investments - Associated Companies	1480		
Investment in Equity - Accounted Joint Venture	1481		
Investment in Associated Companies - Significant Influe	1485		
Investment in Subsidiary Companies	1490		
Deferred Taxes - Non-Current Assets	1495	$ 10,510.00	9
Other Assets and Deferred Charges			
Unrecovered Plant and Regulatory Study Costs	1505		
Other Regulatory Assets	1508	$ 1,456,156.35	10
Preliminary Survey and Investigation Charges	1510		
Emission Allowance Inventory	1515		
Emission Allowances Withheld	1516		
RCVARetail	1518		

2017

2017 Audtied Financial Statement Amounts for Statement of Finanacial Position and Statement of Comprehensive Income

		Sum of or proportions of		
Current Assets:				
Cash & Cash Equivalents		1	$	1,483,510
Accounts Receivable		2	$	1,027,266
Unbilled Revenue - Energy Sales	REF A	3	$	570,747
Unbilled Revenue - Distribution	REF A	4	$	162,262
Inventory		5	$	71,199
Prepaid Expenses		6	$	28,743
Payment in Lieu of Taxes	REF B	7	$	63,196
Total Current Assets			$	3,406,922
Non Current Assets:				
PP&E (net amortization)		8	$	4,640,045
Payment in lieu of deferred taxes		9	$	10,510
Total Non Current Assets			$	4,650,555
Total Assets			**$**	**8,057,477**
Regulatory Assets		10	$	2,680,471
Payment in lieu of deferred tax regulatory assets	REF B	11	$	70,916
Total Assets & Regulatory Deferral Account Debit Balances			**$**	**10,808,865**
Current Liabilities				
Accounts Payable & Accrued Liabilities	REF C	12	$	606,030
Payable for Energy Purchases	REF C	13	$	2,140,288
Current Porton of Long Term Debt	REF D	14	$	83,452
Total Current Liabilities			$	2,829,770
Non Current Liabilities				
Customer Deposits		15	$	222,090
Payment in lieu of deferred taxes	REF E	16	$	70,560
Contributions in aid of construction		17	$	286,384
Employee Future Benefits		18	$	70,067
Long-term obligations	REF D	19	$	2,157,971
Notes Payable		20	$	1,524,511
Total Non Current Liabilities			$	4,331,582
Shareholder's Equity				
Share Capital		21	$	2,281,000
Retained Earnings	REF F	22	$	923,799
Accumulated Other Comprehensive Earnings	REF F	23	$	14,954
Total Liabilities & Shareholder's Equity			$	10,381,106

Special Purpose Charge Assessment Variance Account	1521		
Pension & OPEB Forecast Accrual versus Actual Cash Pa	1522		
Miscellaneous Deferred Debits	1525		
Deferred Losses from Disposition of Utility Plant	1530		
Renewable Connection Capital Deferral Account	1531		
Renewable Connection OM&A Deferral Account	1532		
Renewable Generation Connection Funding Adder Defe	1533		
Smart Grid Capital Deferral Account	1534		
Smart Grid OM&A Deferral Account	1535		
Smart Grid Funding Adder Deferral Account	1536		
Unamortized Loss on Reacquired Debt	1540		
RCVASTR	1548		
LV Variance Account	1550	-$ 135,325.32	24
Smart Metering Entity Charge Variance Account	1551	-$ 2,526.13	10
Smart Meter Capital and Recovery Offset Variance Acco	1555	$ 14,027.12	10
Smart Meter OM&A Variance Account	1556		
Meter Cost Deferral Account	1557		
Board-Approval CDM Variance Account	1567		
LRAM Variance Account	1568		
Extraordinary Event Costs	1572		
Deferred Rate Impact Amounts	1574		
IFRS-CGAAP Transitional PP&E Amounts	1575		
CGAAP Accounting Changes	1576		
RSVA - Wholesale Market Service Charge	1580	-$ 84,045.67	24
RSVAONE-TIME	1582		
RSVA - Retail Transmission Network Charge	1584	$ 9,730.29	10
RSVA - Retail Transmission Connection Charge	1586	$ 537,111.69	10
RSVA - Power (excluding Global Adjustment)	1588	$ 627,953.01	10
RSVA - Global Adjustment	1589	-$ 197,522.15	24
PILs and Tax Variance for 2006 and Subsequent Years	1592		
Disposition and Recovery/Refund of Regulatory Balance	1595	$ 38,019.14	10
Electric Plant and Service - Detailed			
No Records			
A.Intangible Plant			
Organization	1606		
Franchises and Consents	1608		
Capital Contributions Paid	1609		
Miscellaneous Intangible Plant	1610		
Computer Software	1611		
Land Rights	1612		
B.Generation Plants			
Land	1615		
Land Rights	1616		
Buildings and Fixtures	1620		
Leasehold Improvements	1630		
Boiler Plant Equipment	1635		
Engines and Engine-Driven Generators	1640		
Turbogenerator Units	1645		
Reservoirs, Dams and Waterways	1650		
Water Wheels, Turbines and Generators	1655		
Roads, Railroads and Bridges	1660		
Fuel Holders, Producers and Accessories	1665		
Land	1805	$ 88,880.36	8
Buildings and Fixtures	1808	$ 354,801.23	8
Leasehold Improvements	1810		
Transformer Station Equipment - Normally Primary abo	1815		
Distribution Station Equipment - Normally Primary belo	1820	$ 489,375.19	8
Storage Battery Equipment	1825		
Poles, Towers and Fixtures	1830	$ 2,854,430.88	8
Overhead Conductors and Devices	1835	$ 2,290,470.13	8
Underground Conduit	1840	$ 710,347.16	8
Underground Conductors and Devices	1845	$ 164,845.89	8
Line Transformers	1850	$ 1,009,803.45	8
Services	1855	$ 333,677.81	8
Meters	1860	$ 737,156.31	8

Regulatory Liabilities		24	$ 416,893
Payment in lieu of deferred tax regulatory liabilities	REF E	25	$ 10,866
			$ 427,759
Total Equity, Liabilities & Regulatory Deferral Account Credit Balances			**$ 10,808,865**
Revenue:			
Energy Sales	REF G	26	$ 6,745,859
Distribution		27	$ 1,593,631
			$ 8,339,490
Cost of Energy	REF J	28	$ 6,908,603
Gross Profit			$ 1,430,887
Operating Expenses:			
General & Administration	REF I	29	$ 376,015
Billing & Collecting	REF K	30	$ 433,427
Distribution - operations	REF K	31	$ 303,433
Distribution - maintenance		32	$ 285,370
depreciation	REF L	33	$ 153,005
Interest on long-term obligations and notes payable		34	$ 150,875
			$ 1,702,123
Earnings(loss) before other income and payment in lieu of taxes			-$ 271,237
Other Income:			
Interest	REF H	35	$ 18,732
Labour,rental,and other charges	REF H/I	36	$ 99,528
amortization of contributions in aid of construction	REF L	37	$ 8,103
			$ 126,364
Earnings (loss) before payment in lieu of taxes, change in regulatory asset and liability balances and other			-$ 144,873
Payments in lieu of Taxes:			
Current		38	-$ 63,196
Deferred	REF M	39	$ 38,778
			-$ 24,418
Net Earnings (loss) before change in regulatory asset & liability balances and other comprehensive earnings(loss)			-$ 120,455
Change in regulatory assets and liabilities			
Change in regulatory assets and liability account balances related	REF G/J	40	$ 162,745
Change in payment in lieu of deferred tax balances related to regu	REF M	41	$ 38,778
			$ 201,523
Net Earnings before other comprehensive loss:			$ 81,068
Other Comprehensive loss:			
Remeasurement of employee future benefits liability, net of tax		42	-$ 4,327
Net Loss (Income), beinf Total Comprehensive Loss(Income) for the year			$ 76,741

Land	1905			
Buildings and Fixtures	1908			
Leasehold Improvements	1910			
Office Furniture and Equipment	1915	$	64,000.35	8
Computer Equipment - Hardware	1920	$	200,117.75	8
Transportation Equipment	1930	$	641,704.84	8
Stores Equipment	1935	$	10,537.76	8
Tools, Shop and Garage Equipment	1940	$	154,624.81	8
Measurement and Testing Equipment	1945	$	11,947.98	8
Power Operated Equipment	1950			
Communication Equipment	1955	$	19,256.84	8
Miscellaneous Equipment	1960			
Load Management Controls - Customer Premises	1970			
Load Management Controls - Utility Premises	1975			
System Supervisory Equipment	1980			
Sentinel Lighting Rental Units	1985	$	10,220.66	8
Other Tangible Property	1990			
Contributions and Grants - Credit	1995			
Other capital Assets				
Construction Work in Progress--Electric	2055	$	106,501.42	8
Accumulated Depreciation of Electric Utility Plant - Pro	2105	-$	5,612,655.84	8
Total Assets				
Accounts Payable	2205	-$	2,538,647.37	REF C
Customer Credit Balances	2208	-$	98,916.23	15
Customer Deposits	2210	-$	123,173.52	15
Dividends Declared	2215			
Miscellaneous Current and Accrued Liabilities	2220	-$	122,825.20	13
Notes and Loans Payable	2225			
Accounts Payable to Associated Companies	2240			
Notes Payable to Associated Companies	2242			
Debt Retirement Charges(DRC) Payable	2250	-$	14,625.04	13
Commodity Taxes	2290	-$	11,306.29	12
Payroll Deductions / Expenses Payable	2292	-$	58,914.57	12
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294			
Accumulated Provision for Injuries and Damages	2305			
OPEB Liability	2306			
Other Pensions Liability	2308	-$	70,067.00	18
Deferred Tax - Non-Current Liability	2350	-$	81,426.00	REF E
Deferred Revenues	2440	-$	286,384.26	17
Debentures Outstanding - Long Term	2505			
Debenture Advances	2510			
Reacquired Bonds	2515			
Other Non-Current Debt	2520	-$	2,241,422.56	REF D
Term Bank Loans - Long Term	2525			
Advances from Associated Companies	2550	-$	1,524,510.75	20
Common Shares Issued	3005	-$	1,000.00	21
Preference Shares Issued	3008	-$	2,280,000.00	21
Unappropriated Retained Earnings	3045	-$	862,012.20	REF F
Accumulated Other Comprehensive Income	3090	$	4,327.00	22
Balance Transferred From Income	3046	-$	81,067.63	22
Total Liabilities and shareholder's equity				

1

Residential Energy Sales	4006	-$ 4,143,873.00	REF G
Commercial Energy Sales	4010		
Industrial Energy Sales	4015		
Energy Sales to Large Users	4020		
Street Lighting Energy Sales	4025	-$ 27,948.14	REF G
Sentinel Lighting Energy Sales	4030	-$ 3,174.86	REF G
General Energy Sales	4035	-$ 1,640,160.61	REF G
Other Energy Sales to Public Authorities	4040		
Revenue Adjustment	4050		
Energy Sales For Retailers/Others	4055	-$ 219,409.66	REF G
Interdepartmental Energy Sales	4060		
Billed WMS	4062	-$ 308,356.84	REF G
Billed - WMS-ONE-TIME	4064		
Billed NW	4066	-$ 355,571.50	REF G
Billed CN	4068	-$ 221,395.27	REF G
Billed - LV	4075	-$ 161,689.05	REF G
Billed – Smart Metering Entity Charge	4076	-$ 30,793.04	REF G
Distribution Services Revenue	4080	-$ 1,588,262.10	27
Retail Services Revenues	4082	-$ 5,356.80	27
Service Transaction Requests (STR) Revenues	4084	-$ 12.50	27
Interdepartmental Rents	4205		
Rent from Electric Property	4210	-$ 38,440.75	36
Other Utility Operating Income	4215		
Other Electric Revenues	4220		
Late Payment Charges	4225	-$ 15,606.89	35
Sales of Water and Water Power	4230		
Miscellaneous Service Revenues	4235	-$ 37,567.70	36
Provision for Rate Refunds	4240		
Government and Other Assistance Directly Credited to I	4245	-$ 1,430.07	36
Revenues from Merchandise	4325	-$ 2,213.65	36
Costs and Expenses of Merchandising	4330		
Revenues from Non Rate-Regulated Utility Operations	4375	-$ 13,553.25	36
Expenses of Non Rate-Regulated Utility Operations	4380	$ 12,952.05	36
Non Rate-Regulated Utility Rental Income	4385		
Miscellaneous Non-Operating Income	4390	-$ 1,327.43	36
Rate-Payer Benefit Including Interest	4395		
Foreign Exchange Gains and Losses, Including Amortizat	4398		
Interest and Dividend Income	4405	-$ 35,378.16	REF H
Power Purchased	4705	$ 6,034,566.27	REF J
Charges - Global Adjustment	4707		
Charges-WMS	4708	$ 308,356.84	REF J
Cost of Power Adjustments	4710		
Charges-One-Time	4712		
Charges-NW	4714	$ 355,571.50	REF J
System Control and Load Dispatching	4715		
Charges-CN	4716	$ 221,395.27	REF J
Other Expenses	4720		
Charges - LV	4750	$ 161,689.05	REF J
Charges – Smart Metering Entity Charge	4751	$ 30,793.04	REF J
Operation Supervision and Engineering	5005	$ 67,084.52	31
Load Dispatching	5010		
Station Buildings and Fixtures Expense	5012	$ 2,791.81	31
Transformer Station Equipment - Operation Labour	5014		
Transformer Station Equipment - Operation Supplies an	5015		
Distribution Station Equipment - Operation Labour	5016	$ 4,797.96	31
Distribution Station Equipment - Operation Supplies anc	5017	$ 20,215.32	31
Overhead Distribution Lines and Feeders - Operation La	5020	$ 53,406.66	31
Overhead Distribution Lines and Feeders - Operation Su	5025	$ 45,664.27	31
Overhead Subtransmission Feeders - Operation	5030		
Overhead Distribution Transformers- Operation	5035	$ 10,546.09	31
Underground Distribution Lines and Feeders - Operatior	5040	$ 29,426.57	31
Underground Distribution Lines and Feeders - Operatior	5045	$ 9,695.43	31
Underground Subtransmission Feeders - Operation	5050		
Underground Distribution Transformers - Operation	5055	$ 2,187.69	31
Street Lighting and Signal System Expense	5060		
Meter Expense	5065	$ 2,160.25	31
Customer Premises - Operation Labour	5070	$ 26,419.76	31
Customer Premises - Materials and Expenses	5075	$ 1,589.49	31
Miscellaneous Distribution Expense	5085	$ 10,079.84	31
Underground Distribution Lines and Feeders - Rental Pa	5090		
Overhead Distribution Lines and Feeders - Rental Paid	5095	$ 14,556.00	31
Other Rent	5096		

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Maintenance Supervision and Engineering	5105	$	71,095.68	32
Maintenance of Buildings and Fixtures - Distribution Sta	5110	$	8,677.43	32
Maintenance of Transformer Station Equipment	5112			
Maintenance of Distribution Station Equipment	5114	$	12,961.16	32
Maintenance of Poles, Towers and Fixtures	5120	$	24,712.85	32
Maintenance of Overhead Conductors and Devices	5125	$	44,196.93	32
Maintenance of Overhead Services	5130	$	50,209.87	32
Overhead Distribution Lines and Feeders - Right of Way	5135	$	62,205.70	32
Maintenance of Underground Conduit	5145			
Maintenance of Underground Conductors and Devices	5150	$	2,976.90	32
Maintenance of Underground Services	5155	$	1,209.25	32
Maintenance of Line Transformers	5160	$	3,835.43	32
Maintenance of Street Lighting and Signal Systems	5165			
Sentinel Lights - Labour	5170	$	72.41	32
Sentinel Lights - Materials and Expenses	5172	$	10.50	32
Maintenance of Meters	5175	$	3,205.48	32
Customer Installations Expenses- Leased Property	5178			
Maintenance of Other Installations on Customer Premis	5195			
Supervision	5305			
Meter Reading Expense	5310	$	65,820.68	REF K
Customer Billing	5315	$	183,805.78	30
Collecting	5320	$	128,223.93	30
Collecting- Cash Over and Short	5325			
Collection Charges	5330			
Bad Debt Expense	5335	$	58,387.24	30
Miscellaneous Customer Accounts Expenses	5340			
Executive Salaries and Expenses	5605	$	18,540.00	29
Management Salaries and Expenses	5610	$	70,935.16	29
General Administrative Salaries and Expenses	5615	$	35,287.48	29
Office Supplies and Expenses	5620	$	74,115.04	29
Administrative Expense Transferred/Credit	5625			
Outside Services Employed	5630	$	55,633.44	29
Property Insurance	5635	$	5,814.72	29
Injuries and Damages	5640	$	10,058.86	29
OMERS Pensions and Benefits	5645	$	4,761.04	29
Employee Pensions and OPEB	5646			
Employee Sick Leave	5647			
Franchise Requirements	5650			
Regulatory Expenses	5655	$	93,182.74	29
General Advertising Expenses	5660	$	571.69	29
Miscellaneous General Expenses	5665	$	1,153.90	29
Rent	5670			
Lease Payment Expense	5672			
Maintenance of General Plant	5675			
Electrical Safety Authority Fees	5680	$	3,017.00	29
Special Purpose Charge Expense	5681			
Independent Market Operator Fees and Penalties	5685			
OM&A Contra	5695			
Depreciation Expense - Property Plant, and Equipment	5705	$	144,901.69	33
Interest on Long Term Debt	6005	$	83,643.56	34
Amortization of Debt Discount and Expense	6010			
Amortization of Premium on Debt/Credit	6015			
Amortization of Loss on Reacquired Debt	6020			
Amortization of Gain on Reacquired Debt--Credit	6025			
Interest on Debt to Associated Companies	6030	$	67,231.08	34
Other Interest Expense	6035	$	15,169.34	REF I
Allowance For Borrowing Costs Applied to CWIP - Credi	6040			
Allowance For Other Borrowing Costs Applied to CWIP -	6042			
Interest Expense on Finance Capital Lease Obligations	6045			
Taxes Other Than Income Taxes	6105			
Income Taxes	6110	-$	63,196.00	38
Provision for Deferred Taxes - Income Statement	6115			
Donations	6205	$	2,080.00	29
Available-for-Sale Financial Asset or Cash Flow Hedge -	7005			
Pension Actuarial Gains or Losses or Remeasurement A	7010	$	4,327.00	42
Current Taxes - Other Comprehensive Income	7020			
Deferred Taxes - Other Comprehensive Income	7025			
Miscellaneous - Other Comprehensive Income	7030			

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		$ 570,747.40	3	
		$ 162,261.74	4	
	REF A	$ 733,009.14		
		$ 63,196.00	7	
		$ 70,916.00	11	
	REF B	$ 134,112.00		
		-$ 535,809.24	12	
		-$ 2,002,838.13	13	
	REF C	-$ 2,538,647.37		
		-$ 83,452.00	14	
		-$ 2,157,970.56	19	
	REF D	-$ 2,241,422.56		
		-$ 70,560.00	16	
		-$ 10,866.00	25	
	REF E	-$ 81,426.00		
		-$ 14,954.00	23	
		-$ 847,058.20	22	
	REF F	-$ 862,012.20		
Note Payable Town Espanola		-$ 6,745,858.66	26	
Note Payable Township Spanish-Sables Rivers		$ 366,513.31	40	
	REF G	-$ 7,112,371.97		
		-$ 3,125.36	35	
		-$ 32,252.80	36	
	REF H	-$ 35,378.16		
		$ 14,305.19	36	
		$ 864.15	29	
	REF I	$ 15,169.34		
		$ 6,908,603.30	28	
		-$ 203,768.67	40	
	REF J	$ 7,112,371.97		
		$ 63,009.75	30	
		$ 2,810.93	31	
	REF K	$ 65,820.68		
Journal entry that was not made for amortization of co	5705	$ 8,103.00	33	REF L
Amortization of Contributions in aid of construction	4245	-$ 8,103.00	37	REF L
		$ 38,778.00	39	REF M
		$ 38,778.00	41	REF M

Espanola Regional Hydro Distribution Corporation

Filing : 2.1.13
RRR Section: A distributor shall provide in the form and manner required by the Board annually the uniform system of account balances mapped and reconciled to the annual audited financial statements.

2018 Trial Balance Mapped to Audited Financial Statements

Color Legend: Assets | Liabilities and Equity | Income Statement

Current Assets

Account Description	OEB	Amount	Category
Cash	1005	$ 767,296.05	1
Cash Advances and Working Funds	1010	$ 200.00	1
Interest Special Deposits	1020		
Dividend Special Deposits	1030		
Other Special Deposits	1040		
Term Deposits	1060		
Current Investments	1070		
Customer Accounts Receivable	1100	$ 748,996.23	2
Accounts Receivable - Services	1102		
Accounts Receivable - Recoverable Work	1104	$ 123,636.76	2
Accounts Receivable - Merchandise Jobbing, etc.	1105		
Other Accounts Receivable	1110	$ 279,148.31	2
Accrued Utility Revenues	1120	$ 684,151.13	REF A
Accumulated Provision for Uncollectible Accounts--Credit	1130		
Interest and Dividends Receivable	1140		
Rents Receivable	1150		
Notes Receivable	1170		
Prepayments	1180	$ 159,864.87	4
Miscellaneous Current and Accrued Assets	1190	$ 182,134.00	REF B
Accounts Receivable from Associated Companies	1200		
Notes Receivable from Associated Companies	1210		
Inventory			
Fuel Stock	1305		
Plant Materials and Operating Supplies	1330	$ 50,382.96	5
Merchandise	1340		
Non Rate-Regulated Materials and Supplies	1350		
Non-Current Assets			
Non-Current Investments in Non-Associated Companies	1405		
Finance Lease Receivable	1407		
Long Term Receivable - Street Lighting Transfer	1408		
Other Special or Collateral Funds	1410		
Sinking Funds	1415		
Unamortized Debt Expense	1425		
Unamortized Discount on Long-Term Debt--Debit	1445		
Unamortized Deferred Foreign Currency Translation Gains	1455		
Other Non-Current Assets	1460		
Portfolio Investments - Associated Companies	1480		
Investment in Equity - Accounted Joint Venture	1481		
Investment in Associated Companies - Significant Influenc	1485		
Investment in Subsidiary Companies	1490		
Deferred Taxes - Non-Current Assets	1495	$ 11,392.00	6
Other Assets and Deferred Charges			

2018

2018 Audtied Financial Statement Amounts for Statement of Finanacial Position and Statement of Comprehensive Income

		Sum of or proportions of	
Current Assets:			
Cash & Cash Equivalents		1	$ 767,496
Accounts Receivable		2	$ 1,151,781
Unbilled Revenue - Energy Sales	REF A	3	$ 532,037
Unbilled Revenue - Distribution	REF A	23	$ 152,114
Inventory		5	$ 50,383
Prepaid Expenses		4	$ 159,865
Payment in Lieu of Taxes	REF B	24	$ 79,202
Total Current Assets			$ 2,892,878
Non Current Assets:			
PP&E (net amortization)		7	$ 4,880,215
Payment in lieu of deferred taxes		6	$ 11,392
Total Non Current Assets			$ 4,891,607
Total Assets			$ 7,784,486
Regulatory Deferral Account Debit Balances	REF F	8	$ 2,543,513
Deferred Tax Associated with Regulatory Deferral Account Balances	REF B	9	$ 102,932
Total Assets & Regulatory Deferral Account Debit Balances			**$ 10,430,930**
Current Liabilities			
Accounts Payable & Accrued Liabilities	REF C	10	-$ 655,887
Payable for Energy Purchases	REF C	11	-$ 1,454,594
Current Porton of Long Term Debt	REF D	12	-$ 86,359
Total Current Liabilities			-$ 2,196,840
Non Current Liabilities			
Customer Deposits	REF E	13	-$ 210,362
Deferred Revenue	REF E	14	-$ 137,257
Payment in lieu of deferred taxes		15	-$ 114,324
Contributions in aid of construction		16	-$ 316,758
Employee Future Benefits		17	-$ 84,387
Long-term obligations	REF D	18	-$ 2,071,612
Notes Payable		19	-$ 1,524,511
Total Non Current Liabilities			-$ 6,656,050

Unrecovered Plant and Regulatory Study Costs	1505			
Other Regulatory Assets	1508	$	1,320,201.05	REF F
Preliminary Survey and Investigation Charges	1510			
Emission Allowance Inventory	1515			
Emission Allowances Withheld	1516			
RCVARetail	1518			
Special Purpose Charge Assessment Variance Account	1521			
Pension & OPEB Forecast Accrual versus Actual Cash Payr	1522			
Miscellaneous Deferred Debits	1525			
Deferred Losses from Disposition of Utility Plant	1530			
Renewable Connection Capital Deferral Account	1531			
Renewable Connection OM&A Deferral Account	1532			
Renewable Generation Connection Funding Adder Deferra	1533			
Smart Grid Capital Deferral Account	1534			
Smart Grid OM&A Deferral Account	1535			
Smart Grid Funding Adder Deferral Account	1536			
Unamortized Loss on Reacquired Debt	1540			
RCVASTR	1548			
LV Variance Account	1550	-$	164,083.47	22
Smart Metering Entity Charge Variance Account	1551	-$	4,938.06	8
Smart Meter Capital and Recovery Offset Variance Accou	1555	$	14,242.25	8
Smart Meter OM&A Variance Account	1556			
Meter Cost Deferral Account	1557			
Board-Approval CDM Variance Account	1567			
LRAM Variance Account	1568			
Extraordinary Event Costs	1572			
Deferred Rate Impact Amounts	1574			
IFRS-CGAAP Transitional PP&E Amounts	1575			
CGAAP Accounting Changes	1576			
RSVA - Wholesale Market Service Charge	1580	-$	84,416.48	22
RSVAONE-TIME	1582			
RSVA - Retail Transmission Network Charge	1584	$	5,849.63	8

Shareholder's Equity				
Share Capital		20	-$	2,281,000
Retained Earnings	REF G	21	-$	1,003,493
Accumulated Other Comprehensive Earnings	REF G	25	-$	998
Total Liabilities & Shareholder's Equity			-$	3,285,491
Regulatory Deferrral Account Credit Balances	REF F	22	-$	489,389
Payment in lieu of deffered tax regualtory liabilities			$	-
			-$	489,389
Total Equity, Liabilities & Regulatory Deferral Account Credit Balances			-$	10,430,930
Revenue:				
Energy Sales		26	$	6,729,611
Distribution		27	$	1,630,447
			$	8,360,058
Cost of Energy		28	-$	6,520,156
Gross Profit			$	1,839,902
Operating Expenses:				
General & Administration	REF H	29	-$	329,322
Billing & Collecting		30	-$	429,732
Distribution - operations		31	-$	374,289
Distribution - maintenance		32	-$	267,091
depreciation	REF J	33	-$	161,274
Interest on long-term obligations and notes payable		34	-$	148,067
			-$	1,709,775

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RSVA - Retail Transmission Connection Charge	1586	$	710,413.14	8
RSVA - Power (excluding Global Adjustment)	1588	$	454,732.52	8
RSVA - Global Adjustment	1589	-$	237,469.89	22
PILs and Tax Variance for 2006 and Subsequent Years	1592			
Disposition and Recovery/Refund of Regulatory Balances	1595	$	39,593.06	8
Electric Plant and Service - Detailed				
No Records				
A.Intangible Plant				
Organization	1606			
Franchises and Consents	1608			
Capital Contributions Paid	1609			
Miscellaneous Intangible Plant	1610			
Computer Software	1611			
Land Rights	1612			
B.Generation Plants				
Land	1615			
Land Rights	1616			
Buildings and Fixtures	1620			
Leasehold Improvements	1630			
Boiler Plant Equipment	1635			
Engines and Engine-Driven Generators	1640			
Turbogenerator Units	1645			
Reservoirs, Dams and Waterways	1650			
Water Wheels, Turbines and Generators	1655			
Roads, Railroads and Bridges	1660			
Fuel Holders, Producers and Accessories	1665			

