EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

2021 Cost of Service

Halton Hills Hydro Inc.
EB-2020-0026

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1.2 EXECUTIVE SUMMARY

1.2.1 INTRODUCTION

Halton Hills Hydro. (HHHI") is pleased to present its Cost of Service application for rates effective May 1, 2021. This application consists of the following Exhibits, and Excel live models in support of the evidence presented in this application.

- ✓ Exhibit 1: Administrative Documents
- ✓ Exhibit 2: Rate Base and DSP
- ✓ Exhibit 3: Revenues
- ✓ Exhibit 4: Operation, Maintenance and Administrative Costs
- ✓ Exhibit 5: Cost of Capital
- ✓ Exhibit 6: Revenue Requirement
- ✓ Exhibit 7: Cost Allocation
- ✓ Exhibit 8: Rate Design
- ✓ Exhibit 9: Deferral and Variance Accounts

- ✓ EB-2020-0026 HHHI Benchmarking Forecast Model
- ✓ EB-2020-0026 HHHI Cost Allocation
- ✓ EB-2020-0026 HHHI LRAMVA Workform
- ✓ EB-2020-0026 HHHI PILs Workform
- ✓ EB-2020-0026 HHHI Rev Req Workform
- ✓ EB-2020-0026 HHHI RTSR Workform
- ✓ EB-2020-0026 HHHI Load Forecast Model
- ✓ EB-2020-0026 HHHI GA Analysis Workform
- ✓ EB-2020-0026 HHHI COS Checklist
- ✓ EB-2020-0026 HHHI Tariffs of Rates and Charges and Bill Impacts
- ✓ EB-2020=0026 HHHI Version of Chapter 2 Appendix 2-C
- ✓ EB-2020-0026 HHHI DVA Continuity Schedule

- ✓ EB-2020-0026 HHHI Chapter 2 Appendices [1]

All documents have been submitted to the OEB via their website.

The application along with all supporting evidence will also be posted on the utility's website and customers informed of the filing via Social Media once the application is accepted by the Ontario Energy Board ("OEB" or the "Board").

1.2.2 EXECUTIVE SUMMARY AND BUSINESS PLAN[2]

Halton Hills Hydro Inc. ("HHHI") is an innovative local distribution company ("LDC") which distributes electricity within the municipal boundaries of the Town of Halton Hills. The service territory covers 281 sq. km including 26 sq. km of urban and 255 sq. km of rural territory. The urban areas encompass the towns of Acton and Georgetown as well as several smaller hamlets. HHHI continues to maintain a strong and reliable infrastructure covering a large service area with fewer customers per sq. km to bear the cost. HHHI continues to look for efficient and resourceful ways to provide excellent service.

HHHI is owned by Halton Hills Community Energy Corporation who is wholly owned by the Town of Halton Hills. The utility services approximately 22,400 customers. Approximately 20,332 of those customers are residential, 1,895 small commercial, 193 renewable generation connections and the remaining customers spread across the remaining customer classes.

HHHI's mission statement is to "Provide Halton Hills with Electricity Distribution Excellence in a safe and reliable manner" and demonstrated by the following eight (8) strategic goals.

- Safety – for customers, employees and the general public;

[1] MFR - Chapter 2 appendices in live Microsoft Excel format
[2] MFR - Plain language description of objectives and business plan and how they relate to the application and the RRFE objectives. Description should aid the OEB in understanding the impacts of the business plan on key areas such as customer service, system reliability, costs and bill impacts. Description of how customer feedback is reflected

- Reliability – reliability of electricity supply, reliability of service, reliability of customer care;
- Competitive Rates – customers understand the value proposition in fair and reasonable rates for the services provided;
- Financial Metrics – balancing shareholder and customer expectations, stable rate setting, reasonable rate of return;
- Conservation – exploring energy conservation opportunities for customers and the utility;
- Environmental – finding ways to reduce waste, conserve and minimize the environmental footprint of the organization while strengthening the distribution system against the impacts of climate change;
- Community Focused – proud part of the Town of Halton Hills, active, visible presence in the community, exceeding customers' expectations;
- Smart Grid Implementation – building a resilient distribution system with future technology in mind, leveraging technology for customer service, system reliability and data security.

Safety and reliability are top priorities for the utility and are two keyways the utility strives to provide distribution excellence to customers.

HHHI's mission and strategic objectives lay the foundation for the 2021-2025 strategic plan and Corporate Business Plan. The strategic plan is still pending approval from HHHI's Board of Directors and will be provided upon request and its Board of Director approval. The 2020 Corporate Business Plan is shown in Appendix 1-1.

HHHI's 2021-2025 strategic plan is built around the theme of resiliency. The strategic plan sets out the corporation's goals, strategies and priorities that will guide the annual business planning and budgeting processes for the next five (5) years.

This plan is the foundation for the five (5) year distribution system plan and reflects a collaborative effort and shared vision of the entire leadership team at HHHI. It is a forward-looking plan, which strikes a balance between customer and shareholder expectations while preparing the utility for the future. It anticipates and sets strategies for change in the utility, technology, customer expectations and in the environment.

HHHI's innovation culture to find efficiencies and create a strong value proposition will continue to be a priority. Within HHHI, anticipated staffing changes will necessitate a strong succession planning strategy.

Risk management is one of the key priorities of this plan as the utility prepares its grid to be more resilient to climate change and its systems to be more resilient to cyber security threats. HHHI established an Enterprise Risk Management Framework in 2012, which provides a risk-based approach to strategic planning and decision-making. Effective risk management occurs through consistent monitoring, communication and reporting of those risks that might have a material impact on operations, financial performance, regulatory compliance and the reputation of HHHI. Risk management is incorporated into the corporation's strategic and business planning processes and supports major decisions throughout the organization.

HHHI strongly believes in Customer Service and strives to always provide great service to customers. A comprehensive discussion of HHHI's customer engagement efforts, the customer feedback and preferences identified as a result of these efforts and steps HHHI is taking to ensure that customer preferences are being addressed as part of its business activities, are included in a more comprehensive discussion in the Customer Engagement and Customer Focus section later in this Exhibit.

Customer needs and expectations continue to evolve. In particular, customers are connecting more renewable energy and backup generation and installing more electric vehicle charging stations, all of which require innovative thinking to integrate seamlessly with the traditional electricity grid. Additionally, customers are requesting more innovative methods to manage their bills.

The Town of Halton Hills expects to see significant growth in coming years; in particular, the Vision Georgetown development is expected to break ground within the window of this plan. The utility is prepared to handle this growth while managing capital expenditures and applying prudent asset management principles to replacing aging infrastructure.

This application supports the achievement of the four (4) key OEB established performance outcomes as identified in the Renewed Regulatory Framework for Electricity Distributors ("RRFE"):

- 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.

HHHI's 2018 OEB Scorecard including Management Discussion and Analysis in addition to HHHI's 2019 Draft OEB Scorecard are included as Appendix 1-2. It is evident from the Scorecard metrics that HHHI continues to exceed OEB standards. In particular, HHHI continues to prudently manage costs and for seven (7) consecutive years, HHHI has remained in Group 1 of the PEG report; OEB's Benchmark model most recent report dated August 2019. As evidenced in Table 1 - Summary of Cost Benchmarking, HHHI continually performs under predicted costs; on values related to 2016 to 2018, HHHI is currently operating at 28.4% below predicted costs. Additionally, HHHI has forecasted 2019, 2020 Bridge Year and 2021 Test Year Cost Benchmarking.

Table 1 - Summary of Cost Benchmarking

Summary of Cost Benchmarking Results

Cost Benchmarking Summary	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 (Bridge)	2021 (Test Year)	2022 Forecast	2023 Forecast
Actual Total Cost	17,028,654	16,934,734	17,821,525	15,861,465	16,799,832	17,937,568	18,374,897	18,802,766
Predicted Total Cost	22,429,778	22,492,011	23,853,248	25,155,628	26,545,058	27,795,572	29,086,739	30,411,572
Difference	(5,401,124)	(5,557,277)	(6,031,723)	(9,294,163)	(9,745,226)	(9,858,004)	(10,711,842)	(11,608,807)
Percentage Difference (Cost Performance)	**(27.5%)**	**(28.4%)**	**(29.2%)**	**(46.1%)**	**(46.6%)**	**(42.7%)**	**(45.2%)**	**(47.3%)**
Three-Year Average Performance					(40.6%)	(45.1%)	(44.8%)	(45.1%)
Stretch Factor Cohort								
Annual Result	1	1	1	1	1	1	1	1
Three Year Average	1	1	1	1	1	1	1	1

It is important to note that even with the 2021 Test Year increases, HHHI is forecasting to remain in Group 1 of the PEG report.

The Distribution System Plan ("DSP") is a document that details HHHI's historical capital expenditures and lays the foundation for the next five (5) years of capital expenditures. The key drivers for all investments in HHHI's DSP are aligned with the asset management objectives as outlined in Section 3.2 of the DSP:

- Safety for employees and the community is the number one priority, always.
- Reliability for supply of electricity, reliable customer service.
- Just and reasonable rates for residential and business customers.
- Financial Metrics, ensuring a stable return on investment for the shareholder, the Town of Halton Hills.
- Conservation, promoting energy conservation programs to help our customers save energy and money.

- Environmental, ensuring HHHI considers the environment in purchasing and operating practices.
- Community Focused and proud to be a part of the Town of Halton Hills, participating in community events and supporting the community.
- Smart Grid Implementation of technology to monitor and maintain the electricity system.

The key metrics used to measure DSP success are identified below. The table below summarizes HHHI's key performance targets.

Table 2 - HHHI's Key Performance Targets

Performance Indicator	Target
Reliability (SAIDI)	1.32 hours
Reliability (SAIFI)	1.61 Incidents
Customer Satisfaction Index	90%
Billing Accuracy	98%
PEG Report Benchmarking	Maintaining a stretch factor assignment within the top grouping
ESA Reg 22/04	0 Non-Compliance
Substation Loading	Peak Demand <= Nameplate

Historical capital expenditures are shown in Table 28 - Historical and Planned Capital Expenditures. Proposed capital expenditures by category are summarized in Table 29 - Historical and Forecasted Capital Expenditures by Category or Table 3 - Historical Capital Expenditures by OEB Category below.