Earnings(loss) befor eother income and payment in lieu of taxes			$	130,127
Other Income:				
Interest	REF I	35	$	20,896
Labour,rental,and other charges	REF I	36	$	112,275
amortization of contributions in aid of construction	REF J	37	$	9,846
			$	143,017
Earnings (loss) before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)			$	273,143
Payments in lieu of Taxes:				
Current		38	-$	16,006
Deferred		39	$	42,882
			$	26,876
Net Earnings (loss) before change in regulatory asset & liability balances and other comprehensive earnings(loss)			$	246,267
Change in regulatory assets and liabilities				
Change in regulatory assets and liability account balances related to profit and loss		40	-$	209,455
Change in payment in lieu of deferred tax balances related to regulatory asset and liabilitie		41	$	42,882
			-$	166,573
Net Earnings before other comprehensive loss:			$	79,694
Other Comprehensive loss:				
Remeasurement of employee future benefits liability, net of tax		42	$	13,956
Net Loss (Income), beinf Total Comprehensive Loss(Income) for the year			$	65,738

Land	1805	$	88,880.36	7
Buildings and Fixtures	1808	$	354,801.23	7
Leasehold Improvements	1810			
Transformer Station Equipment - Normally Primary above	1815			
Distribution Station Equipment - Normally Primary below	1820	$	489,375.19	7
Storage Battery Equipment	1825			
Poles, Towers and Fixtures	1830	$	3,012,094.52	7
Overhead Conductors and Devices	1835	$	2,347,420.05	7
Underground Conduit	1840	$	710,347.16	7
Underground Conductors and Devices	1845	$	393,050.84	7
Line Transformers	1850	$	1,029,706.28	7
Services	1855	$	347,860.10	7
Meters	1860	$	738,035.54	7
Other Installations on Customer's Premises	1865			
Leased Property on Customer Premises	1870			
Street Lighting and Signal Systems	1875			
E.General Plant				
Land	1905			
Buildings and Fixtures	1908			
Leasehold Improvements	1910			
Office Furniture and Equipment	1915	$	64,000.35	7
Computer Equipment - Hardware	1920	$	201,737.75	7
Transportation Equipment	1930	$	641,704.84	7
Stores Equipment	1935	$	10,537.76	7
Tools, Shop and Garage Equipment	1940	$	154,624.81	7
Measurement and Testing Equipment	1945	$	11,947.98	7
Power Operated Equipment	1950			
Communication Equipment	1955	$	19,256.84	7
Miscellaneous Equipment	1960			
Load Management Controls - Customer Premises	1970			
Load Management Controls - Utility Premises	1975			
System Supervisory Equipment	1980			
Sentinel Lighting Rental Units	1985	$	10,120.66	7
Other Tangible Property	1990			
Contributions and Grants - Credit	1995			
Other capital Assets				
Property Under Finance Leases	2005			
Electric Plant Purchased or Sold	2010			
Experimental Electric Plant Unclassified	2020			
Electric Plant and Equipment Leased to Others	2030			
Electric Plant Held for Future Use	2040			
Completed Construction Not Classified--Electric	2050			
Construction Work in Progress--Electric	2055	$	51,184.40	7
Electric Plant Acquisition Adjustment	2060			
Other Electric Plant Adjustment	2065			
Other Utility Plant	2070			
Non Rate-Regulated Utility Property Owned or Under Fina	2075			
Accumulated Amortization				
Accumulated Depreciation of Electric Utility Plant - Prope	2105	-$	5,796,471.28	7
Accumulated Amortization of Electric Utility Plant - Intang	2120			
Accumulated Amortization of Electric Plant Acquisition Ac	2140			
Accumulated Depreciation of Other Utility Plant	2160			
Accumulated Depreciation of Non Rate-Regulated Utility	2180			
Total Assets		$	9,941,541.44	

Accounts Payable	2205	-$	2,079,495.76	REF C
Customer Credit Balances	2208	-$	87,028.67	13
Customer Deposits	2210	-$	260,589.93	REF E
Dividends Declared	2215			
Miscellaneous Current and Accrued Liabilities	2220	-$	331.40	10
Commodity Taxes	2290	$	27,810.29	10
Payroll Deductions / Expenses Payable	2292	-$	58,464.19	10
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294			
Accumulated Provision for Injuries and Damages	2305			
OPEB Liability	2306			
Other Pensions Liability	2308			
Vested Sick Leave Liability	2310	-$	84,387.00	17
Deferred Tax - Non-Current Liability	2350	-$	114,324.00	15
Deferred Revenues	2440	-$	316,758.35	16
Debentures Outstanding - Long Term	2505			
Debenture Advances	2510			
Reacquired Bonds	2515			
Other Non-Current Debt	2520	-$	2,157,970.57	REF D
Term Bank Loans - Long Term	2525			
Advances from Associated Companies	2550	-$	1,524,510.75	19
Common Shares Issued	3005			
Preference Shares Issued	3008	-$	2,281,000.00	20
Unappropriated Retained Earnings	3045	-$	924,796.83	REF G
Balance Transferred From Income	3046	-$	79,694.28	REF G
Total Liabilities and shareholder's equity		-$	9,941,541.44	
Residential Energy Sales	4006	-$	3,616,352.27	REF J
Commercial Energy Sales	4010			
Industrial Energy Sales	4015			
Energy Sales to Large Users	4020			
Street Lighting Energy Sales	4025	-$	21,781.25	REF J
Sentinel Lighting Energy Sales	4030	-$	2,632.45	REF J
General Energy Sales	4035	-$	1,505,419.84	REF J
Other Energy Sales to Public Authorities	4040			
Revenue Adjustment	4050			
Energy Sales For Retailers/Others	4055	-$	300,581.95	REF J
Interdepartmental Energy Sales	4060			
Billed WMS	4062	-$	238,508.86	REF J
Billed - WMS-ONE-TIME	4064			
Billed NW	4066	-$	365,865.56	REF J
Billed CN	4068	-$	230,208.71	REF J
Billed - LV	4075	-$	183,647.45	REF J
Billed – Smart Metering Entity Charge	4076	-$	22,193.67	REF J
Distribution Services Revenue	4080	-$	1,625,817.32	27
Retail Services Revenues	4082	-$	4,621.60	27
Service Transaction Requests (STR) Revenues	4084	-$	7.75	27
SSS Administration Revenue	4086			
Electric Services Incidental to Energy Sales	4090			
Transmission Charges Revenue	4105			
Transmission Services Revenue	4110			
Interdepartmental Rents	4205			
Rent from Electric Property	4210	-$	39,674.49	36
Other Utility Operating Income	4215			
Other Electric Revenues	4220			
Late Payment Charges	4225	-$	14,549.46	35
Sales of Water and Water Power	4230			
Miscellaneous Service Revenues	4235	-$	33,631.20	36
Provision for Rate Refunds	4240			
Government and Other Assistance Directly Credited to Inc	4245			
Revenues from Merchandise	4325	-$	5,944.50	36
Revenues from Non Rate-Regulated Utility Operations	4375	-$	174,825.50	36
Expenses of Non Rate-Regulated Utility Operations	4380	$	174,392.41	36
1 Interest and Dividend Income	4405	-$	61,217.41	REF I

Power Purchased	4705	$	5,446,767.76	REF L
Charges - Global Adjustment	4707			
Charges-WMS	4708	$	238,508.86	REF L
Cost of Power Adjustments	4710			
Charges-One-Time	4712			
Charges-NW	4714	$	365,865.56	REF L
System Control and Load Dispatching	4715			
Charges-CN	4716	$	230,208.71	REF L
Other Expenses	4720			
Charges - LV	4750	$	183,647.45	REF L
Charges – Smart Metering Entity Charge	4751	$	22,193.67	REF L
Operation Supervision and Engineering	5005	$	72,015.10	31
Load Dispatching	5010			
Station Buildings and Fixtures Expense	5012	$	2,711.68	31
Transformer Station Equipment - Operation Labour	5014			
Transformer Station Equipment - Operation Supplies and	5015			
Distribution Station Equipment - Operation Labour	5016	$	12,683.02	31
Distribution Station Equipment - Operation Supplies and E	5017	$	21,534.90	31
Overhead Distribution Lines and Feeders - Operation Labo	5020	$	63,063.89	31
Overhead Distribution Lines and Feeders - Operation Supp	5025	$	42,520.29	31
Overhead Subtransmission Feeders - Operation	5030			
Overhead Distribution Transformers- Operation	5035	$	18,844.66	31
Underground Distribution Lines and Feeders - Operation L	5040	$	41,263.32	31
Underground Distribution Lines and Feeders - Operation S	5045	$	23,821.82	31
Underground Subtransmission Feeders - Operation	5050			
Underground Distribution Transformers - Operation	5055	$	11,494.98	31
Street Lighting and Signal System Expense	5060			
Meter Expense	5065	$	6,104.50	31
Customer Premises - Operation Labour	5070	$	34,674.39	31
Customer Premises - Materials and Expenses	5075	$	1,323.25	31
Miscellaneous Distribution Expense	5085	$	7,308.58	31
Underground Distribution Lines and Feeders - Rental Paid	5090			
Overhead Distribution Lines and Feeders - Rental Paid	5095	$	14,657.83	31
Other Rent	5096			
Maintenance Supervision and Engineering	5105	$	71,465.34	32
Maintenance of Buildings and Fixtures - Distribution Static	5110	$	7,368.14	32
Maintenance of Transformer Station Equipment	5112			
Maintenance of Distribution Station Equipment	5114	$	3,262.59	32
Maintenance of Poles, Towers and Fixtures	5120	$	14,126.84	32
Maintenance of Overhead Conductors and Devices	5125	$	47,908.19	32
Maintenance of Overhead Services	5130	$	58,973.19	32
Overhead Distribution Lines and Feeders - Right of Way	5135	$	51,921.83	32
Maintenance of Underground Conduit	5145			
Maintenance of Underground Conductors and Devices	5150	$	8,994.73	32
Maintenance of Underground Services	5155	$	598.40	32
Maintenance of Line Transformers	5160	$	2,306.46	32
Maintenance of Street Lighting and Signal Systems	5165			
Sentinel Lights - Labour	5170			
Sentinel Lights - Materials and Expenses	5172			
Maintenance of Meters	5175	$	164.79	32
Customer Installations Expenses- Leased Property	5178			
Maintenance of Other Installations on Customer Premise	5195			

Supervision	5305			
Meter Reading Expense	5310	$	70,654.44	REF K
Customer Billing	5315	$	187,750.48	30
Collecting	5320	$	140,802.08	30
Collecting- Cash Over and Short	5325			
Collection Charges	5330			
Bad Debt Expense	5335	$	30,792.49	30
Miscellaneous Customer Accounts Expenses	5340			
Executive Salaries and Expenses	5605	$	18,540.00	29
Management Salaries and Expenses	5610	$	75,133.46	29
General Administrative Salaries and Expenses	5615	$	45,091.59	29
Office Supplies and Expenses	5620	$	79,530.47	29
Administrative Expense Transferred/Credit	5625			
Outside Services Employed	5630	$	62,993.43	29
Property Insurance	5635	$	5,928.12	29
Injuries and Damages	5640	$	10,728.00	29
OMERS Pensions and Benefits	5645	$	4,705.24	29
Employee Pensions and OPEB	5646			
Employee Sick Leave	5647			
Franchise Requirements	5650			
Regulatory Expenses	5655	$	15,994.99	29
General Advertising Expenses	5660	$	300.00	29
Miscellaneous General Expenses	5665	$	1,135.94	29
Rent	5670			
Lease Payment Expense	5672			
Maintenance of General Plant	5675			
Electrical Safety Authority Fees	5680	$	5,090.13	29
Special Purpose Charge Expense	5681			
Independent Market Operator Fees and Penalties	5685			
OM&A Contra	5695			
Depreciation Expense - Property Plant, and Equipment	5705	$	151,428.04	33
Interest on Long Term Debt	6005	$	80,835.93	34
Interest on Debt to Associated Companies	6030	$	67,231.08	34
Other Interest Expense	6035	$	24,424.92	REF H
Allowance For Borrowing Costs Applied to CWIP - Credit	6040			
Allowance For Other Borrowing Costs Applied to CWIP - C	6042			
Interest Expense on Finance Capital Lease Obligations	6045			
Taxes Other Than Income Taxes	6105			
Income Taxes	6110	-$	16,006.00	38
Provision for Deferred Taxes - Income Statement	6115			
Donations	6205	$	2,005.00	29
Life Insurance	6210			
Penalties	6215			
Other Deductions	6225			
Available-for-Sale Financial Asset or Cash Flow Hedge - O	7005			
Pension Actuarial Gains or Losses or Remeasurement Adj	7010	$	13,956.00	42
Current Taxes - Other Comprehensive Income	7020			
Deferred Taxes - Other Comprehensive Income	7025			
Miscellaneous - Other Comprehensive Income	7030			

		-$	65,738.28		
		$	532,037.15	3	
		$	152,113.98	23	
REF A		$	684,151.13		
		$	79,202.00	24	
		$	102,932.00	9	
REF B		$	182,134.00		
		-$	624,902.04	10	
		-$	1,454,593.72	11	
REF C		-$	2,079,495.76		
		-$	86,359.00	12	
		-$	2,071,611.57	18	
REF D		-$	2,157,970.57		
		-$	123,333.38	13	
		-$	137,256.55	14	
REF E		$	-		
		-$	3,419.12	22	
		$	1,323,620.17	8	
REF F		$	1,320,201.05		
		-$	998.00	25	
		-$	1,003,493.11	21	
REF G		-$	1,004,491.11		
		$	2,145.87	29	
		$	22,279.05	36	
REF H		$	24,424.92		
		-$	54,870.97	36	
		-$	6,346.44	35	
REF I		-$	61,217.41		
		-$	6,729,611.00	26	
		$	242,418.99	40	
REF J		-$	6,487,192.01		
		$	70,387.23	30	
		$	267.21	31	
REF K		$	70,654.44		
		$	6,520,156.00	28	
		-$	32,963.99	40	
REF L		$	6,487,192.01		
	5705	$	9,845.50	33	REF L
	4245	-$	9,845.50	37	REF L
		$	42,882.00	39	REF M
		$	42,882.00	41	REF M

Espanola Regional Hydro Distribution Corporation

Filing : 2.1.13
RRR Section: A distributor shall provide in the form and manner required by the Board annually the uniform system of account balances mapped and reconciled to the annual audited financial statements.

2019 Trial Balance Mapped to Audited Financial Statements

Color Legend: Assets Liabilities and Equity Income Statement

Current Assets

Account Description	OEB	Amount	Category
Cash	1005	$ 317,686.84	1
Cash Advances and Working Funds	1010	$ 200.00	1
Interest Special Deposits	1020		
Dividend Special Deposits	1030		
Other Special Deposits	1040		
Term Deposits	1060		
Current Investments	1070		
Customer Accounts Receivable	1100	$ 803,304.82	2
Accounts Receivable - Services	1102		
Accounts Receivable - Recoverable Work	1104	$ 165,103.87	2
Accounts Receivable - Merchandise Jobbing, etc.	1105		
Other Accounts Receivable	1110	$ 257,795.51	2
Accrued Utility Revenues	1120	$ 948,420.10	REF A
Accumulated Provision for Uncollectible Accounts--Credit	1130		
Interest and Dividends Receivable	1140		
Rents Receivable	1150		
Notes Receivable	1170		
Prepayments	1180	$ 118,234.75	4
Miscellaneous Current and Accrued Assets	1190	$ 47,730.00	REF B
Accounts Receivable from Associated Companies	1200		
Notes Receivable from Associated Companies	1210		
Inventory			
Fuel Stock	1305		
Plant Materials and Operating Supplies	1330	$ 48,048.78	5
Merchandise	1340		
Non Rate-Regulated Materials and Supplies	1350		
1 Non-Current Assets			

2019

2019 Audtied Financial Statement Amounts for Statement of Finanacial Position and Statement of Comprehensive Income

	Sum of or proportions of	
Current Assets:		
Cash & Cash Equivalents	1	$ 317,887
Accounts Receivable	2	$ 1,226,204
Unbilled Revenue - Energy Sales	3	$ 532,037
Unbilled Revenue - Distribution	23	$ 152,114
Inventory	5	$ 48,049
Prepaid Expenses	4	$ 118,235
Payment in Lieu of Taxes	24	$ 79,202
Total Current Assets		$ 2,473,728
Non Current Assets:		
PP&E (net amortization)	7	$ 5,283,194
Payment in lieu of deferred taxes	6	$ -
Total Non Current Assets		$ 5,283,194
Total Assets		$ 7,756,921
Regulatory Deferral Account Debit Balances	8	$ 2,660,582
Deferred Tax Associated with Regulatory Deferral Account Balances	9	$ 102,932
Total Assets & Regulatory Deferral Account Debit Balances		**$ 10,520,436**

Non-Current Investments in Non-Associated Companies	1405			
Finance Lease Receivable	1407			
Long Term Receivable - Street Lighting Transfer	1408			
Other Special or Collateral Funds	1410			
Sinking Funds	1415			
Unamortized Debt Expense	1425			
Unamortized Discount on Long-Term Debt--Debit	1445			
Unamortized Deferred Foreign Currency Translation Gains and L	1455			
Other Non-Current Assets	1460	-$	167,980.00	
Portfolio Investments - Associated Companies	1480			
Investment in Equity - Accounted Joint Venture	1481			
Investment in Associated Companies - Significant Influence	1485			
Investment in Subsidiary Companies	1490			
Deferred Taxes - Non-Current Assets	1495	$	-	6
Other Assets and Deferred Charges				
Unrecovered Plant and Regulatory Study Costs	1505			
Other Regulatory Assets	1508	$	1,148,162.10	REF F
Preliminary Survey and Investigation Charges	1510			
Emission Allowance Inventory	1515			
Emission Allowances Withheld	1516			
RCVARetail	1518			
Special Purpose Charge Assessment Variance Account	1521			
Pension & OPEB Forecast Accrual versus Actual Cash Payment D	1522			
Miscellaneous Deferred Debits	1525			
Deferred Losses from Disposition of Utility Plant	1530			
Renewable Connection Capital Deferral Account	1531			
Renewable Connection OM&A Deferral Account	1532			
Renewable Generation Connection Funding Adder Deferral Acc	1533			
1 Smart Grid Capital Deferral Account	1534			

Current Liabilities			
Accounts Payable & Accrued Liabilities	10	-$	754,858
Payable for Energy Purchases	11	-$	1,454,594
Current Porton of Long Term Debt	12	-$	86,359
Total Current Liabilities		-$	2,295,811
Non Current Liabilities			
Customer Deposits	13	-$	221,123
Deferred Revenue	14	-$	137,257
Payment in lieu of deferred taxes	15	$	117,100
Contributions in aid of construction	16	$	-
Employee Future Benefits	17	-$	98,543
Long-term obligations	18	-$	2,071,612
Notes Payable	19	$	100
Total Non Current Liabilities		-$	4,707,145
Shareholder's Equity			
Share Capital	20	$	-
Retained Earnings	21	-$	1,003,493
Accumulated Other Comprehensive Earnings	25	-$	998
Total Liabilities & Shareholder's Equity		-$	1,004,491
Regulatory Deferrral Account Credit Balances	22	-$	526,853
Payment in lieu of deffered tax regualtory liabilities		$	-
		-$	526,853
Total Equity, Liabilities & Regulatory Deferral Account Credit Balances		-$	6,238,489

Smart Grid OM&A Deferral Account	1535			
Smart Grid Funding Adder Deferral Account	1536			
Unamortized Loss on Reacquired Debt	1540			
RCVASTR	1548			
LV Variance Account	1550	-$	215,636.67	22
Smart Metering Entity Charge Variance Account	1551	-$	5,443.21	8
Smart Meter Capital and Recovery Offset Variance Account	1555	$	14,494.86	8
Smart Meter OM&A Variance Account	1556			
Meter Cost Deferral Account	1557			
Board-Approval CDM Variance Account	1567			
LRAM Variance Account	1568			
Extraordinary Event Costs	1572			
Deferred Rate Impact Amounts	1574			
IFRS-CGAAP Transitional PP&E Amounts	1575			
CGAAP Accounting Changes	1576			
RSVA - Wholesale Market Service Charge	1580	-$	86,687.06	22
RSVAONE-TIME	1582			
RSVA - Retail Transmission Network Charge	1584	$	11,124.72	8
RSVA - Retail Transmission Connection Charge	1586	$	913,779.89	8
RSVA - Power (excluding Global Adjustment)	1588	$	361,503.65	8
RSVA - Global Adjustment	1589	-$	221,109.98	22
PILs and Tax Variance for 2006 and Subsequent Years	1592			
Disposition and Recovery/Refund of Regulatory Balances Contr	1595	$	41,502.41	8
Electric Plant and Service - Detailed				
No Records				
A.Intangible Plant				
Organization	1606			

Revenue:			
Energy Sales	26	$	6,729,611
Distribution	27	$	1,630,447
		$	8,360,058
Cost of Energy	28	-$	6,520,156
Gross Profit		$	1,839,902
Operating Expenses:			
General & Administration	29	-$	329,322
Billing & Collecting	30	-$	429,732
Distribution - operations	31	-$	374,289
Distribution - maintenance	32	-$	267,091
depreciation	33	-$	161,274
Interest on long-term obligations and notes payable	34	-$	148,067
		-$	1,709,775
Earnings(loss) befor eother income and payment in lieu of taxes		$	130,127
Other Income:			
Interest	35	$	20,896
Labour,rental,and other charges	36	$	112,275
amortization of contributions in aid of construction	37	$	9,846
		$	143,017
Earnings (loss) before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)		$	273,143

Capital Contributions Paid	1609		
Miscellaneous Intangible Plant	1610	$	3,322,007.00
Computer Software	1611		
Land Rights	1612		
B.Generation Plants			
Land	1615		
Land Rights	1616		
Buildings and Fixtures	1620		
Leasehold Improvements	1630		
Boiler Plant Equipment	1635		
Engines and Engine-Driven Generators	1640		
Turbogenerator Units	1645		
Reservoirs, Dams and Waterways	1650		
Water Wheels, Turbines and Generators	1655		
Roads, Railroads and Bridges	1660		
Fuel Holders, Producers and Accessories	1665		
Prime Movers	1670		
Generators	1675		

Payments in lieu of Taxes:			
Current	38	-$	16,006
Deferred	39	$	42,882
		$	26,876
Net Earnings (loss) before change in regulatory asset & liability balances and other comprehensive earnings(loss)		$	246,267
Change in regulatory assets and liabilities			
Change in regulatory assets and liability account balances related to profit ar	40	-$	209,455
Change in payment in lieu of deferred tax balances related to regulatory asse	41	$	42,882
		-$	166,573
Net Earnings before other comprehensive loss:		$	79,694
Other Comprehensive loss:			
Remeasurement of employee future benefits liability, net of tax	42	$	13,956
Net Loss (Income), beinf Total Comprehensive Loss(Income) for the year		$	65,738

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Land	1805	$	88,880.36	7
Buildings and Fixtures	1808	$	354,801.23	7
Leasehold Improvements	1810			
Transformer Station Equipment - Normally Primary above 50 kV	1815			
Distribution Station Equipment - Normally Primary below 50 kV	1820	$	489,375.19	7
Storage Battery Equipment	1825			
Poles, Towers and Fixtures	1830	$	3,230,230.52	7
Overhead Conductors and Devices	1835	$	2,409,295.84	7
Underground Conduit	1840	$	710,347.16	7
Underground Conductors and Devices	1845	$	409,426.20	7
Line Transformers	1850	$	1,087,720.22	7
Services	1855	$	360,572.01	7
Meters	1860	$	738,154.27	7
Other Installations on Customer's Premises	1865			
Leased Property on Customer Premises	1870			
Street Lighting and Signal Systems	1875			
E.General Plant				
Land	1905			
Buildings and Fixtures	1908			
Leasehold Improvements	1910			
Office Furniture and Equipment	1915	$	64,000.35	7
Computer Equipment - Hardware	1920	$	209,496.80	7
Transportation Equipment	1930	$	443,606.74	7
Stores Equipment	1935	$	10,537.76	7
Tools, Shop and Garage Equipment	1940	$	161,790.56	7
Measurement and Testing Equipment	1945	$	11,947.98	7
Power Operated Equipment	1950			
Communication Equipment	1955	$	19,256.84	7
Miscellaneous Equipment	1960			
Load Management Controls - Customer Premises	1970			
Load Management Controls - Utility Premises	1975			
System Supervisory Equipment	1980			
Sentinel Lighting Rental Units	1985	$	10,120.66	7
Other Tangible Property	1990			
Contributions and Grants - Credit	1995	-$	486,545.08	
Other capital Assets				
Property Under Finance Leases	2005			
Electric Plant Purchased or Sold	2010			
Experimental Electric Plant Unclassified	2020			
Electric Plant and Equipment Leased to Others	2030			
Electric Plant Held for Future Use	2040			
Completed Construction Not Classified--Electric	2050			
Construction Work in Progress--Electric	2055	$	59,631.47	7
Electric Plant Acquisition Adjustment	2060			
Other Electric Plant Adjustment	2065			
Other Utility Plant	2070			
Non Rate-Regulated Utility Property Owned or Under Finance L	2075			
Accumulated Amortization				

Accumulated Depreciation of Electric Utility Plant - Property, Pl	2105	-$	5,585,998.37	7
Accumulated Amortization of Electric Utility Plant - Intangibles	2120			
Accumulated Amortization of Electric Plant Acquisition Adjustm	2140			
Accumulated Depreciation of Other Utility Plant	2160			
Accumulated Depreciation of Non Rate-Regulated Utility Prope	2180			
Total Assets		$	12,618,891.09	
Accounts Payable	2205	-$	1,958,502.81	REF C
Customer Credit Balances	2208	-$	97,790.04	13
Customer Deposits	2210	-$	227,359.98	REF E
Dividends Declared	2215			
Miscellaneous Current and Accrued Liabilities	2220	-$	33.57	10
Notes and Loans Payable	2225	-$	435,000.00	
Accounts Payable to Associated Companies	2240	-$	351,350.93	
Notes Payable to Associated Companies	2242			
Debt Retirement Charges(DRC) Payable	2250			
Transmission Charges Payable	2252			
Electrical Safety Authority Fees Payable	2254			
Independent Electricity System Operator Fees and Penalties Pay	2256			
Current Long Term Debt	2260			
OMERS - Current	2264			
Non-OMERS - Current	2265			
Accrued Interest on Long Term Debt	2268			
Matured Long Term Debt	2270			
Matured Interest on Long Term Debt	2272			
Obligations Under Finance Leases - Current	2285			
Commodity Taxes	2290	-$	25,902.92	10
Payroll Deductions / Expenses Payable	2292	-$	104,019.66	10
Accrual for Taxes Payments in Lieu of Taxes, Etc.	2294			
Accumulated Provision for Injuries and Damages	2305			
OPEB Liability	2306			
Other Pensions Liability	2308			
Vested Sick Leave Liability	2310	-$	98,543.00	17
Past Service Costs - Other Post-Employment Benefits	2312			
Past Service Costs - Other Pension Plans	2313			
Accumulated Provision for Rate Refunds	2315			
Other Miscellaneous Non-Current Liabilities	2320			
Obligations Under Finance Lease - Non-Current	2325			
Non-Current Customer Deposits	2335			
Collateral Funds Liability	2340			
Unamortized Premium on Long Term Debt	2345			
OMERS - Long-Term	2348			
Deferred Tax - Non-Current Liability	2350	$	117,100.03	15
Other Regulatory Liabilities or Credits	2405			
Deferred Gains from Disposition of Utility Plant	2410			
Unamortized Gain on Reacquired Debt	2415			
Other Deferred Credits	2425			
Accrued Rate-Payer Benefit	2435			
Deferred Revenues	2440			16
Debentures Outstanding - Long Term	2505			
Debenture Advances	2510			
Reacquired Bonds	2515			
Other Non-Current Debt	2520	-$	9,907,801.17	REF D
Term Bank Loans - Long Term	2525			
Advances from Associated Companies	2550	$	100.00	19

Common Shares Issued	3005	-$	100.00	
Preference Shares Issued	3008	$	-	20
Contributed Surplus	3010			
Donations Received	3020			
Development Charges Transferred to Equity	3022			
Capital Stock Held in Treasury	3026			
Miscellaneous Paid-In Capital	3030			
Installments Received on Capital Stock	3035			
Appropriated Retained Earnings	3040			
Unappropriated Retained Earnings	3045	$	231,377.59	REF G
Appropriations of Retained Earnings - Current Period	3047			
Dividends Payable-Preference Shares	3048			
Dividends Payable-Common Shares	3049			
Adjustment to Retained Earnings	3055			
Unappropriated Undistributed Subsidiary Earnings	3065			
Non Rate-Regulated Utility Shareholders' Equity	3075			
Current Taxes - Shareholders' Equity	3080			
Deferred Taxes - Shareholders' Equity	3081			
Accumulated Other Comprehensive Income	3090			
Balance Transferred From Income	3046	$	233,969.61	REF G
Total Liabilities and shareholder's equity		-$	12,623,856.85	
Residential Energy Sales	4006	-$	3,616,352.27	REF J
Commercial Energy Sales	4010			
Industrial Energy Sales	4015			
Energy Sales to Large Users	4020			
Street Lighting Energy Sales	4025	-$	21,781.25	REF J
Sentinel Lighting Energy Sales	4030	-$	2,632.45	REF J
General Energy Sales	4035	-$	1,505,419.84	REF J
Other Energy Sales to Public Authorities	4040			
Revenue Adjustment	4050			
Energy Sales For Retailers/Others	4055	-$	300,581.95	REF J
Interdepartmental Energy Sales	4060			
Billed WMS	4062	-$	238,508.86	REF J
Billed - WMS-ONE-TIME	4064			
Billed NW	4066	-$	365,865.56	REF J
Billed CN	4068	-$	230,208.71	REF J
Billed - LV	4075	-$	183,647.45	REF J
Billed – Smart Metering Entity Charge	4076	-$	22,193.67	REF J
Distribution Services Revenue	4080	-$	1,625,817.32	27
Retail Services Revenues	4082	-$	4,621.60	27
Service Transaction Requests (STR) Revenues	4084	-$	7.75	27
SSS Administration Revenue	4086			
Electric Services Incidental to Energy Sales	4090			
Transmission Charges Revenue	4105			
Transmission Services Revenue	4110			

Interdepartmental Rents	4205			
Rent from Electric Property	4210	-$	39,674.49	36
Other Utility Operating Income	4215			
Other Electric Revenues	4220			
Late Payment Charges	4225	-$	14,549.46	35
Sales of Water and Water Power	4230			
Miscellaneous Service Revenues	4235	-$	33,631.20	36
Provision for Rate Refunds	4240			
Government and Other Assistance Directly Credited to Income	4245			
Regulatory Debits	4305			
Regulatory Credits	4310			
Revenues from Electric Plant Leased to Others	4315			
Expenses of Electric Plant Leased to Others	4320			
Special Purpose Charge Recovery	4324			
Revenues from Merchandise	4325	-$	5,944.50	36
Costs and Expenses of Merchandising	4330			
Profits and Losses from Financial Instrument Hedges	4335			
Profits and Losses from Financial Instrument Investments	4340			
Gains from Disposition of Future Use Utility Plant	4345			
Losses from Disposition of Future Use Utility Plant	4350			
Gain on Disposition of Utility and Other Property	4355			
Gain from Retirement of Utility and Other Property	4357			
Loss on Disposition of Utility and Other Property	4360			
Loss from Retirement of Utility and Other Property	4362			
Gains from Disposition of Allowances for Emission	4365			
Losses from Disposition of Allowances for Emission	4370			
Revenues from Non Rate-Regulated Utility Operations	4375	-$	174,825.50	36
Expenses of Non Rate-Regulated Utility Operations	4380	$	174,392.41	36
Non Rate-Regulated Utility Rental Income	4385			
Miscellaneous Non-Operating Income	4390			
Rate-Payer Benefit Including Interest	4395			
Foreign Exchange Gains and Losses, Including Amortization	4398			
Interest and Dividend Income	4405	-$	61,217.41	REF I
Lessor's Net Investment in Finance Lease	4410			
Equity in Earnings of Subsidiary Companies	4415			
Share of Profit or Loss of Joint Venture	4420			

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Power Purchased	4705	$	5,446,767.76	REF L	
Charges - Global Adjustment	4707				
Charges-WMS	4708	$	238,508.86	REF L	
Cost of Power Adjustments	4710				
Charges-One-Time	4712				
Charges-NW	4714	$	365,865.56	REF L	
System Control and Load Dispatching	4715				
Charges-CN	4716	$	230,208.71	REF L	
Other Expenses	4720				
Charges - LV	4750	$	183,647.45	REF L	
Charges – Smart Metering Entity Charge	4751	$	22,193.67	REF L	
Operation Supervision and Engineering	5005	$	72,015.10		31
Load Dispatching	5010				
Station Buildings and Fixtures Expense	5012	$	2,711.68		31
Transformer Station Equipment - Operation Labour	5014				
Transformer Station Equipment - Operation Supplies and Expen:	5015				
Distribution Station Equipment - Operation Labour	5016	$	12,683.02		31
Distribution Station Equipment - Operation Supplies and Expens	5017	$	21,534.90		31
Overhead Distribution Lines and Feeders - Operation Labour	5020	$	63,063.89		31
Overhead Distribution Lines and Feeders - Operation Supplies ar	5025	$	42,520.29		31
Overhead Subtransmission Feeders - Operation	5030				
Overhead Distribution Transformers- Operation	5035	$	18,844.66		31
Underground Distribution Lines and Feeders - Operation Labour	5040	$	41,263.32		31
Underground Distribution Lines and Feeders - Operation Supplie	5045	$	23,821.82		31
Underground Subtransmission Feeders - Operation	5050				
Underground Distribution Transformers - Operation	5055	$	11,494.98		31
Street Lighting and Signal System Expense	5060				
Meter Expense	5065	$	6,104.50		31
Customer Premises - Operation Labour	5070	$	34,674.39		31
Customer Premises - Materials and Expenses	5075	$	1,323.25		31
Miscellaneous Distribution Expense	5085	$	7,308.58		31
Underground Distribution Lines and Feeders - Rental Paid	5090				
Overhead Distribution Lines and Feeders - Rental Paid	5095	$	14,657.83		31
Other Rent	5096				
Maintenance Supervision and Engineering	5105	$	71,465.34		32
Maintenance of Buildings and Fixtures - Distribution Stations	5110	$	7,368.14		32
Maintenance of Transformer Station Equipment	5112				
Maintenance of Distribution Station Equipment	5114	$	3,262.59		32
Maintenance of Poles, Towers and Fixtures	5120	$	14,126.84		32
Maintenance of Overhead Conductors and Devices	5125	$	47,908.19		32
Maintenance of Overhead Services	5130	$	58,973.19		32
Overhead Distribution Lines and Feeders - Right of Way	5135	$	51,921.83		32
Maintenance of Underground Conduit	5145				
Maintenance of Underground Conductors and Devices	5150	$	8,994.73		32
Maintenance of Underground Services	5155	$	598.40		32
Maintenance of Line Transformers	5160	$	2,306.46		32
Maintenance of Street Lighting and Signal Systems	5165				
Sentinel Lights - Labour	5170				
Sentinel Lights - Materials and Expenses	5172				
Maintenance of Meters	5175	$	164.79		32
Customer Installations Expenses- Leased Property	5178				
Maintenance of Other Installations on Customer Premises	5195				

Supervision	5305			
Meter Reading Expense	5310	$	70,654.44	REF K
Customer Billing	5315	$	187,750.48	30
Collecting	5320	$	140,802.08	30
Collecting- Cash Over and Short	5325			
Collection Charges	5330			
Bad Debt Expense	5335	$	30,792.49	30
Miscellaneous Customer Accounts Expenses	5340			
Executive Salaries and Expenses	5605	$	18,540.00	29
Management Salaries and Expenses	5610	$	75,133.46	29
General Administrative Salaries and Expenses	5615	$	45,091.59	29
Office Supplies and Expenses	5620	$	79,530.47	29
Administrative Expense Transferred/Credit	5625			
Outside Services Employed	5630	$	62,993.43	29
Property Insurance	5635	$	5,928.12	29
Injuries and Damages	5640	$	10,728.00	29
OMERS Pensions and Benefits	5645	$	4,705.24	29
Employee Pensions and OPEB	5646			
Employee Sick Leave	5647			
Franchise Requirements	5650			
Regulatory Expenses	5655	$	15,994.99	29
General Advertising Expenses	5660	$	300.00	29
Miscellaneous General Expenses	5665	$	1,135.94	29
Rent	5670			
Lease Payment Expense	5672			
Maintenance of General Plant	5675			
Electrical Safety Authority Fees	5680	$	5,090.13	29
Special Purpose Charge Expense	5681			
Independent Market Operator Fees and Penalties	5685			
OM&A Contra	5695			
Depreciation Expense - Property Plant, and Equipment	5705	$	151,428.04	33
Interest on Long Term Debt	6005	$	80,835.93	34
Amortization of Debt Discount and Expense	6010			
Amortization of Premium on Debt/Credit	6015			
Amortization of Loss on Reacquired Debt	6020			
Amortization of Gain on Reacquired Debt--Credit	6025			
Interest on Debt to Associated Companies	6030	$	67,231.08	34
Other Interest Expense	6035	$	24,424.92	REF H
Allowance For Borrowing Costs Applied to CWIP - Credit	6040			
Allowance For Other Borrowing Costs Applied to CWIP - Credit	6042			
Interest Expense on Finance Capital Lease Obligations	6045			
Taxes Other Than Income Taxes	6105			
Income Taxes	6110	-$	16,006.00	38
Provision for Deferred Taxes - Income Statement	6115			
Donations	6205	$	2,005.00	29
Available-for-Sale Financial Asset or Cash Flow Hedge - Other C	7005			
Pension Actuarial Gains or Losses or Remeasurement Adjustmei	7010	$	13,956.00	42
Current Taxes - Other Comprehensive Income	7020			
Deferred Taxes - Other Comprehensive Income	7025			
1 Miscellaneous - Other Comprehensive Income	7030			

		$	532,037.15	3	
		$	152,113.98	23	
REF A		$	684,151.13		
		$	79,202.00	24	
		$	102,932.00	9	
REF B		$	182,134.00		
		-$	624,902.04	10	
		-$	1,454,593.72	11	
REF C		-$	2,079,495.76		
		-$	86,359.00	12	
		-$	2,071,611.57	18	
REF D		-$	2,157,970.57		
		-$	123,333.38	13	
		-$	137,256.55	14	
REF E		$	-		
		-$	3,419.12	22	
		$	1,323,620.17	8	
REF F		$	1,320,201.05		
		-$	998.00	25	
		-$	1,003,493.11	21	
REF G		-$	1,004,491.11		
		$	2,145.87	29	
		$	22,279.05	36	
REF H		$	24,424.92		
		-$	54,870.97	36	
		-$	6,346.44	35	
REF I		-$	61,217.41		
		-$	6,729,611.00	26	
		$	242,418.99	40	
REF J		-$	6,487,192.01		
		$	70,387.23	30	
		$	267.21	31	
REF K		$	70,654.44		
		$	6,520,156.00	28	
		-$	32,963.99	40	
REF L		$	6,487,192.01		
Journal entry that was not made for amortization of contr in aic	5705	$	9,845.50	33	REF L
Amortization of Contributions in aid of construction	4245	-$	9,845.50	37	REF L
		$	42,882.00	39	REF M
		$	42,882.00	41	REF M

1

APPENDIX 1-E
Map of Distribution Service Territory and Service Areas

APPENDIX 1-F
App. 2-AC Customer Engagement Activities Summary

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	**Provide a list of customer needs and preferences identified through each engagement activity**	**Actions taken to respond to identified needs and preferences. If no action was taken, explain why.**
COS-SPECIFIC CUSTOMER ENGAGEMENT		
SURVEYS		
Bi-annual Customer Satisfaction Survey - Residential and Commercial Customers (2015, 2017 & 2019)	In 2015, 2017 and 2019, customer satisfaction surveys were conducted by the third party organization, UtilityPulse, with both residential and commercial customers. **1. Reliability** **2.Better prices / lower rates** **3. Customer communication / online access** **4. Outage Notification**	ERHDC has made improvements such as, but not limited to, the following areas: **1. Reliability** Smart Meter/AMI data utilization for pro-active service delivery Customer Information System (CIS) upgrade to improve services and response times for customers Improvements in vegetation management and infrastructure renewal VPR Partnership for assistance for those in need during emergencies Accountability training to ensure employees work efficiently **3. Customer Communication/Online Access** Customer Connect online platform to view detailed consumption Improvements in customer service; rebranding as Customer Care Customer Care training for management and staff Website upgrades, social media and local media communications Energy conservation promoted via advertising, website, social media COS Customer Engagement Survey **4. Outage Notification** Upgrades to the phone system to handle more calls during outages Atlas Notification System for planned outages Website and media release information Public Notices
Public Awareness of Electrical Safety Survey (2015, 2016 & 2019)	Ensuring the utility can provide safe electrical distribution Education and awareness about electrical safety, equipment, infrastructure Ensuring the utilities' operations are safe for workers and public Ontario One Call - Call Before You Dig Awareness	ERHDC's latest safety awarness score was 85% Website Safety Section Purchase of Promotional "Dig Safe" for the Ontario One Call program "Give 'Em a Brake" marketing for worker safety
FOCUS GROUPS		
COMMUNITY EVENT INTERACTIONS		
Retail Product Consultation Coupon Campaigns	Energy efficient products Conservation home upgrades	Partnerships with local hardware and home supply stores CDM product consultations in-store Promote energy efficient products, how it will help kWh usage Coupons to purchase products Conservation tips/tools available
Festivals (Pumpkin Fest)	Rate information Provincial rebates and regulations Face-to-face interactions with customers Ability to ask questions and have conversations about high costs Individual concerns	CDM promoted HEAR program, initiatives Explained Time-of-Use, Smart Meters, Online Services such as Customer Connect), capital projects, and sign-up customers for programs when eligible Customer Care & CDM reps on-site to answer questions personally

SAFETY		
Marketing Campaigns "Give Our Workers a Brake" and the "Call Before you Dig"	Providing a safe electrical service Ensuring that safety is our top priority with workers/community	Marketing campaigns to promote safety Providing in-house underground utility location services to the community
CUSTOMER CARE		
Customer C.A.R.E. Training	Customers want to be treated fairly Customer-focus and valued Speak with a professional that can resolve their problems	Entire customer service staff underwent customer care training that included: How to ensure is customer centered in everything we do Customer Loyalty Review of Customer Satisfaction survey (UtilityPulse-2017), what actual customers have said they want/need Effective communication, active listening Why customers get upset, resolving customer concerns Also re-branded its Customer Service to Customer Care to improve overall experience for each customer. Customer Care department will take the time to go through a person's bill with them. The representatives will connect customers with an Engineer or Planner to assist with questions related to neighbourhood projects.
Internal Training	Consistent messaging from employees Knowledgeable, professional staff Information about electricity rates, industry changes, government rebates, and conservation program initiatives	Monthly staff meetings (include info about OEB backgrounders, winter disconnections, rate changes) CDM and Line Departments provide Customer Care, Billing and Metering departments with presentations review programs available Line department provides Customer Care department with presentations to help with terminology and understanding of the electrical distribution system
Customer Information System (CIS) and MCare (Electronic Service Orders)	Reliability with services offered Customer satisfaction Overall trust in ERHDC	ERHDC introduced the system upgrades to assist with inefficiencies with metering services, wrong meter readings, and customer billing issues. Upgraded from Harris to NorthStar system Shorter wait times, quicker response Improved communication between customer and Customer Care, to ensure we can provide reliable services for our customers.
Customer Connect	Monitoring consumption Customer control, ability to review bills Needed assistance with understanding bill breakdown How to manage usage, Time-of-Use Help with lowering bills	ERHDC introduced the Customer Connect option Online customer platform for easy access to information Ability to view current and historical data Allows for real-time access so the Customer Care department can analyze customer's bills, review spikes and provide information for better consumption habits based on the individual's usage
Vulnerable Persons' Registry	Disabled customers or customers that experience any type of barrier Emergency services Reliability Ensuring safety is a priority for the community	ERHDC partnered with the Canadian Red Cross Confidential database Alerts Operations and Customer Care whenever an outage may impact a vulnerable person(s). Standard operating procedure includes cooperation with emergency services so ERHDC contacts first responders. Better communication during emergencies Ability to assist those in need, vulnerable/disabled
COMMUNITY SUPPORT		
Community Outreach	Corporate Social Responsibility Donations Event Sponsorships Investments back into the Community	**Pumpkin Festival Sponsorship** **LEAP Program** - Since 2012, donated over $16,000 to help low-income customers pay their electricity bills
COMMUNICATIONS		
Online Communications	Accessibility to information Knowledge of power outages Industry changes Conservation Program Availability Upcoming events, promotions Online services	**Website** - Upgraded to user-friendly, online Customer-focused portal "Customer Connect" for monitored consumption data, tree trimming services, "Call Before You Dig", infrastructure renewal projects, conservation tips, and program initiatives for homes and businesses
Public Notices	Accessibility to information Knowledge of power outages Reliability	ERHDC provides public notices to neighbourhoods in advance of planned major projects that could be impactive to property or service These notices are hand delivered to ensure customers receive them and are aware of any issues that may affect them or their routines
Public Relations / Media Relations	Accessibility to information Power Outage Notification Industry updates, Government rebates Conservation Program Availability Upcoming events, promotions Rate changes	Information provided to local online, print and radio media channels to ensure customers of all demographics receive the same information. Press releases
Advertising	Accessibility to information	Public Service Announcements Time-of-Use ads Conservation tips Tree trimming, worker safety
Bill Inserts	Improve rates Increase communication	ERHDC utilizes bill inserts to communicate regulatory information, new initiatives (such as the Atlas Outage Notification System), Government rebates, CDM programs and eligibility
Paperless Billing (E-Billing)	Reducing environmental impact Online access to bill (current and previous) Convenience	Online resource for customers 24/7 Access with Customer Connect platform (historical & current data) Paperless Billing Campaign is a future initiative to increase enrollment

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APPENDIX 1-G
Customer Engagement Survey

ERH Customer Survey

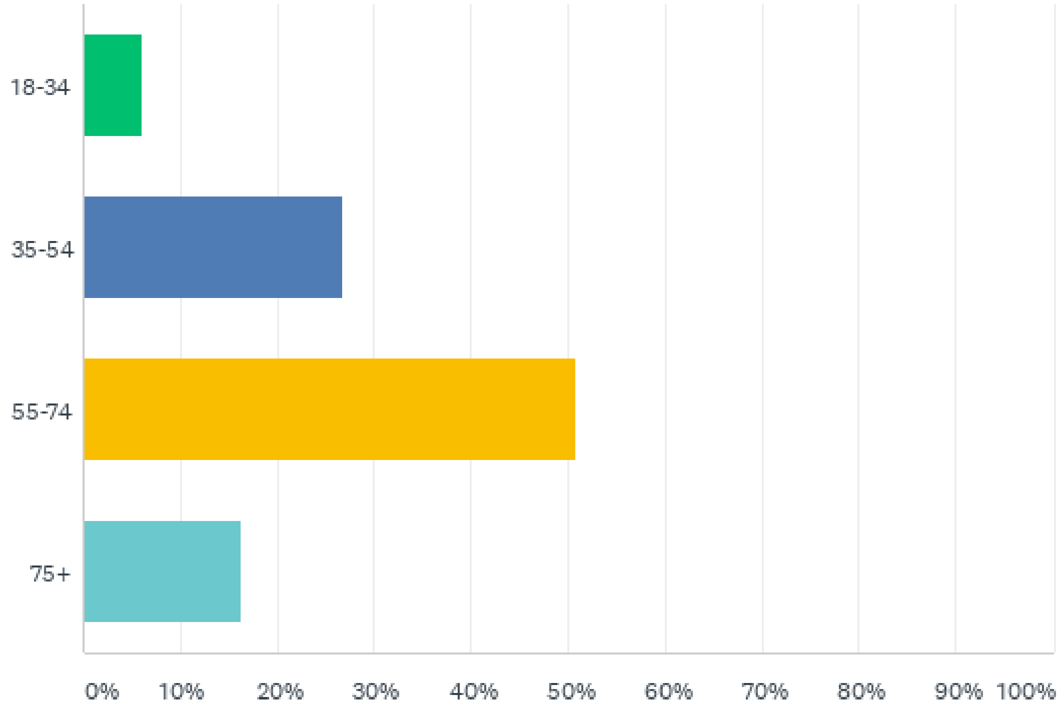
Tuesday, December 01, 2020

67

Total Responses

Date Created: Thursday, November 05, 2020

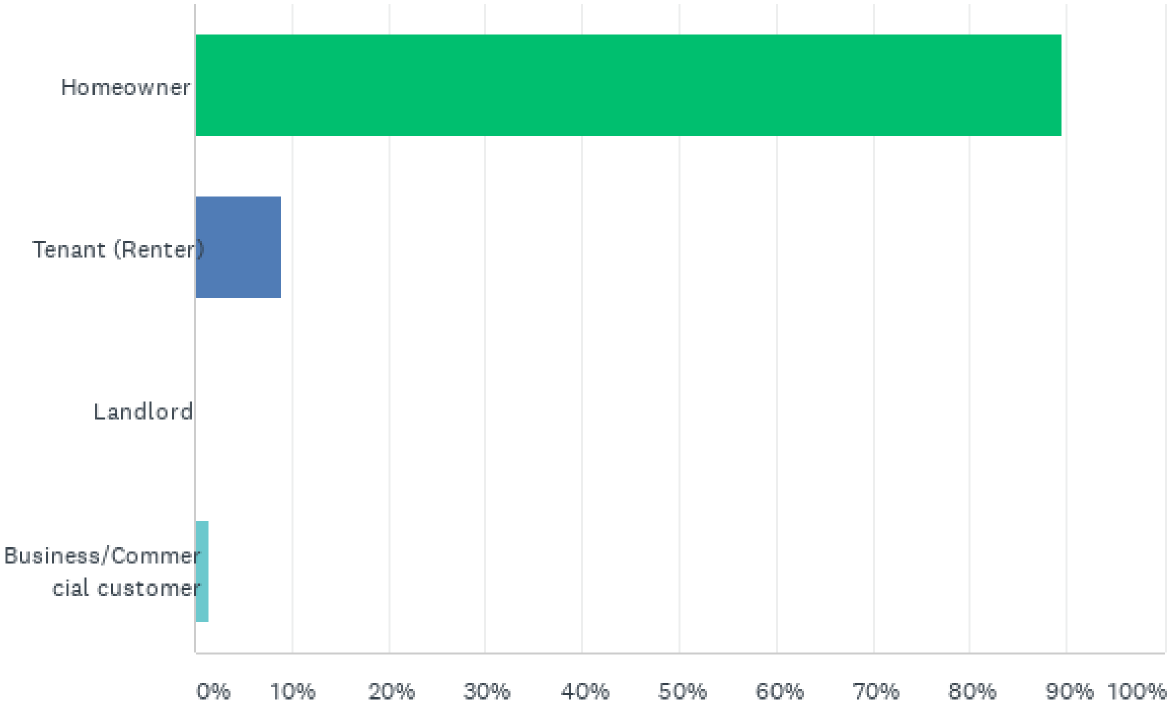
Q2: What is your age range?



Q2: What is your age range?

ANSWER CHOICES	RESPONSES	
18-34	5.97%	4
35-54	26.87%	18
55-74	50.75%	34
75+	16.42%	11
TOTAL		67

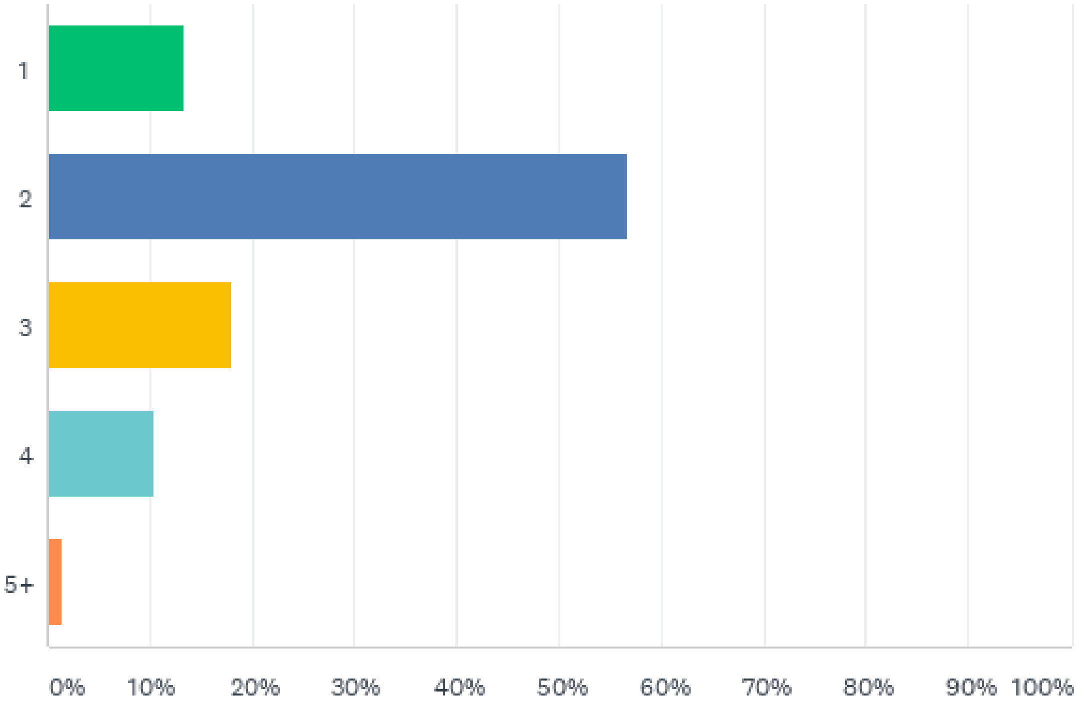
Q3: Which of the following best describes you?



Q3: Which of the following best describes you?