Table 3 - Historical Capital Expenditures by OEB Category

CATEGORY	Historical Period															Forecast Period (planned)				
	2016			2017			2018			2019			2020			2021	2022	2023	2024	2025
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Budget	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	1,161	1,161	(0.0%)	886	1,587	79.1%	3,331	2,182	(34.5%)	967	1,796	85.7%	2,524	2,524	0.0%	2,530	1,810	3,243	2,999	2,099
System Renewal	4,120	4,991	21.2%	4,227	4,601	8.8%	2,818	4,196	48.9%	3,891	3,406	(12.5%)	2,070	2,070	0.0%	2,362	2,669	1,427	1,776	2,425
System Service	2,303	2,035	(11.6%)	2,411	1,574	(34.7%)	2,959	1,747	(41.0%)	3,321	2,000	(39.8%)	1,525	1,525	0.0%	882	1,111	1,424	968	1,099
General Plant	778	491	(36.9%)	479	793	65.4%	421	496	17.9%	425	654	53.8%	621	621	0.0%	828	582	607	694	618
TOTAL EXPENDITURE	**8,361**	**8,678**	**3.8%**	**8,004**	**8,555**	**6.9%**	**9,529**	**8,622**	**(9.5%)**	**8,605**	**7,856**	**(8.7%)**	**6,741**	**6,741**	**0.0%**	**6,602**	**6,172**	**6,701**	**6,437**	**6,241**
Capital Contributions	652	655	0.4%	596	1,451	143.6%	1,741	998	(42.7%)	711	833	17.2%	1,068	1,068	0.0%	1,135	885	1,479	1,391	997
Net Capital Expenditures	**7,709**	**8,023**	**4.1%**	**7,408**	**7,104**	**(4.1%)**	**7,788**	**7,624**	**(2.1%)**	**7,894**	**7,023**	**(11.0%)**	**5,673**	**5,673**	**0.0%**	**5,467**	**5,287**	**5,222**	**5,046**	**5,244**

Table 4 - Forecasted Capital Expenditures by OEB Category

				Forecast Period (planned)				
CATEGORY	**2020**			**2021**	**2022**	**2023**	**2024**	**2025**
	Plan	**Actual[2]**	**Var**					
	$ '000		%	*$ '000*				
System Access	$2,524	$2,524	0.0%	$2,530	$1,810	$3,243	$2,999	$2,099
System Renewal	$2,070	$2,070	0.0%	$2,362	$2,669	$1,427	$1,776	$2,425
System Service	$1,525	$1,525	0.0%	$882	$1,111	$1,424	$968	$1,099
General Plant	$621	$621	0.0%	$828	$582	$607	$694	$618
TOTAL EXPENDITURE	$6,741	$6,741	0.0%	$6,602	$6,172	$6,701	$6,437	$6,241
Capital Contributions	$1,068	$1,068	0.0%	$1,135	$885	$1,479	$1,391	$997
Net Capital Expenditures	$5,673	$5,673	0.0%	$5,467	$5,287	$5,222	$5,046	$5,244
System O&M	$1,708	$1,708	0.0%	$1,982	$2,031	$2,082	$2,134	$2,187

<u>System Access</u>

These projects include customer connections, new development, renewable generation connections, service upgrades for safety reasons, municipal relocation projects where the utility is required to relocate infrastructure to accommodate road improvement projects.

<u>System Renewal</u>

System renewal projects are investments a distributor makes involving replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services. These projects are distributor driven. HHHI's goal with system renewal projects is to ensure the assets used in the delivery of power as well as the supporting infrastructure are in good condition, are safe to operate, and will continue providing reliability to customers. This category includes plans to replace defective, obsolete, and end-of-useful life assets.

<u>System Service</u>

System service projects are investments a distributor makes involving modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. These projects are distributor driven; they address system constraints, and promote operational effectiveness. HHHI's goal with system service projects is to ensure the distribution system is free of constraints that may impact system functionality and increases the utilities ability to operate the distribution system. The identified projects demonstrate system planning and the effective execution of the projects will provide system reliability and prepare for long-term growth.

<u>General Plant</u>

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities

Investments to improve reliability are an important part of HHHI's asset management strategy. In particular, this DSP focuses on a number of programs to proactively replace aging equipment. In particular, the failure of certain types of assets such as porcelain switches and insulators have been the source of a number of larger power outages in the Town of Halton Hills. Through 2018 and 2019, HHHI replaced eleven (11) porcelain switches and four (4) porcelain insulators. HHHI plans to continue to proactively replace these devices in the field. HHHI's proactive replacement strategy has led to a reduction in equipment failure power outages. It is also a strategy strongly supported by HHHI's customers as seen through customer engagement initiatives. As such, proactive replacement continues to be a strong priority for HHHI investment.

Historical performance in the other metrics indicate that targets can be achieved with existing processes, practices, resources, etc. and as such preclude the need for specific investments in the DSP to address any of their targets.

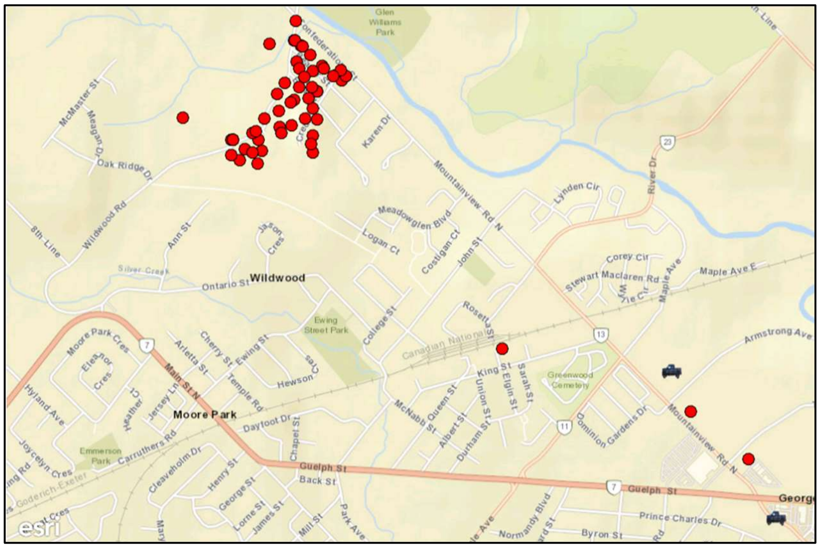
Future performance, outside of the targets, would trigger re-evaluation for inclusion in a subsequent DSP.

Realized efficiencies due to smart meters

HHHI leverages smart meter data for engineering analysis and for power outage information through its SmartLook Operational Data Store operated by Savage Data Systems.

Utilizing the last gasp functionality within the smart meters, outage information is mapped in real time providing a smart meter based outage management system. Currently, this system is used to assist in providing accurate customer facing outage maps on HHHI's corporate website and social media feeds. As well, HHHI's metering department leverages this tool to 'ping' meters to confirm outage status. This feature provides cost savings and efficiency gains to HHHI by confirming meter power status without requiring a truck roll. Future plans include rolling out this tool to the control room to provide them with sub-feeder level access to power outage information. The Outage Management System ("OMS") map includes layers from the utility's Geographic Information System ("GIS") showing switches and feeders as well as Global Positioning System ("GPS") coordinates of crew vehicles. There is a potential for increased efficiency in power outage restoration through the intelligence provided through this map.

Table 5 – Advanced Metering Infrastructure ("AMI") data used for Outage Management

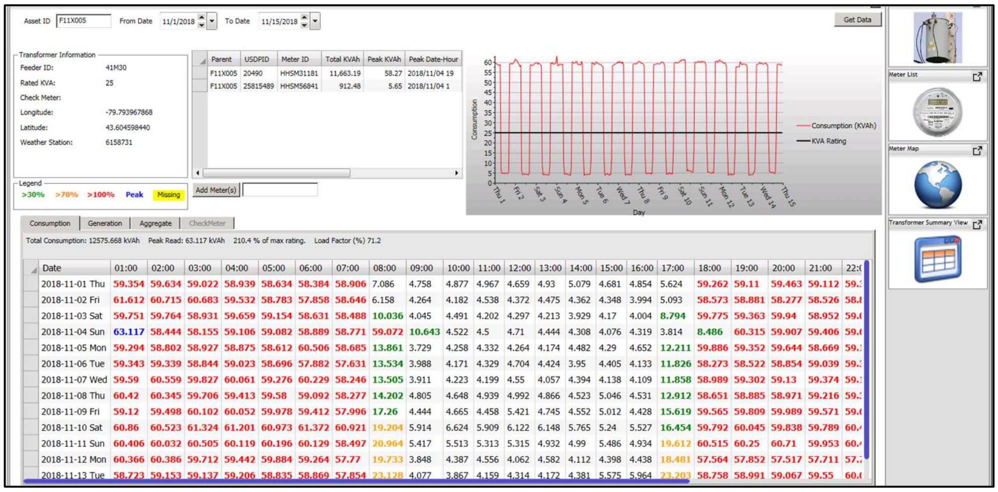


HHHI's engineering staff leverage the data provided through the AMI ODS for transformer loading. Overloaded or under loaded transformers are mapped based on any date range and percent of loading. This allows for proactive identification of extremely heavily loaded transformers.

When undertaking design jobs such as pole-line rebuilds, AMI data is utilized to run various transformer loading scenarios to optimize size and placement of assets.

As HHHI continues to look for innovative opportunities for cost savings, efficiency gains and accommodation of new technologies, the AMI data will be leveraged further.

Table 6 - Sample Transformer Loading screen from ODS



In addition to the efficiencies, noted above HHHI's customers also benefit from the data these meters provide.

Application

HHHI is applying to the OEB for just and reasonable rates and other service charges for the distribution of electricity effective May 1, 2021. These reflect the need to recover $5,422,387 not covered by existing rates. The main drivers of the increase are shown below in Table 7 - Calculation of Revenue Deficiency.

1 **Table 7 - Calculation of Revenue Deficiency**

Service Revenue Requirement	**2016 Board Approved**	**2021 Revenue at Exiting Rate Rates Allocated in Proportion to 2016 Board Approved**	**2021 Test Year Proposed**	**Revenue Deficiency**
	(A)	***(B)***	***(C)***	***D= (C) - (B)***
OM&A, including LEAP	6,007,592	6,398,630	7,580,262	1,181,632
Property Tax	104,440	111,238	157,546	46,308
Depreciation	1,508,054	1,606,214	3,611,342	2,005,128
Return on Equity	2,257,893	2,404,861	3,552,813	1,147,953
Deemed Interest	1,035,156	1,102,535	2,143,902	1,041,367
Service Revenue Requirement	**10,913,135**	**11,623,478**	**17,045,865**	**5,422,387**
				Rate Base Difference
				E = (C) - (A)
Rate Base	**61,422,556**		**104,249,216**	**42,826,661**

2

3 **Financial Viability**

4 Financial viability is one of the performance measurements defined in the OEB's RRFE for electricity
5 distributors. The four (4) financial metrics included are liquidity, leverage, deemed return on equity
6 and achieved return on equity. Historically, HHHI has not achieved the Deemed Regulated Return
7 on Equity. HHHI's metrics for historical years 2016 to 2019 are shown in Table 8 - Actual ROE
8 compared to Deemed ROE below.

9 **Table 8 - Actual ROE compared to Deemed ROE**

Financial Ratios		**2016**	**2017**	**2018**	**2019**
Liquidity Ratio		0.91	1.08	0.46	0.86
Leverage Debt to Equity Ratio		1.13	1.31	1.88	2.34
Return on Equity	Deemed	9.19%	9.19%	9.19%	9.19%
	Achieved	6.76%	6.98%	7.07%	4.24%

10

11

Load Forecast

HHHI's Load Forecast predicts a reasonable increase in customers / connections, consumptions (kWhs) and demand (kWs) as shown in detail in Exhibit 3 with the exception of the General Service 1,000 to 4,999 kW class which is expected to see a significant decrease in customers, consumption and demand and the General Service less than 50 kW which will see a modest decrease. This decrease is a result of: (i) customers either closing their business or moving production to other locations; or (ii) installing combined heat and power equipment to reduce consumption and demand requirements.

HHHI has utilized a variable in the load forecast to adjust for the implications of COVID-19.

Incremental Capital Module – Municipal Transformer Station (EB-2018-0328)

HHHI built a new Municipal Transformer Station (MTS1) as recommended by the IESO in their GTA West Regional Planning. MTS1 was commissioned in November 2019.

1.2.3 COVID-19 IMPACT

The COVID-19 outbreak was declared a pandemic by the World Health Organization on March 11, 2020. This has resulted in governments worldwide, including the Canadian and Ontario governments, enacting emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally and in Ontario resulting in an economic slowdown.

Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions; however, the success of these interventions is not currently determinable.

The current challenging economic climate may lead to adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct impact on the HHHI's operating results and financial position in the future.

The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and HHHI's business are not known at the time of filing this application.

1.2.4 SUMMARY OF APPLICATION INTENDED FOR HHHI CUSTOMERS[3]

Halton Hills Hydro Inc. ("HHHI") is an innovative local distribution company ("LDC") which distributes electricity within the municipal boundaries of the Town of Halton Hills. The service territory covers 281 sq. km including 26 sq. km of urban and 255 sq. km of rural territory. The urban areas encompass the towns of Acton and Georgetown as well as several smaller hamlets. HHHI maintains 1,687 kilometers of medium- and low-voltage distribution circuits that transport electricity from the provincial transmission grid. HHHI continues to maintain a strong and reliable infrastructure covering a large service area with fewer customers per square km. HHHI always looks for efficient and resourceful ways to provide excellent service.

Halton Hills Community Energy Corporation ("HHCEC"), incorporated under the Business Corporations Act (Ontario), is the parent holding company of Halton Hills Hydro Inc. The Corporation of the Town of Halton Hills (Municipal Shareholder) is the sole shareholder of HHCEC.

Halton Hills Hydro Inc. (HHHI) has applied to the Ontario Energy Board for a change in the distribution rates that it charges its customers. The distribution rates are based on the amount of capital investments made by HHHI as well as the cost to operate and maintain the distribution system, along with a percentage for a return on equity to the Town of Halton Hills.

Customer engagement is an important driver for HHHI's planning process. In 2019, the utility launched an innovative, cost effective customer engagement platform. The customer engagement website, HaveYourSay customer engagement platform was promoted extensively through e-mails to customers, HHHI's social media pages on Facebook, Twitter, LinkedIn and Instagram and through Google. The website features discussion forums, quick polls, surveys and an information blog providing information on utility projects and practices. This unique approach to customer

[3] MFR – Summary of Application

engagement provided a meaningful way for customers to contribute to the Distribution System Planning process at a fraction of the cost of conventional customer engagement methods. The Electricity Distributor's Association recognized this innovative customer engagement platform with the 2019 Communications Excellence Award.

HHHI regularly and proactively engages with customers throughout the year. The utility has an active presence on social media with over 33% of its customers engaged through Facebook, Twitter, Instagram and LinkedIn. This is one of the highest following rates of any LDC in Ontario. HaveYourSay.HaltonHillsHydro.com provided customers an opportunity to learn about HHH's distribution system planning process, contribute to idea forums and participate in surveys in support of this plan. The website also allowed interactive customer conversation. The goals of the HaveYourSay customer engagement platform were as follows:

- Inform customers on the distribution system planning process
- Engage customers in the conversation about electricity cost and reliability
- Collaborate with customers through surveys, polls and idea forums to gain an understanding of customer's needs and preferences
- Reach as wide a customer audience as possible
- Achieve statistically relevant survey responses
- Keep customers informed throughout the entire planning process

Frequent posts kept customers aware of HHHI activity, projects, power outages and electrical safety information. Customers were able to engage in an ongoing dialogue with the utility throughout the year through these platforms.

HHHI engages with the community at a number of community events throughout the year including Earth Day, Acton Leathertown Festival, Canada Day in Glen Williams and the Acton and Georgetown Santa Claus Parades. Staff throughout the organization participate in these events providing customers a chance to interact directly with their utility. In 2019, HHHI held its third Community Open House providing customers with a chance to tour their utility, engage with staff and learn about utility operations.

Some of the key messages heard from customer feedback include:

- Proactive replacement strategy – Customer response is strongly in favour of a proactive asset replacement strategy to improve reliability even if it results in increased costs. In particular, commercial customer responses reflected a strong preference for proactive replacement strategies.
- Reliability vs Cost - Balancing system reliability with affordable rates continues to be a priority for customers.
- Accommodating renewable energy resources and addressing climate change: Preparing to integrate distributed energy resources and other new technologies is important as HHHI plans for the future. HHHI's customers agree. Over 70% of responses are in favour of HHHI investing to be prepared for new technologies. There were a number of customer comments related to grid modernization, particularly in the context of climate change and the environment. Comments focused on the need for solar power/renewable energy as a way to reduce greenhouse gases and address climate change.
- Customers trust HHHI to make the right decisions, and trust HHHI to maintain its existing investment strategy.

The lessons learned through the customer engagement strategy have informed the Distribution System Plan and HHHI operations.

HHHI provides customers with a robust AccountOnline portal where customers are able to view their detailed energy consumption including comparisons to prior periods and predictions for the current bill. Customers can set up events to record changes in habits or equipment in their home and view the impact of these events on their consumption. For example, a customer could record installing a hot tub and then view the impact on their consumption. Customers can also set up alerts and notifications if their current bill reaches a certain dollar threshold or consumption value. The images below show the AccountOnline customer dashboard and a detailed energy use graph.

Table 9 - AccountOnline portal Dashboard

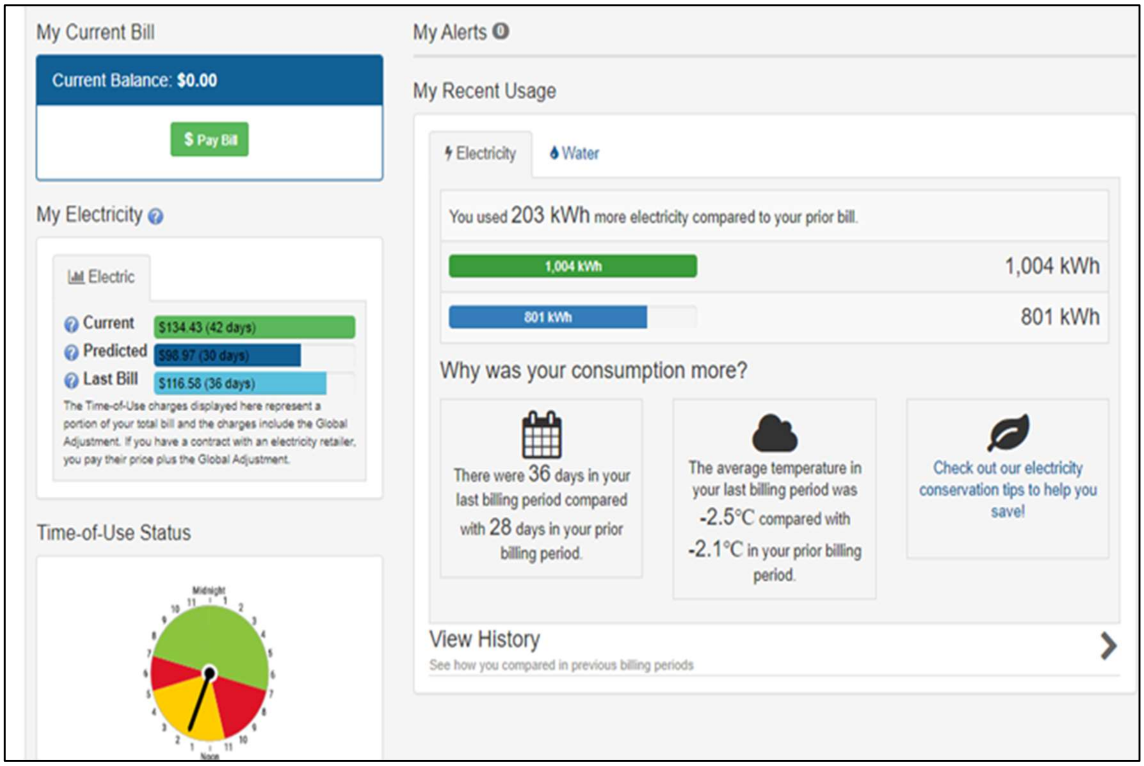
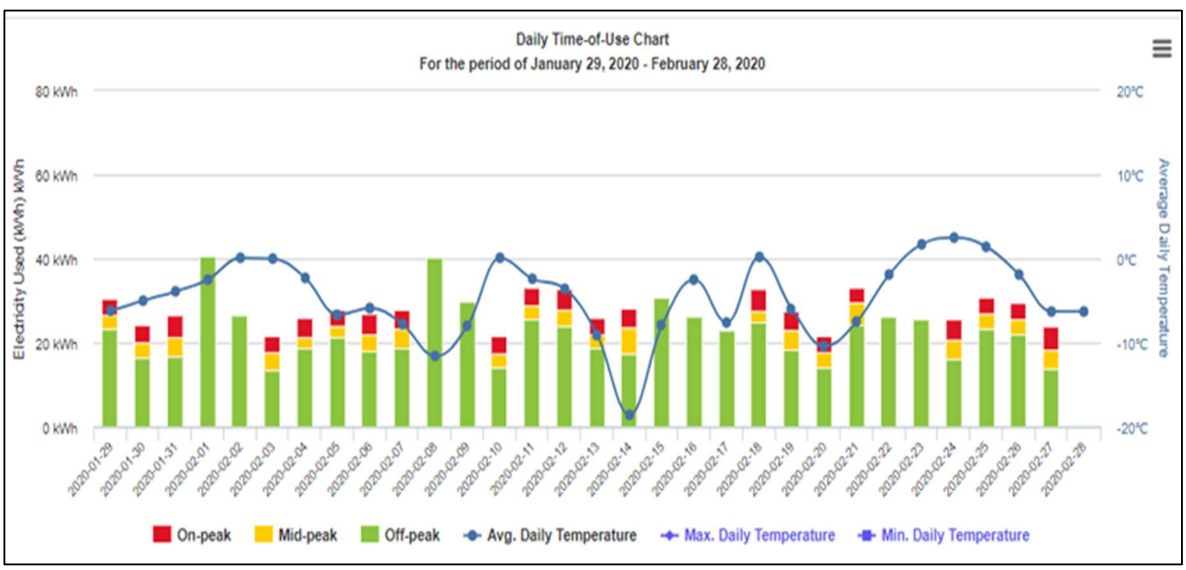


Table 10 - AccountOnline consumption graph



HHHI is measured by the Ontario Energy Board on specific metrics which include:

- Connecting new services in a timely manner

- Meeting customers for appointments on time
- Answering customer calls within 30 seconds, at least 65% of the time
- Resolving customer's issues the first time
- Ensuring customers' bills are accurate
- Results of a Customer Satisfaction Survey
- Public Awareness of Safety
- Compliance with electrical safety requirements
- Electrical incident reporting
- Average number of hours that power to a customer is interrupted
- Average number of times that power to a customer is interrupted
- Maintaining capital expenditures within approved amounts
- Cost per kilometre of distribution wire
- Cost per customer
- Conservation and Demand targets
- Maintaining financial viability through sound financial planning
- Efficiency rankings amongst all electrical utilities in the province

HHHI has always ranked high in all OEB metrics and in most cases, performing significantly better than the OEB standards. The OEB Scorecard for 2014 to 2018 is located on HHHI's website. The 2019 draft Scorecard can be seen in Appendix 1-2 of this rate application before the OEB.