ANSWER CHOICES	RESPONSES	
Homeowner	89.55%	60
Tenant (Renter)	8.96%	6
Landlord	0.00%	0
Business/Commercial customer	1.49%	1
TOTAL		67

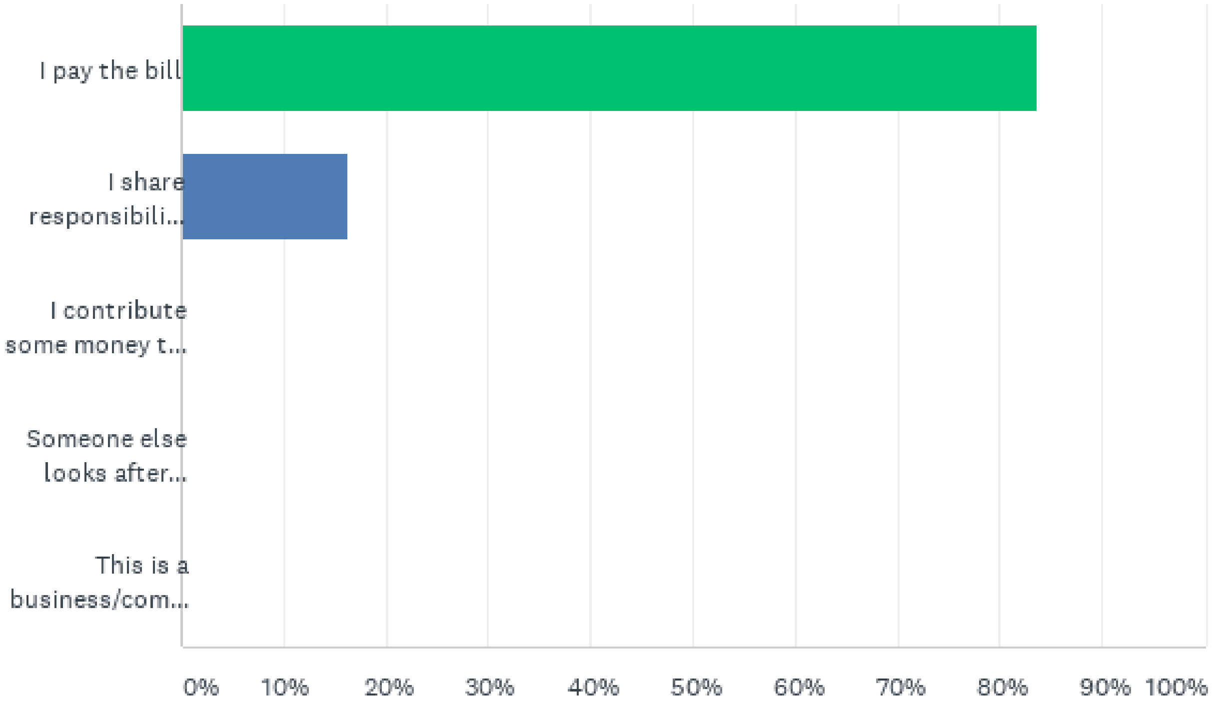
Q4: Including yourself, how many people live in your household, or work in your business?



Q4: Including yourself, how many people live in your household, or work in your business?

ANSWER CHOICES	RESPONSES	
1	13.43%	9
2	56.72%	38
3	17.91%	12
4	10.45%	7
5+	1.49%	1
TOTAL		67

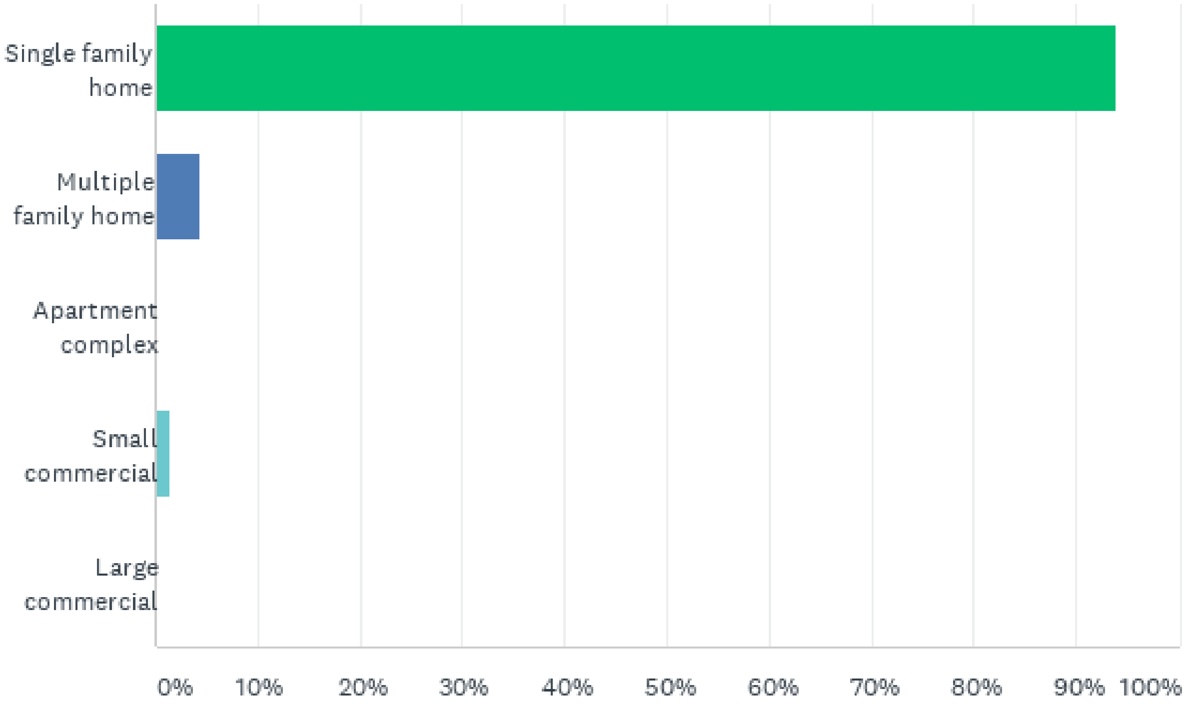
Q5: Which of the following statements best describes your responsibility for paying the electricity bill?



Q5: Which of the following statements best describes your responsibility for paying the electricity bill?

ANSWER CHOICES	RESPONSES	
I pay the bill	83.58%	56
I share responsibility for paying the bill	16.42%	11
I contribute some money to someone else in my household who pays the bill	0.00%	0
Someone else looks after paying the bill	0.00%	0
This is a business/commercial account	0.00%	0
TOTAL		67

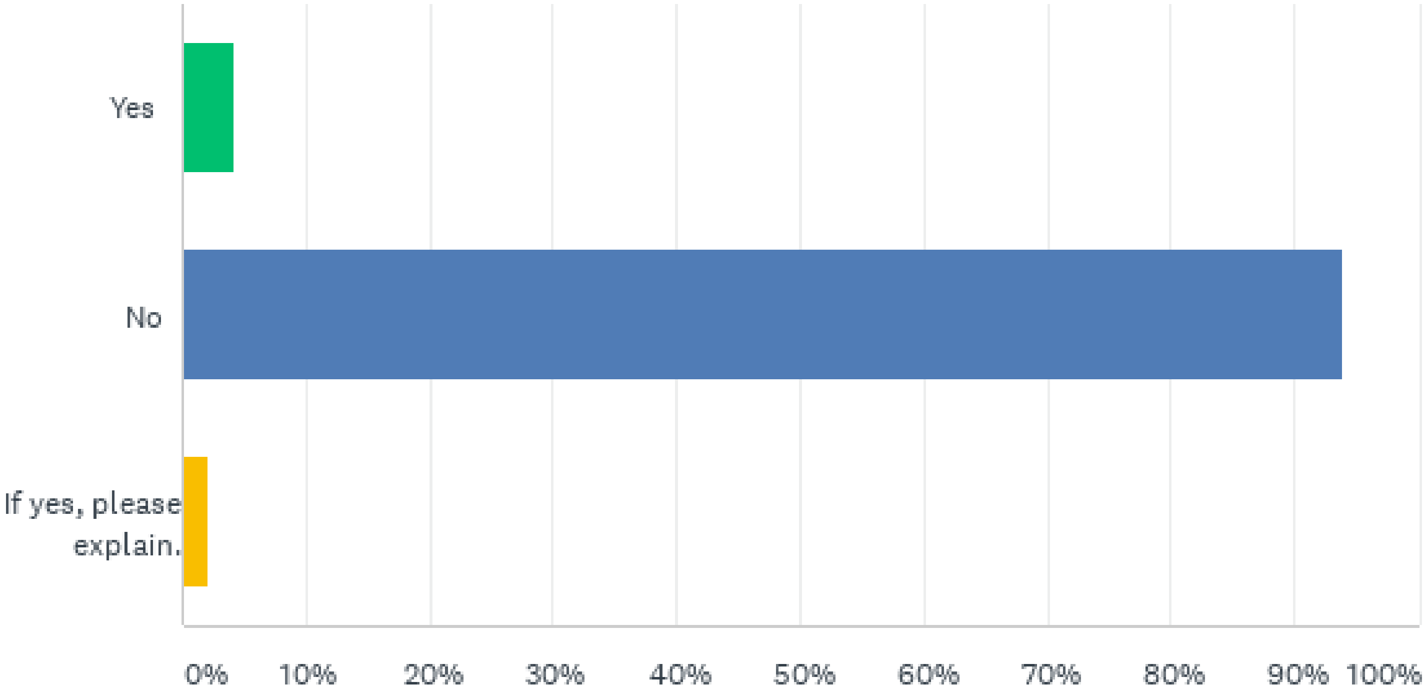
Q6: Which of the following best describes your residence?



Q6: Which of the following best describes your residence?

ANSWER CHOICES	RESPONSES	
Single family home	94.03%	63
Multiple family home	4.48%	3
Apartment complex	0.00%	0
Small commercial	1.49%	1
Large commercial	0.00%	0
TOTAL		67

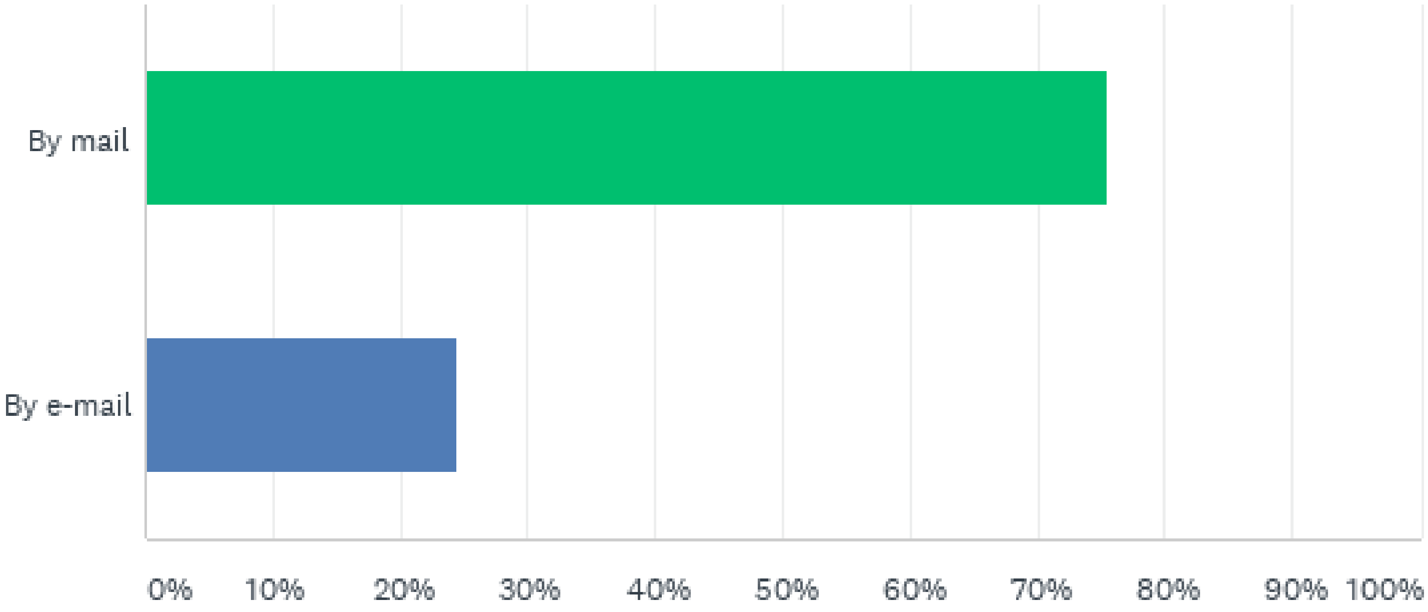
Q7: Have you noticed a reduction or improvements in the level of customer service or communications since October 2019?



Q7: Have you noticed a reduction or improvements in the level of customer service or communications since October 2019?

ANSWER CHOICES	RESPONSES	
Yes	4.08%	2
No	93.88%	46
If yes, please explain.	2.04%	1
TOTAL		49

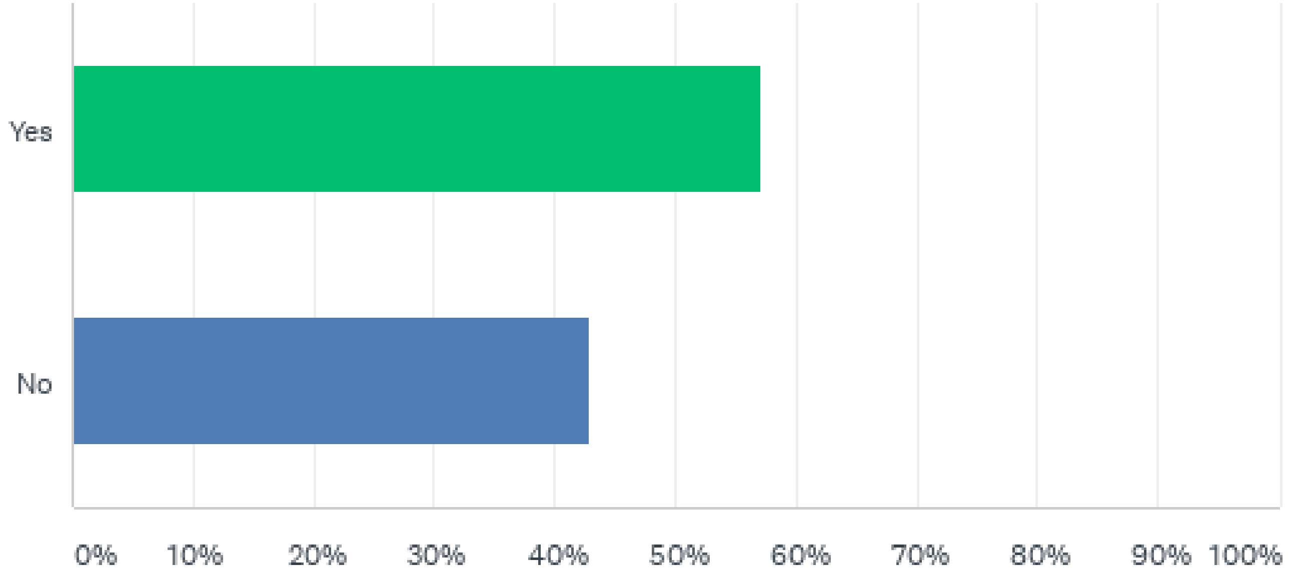
Q8: How do you receive your ERH bill?



Q8: How do you receive your ERH bill?

ANSWER CHOICES	RESPONSES	
By mail	75.51%	37
By e-mail	24.49%	12
TOTAL		49

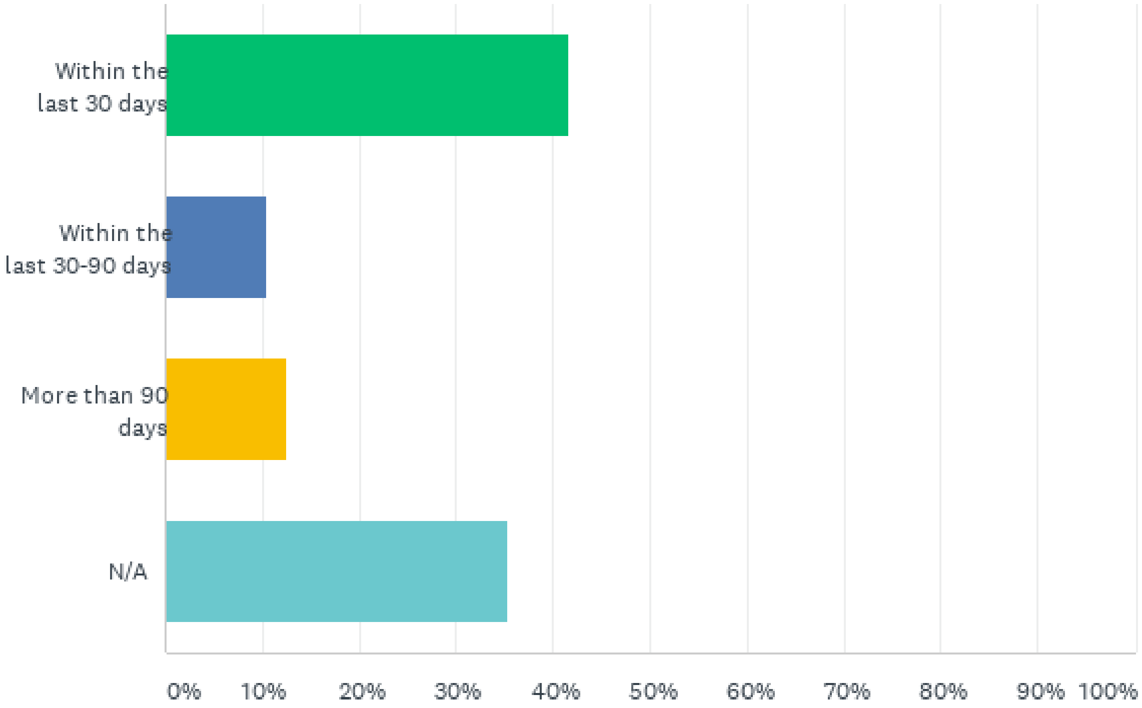
Q9: The ERH website has information on everything from opening a new account, conservation tips and programs, and information on outages. Have you ever visited www.erhydro.com?



Q9: The ERH website has information on everything from opening a new account, conservation tips and programs, and information on outages. Have you ever visited www.erhydro.com?

ANSWER CHOICES	RESPONSES	
Yes	57.14%	28
No	42.86%	21
TOTAL		49

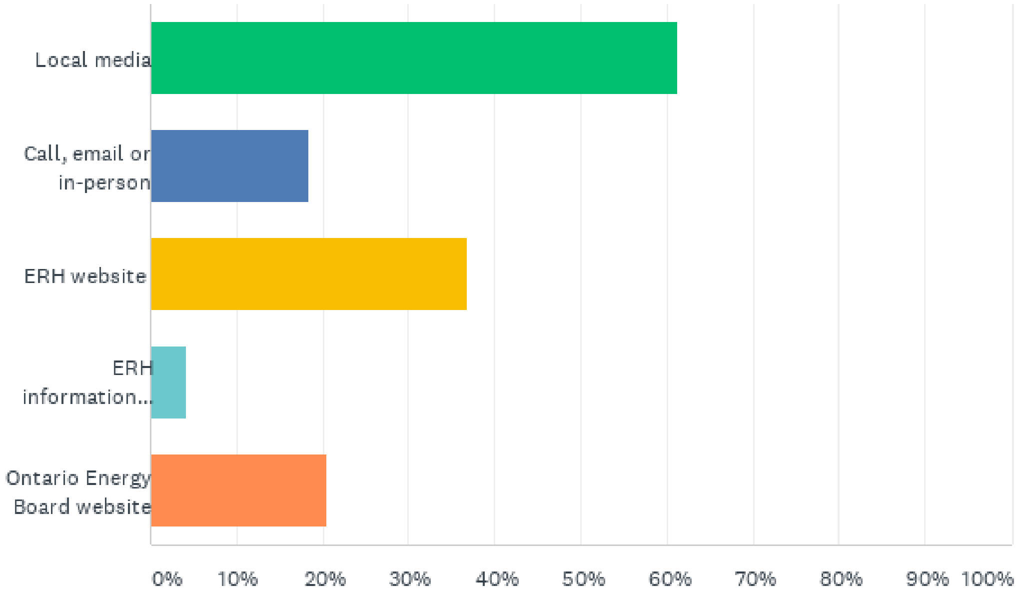
Q10: If so, when was the last time you visited the site?



Q10: If so, when was the last time you visited the site?

ANSWER CHOICES	RESPONSES	
Within the last 30 days	41.67%	20
Within the last 30-90 days	10.42%	5
More than 90 days	12.50%	6
N/A	35.42%	17
TOTAL		48

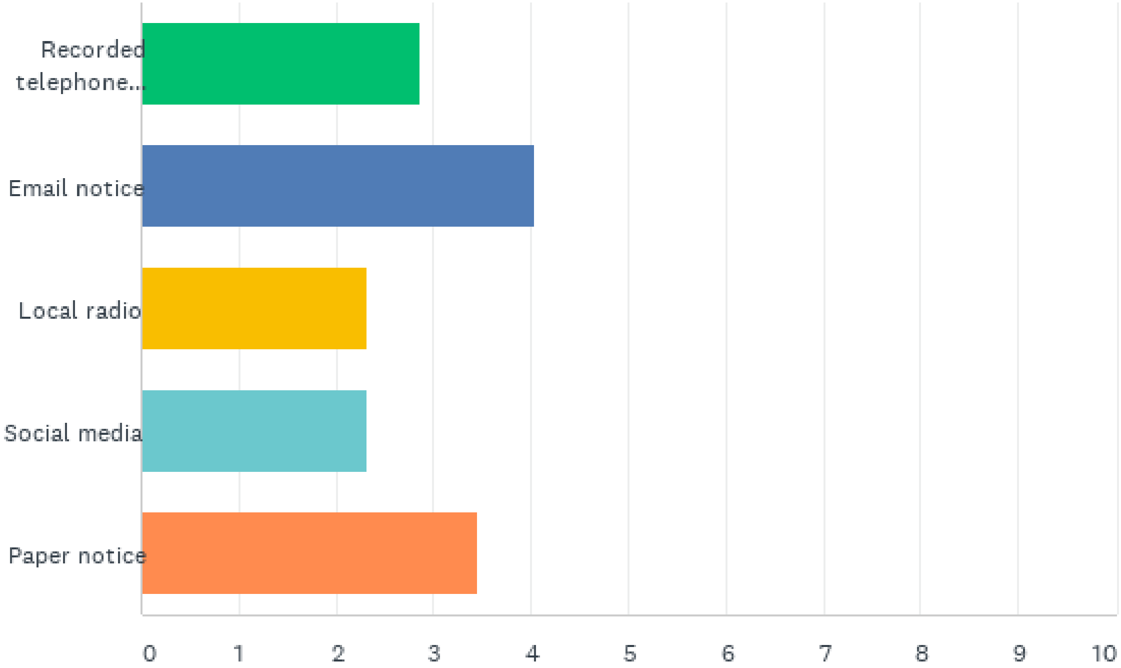
Q11: Where do you currently find information on topics such as: electricity rates, conservation tips and consumption/usage information? Please select ALL that apply.



Q11: Where do you currently find information on topics such as: electricity rates, conservation tips and consumption/usage information? Please select ALL that apply.

ANSWER CHOICES	RESPONSES	
Local media	61.22%	30
Call, email or in-person	18.37%	9
ERH website	36.73%	18
ERH information booths (home/trade shows)	4.08%	2
Ontario Energy Board website	20.41%	10
Total Respondents: 49		

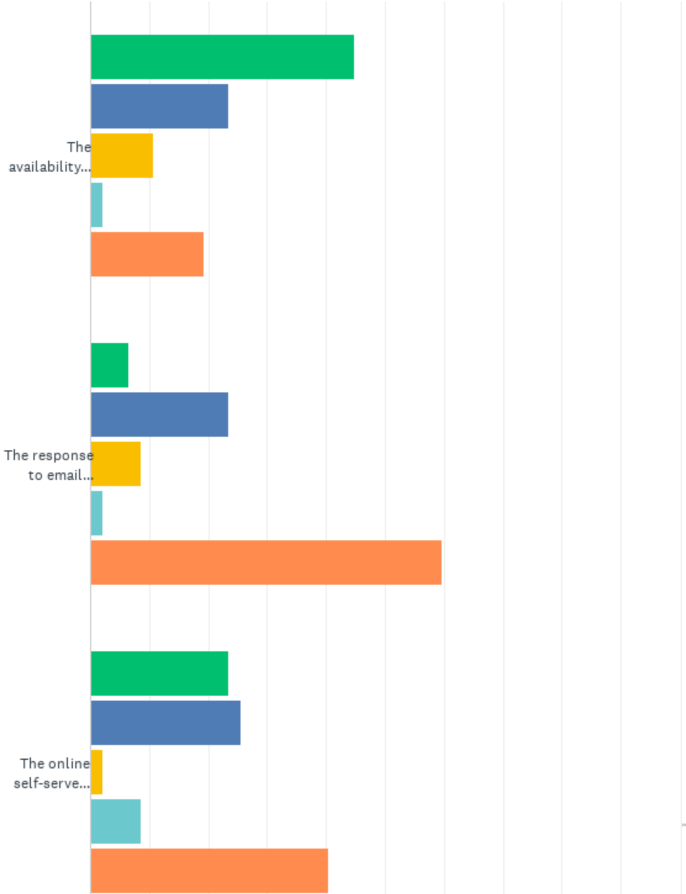
Q12: What is your preferred method for communicating general news? Can you please rank them from most preferred (#1) to least preferred (#5)?



Q12: What is your preferred method for communicating general news? Can you please rank them from most preferred (#1) to least preferred (#5)?

	1	2	3	4	5	TOTAL	SCORE
Recorded telephone message	12.24% 6	26.53% 13	20.41% 10	16.33% 8	24.49% 12	49	2.86
Email notice	48.98% 24	24.49% 12	12.24% 6	10.20% 5	4.08% 2	49	4.04
Local radio	2.04% 1	14.29% 7	26.53% 13	28.57% 14	28.57% 14	49	2.33
Social media	6.12% 3	8.16% 4	24.49% 12	34.69% 17	26.53% 13	49	2.33
Paper notice	30.61% 15	26.53% 13	16.33% 8	10.20% 5	16.33% 8	49	3.45

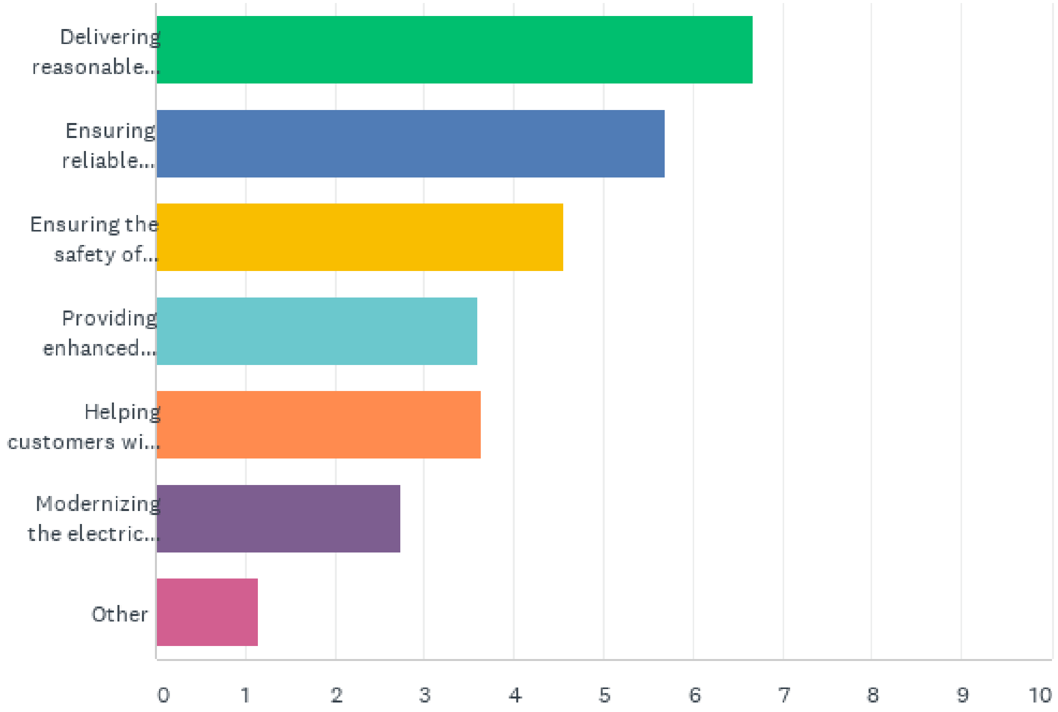
Q13: As it relates to the convenience of accessing services, for each of the following topics, how satisfied are you?



Q13: As it relates to the convenience of accessing services, for each of the following topics, how satisfied are you?