A key metric in utility cost efficiency and effectiveness is the annual Pacific Economics Group (PEG) performance benchmarking report. This report evaluates all Ontario LDCs to determine whether the LDC is spending more money than expected or less money than expected. The report uses data filed by the LDCs to predict how much each LDC should spend. On data filed for 2016, 2017 and 2018, HHHI was determined to be operating at 28.4% below predicted costs. HHHI continues to prudently manage costs and maintain one of the top cost efficiency ratings of LDC's in the Province and has established a target to remain within the top group; one of only six (6) LDCs in the province.

Since HHHI last rebased, HHHI has achieved the following:

- Built and commissioned an HHHI owned Municipal Transformer Station ("MTS")
    - The MTS will provide Halton Hills with the necessary capacity for Vision Georgetown. Through an innovative agreement to connect to the grid through the Halton Hills Generating Station, HHHI was able to save HHHI customers significant dollars by avoiding the need to cross highway 401.
- HHHI implemented a new Decision Support System ("DSS")
    - For the purposes of the Distribution System Plan, the DSS system focuses on poles, transformers, and stations, however, other assets will be integrated into this system over time. The DSS ensures a cost-effective Asset Management strategy through balancing asset condition evaluation and cost to ensure the right assets are replaced at the right time. This strategy ensures prudent spending ensuring safety and cost effectiveness.
- Implemented Government Initiatives such as the Fair Hydro Plan, Ontario Energy Rebate and COVID-19 Off-Peak Billing.
- Launched the HaveYourSay customer engagement platform
    - The website features discussion forums, quick polls, surveys and an information blog providing information on utility projects and practices. This unique approach to customer engagement provided a meaningful way for customers to contribute to the Distribution System Planning process at a fraction of the cost of conventional customer engagement methods.
    - The Electricity Distributor's Association ("EDA") recognized this innovative customer engagement platform with the 2019 Communications Excellence Award.
- Renegotiated loan term debt to mitigate interest rate risk and reduce interest expense to the benefit of the ratepayers
- Maintained operational effectiveness while navigating working from home through the COVID-19 pandemic
- Promoted innovation through Relentless Incrementalism
    - HHHI actively engaged staff through the Creative and Critical Thinking initiative to find additional cost efficiencies throughout the LDC. A new program that HHHI began in 2017 focused on "Relentless Incrementalism" – small steps that make a

difference and help pave the way for more significant change. This initiative involves all staff members examining processes and procedures and implementing changes that create cost savings, efficiencies and/or benefit customers. These efficiencies have been reflected in this application.

  - The Electricity Distributor's Association ("EDA") recognized this innovative customer engagement platform with the 2017 Innovation Excellence Award.

- The Application that results in the rate impacts noted below include a capital and operating plan for 2021. The total proposed revenue requirement for 2021 is $17,045,865. This will allow HHHI to:
  - Replace and refurbish poles, transformers and wires,
  - Invest in additional cybersecurity
  - Ensure reliable supply of electricity
  - Connect new customers
  - Accommodate municipal and regional plans
  - Maintain system assets
  - Offer locate services
  - Provide responsive customer service and billing
  - Ensure staff are well trained to work safely and effectively.
  - The bill impact to residential and small business (General Service less than 50 kW) customers for the 2021 proposed rates compared to the 2020 rates is:

Class	Impacts			
	Distribution		Total Bill	
	$	%	$	%
Residential - Time of Use (750kWhs)	$ 6.83	21.58%	$ 5.44	4.49%
General Service Less Than 50 kW (2,000 kWhs)	$ 29.74	50.72%	$ 23.65	7.93%

Further details about the Application are found on HHHI's website - https://haltonhillshydro.com/about/regulatory/ or customers can contact the HHHI office for more details.

1.3 ADMINISTRATIVE

1.3.1 CONTACT INFORMATION[4]

Application contact information is as follows:

Applicant's Address for Service:	43 Alice St.
	Halton Hills (Acton), ON L7J 2A9
	(519) 853-3700
Contact Information	President and Chief Executive Officer:
	Arthur (Art) A. Skidmore, CPA, CMA
	Tel: (519) 853-3700, ext. 225
	Fax: (519) 853-5592
	Email: askidmore@haltonhillshydro.com
	Chief Financial Officer:
	David J. Smelsky, CPA, CMA, C.Dir.
	Tel: (519) 853-3700, ext. 208
	Fax: (519) 853-5592
	Email: dsmelsky@haltonhillshydro.com

[4] MFR - Primary contact information (name, address, phone, fax, email)

Primary Application Contact:

David J. Smelsky, CPA, CMA, C.Dir.
(Contact info above)

Applicant's Counsel: Osler, Hoskin & Harcourt LLP
100 King Street West
1 First Canadian Place
Suite 6200, P.O. Box 50
Toronto, ON M5X 1B8

Primary Legal Contact: Richard King
Partner

Telephone:	(416) 862-6626
Email:	rking@osler.com
Fax:	(416) 862-6666

1.3.2 CONFIRMATION OF INTERNET ADDRESS[5]

Halton Hills Hydro Inc. website: www.haltonhillshydro.com

The EB-2020-0026 Application can be viewed at: https://haltonhillshydro.com/about/regulatory/

Customer Engagement website https://haveyoursay.haltonhillshydro.com/

Specific project pages within the Customer Engagement site related to cost of service customer engagement include:

- Help Shape Our Future – engagement through ideas, polls, surveys & Q&A: https://haveyoursay.haltonhillshydro.com/help-shape-our-future
- Learning Pages – articles, videos and blogs about the distribution system, planning process, rates and cost: https://haveyoursay.haltonhillshydro.com/learn-about-us
- Why Participate? – Call to action to explain the project and why customer input matters: https://haveyoursay.haltonhillshydro.com/why-participate

Social Media Platforms:

- Facebook: https://www.facebook.com/haltonhillshydro
- Twitter: https://twitter.com/HHHydro
- Instagram: https://www.instagram.com/haltonhillshydro/
- LinkedIn: https://www.linkedin.com/company/halton-hills-hydro

[5] MFR - Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers

1.3.3 STATEMENT OF PUBLICATION[6]

Residents, businesses and institutions in the Town of Halton Hills who receive electricity distribution services from HHHI will be affected by the Application.

HHHI suggests publication of the Notice of Application in both The Independent Free Press, a free publication with a circulation of approximately 20,000 homes, and The New Tanner, a free publication with a circulation of approximately 15,000 homes. Utilizing both publications offers a wide distribution throughout all areas in the Town of Halton Hills.

The Application and related materials will be posted on the HHHI website and will be available for viewing on the HHHI website: https://haltonhillshydro.com/about/regulatory/

HHHI suggests the following be conveyed in the notice:

Table 11 - Bill Impacts for Notice

	Impacts			
Class	**Distribution**		**Total Bill**	
	$	**%**	**$**	**%**
Residential - Time of Use (750kWhs)	$6.83	23.13%	$5.44	4.93%
General Service Less Than 50 kW (2,000 kWhs)	$29.74	50.72%	$23.65	7.93%

HHHI is an innovative local distribution company ("LDC") which distributes electricity primarily within the municipal boundaries of the Town of Halton Hills. The service territory covers 281 sq. km including 26 sq. km of urban and 255 sq. km of rural territory. The urban areas encompass the towns of Acton and Georgetown as well as several smaller hamlets. HHHI continues to maintain a strong and reliable infrastructure covering a large service area with fewer customers per square km. HHHI continues to look for efficient and resourceful ways to provide excellent service.

[6] MFR - Statement identifying where notice should be published and why.

1.3.4 MATERIAL IMPACTS

Based on the bill impacts noted above, there are no proposed changes in the Application at this time that will have a material impact on any customer class. However, HHHI is seeking approval to implement a Standby / Capacity Reserve Charge for General Service customers with a demand greater than 50 kW and load displacement generation.

As a result of this Application, all customers will be affected by the proposed rate changes. A summary of the bill impacts for all rate classes is provide later in the Exhibit as shown in Table 12 - Total Bill Impacts.

1.3.5 LEGAL APPLICATION

APPLICATION

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O 1998, c15;

AND IN THE MATTER OF an Application by Halton Hills Hydro Inc. to the Ontario Energy Board for an Order or Orders approving of fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2021.

Applicant's Name: Halton Hills Hydro Inc.

1. The Applicant is Halton Hills Hydro Inc., further referred to in this Application as the "Applicant" or "HHHI". The Applicant is a corporation incorporated pursuant to the Business Corporations Act (Ontario) with its head office in the Town of Halton Hills (Acton). The Applicant carries on the business of distributing electricity as stated in HHHI's Licence ED-2002-0552.
2. The Applicant hereby applies to the Ontario Energy Board (the "Board") pursuant to Section 78 of the *Ontario Energy Board Act, 1998* as amended (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2021. A list of specific requested approvals is set out in this Exhibit 1. The Applicant is a corporation incorporated pursuant to the Business Corporations Act (Ontario) with its administration offices located at 43 Alice Street, Halton Hills (Acton). Ontario.
3. The Application has been prepared pursuant to the OEB's Renewed Regulatory Framework for Electricity Distributors as detailed in the Report of the Board dated October 18, 2012 (the "RRFE").
4. Unless specifically stated otherwise in the Application, the Applicant followed Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications last revised on May 14, 2020.

5. The Applicant has prepared a Consolidated Distribution System Plan ("DSP") in accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Transmission and Distribution Applications.
6. The Applicant acknowledges that the OEB will publish an update to the Cost of Capital Parameters and that these matters will affect the Revenue Requirement that the Applicant has requested in this Application.
7. The Applicant has filed a copy of the 2020 COS Checklist as an appendix to this Application.

A full list of approvals is presented in PDF format at Appendix 1-3 of this Exhibit.

Certification of accuracy and completeness of application:

HHHI hereby certifies that the application has been reviewed and approved by the Chief Financial Officer. The HHHI Board of Directors have been kept informed throughout the preparation of the budget and application, have passed a resolution approving the application. HHHI confirms that the information and evidence presented herein is accurate to the best of HHHI's knowledge. [7]

Confidential Information:

HHHI confirms that the application does not include any confidential information.[8]

[7] MFR - Certification by a senior officer that the evidence filed is accurate, consistent and complete
[8] MFR - Confidential Information - Practice Direction has been followed

Align rate year with fiscal year and proposed Effective Date of Rate Order:

HHHI is not proposing to align its rate year with its fiscal year in this proceeding. Therefore, no further adjustments are required in that respect.[9] HHHI notes that it has no special conditions in its license with the exception of an exemption to Section 6.5.3 of the Distribution System Code (Elimination of Load Transfer Arrangements) as per the Board Decision and Order in proceeding EB-2016-0366.

HHHI requests that the OEB make its Rate Order effective May 1, 2021 in accordance with the Filing Requirements.

[9] MFR - Aligning rate year with fiscal year - request for proposed alignment
MFR - List of approvals requested (and relevant section of legislation), including accounting orders - a PDF copy of Appendix 2-A should be provided in this section

1.3.6 BILL IMPACTS[10]

The proposed May 1, 2021 distribution rates proposed by HHHI will result in overall bill impacts for residential customers using 750kWh per month of $5.44 and General Service<50 using 2,000kWh per month of $23.65. General Service 50 to 999kW in expected to decrease by 1.71% and General Service 1,000 to 4,999 is expected to increase by 0.11%. Unmetered Scattered Load are projected to increase by 0.83%, Sentinel Lighting will decrease by 5.00% and Street Lighting will go up by 1.44%. Table 12 - Total Bill Impacts below shows a summary of all components of the bill impacts.

A full list of the bill impacts applicable to all customer classes is found in Exhibit 8, Section 8.1.15 of this application. All HHHI's customers will be affected by this application.[11]

Table 12 - Total Bill Impacts

Rate Class	**Volumes**		**2020 Bill**	**2021 Bill**	**Total Bill Impact**
	kWhs	**kWs**	**$**	**$**	**%**
Residential - Time of Use	750	-	$121.05	$126.49	4.49%
General Service Less Than 50 kW	2,000	-	$298.22	$321.87	7.93%
General Service 50 to 999 kW	328,500	500	$50,916.29	$50,046.17	(1.71%)
General Service 1,000 to 4,999 kW	1,600,000	2,500	$232,630.00	$232,890.86	0.11%
Unmetered Scattered Load	150	-	$20.80	$20.98	0.83%
Sentinel Lighting	650	1	$113.33	$107.66	(5.00%)
Street Lighting	94,033	251	$27,559.97	$27,955.73	1.44%

[10] MFR - Bill impacts - distribution only impacts for 750 kWh residential and 2000 kWh GS<50 (sub-total A of Tariff Schedule and Bill Impact Spreadsheet Model) to be used for notice
[11] MFR - Statement identifying customers materially affected by the application including any change to any rate or charge and specific statement of what individual customer or customer groups would be affected by the proposed change

1.3.7 STATEMENT AS TO THE FORM OF HEARING REQUESTED[12]

HHHI requests that this Application be disposed of by way of a written hearing. A written hearing will be the most prudent and cost effective means to process the application. Additionally, with the current limitations related to COVID-19, a written hearing is in the best interest all participants.

1.3.8 PROPOSED ISSUES LIST[13]

In establishing the overall appropriateness of the proposed rates, HHHI anticipates that the following issues will be addressed by the Board and intervenors.

Planning

Capital

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriately and adequately explained, giving due consideration to:

- ✓ customer feedback and preferences
- ✓ productivity
- ✓ benchmarking of costs
- ✓ reliability and service quality
- ✓ impact on distribution rates
- ✓ trade-offs with OM&A spending
- ✓ government-mandated obligations, and
- ✓ the objectives of the Applicant and its customers.

[12] MFR - Form of hearing requested and why
[13] MFR - List of approvals requested (and relevant section of legislation), including accounting orders - a PDF copy of Appendix 2-A should be provided in this section

OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

- ✓ customer feedback and preferences
- ✓ productivity
- ✓ benchmarking of costs
- ✓ reliability and service quality
- ✓ impact on distribution rates
- ✓ trade-offs with capital spending
- ✓ government-mandated obligations, and
- ✓ the objectives of the Applicant and its customers.

Revenue Requirement

- ✓ Are all elements of the Revenue Requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?
- ✓ Has the Revenue Requirement been accurately determined based on these elements?

Load Forecast, Cost Allocation, and Rate Design

- ✓ Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the number and energy and demand requirements of the applicant’s customers?
- ✓ Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?
- ✓ Are the applicant’s proposals, including the proposed fixed/variable splits, for rate design appropriate?
- ✓ Are the proposed Retail Transmission Service Rates and Low Voltage Service Rates appropriate?

Accounting

- ✓ Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?
- ✓ Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, and the continuation of existing accounts appropriate?

1.3.9 STATEMENT OF DEVIATION OF FILING REQUIREMENTS[14]

HHHI has not, to the best of its knowledge, deviated from the Ontario Energy Board's ("OEB") 2021 Filing Requirements for Electricity Distribution Rate Applications last revised May 14, 2020

1.3.9 Changes in Methodologies[15]

The projections for the 2021 Test Year were prepared in accordance with HHHI's budget process as described in Section 1.5 of this Exhibit. All processes are in compliance with policies, directives and rules and guidelines from the OEB and other regulators.

1.3.10 BOARD DIRECTIVE FROM PREVIOUS DECISIONS[16]

<u>2016 Cost of Service – EB-2015-0074 – Settlement Agreement</u>

a) Section 2.1 – Revenue Requirement, part (c) – Cost of Capital states:

"*HHHI acknowledges that establishment of the debt rate on the Promissory Note at 4.12% is not reflective of an agreement by the Parties to establish the debt rate at any deemed or default*

[14] MFR - Statement identifying all deviations from Filing Requirements; identify concerns with models or changes to models
[15] MFR - Statement identifying and describing any changes to methodologies used vs previous applications
[16] MFR - Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision)

rate. HHHI agrees that prior to its next cost-of-service application, it will conduct a review of long-term debt financing options available to HHHI, and will file the results of such review in its next cost-of-service application.”

The Board approved the Settlement Agreement in its Decision and Order dated March 24, 2016. While the Board did not specifically issue a directive, HHHI has treated this section of the Settlement Agreement as such. The review has been completed and the details are included in Exhibit 5 of this application.

<u>2018 IRM – EB-2017-0045 – Decision and Rate Order</u>

a) HHHI requested approval from the OEB to establish a deferral and variance account (“DVA”) to record an annual adjustment to revenue requirement of $330,259 for the period 2016 to 2021 (or until such time as HHHI’s next cost of service rate application). The annual amount relates to an error HHHI identified in the calculation of depreciation expense in its last cost of service (EB-2015-0074) application for May 1, 2016 rates.

   In its Decision and Rate Order, the OEB found:

   “*The OEB will approve the establishment of a deferral account effective January 1, 2018 subject to the following conditions:*

- *No amounts for 2016 and 2017 may be recorded in the deferral account.*
- *An amount of $330,259 per year shall be recorded in the deferral account until such time as the effective date of Halton Hills Hydro’s rates from its next rebasing rate application (cost of service or custom incentive rate-setting). This amount is the depreciation error of $339,393 less return on capital.*
- *No interest will apply to the balance in the deferral account as depreciation expense is a non-cash item.*
- *No disposition of the deferral account will be permitted if Halton Hills Hydro’s actual regulated ROE exceeds the OEB’s approved ROE for the aggregated period from January 1, 2018 until December 31 of the last audited fiscal year for the next rebasing application.*
- *Disposition of the deferral account will be determined as part of Halton Hills Hydro’s next rebasing (cost of service or custom incentive rate-setting application).*

- *Halton Hills Hydro shall report the balance in the deferral account annually as part of the OEB's reporting and record-keeping requirements using Account 1508, Other Regulatory Assets, sub-account Net Deferred Depreciation*."

HHHI has complied with the OEB findings. Deferred Depreciation in the amount of $330,259 was posted to Account 1508, Other Regulatory Assets, sub-account Net Deferred Depreciation for 2018 and 2019 and are shown in Exhibit 9 – Deferral and Variance Accounts. Forecasted amounts were also entered on the Continuity Schedule for 2020 and for January 1, 2021 to April 30, 2021. No carrying charges were applied to the Account and the year end balances were reported in HHHI's annual filings to the OEB. As seen in Exhibit 5 – Cost of Capital and Capital Structure, HHHI's ROE was far below the OEB approved 9.19% ROE in each year. HHHI has requested disposition of the balance, including forecasted amounts up to April 30, 2021. Further details can be found in Exhibit 9.

<u>2019 Incremental Capital Module Application – EB-2018-0328 – Decision and Rate Order</u>

a) HHHI commissioned a new Municipal Transformer Station, MTS1 in November of 2019. As a result of the costs to build MTS1, HHHI requested recovery of incremental revenue requirement related to the costs associated with MTS1, based on estimated construction costs, through the OEB's Incremental Capital Module. In its Decision and Rate Order dated April 4, 2019, the OEB found that HHHI had met the eligibility criteria of materiality, need and prudence.
b) In EB-2018-0328, HHHI also requested recovery of incremental OM&A costs incurred by owning and operating MTS1. In its Decision and Rate Order, the OEB denied the request for incremental OM&A recovery.
c) As part of the ICM application, HHHI requested the OEB deem MTS1 a Distribution Asset. The OEB deemed the new TS to be a distribution asset pursuant to section 84(a) of the OEB Act.
d) To track the costs associated with MTS1, HHHI agreed to use generic 1508 sub-accounts to record ICM/ACM related capital expenditures, depreciation expenses, rate riders and carrying charges as per the ACM report and the Filing Requirements. HHHI had requested

an additional 1508 sub-account to track incremental OM&A costs. The OEB denied the request for the additional account.

2020 IRM – EB-2019-0039 – Decision and Rate Order

a) In is findings related to Group 1 Deferral and Variance Accounts ("DVA"), the OEB stated:

"*The OEB approves Halton Hills Hydro's request to defer the disposition of its Group 1 account balances to its 2021 rates application as the OEB is unable to determine if the account balances are reasonable in the current proceeding. This is, in part, because Halton Hills Hydro was unable to prepare a substantive response to OEB staff's questions of January 28, 2020 and, in the result, there is insufficient information on the record to make that determination.*

The OEB accepts Halton Hills Hydro's proposal to respond to OEB staff's questions at a later date. This finding is made in the light of the fact that Halton Hills Hydro has committed to providing supporting information for its Account 1588 and Account 1589 balances in its next application for 2021 rates. The OEB also notes that as part of providing this supporting information, Halton Hills Hydro has agreed to provide a substantive response to the questions raised by OEB staff in this proceeding, address the list of items detailed in its letter, and perform a review of its true-up processes…

…In its 2021 rates application, Halton Hills Hydro shall then provide a status update on the implementation of the new accounting guidance, a review of historical balances, results of the review, and any adjustments made to account balances (i.e. Account 1588 and Account 1589).