	FAIRLY SATISFIED	NEITHER SATISFIED NO DISSATISFIED	FAIRLY DISSATISFIED	VERY DISSATISFIED	DON'T KNOW	TOTAL
The availability of call centre staff Monday to Friday from 9:00 am to 4:30 pm	44.68% 21	23.40% 11	10.64% 5	2.13% 1	19.15% 9	47
The response to email questions	6.38% 3	23.40% 11	8.51% 4	2.13% 1	59.57% 28	47
The online self-serve options for managing your account	23.40% 11	25.53% 12	2.13% 1	8.51% 4	40.43% 19	47
The online self-serve options for requesting service	8.51% 4	27.66% 13	2.13% 1	8.51% 4	53.19% 25	47

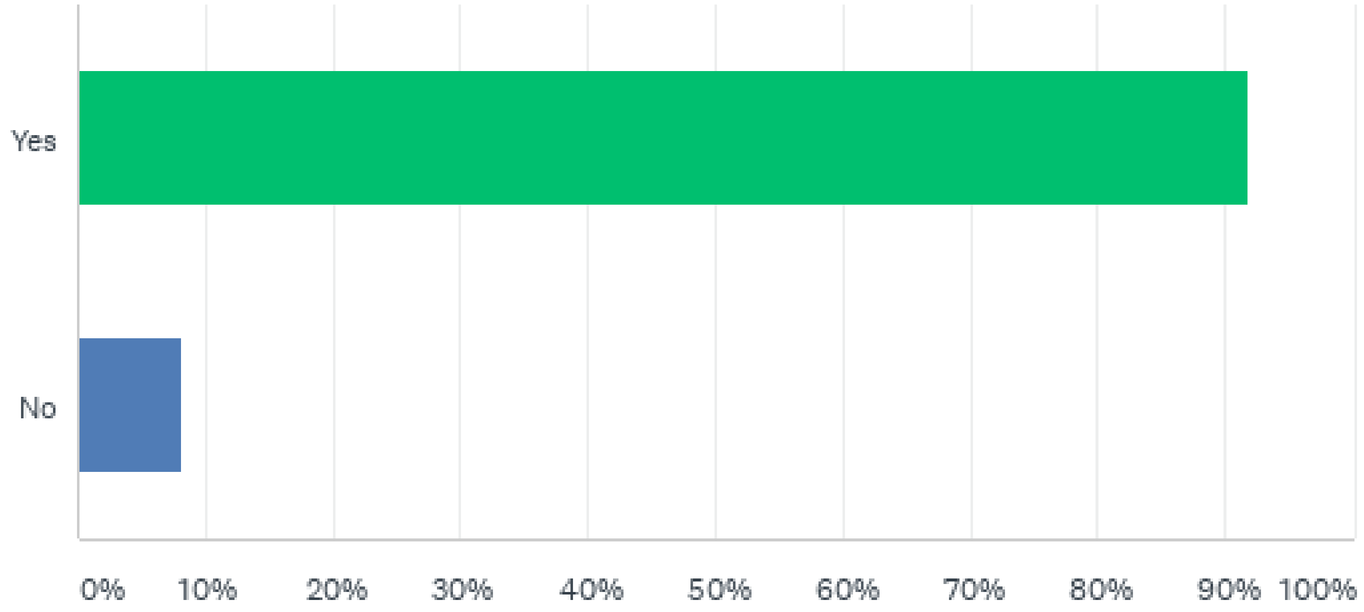
Q14: In an effort to better understand how we should set our priorities moving forward, please answer the following:Please rank your your priorities - where #1 should be the most important.



Q14: In an effort to better understand how we should set our priorities moving forward, please answer the following:Please rank your priorities - where #1 should be the most important.

	1	2	3	4	5	6	7	TOTAL	SCORE
Delivering reasonable electricity prices	73.47% 36	22.45% 11	2.04% 1	2.04% 1	0.00% 0	0.00% 0	0.00% 0	49	6.67
Ensuring reliable electrical service	16.67% 8	56.25% 27	10.42% 5	12.50% 6	4.17% 2	0.00% 0	0.00% 0	48	5.69
Ensuring the safety of electrical infrastructure	4.08% 2	8.16% 4	46.94% 23	24.49% 12	14.29% 7	2.04% 1	0.00% 0	49	4.57
Providing enhanced customer service	0.00% 0	8.33% 4	14.58% 7	29.17% 14	25.00% 12	22.92% 11	0.00% 0	48	3.60
Helping customers with electricity conservation and efficient usage	4.08% 2	4.08% 2	20.41% 10	16.33% 8	36.73% 18	14.29% 7	4.08% 2	49	3.63
Modernizing the electrical system (e.g. electrical vehicles, net metering, etc.) to support the reduction of greenhouse gases and lessen climate change.	2.08% 1	2.08% 1	6.25% 3	14.58% 7	18.75% 9	45.83% 22	10.42% 5	48	2.75
Other	0.00% 0	0.00% 0	0.00% 0	0.00% 0	0.00% 0	14.58% 7	85.42% 41	48	1.15

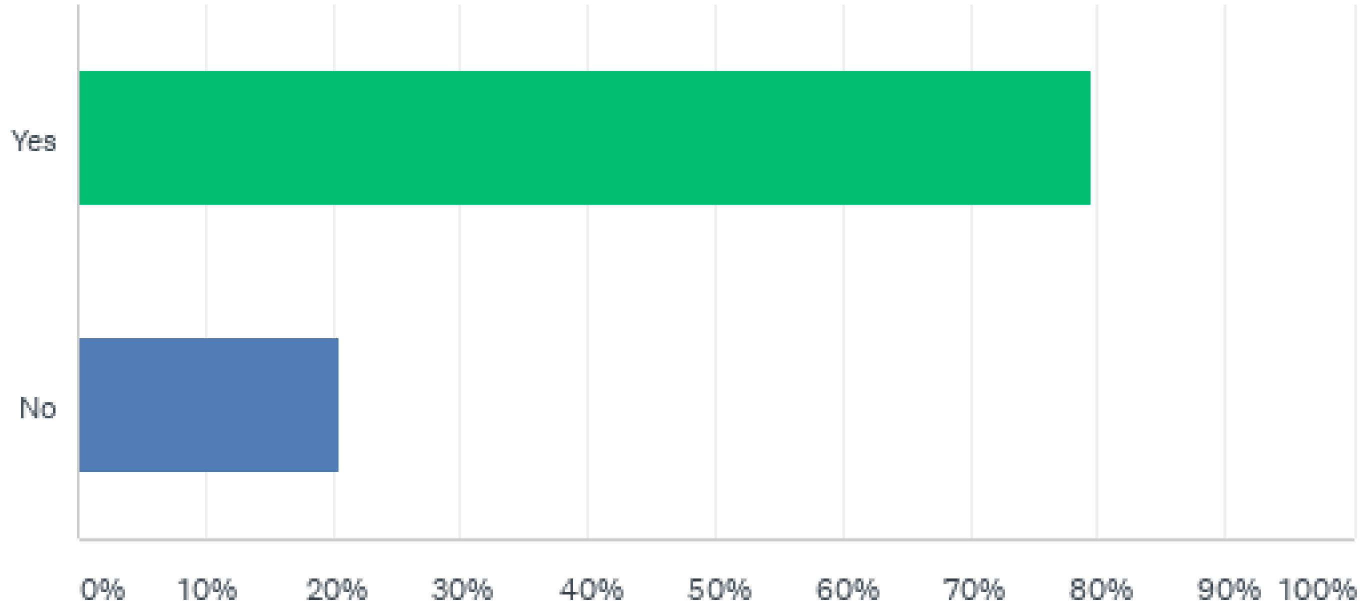
Q17: Should ERH be pro-active in maintaining and upgrading our equipment to ensure electricity is supplied reliably and safely in our network?



Q17: Should ERH be pro-active in maintaining and upgrading our equipment to ensure electricity is supplied reliably and safely in our network?

ANSWER CHOICES	RESPONSES	
Yes	91.84%	45
No	8.16%	4
TOTAL		49

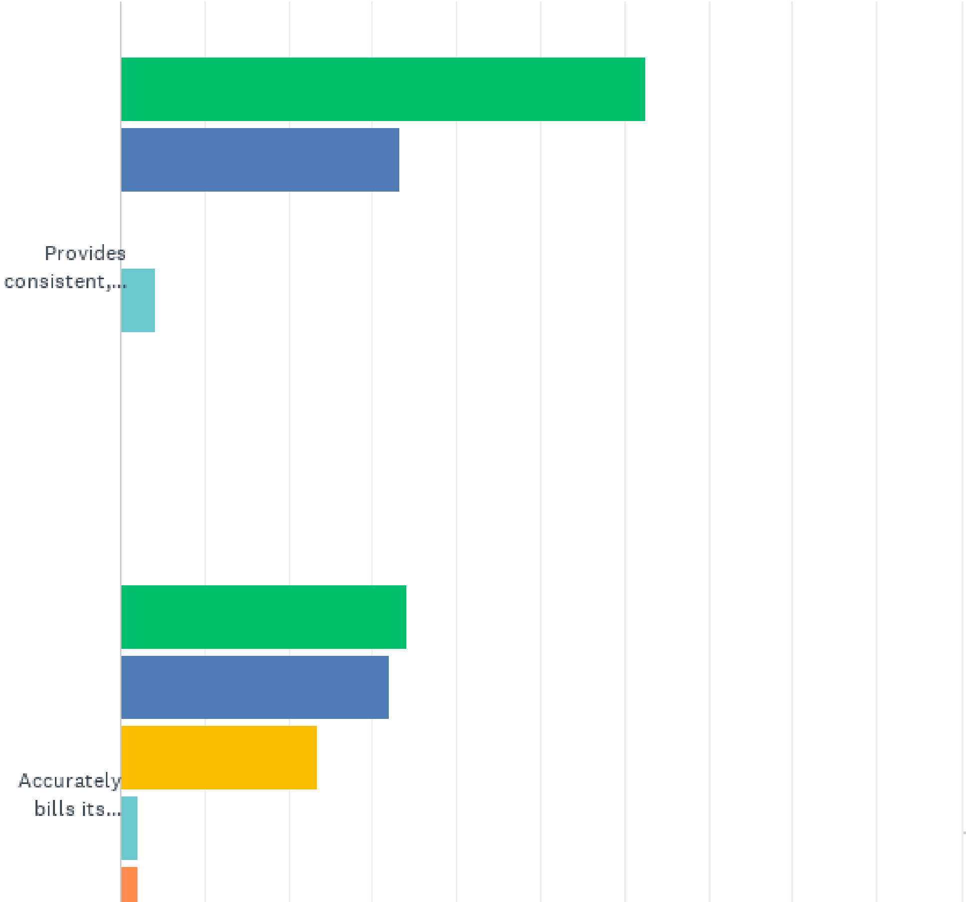
Q18: Would you like to see more updates or communication surrounding future plans of this nature?



Q18: Would you like to see more updates or communication surrounding future plans of this nature?

ANSWER CHOICES	RESPONSES	
Yes	79.59%	39
No	20.41%	10
TOTAL		49

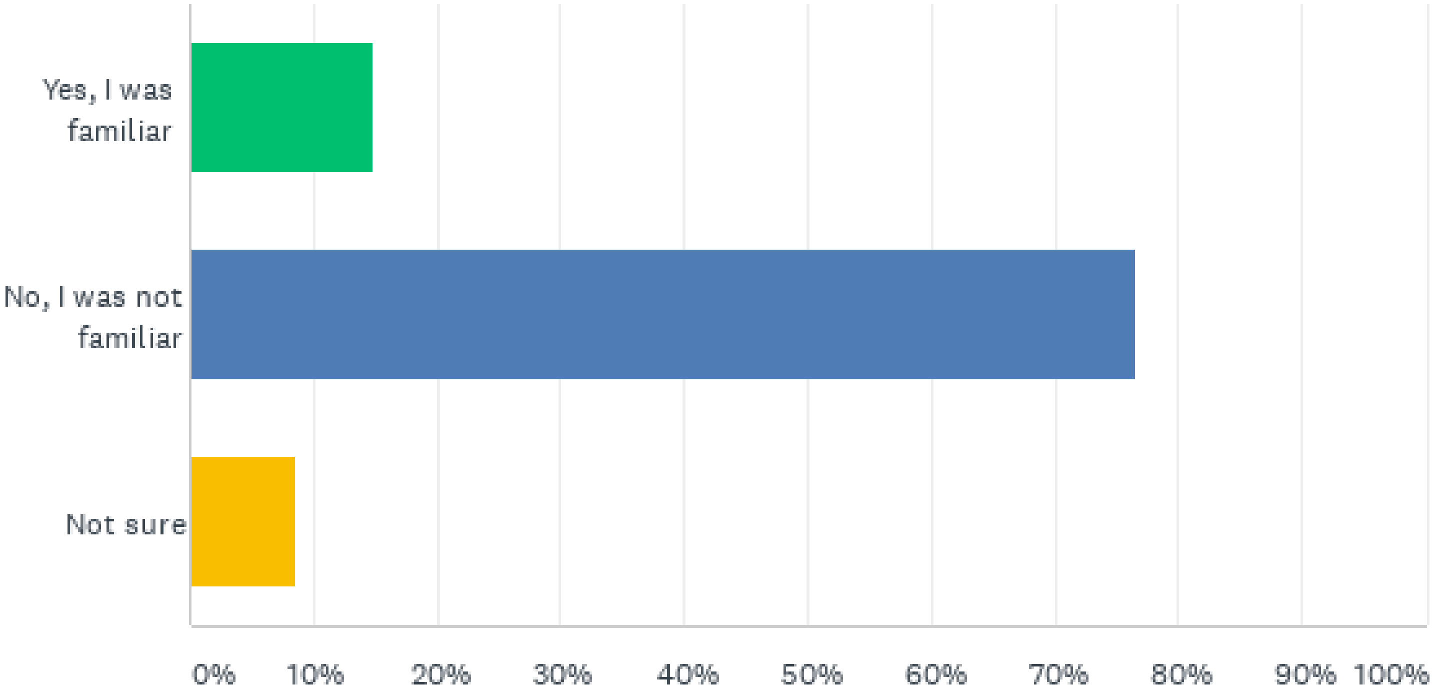
Q19: Please answer the following about ERH Service:



Q19: Please answer the following about ERH Service:

	AGREE STRONGLY	AGREE SOMEWHAT	NEITHER AGREE OR DISAGREE	DISAGREE SOMEWHAT	DISAGREE STRONGLY	DON'T KNOW	TOTAL
Provides consistent, reliable electricity	62.50% 30	33.33% 16	0.00% 0	4.17% 2	0.00% 0	0.00% 0	48
Accurately bills its customers	34.04% 16	31.91% 15	23.40% 11	2.13% 1	2.13% 1	6.38% 3	47
Has a standard of reliability delivering electricity that meets your expectations	50.00% 24	41.67% 20	8.33% 4	0.00% 0	0.00% 0	0.00% 0	48
Quickly handles outages and restores power	52.08% 25	25.00% 12	14.58% 7	2.08% 1	2.08% 1	4.17% 2	48
Communicates information and construction on investment activities	16.67% 8	16.67% 8	31.25% 15	14.58% 7	6.25% 3	14.58% 7	48

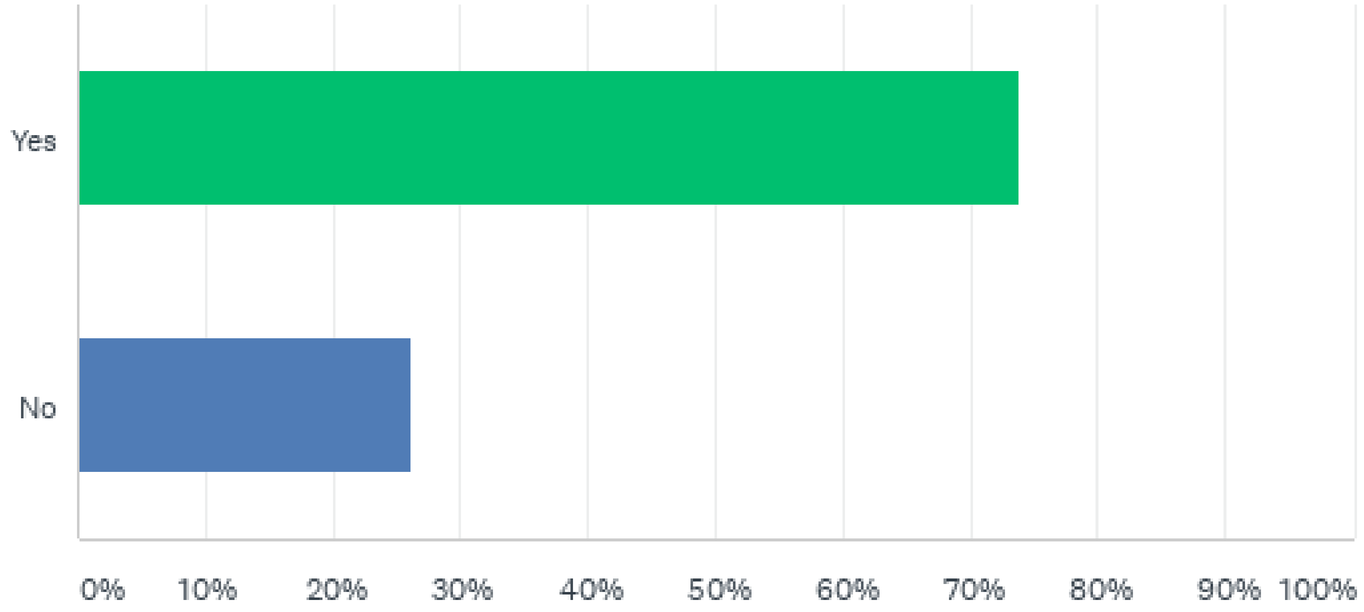
Q20: Before this survey, were you familiar with the percentage of your electricity bill that went to ERH?



Q20: Before this survey, were you familiar with the percentage of your electricity bill that went to ERH?

ANSWER CHOICES	RESPONSES	
Yes, I was familiar	14.89%	7
No, I was not familiar	76.60%	36
Not sure	8.51%	4
TOTAL		47

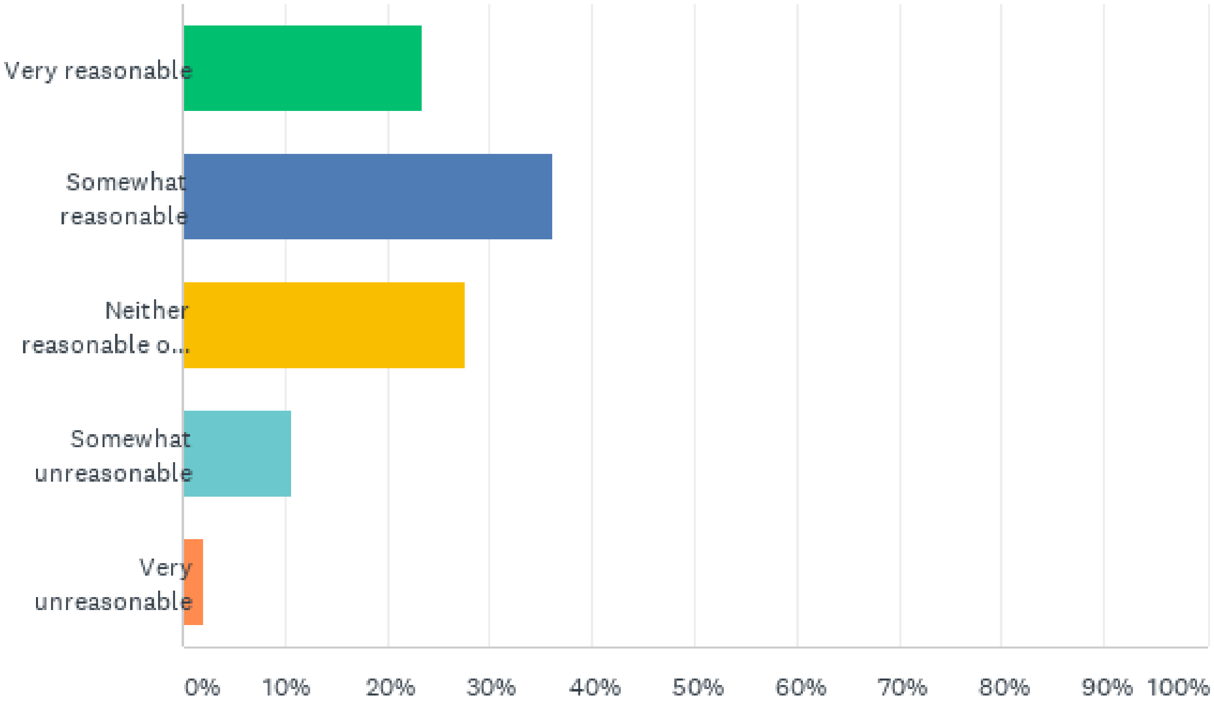
Q21: Would you be interested in learning more details of what ERH does with the 25%?



Q21: Would you be interested in learning more details of what ERH does with the 25%?

ANSWER CHOICES	RESPONSES	
Yes	73.91%	34
No	26.09%	12
TOTAL		46

Q22: Do you think the amount retained by ERH, e.g. $29 on a $119 estimated average residential bill is reasonable to operate and maintain a safe, local electricity service?

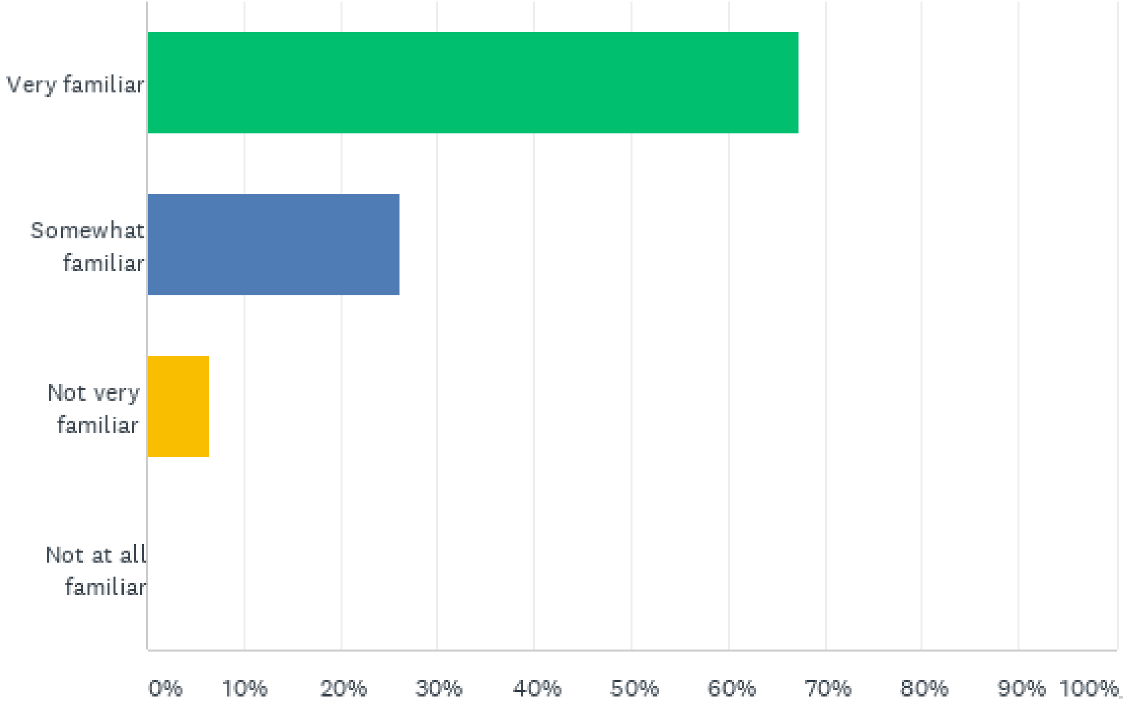


Q[illegible]: Do you think the amount retained by [illegible], e.g. $[illegible] on a $[illegible] estimated average residential bill is reasonable to operate and maintain a safe, local electricity service?

Answered: 47   Skipped: 20

ANSWER CHOICES	RESPONSES	
Very reasonable	23.40%	11
Somewhat reasonable	36.17%	17
Neither reasonable or unreasonable	27.66%	13
Somewhat unreasonable	10.64%	5
Very unreasonable	2.13%	1
TOTAL		47

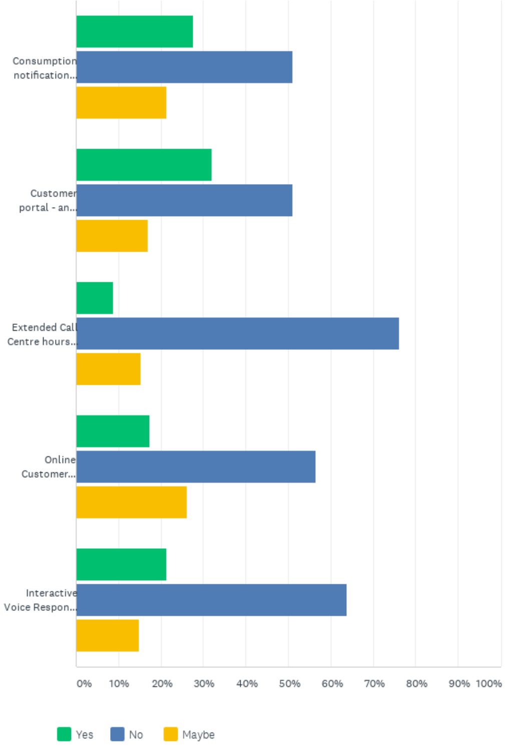
Q23: How familiar are you with the Time-Of-Use information about off-peak, on-peak and mid-peak usage rates? For example, holidays are off-peak and if the holiday is on a weekend then the following weekday is off-peak in lieu of.



Q23: How familiar are you with the Time-Of-Use information about off-peak, on-peak and mid-peak usage rates? For example, holidays are off-peak and if the holiday is on a weekend then the following weekday is off-peak in lieu of.

ANSWER CHOICES	RESPONSES	
Very familiar	67.39%	31
Somewhat familiar	26.09%	12
Not very familiar	6.52%	3
Not at all familiar	0.00%	0
TOTAL		46

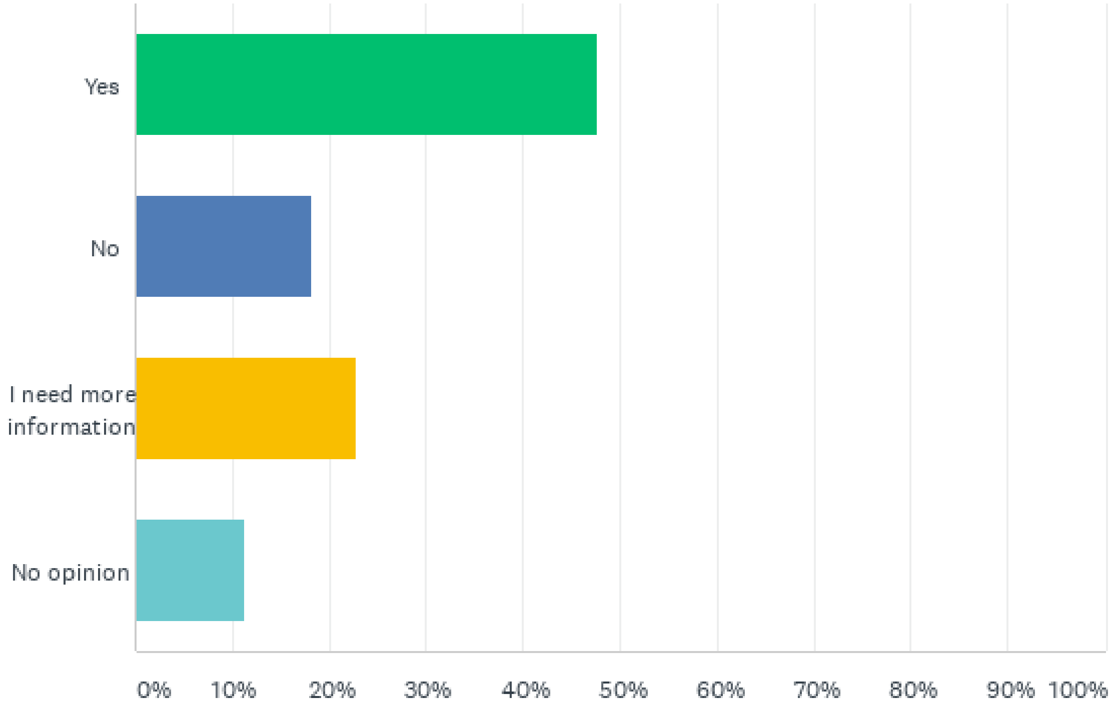
Q24: In addition to the amount you currently pay on your electricity bill, would you be willing to pay for the following customer services?