It is also the OEB's expectation that Halton Hills Hydro will apply for disposition of all eligible Group 1 accounts in its 2021 rate application, given the several years of balances that have accumulated to date."

HHHI conducted an augmented review of the Accounting Guidance on the commodity accounts, dated February 21, 2019, including the OEB Regulated Price Plan ("RPP") Settlement model. As part of the review, HHHI implemented the OEB RPP Settlement model and completed the model for settlement from January 2017 to current. As a result of the review, HHHI determined that adjustments were required to Account 1588 – Cost of Power and Account 1589 – Global Adjustment. The adjustments are reflected in the Exhibit 9 2021 DVA Continuity Schedule model and are detailed, with explanations and supporting documentation in Exhibit 9. HHHI believes that the details of the adjustments and the detailed description of HHHI's revised settlement and true-up processes answer the questions raised by the Board Staff in EB-2019-0039.

As an additional review measure, HHHI conducted an overview of the RPP Settlement process, utilizing the OEB RPP Settlement model, with HHHI's audit firm KPMG.

HHHI has requested disposition of Group 1 balances with this application. Details are provided in Exhibit 9.

1.3.11 CONDITIONS OF SERVICE

HHHI's Conditions of Service is current as of August 2020 and is available on the HHHI website (https://haltonhillshydro.com). Since last filing a Cost of Service, HHHI has revised its Condition of Service in 2018, 2019 and 2020. Changes made to the Conditions of Service were to provide clarification for customers related to various requirements, reflect OEB Customer Service Rules and provincial legislative changes, align with relevant Code revisions and address load displacement requirements. The Conditions of Service contains a change history at the end of the document.

There are no rates or charges listed in the Conditions of Service that are not on HHHI's Tariff of Rates and Charges. The Conditions of Service will be updated as a result of this Application for the proposed Standby/Capacity Reserve Charge.[17]

1.3.12 ACCOUNTING STANDARDS FOR REGULATORY AND FINANCIAL REPORTING

Changes in Tax Status:[18]

HHHI is a corporation incorporated pursuant to the Ontario Business Corporations Act and has not had a change in tax status since its last Cost of Service Application.

Existing/Proposed Accounting Orders[19]

The Accounting Standard Board ("AcSB") adopted MIFRS for qualifying rate-regulated entities on January 1, 2015. In accordance with a Board's letter of July 17, 2013, electricity distributors electing to remain on CGAAP were required to implement regulatory accounting changes for depreciation expenses and capitalization policies by January 1, 2013.

HHHI confirms it implemented the regulatory accounting changes for depreciation in 2015 with restatement of 2014. The herein 2021 Cost of Service Application is being filed based on the MIFRS accounting basis.

[17] MFR - Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided
[18] Any change in tax status
[19] Accounting Standards used for financial statements and when adopted

Accounting Standard used in Application

HHHI adopted International Financial Reporting Standards ("IFRS") effective January 1, 2015 with restatement to January 1, 2014 balances ("transition date"). HHHI adopted Modified International Financial Reporting Standards (MIFRS) for rate making purposes effective January 1, 2015 and follows the OEB's Accounting Procedures Handbook ("APH"). [20]

In this Application, HHHI presents all years under MIFRS.

Employee Pension and Benefits.

Projected post-retirement benefits and projections used in the Application were provided to HHHI by its independent advisor and actuary, RSM Canada Consulting LP, a firm of consultants and actuaries with considerable experience in the field of pensions and benefits. This application includes relatively consistent annual cost related to the post-retirement benefits, aligned with the latest (December 31, 2019) actuarial valuation. The December 31, 2019 actuarial valuation report is provided in Appendix 4-4 of Exhibit 4.

Compliance with the Uniform System of Accounts[21]

HHHI has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

The useful lives proposed by HHHI in this Application are consistent with the typical useful lives in the HHHI specific Kinectrics Report shown in Exhibit 4.

HHHI has not capitalized administration and other general overhead costs, which is, in any event, no longer permitted under MIFRS.

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[20] MFR - State accounting standard(s) used in historical, bridge and test years. Provide a summary of changes to its accounting policies made since the applicant's last cost of service filing. Identify all material changes or confirm no material changes in the adoption of IFRS. Appendix 2-Y

[21] Existing accounting orders and departures from the accounting orders and USoA

HHHI has also adopted the various account changes prescribed by the Board in relation to the USoA (Article 210 – Chart of Accounts and Account 220 – Account Descriptions). Consistent with recent applications to the Board, HHHI no longer includes tax in its OM&A cost estimates. Regulatory costs related to this 2021 Cost of Service application have been normalized by allocating one fifth of those costs to the 2021 Test Year.

Monthly Billing[22]

HHHI confirms that all its customers are billed on a monthly basis.

1.3.13 ACCOUNTING TREATMENT OF NON-UTILITY RELATED BUSINESS

The accounting for any non-utility related business activities is segregated from HHHI's rate regulated activities in accordance with the Board's Accounting Procedures Handbook for Electricity Distributors.

HHHI provides services to SouthWestern Energy Inc. related to water billing. HHHI confirms that the accounting treatment of any non-utility business was segregated activities from rate regulated activities for that time period.[23]

1.3.14 CORPORATE ORGANIZATION[24]

Halton Hills Community Energy Corporation ("HHCEC"), incorporated under the Business Corporations Act (Ontario), is the parent holding company of Halton Hills Hydro Inc. The

[22] MFR - Statement confirming that the distributor will have implemented monthly billing for all customers by December 31, 2016
[23] MFR - Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities
[24] MFR - Description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control

Corporation of the Town of Halton Hills (Municipal Shareholder) is the sole shareholder of HHCEC.

The Municipal Shareholder appoints directors to the Board of Halton Hills Hydro Inc.

The Board of Directors of HHHI consist of:

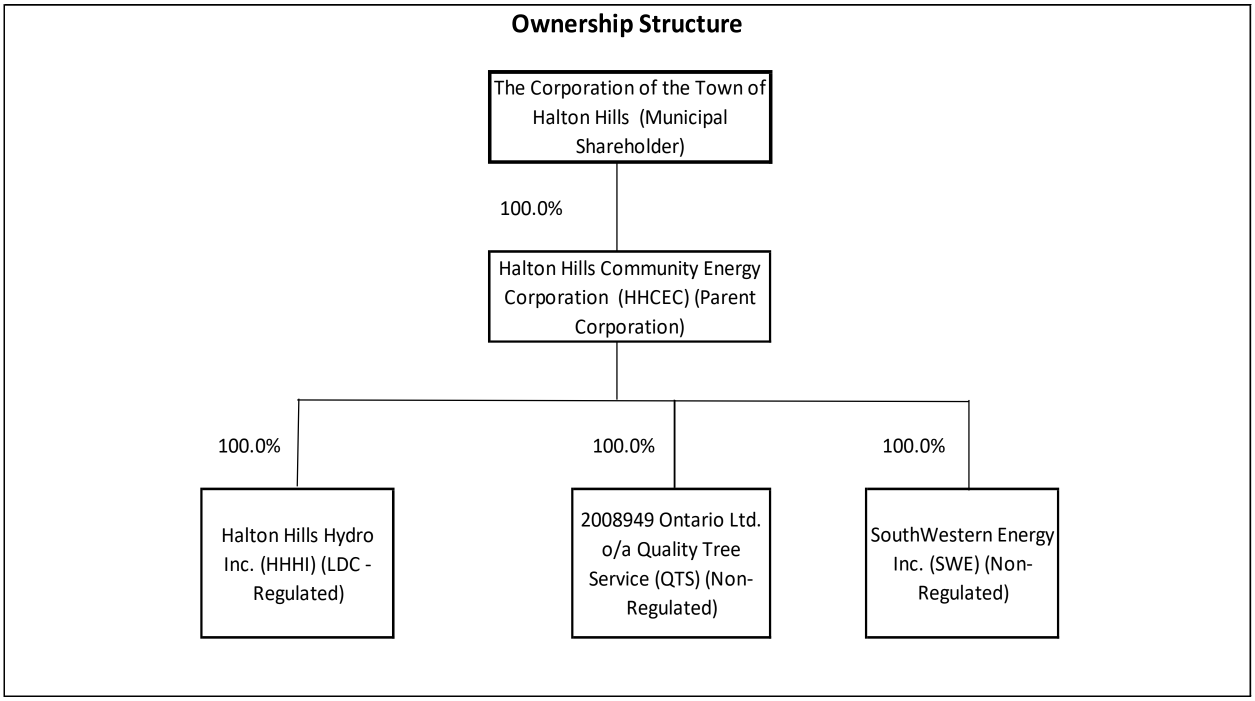
- Mayor of the Town of Halton Hills
- CAO of the Town of Halton Hills
- Five (5) to seven (7) independent directors

There are no planned changes in corporate or operational structure, as well as no changes to its legal organization and control.