Q24: In addition to the amount you currently pay on your electricity bill, would you be willing to pay for the following customer services?

	YES	NO	MAYBE	TOTAL
Consumption notification - getting notified via email, text alert when consumption hits certain level	27.66% 13	51.06% 24	21.28% 10	47
Customer portal - an updated customer portal giving more detailed information, billing, usage, outages, etc.	31.91% 15	51.06% 24	17.02% 8	47
Extended Call Centre hours beyond M-F 9:00am - 4:30pm (i.e. 7 days a week 9:00am - 9:00pm)	8.70% 4	76.09% 35	15.22% 7	46
Online Customer Service - live chat with customer service representative during M-F 9:00am - 4:30pm.	17.39% 8	56.52% 26	26.09% 12	46
Interactive Voice Response - telephone system that allows our computer system to interact with customers through a telephone keypad, providing account status, and outage updates.	21.28% 10	63.83% 30	14.89% 7	47

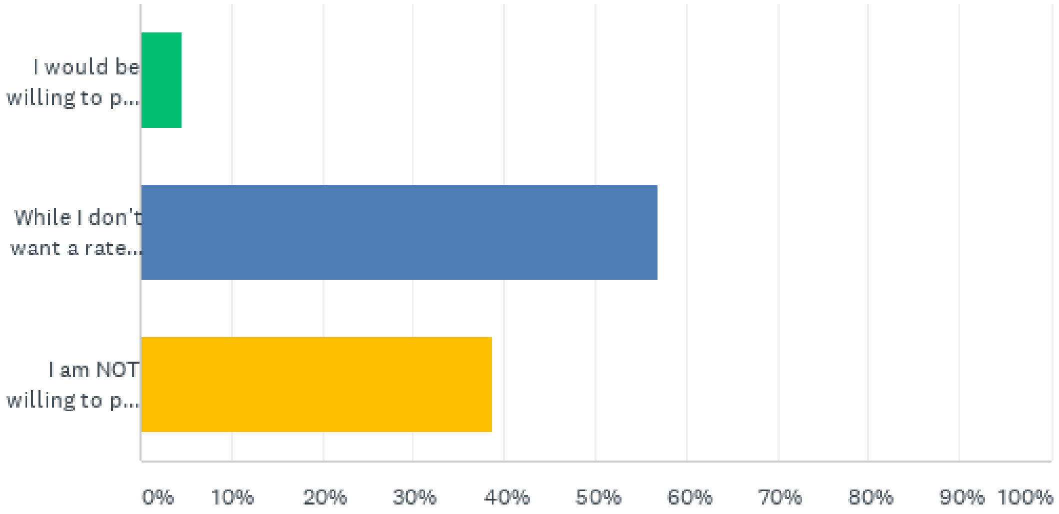
Q25: Now that you're familiar with the rising costs associated with our OM&A and capital needs, do you feel you have a better understanding of the need for a rate increase to cover those costs?



Q25: Now that you're familiar with the rising costs associated with our OM&A and capital needs, do you feel you have a better understanding of the need for a rate increase to cover those costs?

ANSWER CHOICES	RESPONSES	
Yes	47.73%	21
No	18.18%	8
I need more information	22.73%	10
No opinion	11.36%	5
TOTAL		44

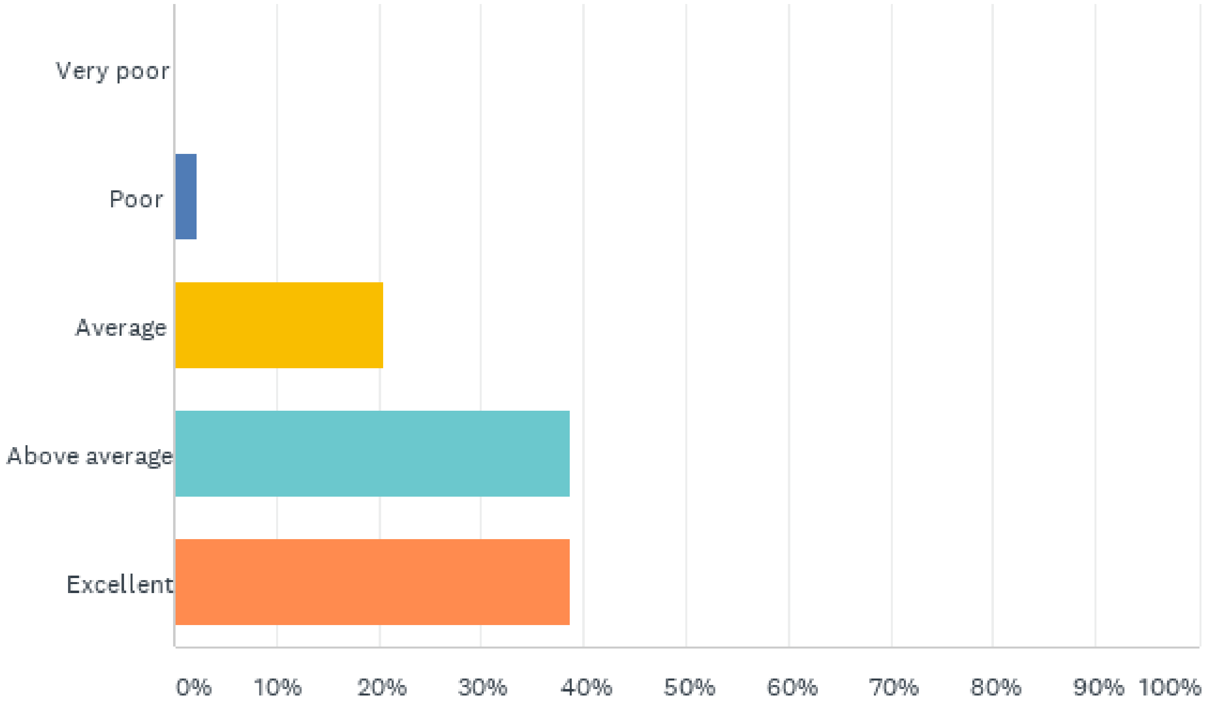
Q26: These cost increases and infrastructure investments will result in a rate increase for ERH customers; estimates at this time are an approximate increase of 8% on a total bill, or about $10/month for an average residential customer. Which statement best represents your point of view?



Q26: These cost increases and infrastructure investments will result in a rate increase for ERH customers; estimates at this time are an approximate increase of 8% on a total bill, or about $10/month for an average residential customer. Which statement best represents your point of view?

ANSWER CHOICES	RESPONSES	
I would be willing to pay any rate increase (e.g. 15%) that allowed ERH to invest as much as possible to improve the reliability and overall performance of the system.	4.55%	2
While I don't want a rate increase, I would be willing to pay the proposed increase on my bill to maintain reliability and service through a dedicated local workforce and well-planned infrastructure renewal.	56.82%	25
I am NOT willing to pay any additional charged on the ERH portion of my bill knowing that the level of reliability and service could decline.	38.64%	17
TOTAL		44

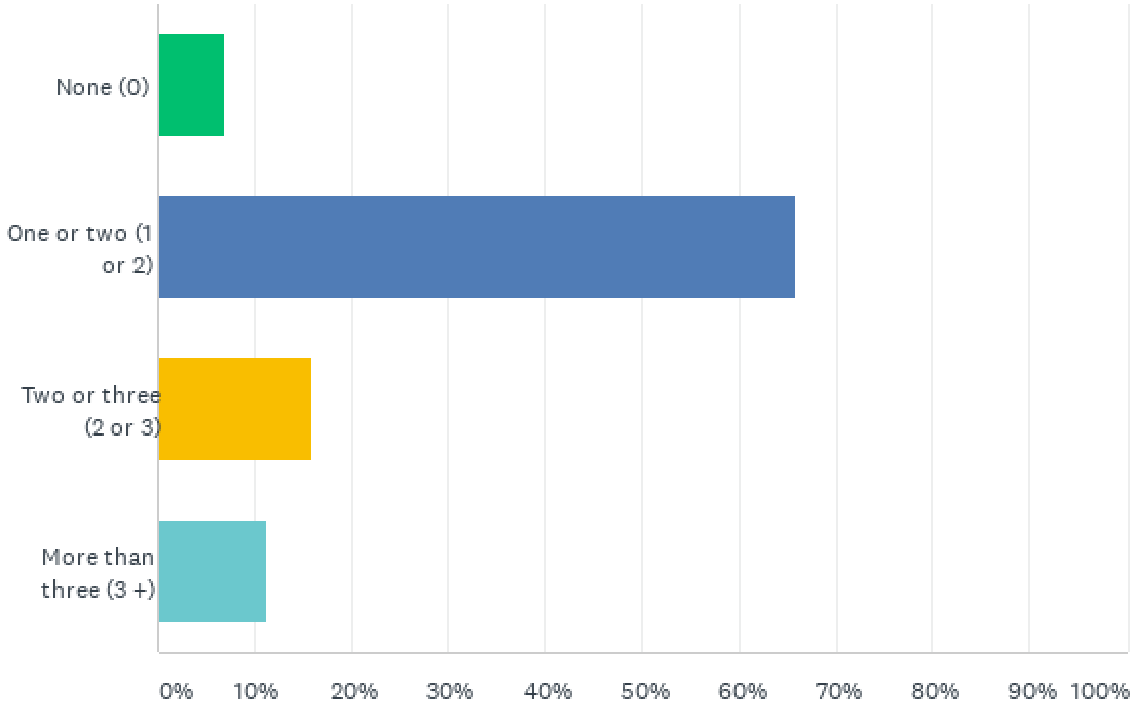
Q27: Please answer the following: ERH reliability of electrical service is:



Q27: Please answer the following: ERH reliability of electrical service is:

ANSWER CHOICES	RESPONSES	
Very poor	0.00%	0
Poor	2.27%	1
Average	20.45%	9
Above average	38.64%	17
Excellent	38.64%	17
TOTAL		44

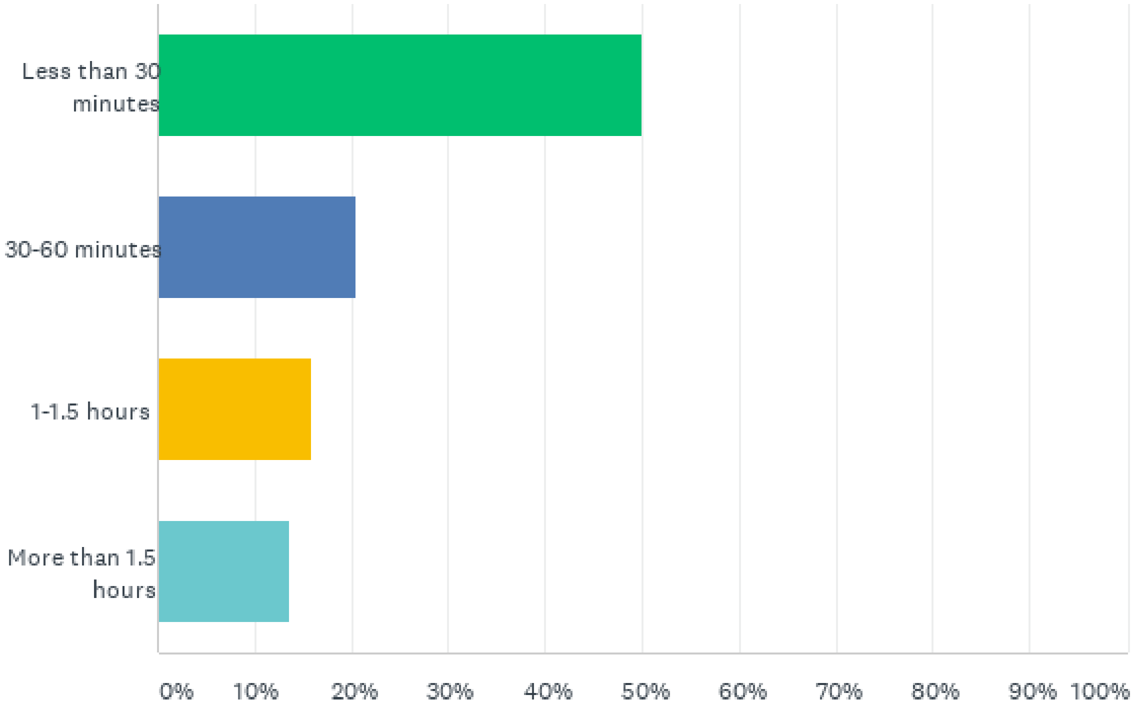
Q28: In the past year, how many power outages have you experienced?



Q28: In the past year, how many power outages have you experienced?

ANSWER CHOICES	RESPONSES	
None (0)	6.82%	3
One or two (1 or 2)	65.91%	29
Two or three (2 or 3)	15.91%	7
More than three (3 +)	11.36%	5
TOTAL		44

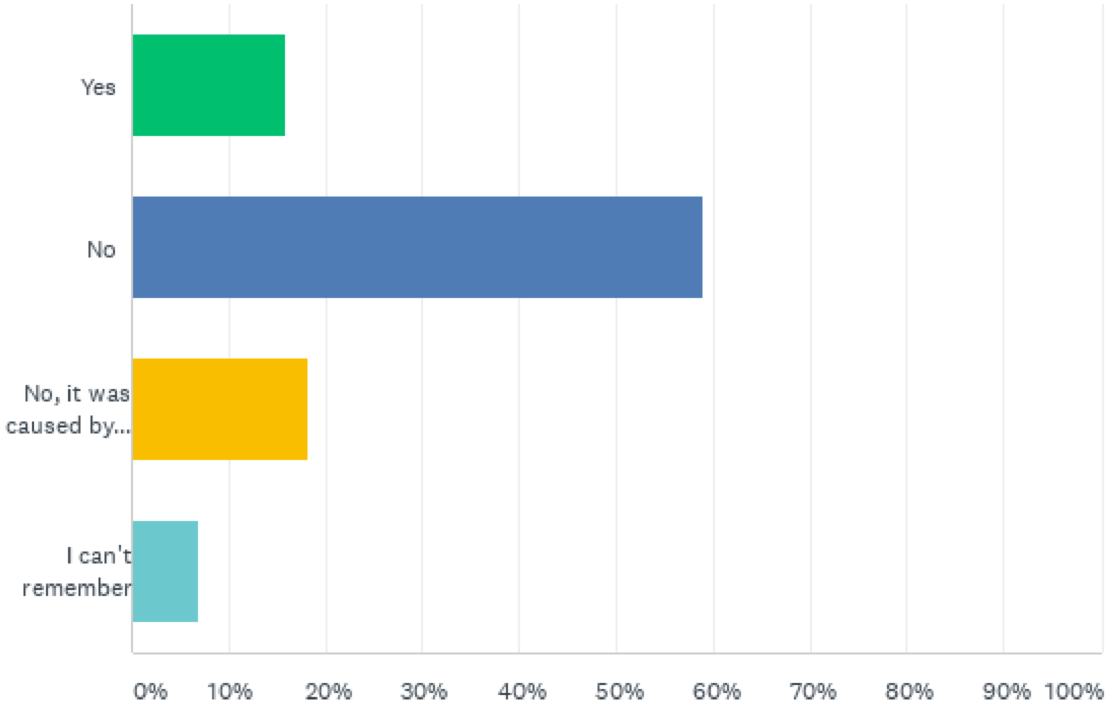
Q29: What was the longest power outage that you had in the past year?



Q29: What was the longest power outage that you had in the past year?

ANSWER CHOICES	RESPONSES	
Less than 30 minutes	50.00%	22
30-60 minutes	20.45%	9
1-1.5 hours	15.91%	7
More than 1.5 hours	13.64%	6
TOTAL		44

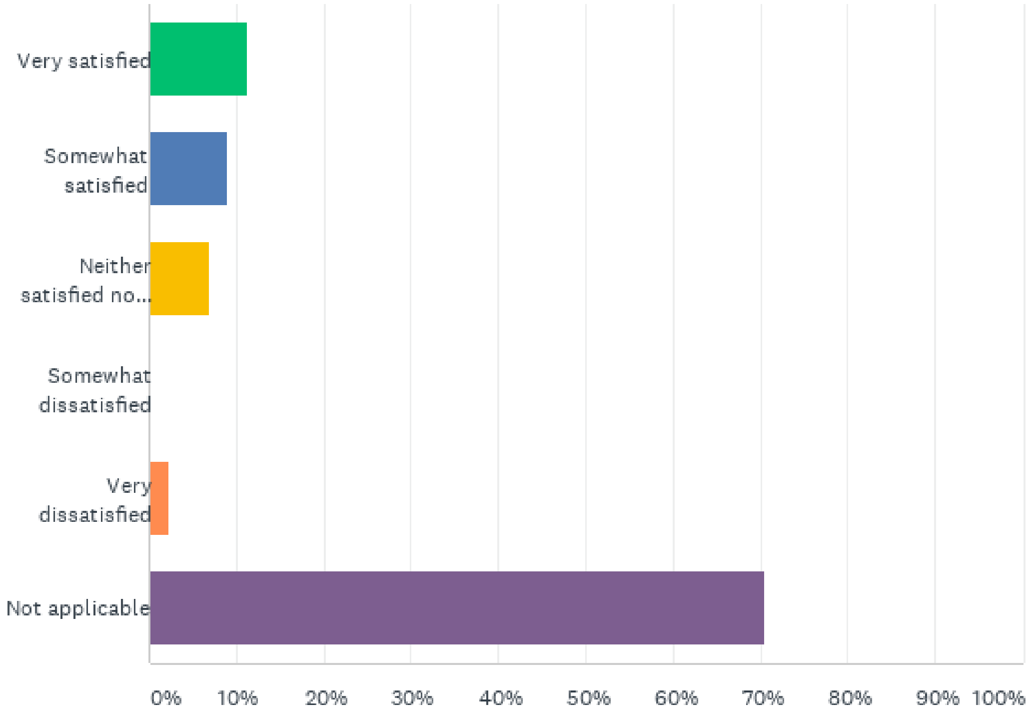
Q30: Did you contact ERH about the power outage?



Q30: Did you contact ERH about the power outage?

ANSWER CHOICES	RESPONSES	
Yes	15.91%	7
No	59.09%	26
No, it was caused by extreme/unusual weather	18.18%	8
I can't remember	6.82%	3
TOTAL		44

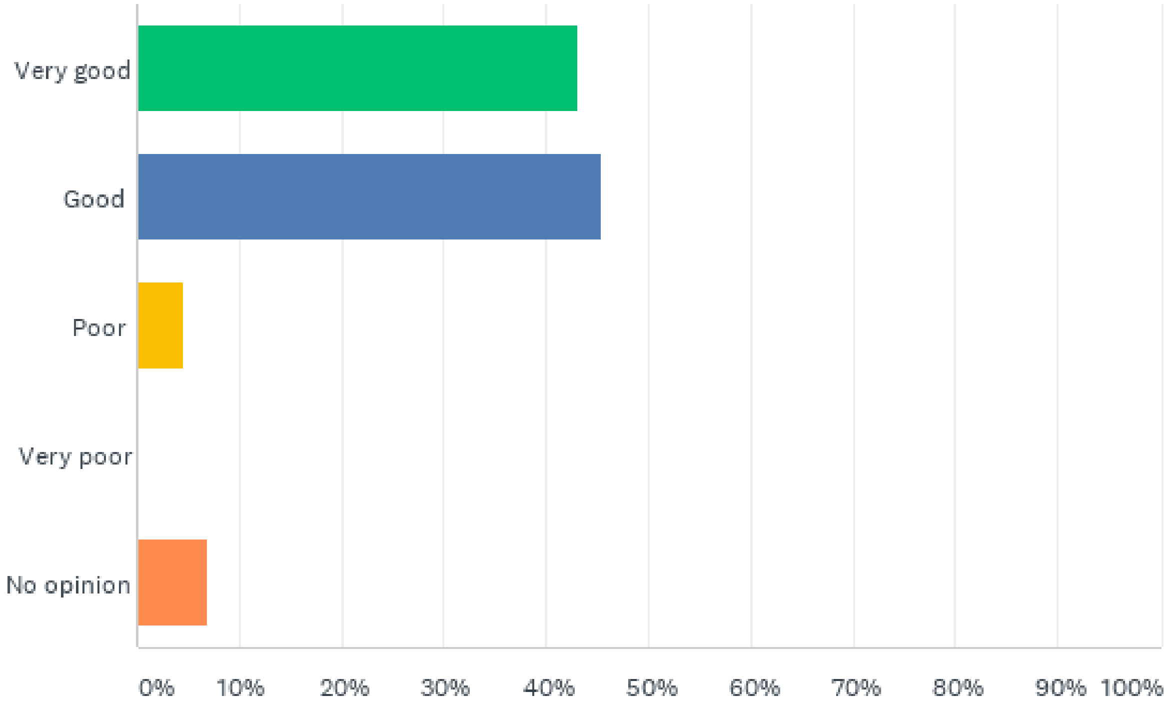
Q31: If you contacted ERH about a power outage, how satisfied were you with the way ERH responded to the outage?



Q31: If you contacted ERH about a power outage, how satisfied were you with the way ERH responded to the outage?

ANSWER CHOICES	RESPONSES	
Very satisfied	11.36%	5
Somewhat satisfied	9.09%	4
Neither satisfied nor dissatisfied	6.82%	3
Somewhat dissatisfied	0.00%	0
Very dissatisfied	2.27%	1
Not applicable	70.45%	31
TOTAL		44

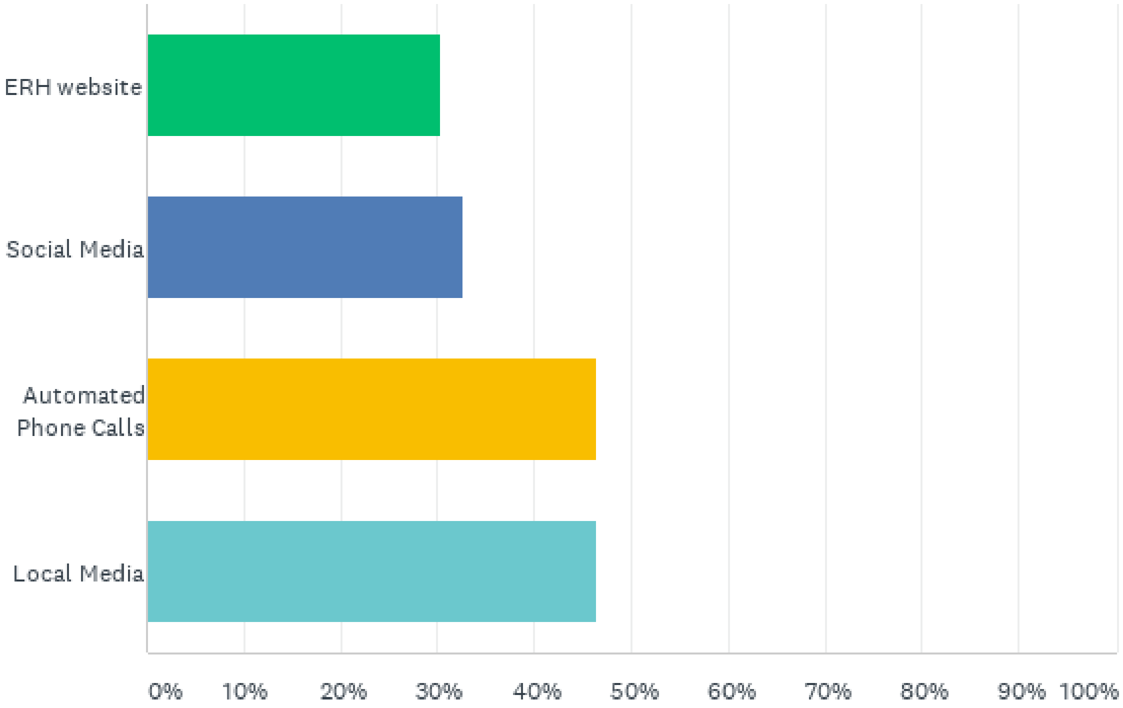
Q32: On average, an EKR customer loses power due to outages for less than 60 minutes over the year. Do you feel this level of reliability is:



Q32: On average, an ERH customer loses power due to outages for less than 60 minutes over the year. Do you feel this level of reliability is:

ANSWER CHOICES	RESPONSES	
Very good	43.18%	19
Good	45.45%	20
Poor	4.55%	2
Very poor	0.00%	0
No opinion	6.82%	3
TOTAL		44

Q33: How would you prefer ERH to communicate before, during and after planned or unplanned power outages?



Q33: How would you prefer ERH to communicate before, during and after planned or unplanned power outages?

ANSWER CHOICES	RESPONSES	
ERH website	30.23%	13
Social Media	32.56%	14
Automated Phone Calls	46.51%	20
Local Media	46.51%	20
Total Respondents: 43		

APPENDIX 1-H
Customer Satisfaction Survey

Espanola Regional Hydro

ESPANOLA REGIONAL HYDRO

21st Annual Electric Utility Customer Satisfaction Survey

UtilityPULSE

- **Customers continue to be concerned about costs; but nowhere near where they were in 2016 and the early part of 2017**
- **Based on telephone interviews of 201 *respondents* who pay or look after the electricity bills for *Espanola***
- **Note: A sample size of 409 will provide confidence level of 95% (+/-6.9x%)**
- **Customers surveyed were based on a *random sample* approach**
- **704 households and small businesses were contacted, 201 completed interviews; response rate is 29%**
- **The following *segments* were surveyed:**
  - **Residential – 85%**
  - **Commercial – 15%**
- **UtilityPULSE segmented respondents into 3 "average kWh usage groups". Group 1 represents lowest 25% of kWh usage, Group 2 middle 50% and Group 3 top 25%.**
- **The Utility*PULSE* Report Card® is computed by formulas which map the attributes of corporate image to customer satisfaction and loyalty**
- **Comparator data:**
  - **Ontario benchmark**
  - **National benchmark**
  - **UtilityPULSE database for 2019**

Electric Utility
Customer Satisfaction Survey

UtilityPULSE
A Division of Simul Corporation

NUMBERS
at a Glance

	Espanola 2019	National 2019	Ontario 2019
Customer Satisfaction: Initial	**91%**	93%	92%
Customer Satisfaction: Post	**93%**	93%	92%
Communication Score	**79%**	--	79%
Overall Satisfaction with most recent experience	**70%**	81%	79%
Convenience of Service Score	**77%**	--	79%
Customer Experience Performance Rating (CEPr)	**87%**	85%	86%
Customer Centric Engagement Index (CCEI)	**88%**	83%	83%
Credibility & Trust Index	**88%**	84%	84%
UtilityPulse Report Card©	**A**	A	A

Credibility and Trust Rating:

Demonstrating Credibility and Trust
Knowledge
The utility is seen as being knowledgeable about the services it provides, about what is happening in the industry, and how customers can reduce costs or create more value.
Integrity
The utility is seen as an organization that will act in the best interests of its customers and can be counted on to provide services and resolve problems in a professional manner.
Involvement
The utility is actively involved in the industry, in the community and in things that affect the customer.
Trust
The utility is an organization that can be trusted and is worthy of respect.
Overall Espanola Regional Hydro 88% **[Ontario 84%; National 84%]**

"What our Customers Say"

92%

"Is a trusted and trustworthy company…"

Base: total respondents

Corporate Image and Reputation

Attributes linked to Company Image and Reputation	Espanola	National	Ontario
Respected in the community	93%	85%	85%
Keeps its promises to its customers and community	86%	82%	83%
Adapts well to changes in customer expectations	78%	75%	74%
Pro-active in communicating changes and issues affecting customers	82%	77%	78%
Customer-focused and treats customers as if they're valued	83%	82%	80%
Is a socially responsible company	84%	82%	82%
Company to recommend	88%	83%	82%
Delivers on its service commitments	89%	88%	88%
Is 'easy to do business with'	93%	83%	83%
Operates a cost-effective electricity system	79%	72%	72%
Overall the utility provides excellent quality services	87%	86%	87%
Is a trusted and trustworthy company	92%	85%	85%

Base: total respondents with an opinion

Communication and Services Measurement

Satisfaction with Information provided		
Top 2 Boxes: 'very + fairly satisfied'	**Ontario LDCs**	**Espanola**
The quality of information available when outages occur	76%	76%
The electricity safety education provided to the public	72%	75%
The timeliness and relevance of information for things such as planned outages, construction activity, tree trimming.	77%	85%

Base: An aggregate of respondents from 2019 participating LDCs / total respondents from the local utility

Communication Score	
Ontario LDCs	**Espanola**
79%	79%

Base: An aggregate of respondents from 2019 participating LDCs / total respondents from the local utility

"What our Customers Say"

79%

"… Communication Score…"

Communication Channels

Preferred method of communication to receive notice of a billing issue

76%	1%	6%	16%
Telephone	Voice Mail	Text	Email

Preferred method of communication to receive notice of a billing issue		
	Ontario LDCs	**Espanola**
Telephone	**54%**	**76%**
Voice Mail	**0%**	**1%**
Text	**8%**	**6%**
Email	**35%**	**16%**
Don't know	**1%**	**0%**

Base: An aggregate of respondents from 2019 participating LDCs / total respondents from the local utility

"What our Customers Say"

76%

"… prefer to receive notice of a billing issue via telephone…"

Convenience of Services Score

Access to services		
Top 2 Boxes: ‘very + somewhat satisfied’	**Ontario LDCs**	**Espanola**
The availability of call-centre staff Monday to Friday	74%	79%
The 24/7 availability of system operators to respond to respond to outages	75%	74%
The online self-serve options for managing your account	61%	43%
The online self-serve options for requesting services	53%	45%

Base: An aggregate of respondents from 2019 participating LDCs / total respondents from the local utility
Hours: Ontario LDCs 8:30 am to 4:30 pm, Espanola Regional Hydro 9:00 am to 4:30 pm

Convenience of Services Score

Convenience of Services Score	
Ontario LDCs	**Espanola**
79%	77%

Base: An aggregate of respondents from 2019 participating LDCs / total respondents from the local utility

77%

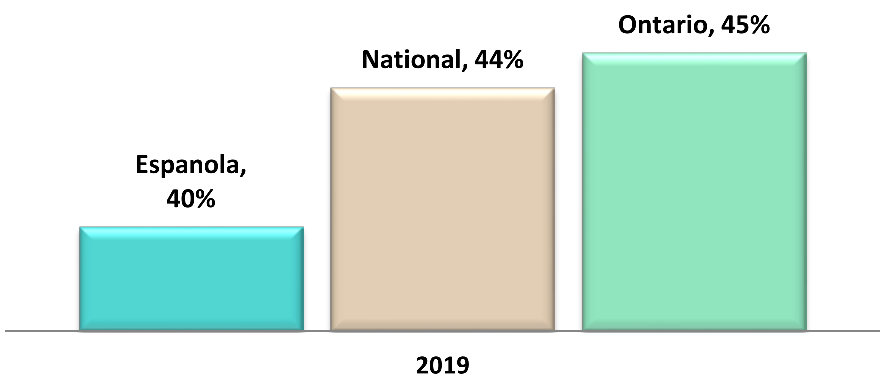
“… Convenience of Services Score…”

Outage Problems (last 12 months)

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	Espanola	National	Ontario
2019	40%	44%	45%
2018	-	39%	44%
2017	30%	37%	38%
2016	-	46%	46%
2015	26%	53%	51%

Base: total respondents/ (-) not a participant of the survey year

Blackout or Outage Problems in the last 12 months



Base: total respondents/ (-) not a participant of the survey year

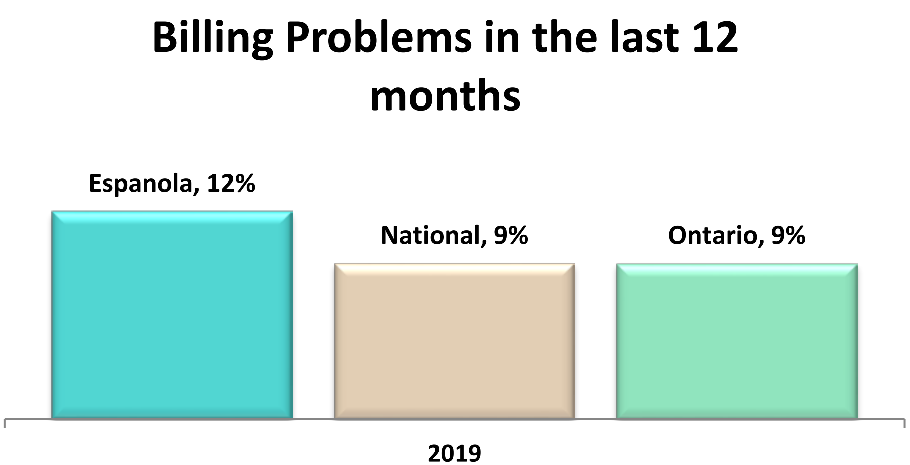
94%

"… Quickly handles outages and restores power…"

Billing Problems (last 12 months)

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	Espanola	National	Ontario
2019	12%	9%	9%
2018	-	9%	9%
2017	20%	12%	15%
2016	-	15%	25%
2015	17%	9%	15%

Base: total respondents/ (-) not a participant of the survey year



Base: total respondents/ (-) not a participant of the survey year

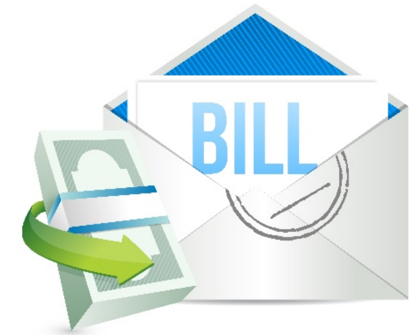
90%

"... Provides accurate billing..."

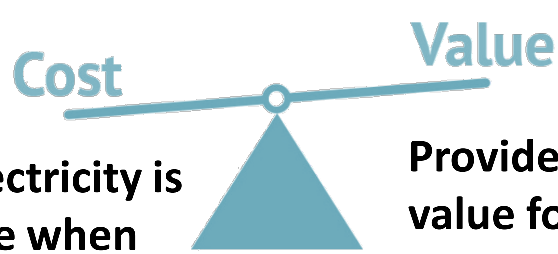
Types of billing problems

Types of Billing Problems	
	Espanola
The amount owed was too high	**52%**
Complaint about rates or charges	**12%**
Payment incorrectly recorded	**12%**
Missed payment	**12%**
Did not receive the bill	**8%**
Wrong information on the bill	**4%**

Base: total respondents with billing problems



Looking purely at the cost of something, it's easy to argue that anything is overpriced. However, we accept the cost of some things, because of VALUE.



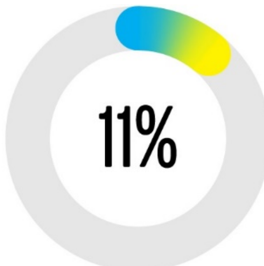
Cost of electricity is reasonable when compared to other utilities= 71%

Provides good value for your money= 75%

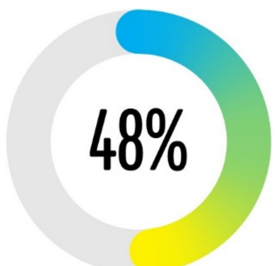
52%

"… Amount owed was too high …"

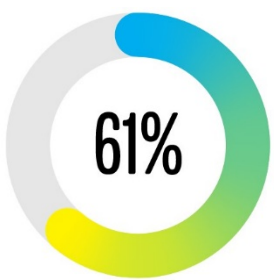
Bill Payer’s Problems and Problem Resolution



11% of Espanola respondents with an outage problem did contact the utility.



48% of Espanola respondents with a billing problem did contact the utility.



Respondents who said they contacted the utility were also asked “Do you consider the problem solved or not solved?” 61% of your LDC’s respondents said their problem was solved.

Customer Service

Customer Service Expectations	Espanola	National	Ontario
The time it took to contact someone	73%	69%	71%
The time it took someone to deal with your problem	68%	72%	70%
The helpfulness of the staff who dealt with you	73%	77%	78%
The knowledge of the staff who dealt with you	70%	74%	71%
The level of courtesy of the staff who dealt with you	84%	79%	77%
The quality of information provided by the staff who dealt with you	64%	75%	74%

Overall satisfaction with most recent experience

	Espanola	National	Ontario
Top 2 Boxes: 'very + fairly satisfied'	70%	81%	79%

83%

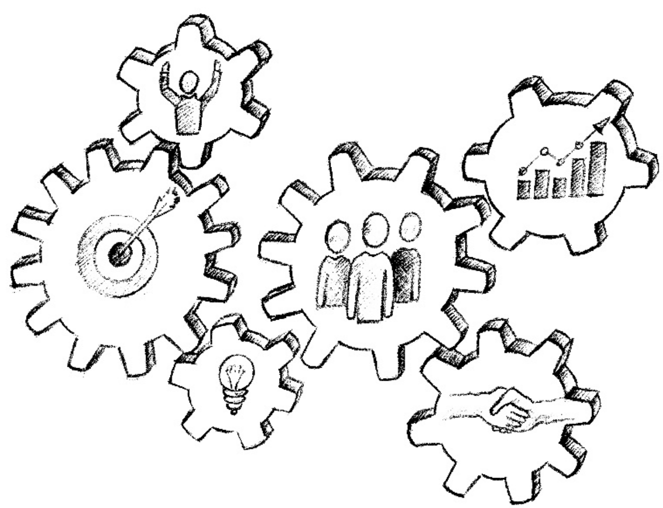
"Deals professionally with customers' problems…"

Base: total respondents

Core Operational Attributes

Core Operational Attributes			
Top 2 Boxes: 'Strongly + Somewhat agree'	**Espanola**	**National**	**Ontario**
Provides consistent, reliable electricity	94%	91%	91%
Quickly handles outages and restores power	94%	88%	88%
Accurate billing	90%	88%	89%
Has a standard of reliability that meets expectations	93%	89%	90%
Makes electricity safety a top priority	89%	88%	89%

Base: total respondents with an opinion



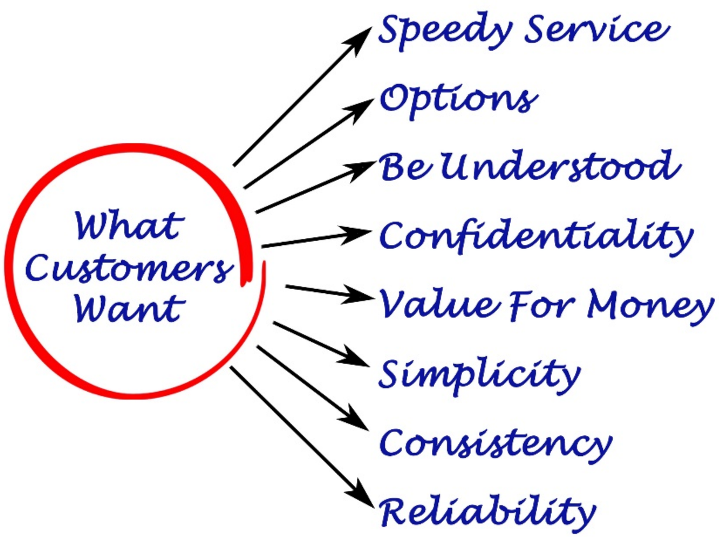
94%

"Provides consistent, reliable electricity…"

Core Customer Service Quality Attributes

Core Customer Service Quality Attributes			
	Espanola	National	Ontario
Deals professionally with customers' problems	83%	85%	84%
Customer-focused and treats customers as if they're valued	83%	82%	80%
Is a company that is 'easy to do business with'	93%	83%	83%

Base: total respondents with an opinion

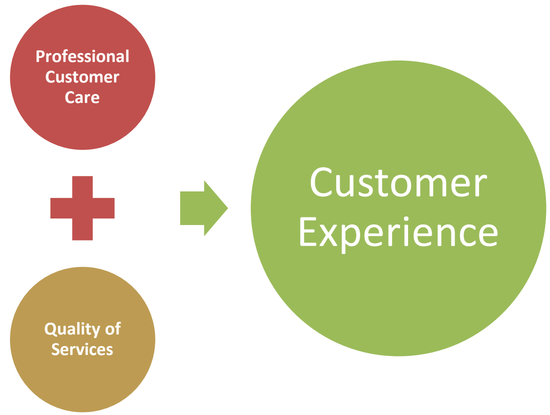


"… Customer-focused and treats customers as if they're valued…"

CEPr: Customer Experience Performance rating

Customer Experience Performance rating (CEPr)			
	Espanola	National	Ontario
CEPr	87%	85%	86%

Base: total respondents



"What our Customers Say"

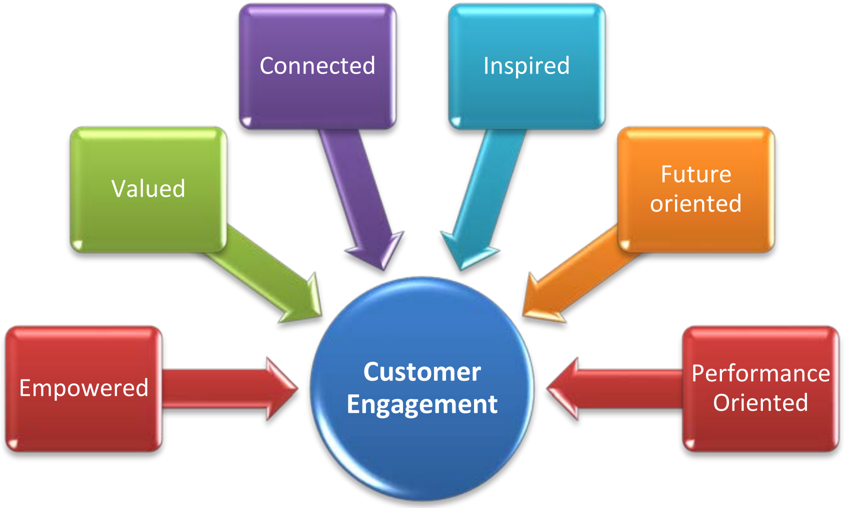
87%

"CEPr: Customer experience rating…"

CCEI: Customer Centric Engagement Index

Customer Centric Engagement Index (CCEI)			
	Espanola	**National**	**Ontario**
CCEI	**88%**	**83%**	**83%**

Base: total respondents



88%

"… CCEI: Customer Centric Engagement Index…"

Customer Satisfaction:

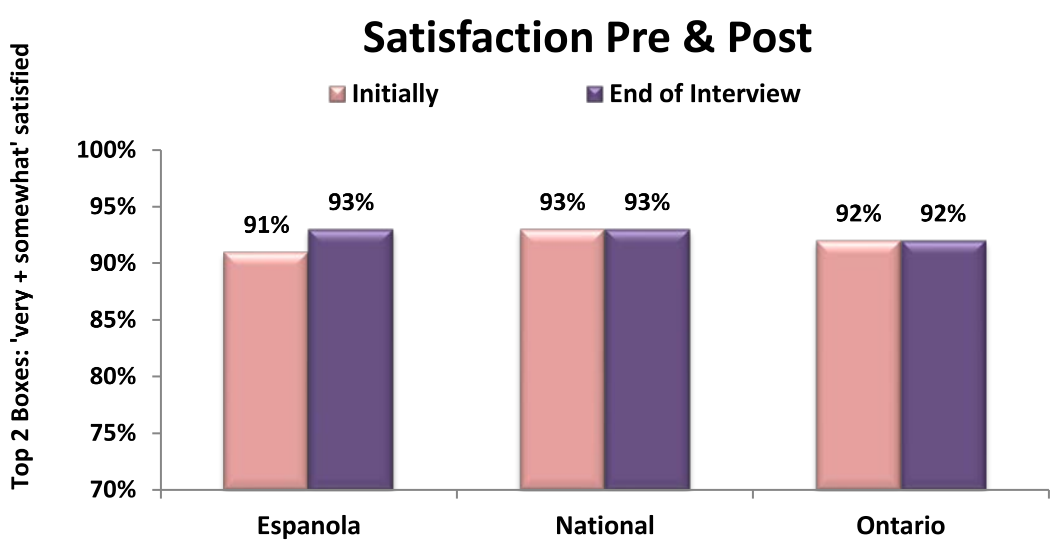
Electricity bill payers who are 'very or fairly' satisfied with…			
Top 2 Boxes: 'very + fairly satisfied'	**Espanola**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	**91%**	**93%**	**92%**
POST: End of Interview	**93%**	**93%**	**92%**

Base: total respondents

"What our Customers Say"

PRE **91%**

"SATISFIED: Beginning of Interview"



"What our Customers Say"

POST **93%**

"SATISFIED: End of Interview"

Base: total respondents

Customer Loyalty

34% Secure | 23% Favorable | 35% Indifferent | 8% At Risk

Loyalty Factor			
	Espanola	National	Ontario
Secure	34%	27%	27%
Favorable	23%	17%	16%
Indifferent	35%	49%	48%
At Risk	8%	7%	9%

Base: total respondents

UtilityPULSE Report Card®: A

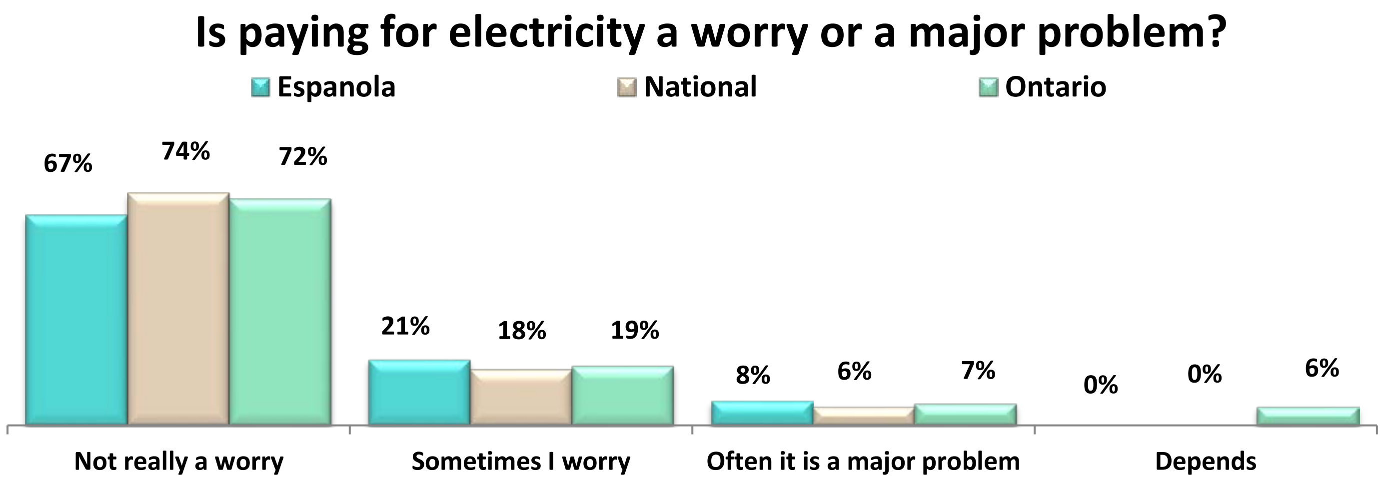
Espanola's UtilityPULSE Report Card®			
	Category	Espanola	Ontario
1	**Customer Care**	**A**	**B+**
	Price and Value	B+	B+
	Customer Service	A	A
2	**Company Image**	**A**	**A**
	Company Leadership	A	A
	Corporate Stewardship	A	A
3	**Management Operations**	**A+**	**A**
	Operational Effectiveness	A+	A
	Power Quality and Reliability	A+	A
	OVERALL	**A**	**A**

"A ... Customer Care"

"A ... Company Image"

"A+ ... Management Operations"

Paying for electricity



Base: total respondents

Is paying for electricity a worry or a major problem?				
	Not a worry	Sometimes	Often	Depends
<$30K	47%	43%	7%	3%
$30K<$75K	62%	25%	11%	0%
$75K+	84%	11%	2%	0%

Base: total respondents

How can service be improved?

One or two most important things 'your local utility' could do to improve service	Espanola
Better prices / lower rates	43%
Better communications / be pro-active	10%
Better information on outages when they occur	7%
Improve customer service/reliability of staff	7%
Eliminate SMART meters	6%
Better power reliability / less power outages	5%
Improve / simplify / clarify billing	4%
Information & incentives on energy conservation	3%
Restore power faster	3%
End Time of Use	3%
Pay bills online	2%
Be more efficient / cost-effective	2%

WISDOM FROM CUSTOMERS

"What our Customers Say"

43%

"Better prices/lower rates..."

Base: total respondents with suggestions

NUMBERS at a Glance

	Espanola 2019	National 2019	Ontario 2019
Customer Satisfaction: Initial	**91%**	93%	92%
Customer Satisfaction: Post	**93%**	93%	92%
Communication Score	**79%**	--	79%
Overall Satisfaction with most recent experience	**70%**	81%	79%
Convenience of Service Score	**77%**	--	79%
Customer Experience Performance Rating (CEPr)	**87%**	85%	86%
Customer Centric Engagement Index (CCEI)	**88%**	83%	83%
Credibility & Trust Index	**88%**	84%	84%
UtilityPulse Report Card©	**A**	A	A

UtilityPULSE

A Division of Simul Corporation

Electric Utility Customer Satisfaction Survey

All comments and questions should be addressed to:

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Simul

APPENDIX 1-I
ERHDC's Business Plan

Espanola Regional Hydro Distribution Corporation (ERHDC)

Business Plan

2020 to 2021

1.1 SUMMARY

1.2 Introduction

ERHDC is a licensed electricity distributor that owns and operates the electricity distribution system that serves approximately 3,300 electricity customers in the Town of Espanola and the Township of Sables-Spanish Rivers. ERHDC's office is located in the Town of Espanola.

ERHDC is, in part, a virtual utility. ERHDC has 7 employees, who are actively involved in the day to day operation of the company. ERHDC is also party to a Services Agreement with PUC Services Inc. ("**PUC**") that will continue until February 28, 2022, pursuant to which PUC provides a comprehensive suite of management services, customer services and IT services to support the day-to-day operations of ERHDC. ERHDC's service territory characteristics are detailed in the following chart:

Communities Served	Town of Espanola and Township of Sables-Spanish River
Total Service Territory	102 sq. km
Urban Service Territory	26 sq. km
Rural Service Territory	76 sq. km
Municipal Population	8,236
Customers per square km	32
Overhead circuit km of line	90
Underground circuit km of line	12
Total circuit km of line	102
# of Customers per km of line	32

In accordance with the Ontario Energy Board Decision and Order, EB_2019-0015 dated August 22, 2019 North Bay (Espanola) Acquisition Inc. (NBEAI) received approval to:

1. acquire 100% of the issued and outstanding common shares of Espanola Regional Hydro Holdings Corporation ("**ERHHC**") and 100% of the special shares of Espanola Regional Hydro Distribution Corporation ("**ERHDC**") from The Corporation of the Town of Espanola

and The Corporation of the Township of Sables-Spanish Rivers, pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998*; and

2. amalgamate NBEAI, ERHHC and ERHDC to create a new company operating under the name Espanola Regional Hydro Distribution Corporation, made pursuant to section 86(1)(c) of the *Ontario Energy Board Act, 1998*; and

3. to proceed with the proposed (described below) rate making framework under section 78 of the *Ontario Energy Board Act, 1998*.

The amalgamation was completed as of September 30, 2019. NBHDL and ERHDC will continue to operate as independent utilities until 2022 (i.e. after the PUC Services Agreement expires). Operational synergies are not yet possible because of ERHDC's obligations under, and PUC's rights under, the PUC Services Agreement. For this reason, PUC will continue to provide services to ERHDC pursuant to the PUC Services Agreement.

ERHDC has not been before the Board for a cost of service application in seven (7) years, has not had rates adjusted in nearly four (4) years, and has been operating under interim rates since May 1,2016.

ERHDC will file a cost of service rebasing application for rates effective May 1, 2021 (the "**Espanola Rebasing Application**"). The Espanola Rebasing Application is required to maintain the ongoing financial viability of ERHDC, which earned an actual regulatory ROE's of 6.29% in 2016, 2.45% in 2017, 4.25% in 2018, a loss in 2019 and an expected loss in 2020.

The Espanola Rebasing Application will also address a number of regulatory issues including:

- Moving ERHDC towards full compliance with OEB regulatory requirements by allowing ERHDC to begin the transition of residential consumers towards fully fixed rates.

- Ending the ICM rate rider, and rolling the substation properly into rates, which will help reduce rates to the benefit of customers (the actual costs of the substation were less than what was previously forecasted).

- Filing a modified Distribution System Plan (DSP). After the merger, North Bay Hydro will completely replace the ERHDC distribution system planning function with existing North Bay Hydro resources. In this circumstance, it does not make sense to invest considerable funds to create a detailed DSP from scratch which document will be worthless after only 1 year. This would involve hiring third party engineering experts to draft a standalone DSP – which would be a waste of time and money. Therefor ERHDC will scale back the scope of the DSP as follows:
  - Deferring completing the formal Asset Management Plan and Asset Condition Assessment until after the North Bay Hydro merger. The ERHDC asset management plan is simply a

one (1) year continuation of the status quo capital program. This gives North Bay Hydro time to complete this work in the years after the merger.

- Limiting the DSP to a limited one (1) year forward test year plan. The plan is set out for 1 year until the merger with North Bay Hydro is completed, at which point any standalone DSP would become moot.
- Disposing of Group 1 DVAs, which were last disposed of for December 31, 2013 balances, and LRAMVA which was last approved for 2014 rates for pre-2012 programs in 2011 until April 2012.
- Updating ERHDC's load forecast, cost allocation and rate design to reflect more current information.

Upon completion of the Espanola Rebasing Application, the NBH Rebasing Application, the transition of services from PUC to NBHDL, and the expiry of the PUC Services Agreement, it is ERHDC's understanding that NBHDL will bring a second application to the Board to approve the second phase ("Phase 2") of the transaction to allow for the amalgamation of NBHDL and ERHDC under section 86(1)(c) of the *Ontario Energy Board Act, 1998* (the "**Phase 2 Transaction**"). The ultimate amalgamated entity will operate under the name North Bay Hydro Distribution Ltd. ("**New NBHDL**").

Following completion of the Phase 2 Transaction, NBHDL would commit to only defer rebasing and rate harmonization of the consolidated utility for five (5) years. This would ensure that ratepayers would see the benefits of the amalgamation of NBHDL and ERHDC by 2026, a full two (2) years earlier than if the 10-year deferred rebasing period was applied following the completion of the Phase 1 Transaction.