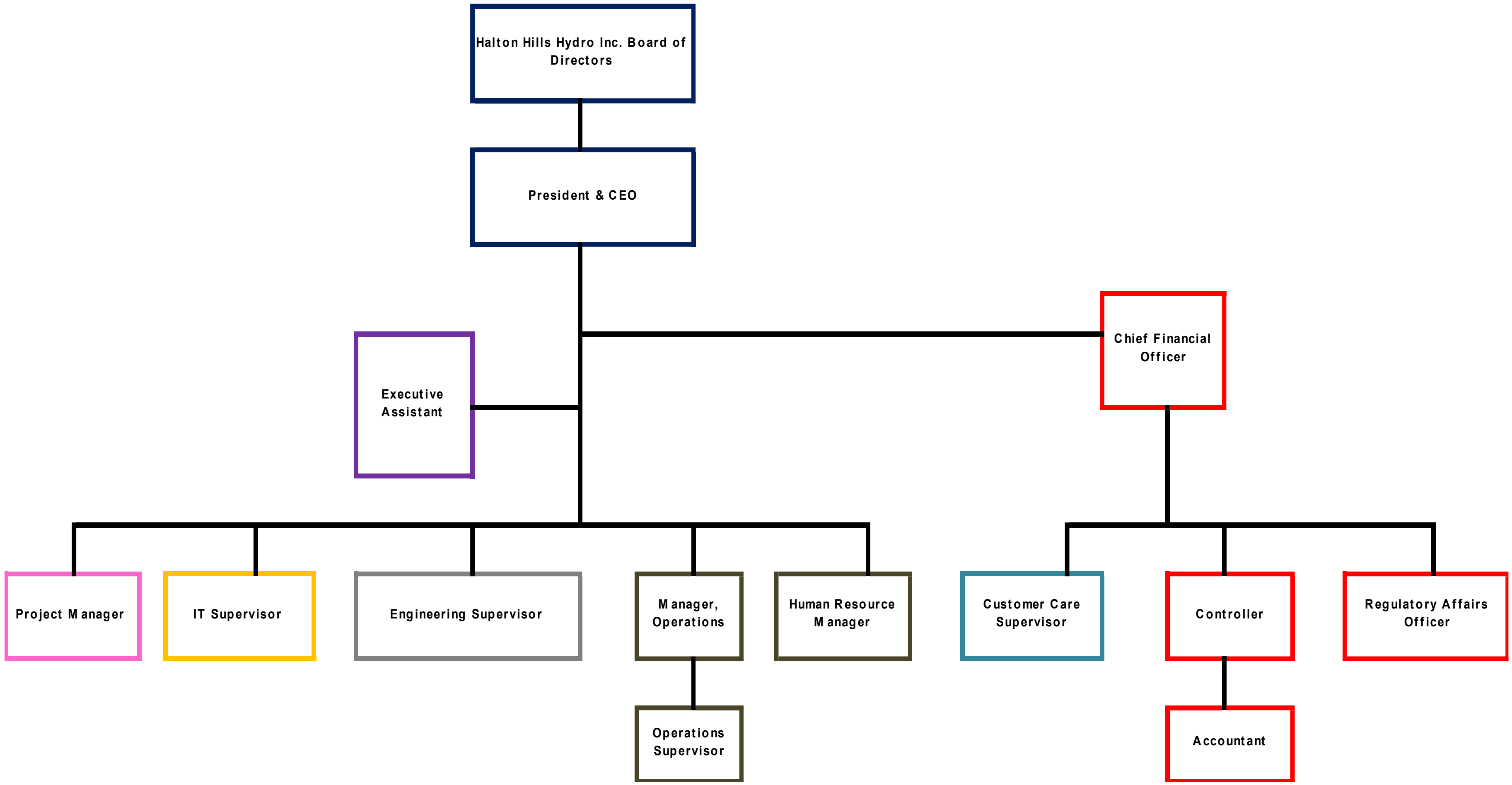
Table 13 - HHHI Ownership Structure and

Table 14 - Utility Organization Chart for Halton Hills Hydro Inc. demonstrates the reporting relationships between management and the parent company.

Table 13 - HHHI Ownership Structure



1 **Table 14 - Utility Organization Chart for Halton Hills Hydro Inc.**



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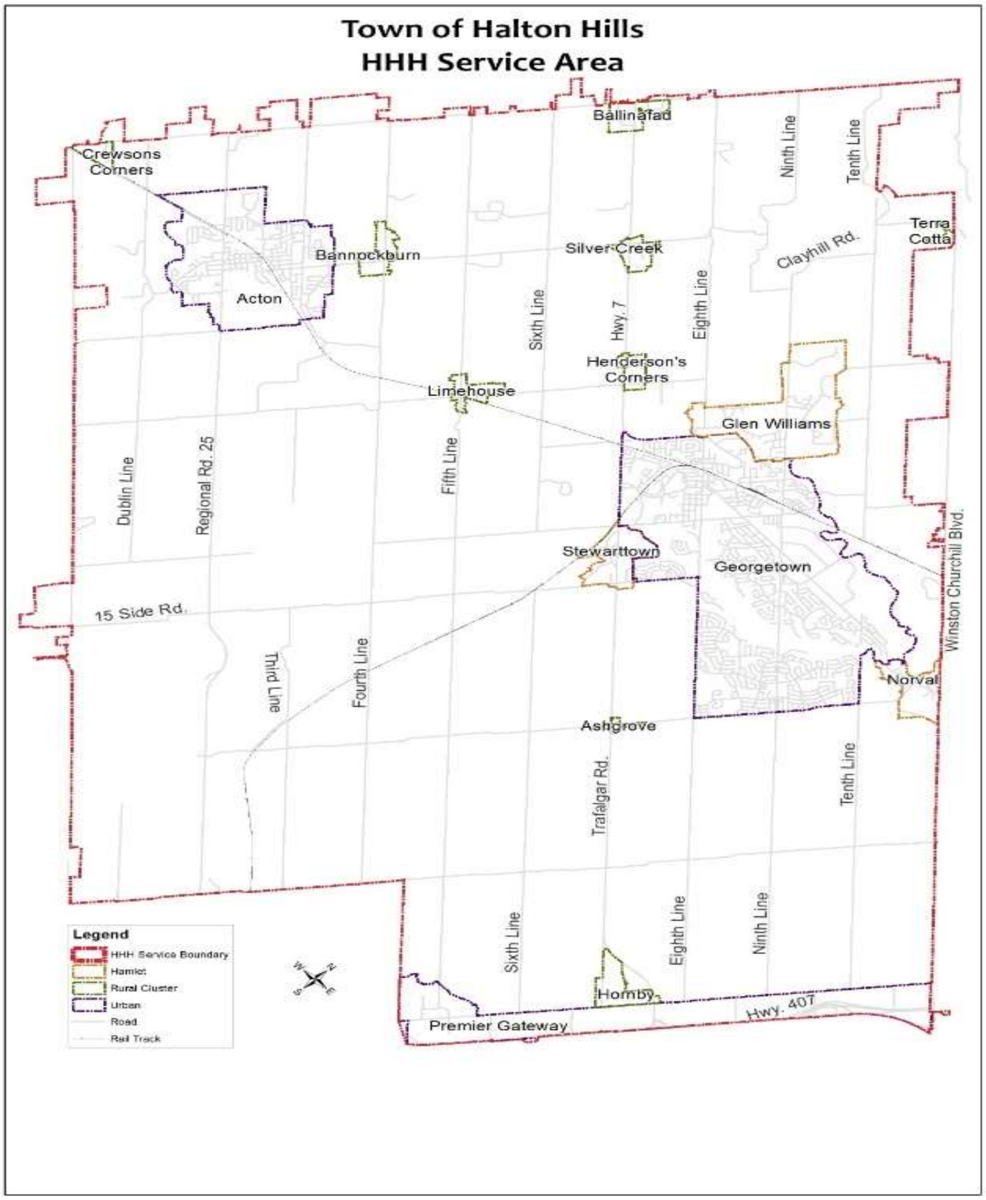
1.4 DISTRIBUTION OVERVIEW

1.4.1 SERVICE AREA

HHHI's service territory covers 281 square kilometers. 255 sq. km of the territory is rural and the remaining 26 sq. km is urban. The urban areas encompass the towns of Acton and Georgetown as well as several smaller hamlets. The Applicant carries on the business of distributing electricity as stated in HHHI's Licence ED-2002-0552. HHHI currently has long-term load transfers with Alectra Utilities for customers on Winston Churchill Blvd. between 5 Side Road and Tenth Line.

Table 15 - Map of Urban and Rural Service Territory



HHHI's distribution network consists of one (1) Municipal Transformer Station, twelve (12) municipal substations and 1,687 km of underground and overhead distribution lines. HHHI is owned by Halton Hills Community Energy Corporation who is wholly owned by the Corporation of the Town of Halton Hills. The utility services approximately 22,400 customers. Approximately 20,332 of those customers are residential, 1,895 small commercial, 193 renewable generation connections and the remaining customers spread across the remaining customer classes.

HHHI distributes electricity at the sub-transmission and primary distribution voltage levels listed below:

- Three-phase three-wire 44 kV sub-transmission
- Three-phase four-wire 16/27.6Y kV distribution
- Three-phase four-wire 4.8/8.32Y kV distribution
- Three-phase four-wire 2.4/4.16Y kV distribution

HHHI maintains 1,687 kilometers of medium- and low-voltage distribution circuits that transport electricity from the provincial transmission grid. The utility receives primary supply from four (4) locations as follows:

- Three-phase three-wire 44 kV sub-transmission – HHHI has three (3) feeder positions (designated 42M23, 42M25 and 42M28) from the Hydro One Networks Inc. ("HONI") owned Pleasant Transformer Station;
- Three-phase three-wire 44 kV sub-transmission – HHHI shares a feeder position with Milton Hydro, and Guelph Hydro (73M4) that emanates from the HONI owned Fergus TS;
- Three-phase four-wire 16/27.6Y kV distribution – HHHI has three (3) feeder positions (designated 41M21, 41M29 and 41M30) from the HONI owned Halton Transformer Station;
- Three-phase four-wire 16/27.6 kV distribution – HHHI has two (2) active feeder positions (1M2 and 1M5) with provisions for a total of eight (8)feeders from the HHHI owned Halton Hills MTS1 Transformer Station (deemed a distribution asset).

Twelve (12) municipal substations are strategically located throughout HHHI's service territory that provide 2.4/4.16Y kV primary distribution voltages in the urban areas (i.e. Action and Georgetown) and 4.8/8.32Y kV primary distribution voltages in the rural areas of the service territory.

1.4.2 EMBEDDED DISTRIBUTOR[25]

HHHI is bounded by four (4) LDC's, one of which is HONI on the north and east boundaries of HHHI's service territory. North of Halton-Erin Road (also known as 32 Side Road) HONI's distribution system is embedded to HHHI and is metered using a primary metering unit. The upstream supply point originates from HHHI's 44kV feeder (42M23) supplied from HONI's transformer station Pleasant TS DESN1 located in Brampton. The 42M23 feeder enters HHHI's service territory along Bovaird Drive, crosses rural territory (fields) through Norval, along 10 Side Road, Trafalgar Road, 27 Side Road, then 8th Line, at which point the 44kV is stepped down to 8.32kV at our municipal substation MS-1 near Halton-Erin Road. From municipal substation MS-1, the feeder 1-F1 extends north on 8th Line to 32 Side Road and then east of 32 Side Road one (1) pole span to the primary meter unit. The metering unit is the point at which connection is made to HONI's distribution system (demarcation point) and where HHHI's 1-F1 feeder terminates. At this same point, HHHI's assets end and any assets beyond the metering unit are HONI's.

For the purposes of completing Board Appendix 2-Q, HHHI estimated costs specifically related to HONI for the connection. In preparing its rate application, HHHI advised HONI that it is HHHI's intent to continue to bill HONI as a General Service 1,000 to 4,999 kW customer.

1.4.3 HIGH VOLTAGE ASSETS[26]

As part of HHHI's ICM application (EB-2018-0328), HHHI requested the OEB deem MTS1 a Distribution Asset. The OEB deemed the new TS to be a distribution asset pursuant to section 84(a) of the OEB Act.

[25] MFR - Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor. If the distributor is a host, the applicant should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes such as GS > 50 kW

[26] MFR - Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the OEB as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application

1.5 APPLICATION SUMMARY

This application was prepared using financial actuals from 2016, 2017, 2018 and 2019 along with forecasted budgets for 2020 Bridge Year and 2021 Test Year. Table 16 - Application Summary below lists the main elements of this application which are further discussed below and throughout the balance of the application exhibits.

Table 16 - Application Summary

Application Summary	**2021 Test Year $**
Revenue Requirement	
Base Revenue Requirement	$15,752,483
Revenue Offsets	$1,293,382
Service Revenue Requirement	$17,045,865
Revenue Deficiency	$5,422,387
Rate Base	$104,249,216
Working Capital	$4,892,243
OM&A (Excluding LEAP and Property Taxes)	$7,561,371
Captital Expenditures	$5,466,818

1.5.1 REVENUE REQUIREMENT (EXHIBIT 6) [27]

HHHI's requested Service Revenue Requirement for the 2021 Test Year is $17,045,865 which provides for the recovery of the following:

- Operation, Maintenance Expense;
- Administrative Expenses;
- Property Taxes;
- Depreciation/Amortization Expense;
- Return on Rate Base (Debt Interest Expense + Return on Equity)

[27] MFR - Revenue Requirement - service RR, increase ($ and %) from change from previously approved, main drivers

The Service Revenue requirement represents an increase of $6,132,730 or 56.2% over the Board Approved (EB-2015-0074) Service Revenue Requirement of $10,913,135.