ERHDC must operate its business in compliance with all applicable laws, including the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, the Ontario *Business Corporations Act*, and the rules, policies and requirements of the Ontario Energy Board (the "**OEB**") including the Distribution System Code, the Affiliate Relationships Code, the Retail Settlement Code, the Standard Supply Service Code, the Accounting Procedures Handbook and the Uniform System of Accounts as well as the applicable Rate Handbook and Filing Requirements.

Although it does not pay corporate income taxes, as a municipally owned licenced LDC in the province of Ontario, ERHDC is required to pay Payments in Lieu of Taxes (PILS) to the province. The amount payable is generally speaking calculated based on Federal and Provincial tax rules for corporations.

1.2 Plan Objective

This plan has been put in place in order to maintain the targets as set out in the OEB Renewed Regulatory Framework for Electricity (RRFE) targets and meet ERHDC's Corporate Goals as outlined below:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.
2) Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations, and ensure regulatory compliance.
3) Maintain current staffing requirements, including training and preparing for succession planning.
4) To provide a reasonable rate of return to the Shareholder.

1.3 Financial Plan Assumptions

This report summarizes ERHDC ’s estimated results for 2020 and 2021 budget for the cost of service rate application (test year budget).

The Business Plan is based on the following assumptions and constraints:

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

1.4 Summary of ERHDC’s 2020 & 2021 Budgets

ERHDC’s Financial Plan summary is provided in the attached Appendix. The Plan provides for prudent and sustainable investment in core business operations and subject to certain material risks, results in the following metrics:

	2020 Estimated	2021 Budget
Net Income	($314,856)	($133,549)

Capital Expenditures net of Contributed Capital	$644,600	$463,429

2 BUSINESS RISKS AND MITIGATION

2.1 Material Risks to the Business Plan and Potential Mitigation

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

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

Weather

Weather-related and conservation impacts on distribution revenue in the short term cannot be mitigated, although evidence will be presented in the Cost of Service Rates ("CoS") Application to mitigate the future impact of a weather-related declining revenue trend. Such evidence would generally include the presentation of weather-normalized data as a basis for determining customer specific volumetric distribution charges. In addition, the transition to a fully fixed monthly charge for residential customers will aid in stabilizing a large portion of distribution revenue.

Mitigation of *material* weather-related impacts on costs (e.g., ice storms, high winds, etc.) could be achieved through a request for a z-factor adjustment application before the OEB. The current materiality threshold for z-factor adjustments is 0.5% of distribution revenue, which for ERHDC is approximately $10,000 per event.

Local Economy and Credit Risks

LDCs in general are challenged to mitigate short-term impacts on distribution revenue resulting from declining consumption and poor economic conditions. These aspects are considered to be normal business risks for LDCs and must be taken into consideration as part of the development of the load forecast underlying the CoS Application.

As part of its CoS Application, ERHDC will provide a load forecast that is derived from a multi-factor, single-equation econometric model. The model includes such parameters as weather (Heating degree-days, Cooling degree-days), economic output (manufacturing GDP growth), calendar variables (days in month, number of peak hours), and a “dummy” variable (blackout parameter). LDCs are exposed to revenue reductions during the IRM rate periods from variances between actual loads and the load forecasts underlying distribution rates at the time of the CoS filing. As noted in the IESO report “Electricity System Impact of COVID-19”, dated May 20, 2020, the closure of non-essential business have reduced average daily energy consumption by 7% to 14% on weekdays and by 6% to 10% on weekends. ERHDC has considered the effects of COVID-19 in its 2021 load forecast in order to mitigate the risk of declining consumption.

ERHDC faces credit risk primarily from non-payment of hydro bills. The company’s revenue is earned from a broad base of customers, it does not earn a significant amount of revenue from any single customer. The larger customers are federal, provincial, or municipal government entities which reduces the credit risk. To deal with this risk, ERHDC has adopted credit policies as permitted by OEB regulation that result in a reasonable level of credit risk mitigation. The company does not provide significant electric service to the major industries in the municipality, however, financial difficulties at these companies could adversely affect the entire community and thus the distribution utility. The pending amalgamation with North Bay Hydro will help mitigate credit risk.

Residential and Small Commercial Customers

Management continues to monitor the OEB's review of customer service rules and will analyze the financial impact of any code amendments implemented by the OEB.

Conservation and Demand Management

Revenue loss from customers' CDM efforts may be mitigated through a Lost Revenue Adjustment Mechanism ("LRAM") application with the OEB to accelerate recoveries of foregone revenue from CDM activities.

Equipment Failure

For this application, an adjusted Distribution System Plan (DSP), which includes adoption of current age, visual inspection and formal testing data as inputs has been developed to replace its aging infrastructure. Equipment failure risk is managed through such programs as the annual tree-trimming program, infrared surveys of plant and equipment, non-destructive pole testing and treatment, oil testing of power transformers, and by maintaining an adequate inventory of replacement parts.

Regulatory Risk

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that significantly reduces the rate of return that can be earned by electricity distributors. In addition, the ability to maintain the distribution system depends on, among other factors, the OEB allowing recovery of the operating, maintenance and capital costs required in the future. Lower rates arising from these types of changes could result in distribution earnings and cash flow being lower than the rate increases assumed in the Business Plan.

Failing to continually be aware of and applying changing government regulations is also a corporate risk. The company monitors developments in the electricity industry and also relies on the Electricity Distributors Association to monitor and act on its behalf. Consultants with expertise in certain fields are utilized as required.

Human Resource Risk

As part of the management service contract with PUC Services Inc., PUC Services Inc. provides the management oversight and supplements the workforce necessary to manage

ERHDC. Labour disruptions can affect ongoing operations. Collective agreements with the union employees at ERHDC are in effect until April 30, 2022. The pending amalgamation with North Bay Hydro will help mitigate the human resource risk.

Technology Risk
The use and complexity of the company's electronic infrastructure continues to increase, and its reliability and security are critical to all areas of operation. Outside resources with expertise in specific areas are utilized, as necessary. The pending amalgamation with North Bay Hydro will help mitigate the technology risk.

3 SCORECARD REVIEW

Performance outcomes outlined in the Renewed Regulatory Framework for Electricity (RRFE) are measured on the LDCs scorecard which is published annually. In the most recently published scorecard (2019 results), ERHDC met or exceeded all prescribed targets for scorecard measures except for the 2019 Telephone Calls Answered on Time and Return on Equity. These items are discussed below.

Scorecard Highlights:

Exceeded the 5-year rolling average distributor target in reliability performance.

Sixth consecutive year with zero public safety incidences.

Eighth consecutive year maintaining an efficiency assessment rating of Group 2 which is defined as having actual costs between 10% and 25% below predicted costs under the PEG model.

ERHDC will continue working towards maintaining its high level of customer satisfaction and operational effectiveness in its next cost of service period and beyond. ERHDC's target is to attain all scorecard targets.

Scorecard - Espanola Regional Hydro Distribution Corporation

9/3/2020

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

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

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

3.1 Customer Focus

3.1.1 Service Quality

As detailed in the table below, ERHDC met all the following Service Quality targets for the period 2017 to 2019 except for the 2019 Telephone Calls Answered on Time. The main contributing factor to the missed target was staff turnover which resulted in new staff having longer average talk times with customers. The extra time on the phones with customers then lead to calls waiting in the queue. ERHDC has a fully trained team in place and has seen significant improvement for 2020. ERHDC will continue to monitor this performance measure to identify opportunities for improvement.

YEAR	New Residential/Small Business Services Connected on Time (Target: 90%)	Scheduled Appointments Met on Time (Target: 90%)	Telephone Calls Answered on Time (Target: 65%)
2017	100.00%	98.18%	72.62%
2018	100.00%	100.00%	70.67%
2019	100.00%	98.55%	63.04%
Target 2020	100.00%	100.00%	65.00%
Target 2021	100.00%	100.00%	65.00%

3.1.2 Customer Satisfaction

As detailed in the scorecard above, ERHDC met all the following Customer Satisfaction targets for the period 2017 to 2019:

YEAR	First Contact Resolution	Billing Accuracy (Target: 98%)	Customer Satisfaction Survey Results
2017	99.60%	99.95%	87.00%
2018	99.73%	99.89%	87.00%
2019	99.23%	99.98%	91.00%
Target 2020	100.00%	100.00%	91.00%
Target 2021	100.00%	100.00%	92.00%

Customer Satisfaction Survey Results

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

3.2 Operational Effectiveness

3.2.1 Safety

As detailed in the scorecard above, ERHDC met all the following Customer Satisfaction targets for the period 2017 to 2019:

Level of Compliance with Regulation 22/04

Serious Electrical Incident Index - Number of General Public Incidences

Serious Electrical Incident Index – Rate per 10, 100, 1000 km of line

YEAR	Level of Public Awareness	Level of Compliance with Ontario Regulation 22/04 (Target: substantially compliant)	Number of General Public Incidents	Rate per 10, 100, 1000 km of line
2017	84.00%	C	0	0.000
2018	84.00%	C	0	0.000
2019	85.00%	C	0	0.000
Target 2020	85.00%	C	0	0.000
Target 2021	86.00%	C	0	0.000

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

Safety - Component A – Public Awareness of Electrical Safety

ERHDC's third safety awareness survey was conducted in early 2020. A representative sample of ERHDC's service territory population was surveyed to gauge the public's awareness level of key electrical safety concepts related to distribution assets. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness and identify opportunities where additional education and outreach may be required. ERHDC's score for 2020 was 85% (2017 84%). ERHDC's target for this metric is to improve each year the survey is undertaken.

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

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

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

Safety - Component C – Serious Electrical Incident Index

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

3.2.2 System Reliability

As detailed in the scorecard above, ERHDC met the following System Reliability targets for the period 2017 to 2019:

Average Number of Hours that Power to a Customer is Interrupted

Average Number of Times that Power to a Customer is Interrupted

YEAR	Average Number of Hours Power to Customer is Interrupted	Average Number of Times Power to Customer is Interrupted
2017	0.35	0.10
2018	0.16	0.06
2019	0.35	0.17
Target 2020	0.35	0.35
Target 2021	0.33	0.33

Average Number of Hours that Power to a Customer is Interrupted

The System Average Interruption Duration Index (SAIDI) of 0.35 in 2019 was below the target of 0.67. There are ongoing efforts to improve reliability including replacing aging infrastructure and ongoing vegetation management.

Average Number of Times that Power to a Customer is Interrupted

The System Average Interruption Frequency Index (SAIFI) of 0.17 in 2019 was substantially below the target of 0.33. Consistent with SAIDI, there are ongoing efforts to improve reliability including replacing aging infrastructure and ongoing vegetation management.

3.2.3 Asset Management

Distribution System Plan Implementation Progress

Although ERHDC has employed some degree of distribution system planning for several years, it began drafting its first formal Distribution System Plan (DSP), meeting all OEB Chapter 5 Filing Requirements, in 2015-2016 with the intention of filing the DSP with the OEB as part of a 2017 Cost of Service Application. Activity was halted however in 2017 with the announcement of the pending sale of ERHDC to North Bay Hydro. Now that the acquisition is complete, ERHDC will be updating its DSP in preparation for its 2021 Cost of Service Application. Due to future amalgamation in 2022, the OEB has accepted that the DSP will only cover 2021, rather than a full five-year DSP. The DSP will outline how ERHDC will develop, manage, and maintain its distribution system equipment to provide a safe, reliable, efficient, and cost-effective distribution system.

3.2.4 Cost Control

YEAR	Efficiency Assessment (1 = most efficient 5 = least efficient)	Total Cost ($) per Customer	Total Cost ($) per Km of Line
2017	2	$ 661	$ 15,421
2018	2	$ 683	$ 16,003
2019	2	$ 758	$ 17,789
Target 2020	2	$ 761	$ 17,855
Target 2021	2	$ 818	$ 19,205

Efficiency Assessment

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

The following table summarizes the distribution of all LDC's across the 5 groupings for 2018:

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	6
2	Actual costs are 10% to 25% below predicted costs	More Efficient	19
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	26
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	9
5	Actual costs are 25% or more above predicted costs	Least Efficient	3

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

Total Cost per Customer

Total cost per customer is calculated as the sum of ERHDC's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that ERHDC serves. The cost performance result for 2019 is $758 per customer which is a 10% increase over 2018. Exlcuding one-time divestiture costs incurred in 2019, the cost per customer is $728, which is an increase of 6% over 2018. The projected cost per customer for 2020 is $761, a 0.37% increase over 2019. ERHDC will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. ERHDC's capital and operating programs will be further defined in its 2021 rate application to be filed in 2020. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2016 will continue in order to ensure customers have an opportunity to share their viewpoint on ERHDC's capital spending plans.

Total Cost per Km of Line

This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. ERHDC's 2019 rate is $17,789 per Km of line, a 11% increase over 2018. As mentioned above, this increase is due to increased administrative expenses related to the sale. ERHDC continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth.

3.3 Public Policy and Responsiveness

YEAR	Net Cumulative Energy Savings (Percent of Target Achieved)	Renewable Generation Connection Impact Assessments Completed on Time	New Micro-Embedded Generation Facilities Connected on Time (Target: 90%)
2017	80.32%		100.00%
2018	99.00%		
2019	131.00%		
Target 2020	N/A		
Target 2021	N/A	N/A	N/A

3.3.1 Conservation and Demand Management

(b) **Net Cumulative Energy Savings**

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

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

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

3.3.2 Connection of Renewal Generation

Renewable Generation Connection Impact Assessments Completed on Time

Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. For the year 2019 no CIA requests were received. ERHDC maintains internal processes to ensure all applications are processed within the prescribed timelines when they are received.

New Micro-embedded Generation Facilities Connected On Time

ERHDC received no applications for Micro-embedded Generation Facilities in 2019.

3.4 Financial Performance

3.4.1 Financial Ratios

(c)

YEAR	Liquidity: Current Ratio (>1)	Leverage: Total Debt to Equity Ratio (1.5=60/40)	Profitability: Regulatory Return on Equity - Deemed	Profitability: Regulatory Return on Equity - Achieved	Variance ROE
2017	1.17	1.17	9.12%	2.45%	-6.67%
2018	1.22	1.12	9.12%	4.12%	-5.00%
2019	0.83	- 22.35	9.12%	-9.46%	-18.58%
Target 2020	1.00	- 22.35	9.12%	-5.21%	-14.33%
Target 2021	1.00	- 22.35	8.52%	3.06%	-5.46%

(d)

Liquidity: Current Ratio (Current Assets/Current Liabilities)

As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being “liquid”. The higher the number, the more “liquid” and the larger the margin of safety to cover the company’s short-term debts and financial obligations.

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

Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt to equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring. ERHDC has a debt to equity ratio of -22.35 in 2019 which is below the deemed capital structure. As noted above, the financing structure is temporary and the leverage ratio tied to liquidity will continue to be low until the amalgamation occurs.

Profitability: Regulatory Return on Equity – Deemed (included in rates)

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

Profitability: Regulatory Return on Equity – Achieved

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

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

4 ANALYSIS OF ERHDC's BUSINESS PLAN

The Business Plan, which is for the years 2020 and 2021, provides for prudent and sustainable investment in core business operations. It is anticipated that the amalgamation of ERDHC and North Bay Hydro will be completed by the end of 2022. The achievement of this plan is subject to obtaining approval for rates in 2021 as requested and to business risks as noted above. Following is a summary of the three-year financial plan that is attached in Appendix A**:**

	2020 Estimated	2021 Budget
Net Income	($314,856)	($133,549)
OM&A Expenses*	$1,532,268	$1,756,315
Capital Expenditures**	$644,600	$463,429

*2021 includes $200,000 in expenses for the Cost of Service Application

**Net of capital contributions

Net loss decreases in 2021 are a result of the estimated revenue increase associated with rate rebasing. The distribution revenue amount will be further refined on the completion of the Cost of Service Application modules. The 2021 budget includes only a portion of the increase as it is anticipated that the rate increase will take place as of May 1, 2021. During the period prior to the amalgamation of ERDHC and North Bay Hydro, ERHDC will see significant increases in its debt, which result in interest expense more than the regulated deemed amount. The increased interest amounts adversely affect net income until the amalgamation in 2022.

The Business Plan reflects managed increases in expenditures with due regard for the following:

- Expectations set by the OEB regarding the nature and magnitude of expenditures.
- Prioritization of investments in the context of requirements for distribution system renewal and the needs of Espanola's ratepayers.
- Continued focus on customer engagement and communication.

- Customer affordability.
- A reasonable rate of return for the shareholder.

5 FINANCIAL RESULTS

5.1 Recognition of Regulatory Assets and Liabilities

International Financial Reporting Standards (IFRS) does not permit the recognition of regulatory assets and liabilities. Under IFRS, ERHDC is no longer permitted to record regulatory assets and liabilities on its balance sheet and, as a result, s ettlement differences for non-distribution charges (energy, transmission, wholesale market service charge, etc.) are recorded as net earnings or net costs depending on whether the settlement difference is positive or negative in the period. These settlement differences will be collected/returned to customers in a future period and are not predictable nor can they be readily forecasted/budgeted. Therefore, settlement differences have not been included in budgeted operating revenues/expenses.

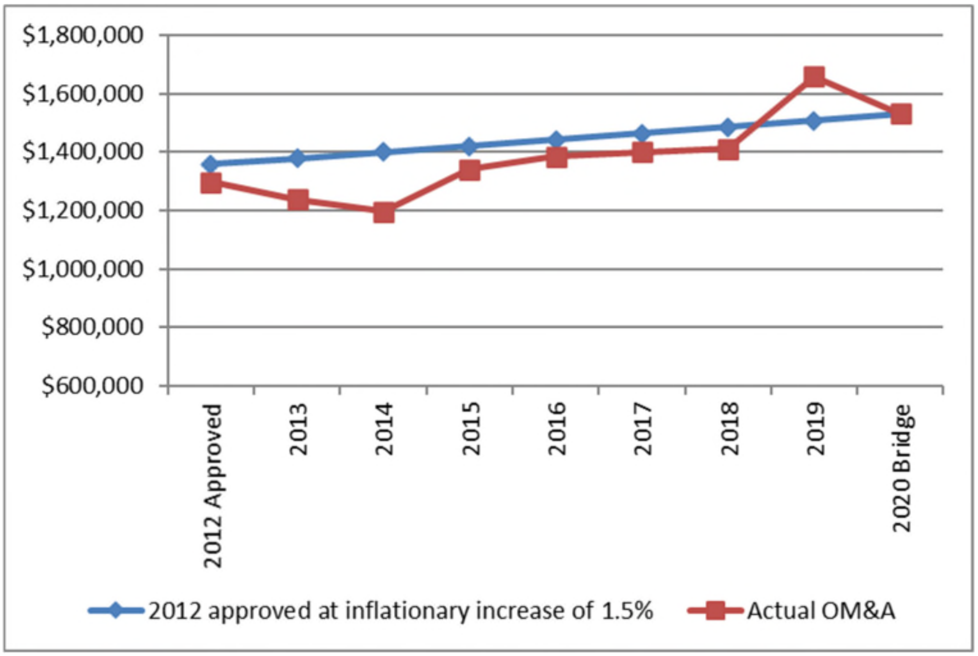
5.2 Revenue

2021 revenue includes the estimated cost of service rate increase. The full effect of the cost of service rate application occurs in 2022. Also included in revenue is estimated Lost Revenue Adjustment Mechanism (LRAM) revenue of $284,000 recoverable over five years.

5.3 Operating, Maintenance and Administrative Expenses

OM&A expenses reflect costs required to operate, maintain, and sustain the electricity distribution operations, including new expenditures to address regulatory changes.

As illustrated in the following chart, ERHDC's OM&A expenditures have increased from the OEB approved $1.598 million in 2012 to the 2020 bridge year amount of $1.531 million, an average annual increase of 1.50%.



Among the items ERHDC is requesting in its Cost of Service rate application which are not currently in expenses being recovered in rates are increased costs to complete a Cost of Service rate application and increased annual OEB fees.

ERHDC's OM&A expenses have increased from the OEB approved $1.388 million in 2012 to the 2021 rate request amount of $1.757 million, an average annual increase of 3.27%. The increase from the 2020 Bridge Year to the 2021 Test Year can mostly be attributed to one-fifth of the cost of the Cost of Service application ($200,000) included in the 2021 Test Year. The average annual increase from the 2012 approved to the 2021 test year is 1.53% excluding the Cost of Service application costs.

In comparison to the 1.53% increase noted above, the average inflationary increase from to 2013 to 2020 as published by the OEB less ERHDC's productivity factor is 1.55% as indicated in the following chart.

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Inflation (IPI)	1.60%	1.70%	1.60%	2.10%	1.90%	1.20%	1.50%	2.00%	2.00%
Productivity Factor	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
Net	1.45%	1.55%	1.45%	1.95%	1.75%	1.05%	1.35%	1.85%	1.85%
							ave. 2013 to 2020	1.55%	

Operational synergies are not yet possible prior to the amalgamation because of ERHDC's obligations under, and PUC's rights under, the PUC Services Agreement. For this reason, PUC will continue to provide services to ERHDC pursuant to the PUC Services Agreement.

5.4 Capital Expenditures

Capital investments are required to maintain adequate security of supply to meet customer needs, as well as to replace end-of-life assets. For this application, an adjusted Distribution System Plan (DSP) which includes adoption of current age, visual inspection and formal testing data as inputs has been developed to replace its aging infrastructure. The plan indicates the areas of the distribution system that should be the focus of resources to maintain reliable service to customers. Upgrading of existing substations will be addressed after the 2022 merger.

Historical Capital Expenditures (net of recoveries)

2012	2013	2014	2015	2016	2017	2018	2019
$284,741	$702,552	$1,742,548	$269,376	$369,381	$690,898	$383,816	$421,653

(Capital expenditures include Sub 4 which is being carried in regulatory assets)

Projected Capital Expenditures (net of recoveries)

2020	2021
$644,600	$463,429

5.5 Financing

Financing consists of existing debt for the smart meter implementation, Substation 4, and the purchase transaction, and new debt for the Cost of Service Application expenses and capital expenditures in 2020 and 2021. During the period prior to the amalgamation of ERDHC and North Bay Hydro, ERHDC has seen significant increases in its debt to equity ratios and reduced ratios tied to liquidity. However, with the proposed amalgamation in 2022 this situation will be temporary. Once amalgamated, the new North Bay Hydro will have strong liquidity and debt service ratios as well as more optimal debt to equity ratios with financial capacity for any necessary borrowing.

6 CONCLUSIONS

ERHDC's 2020 to 2021 Business Plan presents a challenging financial picture for the company, balancing reliability, and service to customers with affordability. All costs and projected revenues have been closely examined and reasonable assumptions respecting growth and expected OEB rate increases have been used.

The OEB's 4th Generation IRM framework will continue to challenge ERHDC's management to find operational savings and efficiencies throughout the organization to achieve reasonable financial results. Although a short-term capital replacement plan is in place, ongoing monitoring of cash flow levels and updated asset condition assessments will necessitate constantly reviewing the plan as more information becomes available to balance reliability and affordability.

Management remains confident that with a successful outcome to the Cost of Service rate application and the North Bay Hydro merger, the financial challenges will not prevent attaining ERHDC's goals of exceeding the service quality indicators as detailed on the LDC scorecard, replacing infrastructure in an effective and prudent manner, maintaining rates at a reasonable level and providing a return to the shareholder.

Appendix A

Pro Forma Financial Statements

Espanola Regional Hydro Distribution Corp.
Results of Operations

	For the Year Ending December 31	
	2020 Estimated	2021 Budget
Revenue		
Net Electricity Distribution Revenue	$ 1,605,977	$ 2,094,396
Other Revenue	$ 156,323	$ 143,862
	$ 1,762,300	$ 2,238,258
Expenses		
Operations	$ 723,495	$ 734,963
Billing, Collecting & Administrative	$ 809,111	$ 1,021,352
Operating Expenses	$ 1,532,606	$ 1,756,315
Depreciation	$ 177,755	$ 229,039
Operating and Depreciation	$ 1,710,361	$ 1,985,354
Income from Operating	$ 51,939	$ 252,904
Interest Expense	$ 366,795	$ 386,453
Income before taxes	$ (314,856)	$ (133,549)
Income taxes	$ -	$ -
Net Income	$ (314,856)	$ (133,549)
Opening Retained Earnings	$ (462,820)	$ (777,676)
Net Income	$ (314,856)	$ (133,549)
Dividends	$ -	$ -
Closing Retained Earnings	$ (777,676)	$ (911,225)

Espanola Regional Hydro Distribution Corp.
Balance Sheets

	For the Year Ending December 31			
		2020 Estimated		2021 Budget
Assets				
Current Assets	$	3,061,520	$	3,585,278
Goodwill	$	3,322,007	$	3,322,007
Net Fixed Assets	$	5,584,680	$	7,651,195
Regulatory Assets	$	2,697,028	$	729,153
	$	14,665,235	$	15,287,632
Liabilities				
Current Liabilities	$	2,412,828	$	2,412,828
Notes Payable	$	10,925,012	$	11,279,854
Deferred Revenue	$	345,940	$	345,940
Other Long Term Liabilities	$	591,673	$	591,673
Regulatory Liabilities	$	567,358	$	567,358
	$	14,842,811	$	15,197,653
Shareholder Equity				
Common Shares	$	100	$	100
Retained Earnings	$	(177,676)	$	89,879
	$	(177,576)	$	89,979
Total Liabilities and Shareholder Equity	$	14,665,235	$	15,287,632

Espanola Regional Hydro Distribution Corp.
Statement of Cash

	For the Year Ending December 31			
	2020 Estimated		2021 Budget	
Opening Cash	$	317,887	$	118,696
Net Income	$	(314,856)	$	(133,549)
Add Depreciation	$	205,035	$	256,319
Less Net Capital Expenditures	$	(644,600)	$	(463,429)
Add Loan Proceeds	$	1,244,600	$	863,429
Add Recovery of Regulatory Assets	$	-	$	108,470
Less Principle Repayments	$	(89,370)	$	(108,587)
	$	(600,000)	$	(400,000)
Ending Cash	$	118,696	$	241,350

APPENDIX 1-J
OEB Appendix 2-A List of Requested Approvals

Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

North Bay Hydro Distribution Limited - Espanola service territory is seeking the following approvals in this application:

1		Approval to charge rates effective May 1, 2021 to recover a revenue requirement of $2,272,419 which includes a revenue deficiency of $449,736 as set out in Exhibit 6
2		Approval to transition to fully-fixed rates for residential customers
3		Approval of the proposed loss factor of 1.0673 as set out in Exhibit 8
4		Approval to charge a Retail Transmission Network Service rate as proposed and described in Exhibit 8
5		Approval to continue to charge Wholesale Market Service Charge
6		Approval to continue the Specific Service Charges and Transformer Allowance
7		Approval to dispose of Account 1508, Other Regulatory Assets, sub-accounts for Distribution Station 4 which was subject of an ICM application (EB-2013-0127)
8		Approval of the rate riders for disposition of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") and Lost Revenue Adjustment Mechanism ("LRAM") for lost revenue for the 2011-2019 program years, with persistence to April 30, 2021. For additional information, please refer to Exhibit 4
9		Approval of the rate riders for disposition of the Group 1 and Group 2 and Other Deferral and Variance Accounts as detailed in Exhibit 9
10		Approval of the updated province-wide fixed monthly charge of $4.55 for MicroFIT 11 Generator Service Classification
11		Approval to continue to use Account 1509 – Impacts Arising from the COVID-19 Emergency
12		May 1, 2016 interim rates be declared final rates
13		Such other approvals as ERHDC may advise and the OEB may deem as just and reasonable.

APPENDIX 1-K
Certificate of Evidence

(see attached)

APPENDIX 1-K
Certificate of Evidence

I, Matt Payne, President and Chief Executive Officer of Espanola Regional Hydro Distribution Corporation certify that the evidence filed is accurate, consistent, and complete to the best of my knowledge.

Matt Payne, P.Eng.
President and CEO