Table 17 - Revenue Requirement Computation compares the revenue requirement calculations of the 2016 Board Approved and 2021 Test Year.

Table 17 - Revenue Requirement Computation

Application Summary	2016 Board Approved	2021 Test Year
Net Fixed Assets (Average)	$55,757,588	$99,356,973
Working Capital Allowance	$5,664,968	$4,892,243
Rate Base	**$61,422,556**	**$104,249,216**
Working Capital Allowance %	7.5%	7.5%
Regulated Return on Capital	$3,293,050	$5,696,715
OM&A including Property Taxes	$6,112,032	$7,737,808
Amortization Expense	$1,508,054	$3,611,342
PILs	$0	$0
Service Revenue Requirement	**$10,913,136**	**$17,045,865**
Less: Revenue Offsets	$959,144	$1,293,382
Base Revenue Requirement	**$9,953,992**	**$15,752,483**

Based on the projected load forecast and customer growth for the 2021 Test Year, as provided for in this Application, HHHI has estimated a revenue deficiency of $5,422,387 based on its current rates. The computation of the revenue deficiency is show in Table 18 - Calculation of Revenue Deficiency below, as provided in Exhibit 6.

Table 18 - Calculation of Revenue Deficiency

Service Revenue Requirement	**2016 Board Approved**	**2021 Revenue at Exiting Rate Rates Allocated in Proportion to 2016 Board Approved**	**2021 Test Year Proposed**	**Revenue Deficiency**
	(A)	***(B)***	***(C)***	***D= (C) - (B)***
OM&A, including LEAP	6,007,592	6,398,630	7,580,262	1,181,632
Property Tax	104,440	111,238	157,546	46,308
Depreciation	1,508,054	1,606,214	3,611,342	2,005,128
Return on Equity	2,257,893	2,404,861	3,552,813	1,147,953
Deemed Interest	1,035,156	1,102,535	2,143,902	1,041,367
Service Revenue Requirement	**10,913,135**	**11,623,478**	**17,045,865**	**5,422,387**
				Rate Base Difference
				E = (C) - (A)
Rate Base	**61,422,556**		**104,249,216**	**42,826,661**

The revenue deficiency of $5,422,387 for the 2021 Test Year is primarily a result of increases in the following components:

i. Increased depreciation;
ii. Increase in deemed interest expense
iii. Return on rate base due to increased rate base; and
iv. Increase in OM&A expenses

These factors are further explained below:

i. Depreciation has increased as a result of the increase in net fixed assets in service. The 2016 Board Approved average net fixed assets was $55,575,587 compared to $99,356,973 in the 2021 Test Year. Details with respect to the increases in the net fixed assets is provided in evidence in Exhibit 2;
ii. The increase in rate base is also the reason for the increase in deemed interest expense. Details of the increase is presented Exhibit 2;

iii. The return on rate base has increased as a result of a $42,826,661 increase in total Rate Base; and

iv. Increase in OM&A (including LEAP) is detailed in Exhibit 4. Please refer to Exhibit 4.

1.5.2 BUDGETING AND ACCOUNTING ASSUMPTIONS (EXHIBIT 4) [28]

Modified International Financial Reporting Standards ("MIFRS") were used in HHHI's 2016 Cost of Service Application (EB-2015-0074). There have been no additional changes resulting from the transition to IFRS. There are no additional impacts resulting from the transition to IFRS from CGAAP in this COS Application.

All years covered in this Application are presented in Modified IFRS ("MIFRS").

HHHI begins preparation of its annual budget in the third quarter (Q3) for the following year and receives final approval from its Board of Directors in November. Developing the budget is a key process as it identifies past successes as well as future initiatives and projections for capital and operating costs. Care is taken to ensure that the capital and operating budgets support HHHI's core business objectives as well as being prudent and financially sustainable.

For the purposes of this Application, annual budgets were prepared by HHHI's Leadership Team for the 2020 Bridge Year and the 2021 Test Year. Budgets are based on HHHI's strategic plan and annual business plans in addition to current inflation trends as per the consumer price index – Ontario.

[28] MFR - Budgeting and Accounting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards

1.5.3 LOAD FORECAST SUMMARY (EXHIBIT 3) [29]

With the assistance of Borden, Ladner and Gervais, LLP, HHHI used the same regression analysis methodology approved by the OEB in the 2016 HHHI Cost of Service (“COS”) application (EB-2015-0074). The regression analysis has been updated to include actual data to the end of 2019. The updated regression analysis used most of the same variables as those in the 2016 COS application. However, the Number of Customers variable was eliminated since it had a non-intuitive negative coefficient. The estimated monthly CDM activity was included as a variable and not added to the power purchase amount as was done in the 2016 COS application. This allowed the negative coefficient assigned to the Number of Customers variable to be reassigned to a variable in an intuitive manner. HHHI was also concerned with the process used in the 2016 COS application of adding the monthly CDM activity to the power purchased amount as it produced a total billed 2016 kWh amount that was never achieved on an actual and weather normal basis from 2016 to 2019. Additionally, by using the CDM monthly activity as a variable, a slightly better statistical result was produced.

With regards to the overall process of load forecasting, HHHI is of the view that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. HHHI has the data for the amount of electricity (in kWh) purchased from the IESO for use by HHHI's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year, which is converted to billed kWh by rate class. A detailed explanation of the process is provided Exhibit 3.

[29] MFR - Load Forecast Summary - load and customer growth, % change in kWh and customer numbers, methodology description

A summary of load and growth with variances, year over year, are shown in Table 19 - Summary of Billing Determinants and Average Consumption with Variances of Actual and Forecast Data Consistent with Appendix 2-IBbelow and further detailed in Exhibit 3.

Table 19 - Summary of Billing Determinants and Average Consumption with Variances of Actual and Forecast Data Consistent with Appendix 2-IB

	2016 Board Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge Year	2021 Test Year
Residential							
Number of Customers	19,971	20,057	20,188	20,332	20,476	20,663	20,852
kWh -Actuals	205,578,737	204,439,774	193,694,443	208,411,376	202,110,918	205,205,019	207,178,634
kWh - Weather Normalized	205,578,737	200,906,007	195,882,339	204,857,068	202,922,076	205,205,019	207,178,634
Consumption (kWh) per Customer - Actual	10,294	10,193	9,595	10,250	9,871	9,931	9,936
Consumption (kWh) per Customer - Weather Normalized	10,294	10,017	9,703	10,076	9,910	9,931	9,936
Variance Analysis (Year over Year)							
Number of Customers		0.4%	0.7%	0.7%	0.7%	0.9%	0.9%
kWh -Actuals		-0.6%	-5.3%	7.6%	-3.0%	1.5%	1.0%
kWh - Weather Normalized		-2.3%	-2.5%	4.6%	-0.9%	1.1%	1.0%
General Service less than 50 kW							
Number of Customers	1,967	1,844	1,810	1,895	1,824	1,850	1,876
kWh -Actuals	58,991,538	51,296,823	50,527,239	51,979,121	50,654,668	47,217,968	46,722,885
kWh - Weather Normalized	58,991,538	50,410,151	51,097,975	51,092,654	50,857,967	47,217,968	46,722,885
Consumption (kWh) per Customer - Actual	29,995	27,818	27,916	27,430	27,771	25,523	24,899
Consumption (kWh) per Customer - Weather Normalized	29,995	27,337	28,231	26,962	27,883	25,523	24,899
Variance Analysis (Year over Year)							
Number of Customers		-6.2%	-1.8%	4.7%	-3.7%	1.4%	1.4%
kWh -Actuals		-13.0%	-1.5%	2.9%	-2.5%	-6.8%	-1.0%
kWh - Weather Normalized		-14.5%	1.4%	0.0%	-0.5%	-7.2%	-1.0%
General Service 50 to 999 kW							
Number of Customers	206	198	186	205	217	219	219
kWh -Actuals	136,566,740	137,289,389	135,373,696	144,914,027	150,365,345	136,896,088	132,955,988
kWh - Weather Normalized	136,566,740	134,916,325	136,902,824	142,442,621	150,968,826	136,896,088	132,955,988
kW -Actuals	362,031	390,924	394,783	410,875	418,610	382,053	371,084
kW - Weather Normalized	362,031	384,167	399,242	403,868	420,290	382,053	371,084
Consumption (kWh) per Customer - Actual	662,343	693,381	727,816	706,898	692,928	625,096	607,105
Consumption (kWh) per Customer - Weather Normalized	662,343	681,396	736,037	694,842	695,709	625,096	607,105
Consumption (kW) per Customer - Actual	3,212	3,502	3,913	3,448	3,193	2,854	2,772
Consumption (kW) per Customer - Weather Normalized	3,212	3,441	3,957	3,389	3,206	2,854	2,772
Variance Analysis (Year over Year)							
Number of Customers		-4.0%	-6.1%	10.2%	5.9%	0.9%	0.0%
kWh -Actuals		0.5%	-1.4%	7.0%	3.8%	-9.0%	-2.9%
kWh - Weather Normalized		-1.2%	1.5%	4.0%	6.0%	-9.3%	-2.9%
kW -Actuals		8.0%	1.0%	4.1%	1.9%	-8.7%	-2.9%
kW - Weather Normalized		6.1%	3.9%	1.2%	4.1%	-9.1%	-2.9%

Table 20 - Summary of Billing Determinants and Average Consumption with Variances of Actual and Forecast Data Consistent with Appendix 2-IB (cont'd)

	2016 Board Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge Year	2021 Test Year
General Service 1,000 to 4,999 kW							
Number of Customers	13	13	11	10	11	9	9
kWh -Actuals	112,173,675	107,193,041	99,309,703	91,829,369	88,636,118	72,150,643	70,322,012
kWh - Weather Normalized	112,173,675	105,340,196	100,431,466	90,263,284	88,991,853	72,150,643	70,322,012
kW -Actuals	302,644	273,610	262,132	248,453	219,091	172,893	168,373
kW - Weather Normalized	302,644	268,881	265,093	244,216	219,970	172,893	168,373
Consumption (kWh) per Customer - Actual	8,457,793	8,245,619	9,028,155	9,182,937	8,057,829	8,016,738	7,813,557
Consumption (kWh) per Customer - Weather Normalized	8,457,793	8,103,092	9,130,133	9,026,328	8,090,168	8,016,738	7,813,557
Consumption (kW) per Customer - Actual	637,710	634,278	820,741	918,294	732,530	890,749	868,173
Consumption (kW) per Customer - Weather Normalized	637,710	623,315	830,012	902,633	735,470	890,749	868,173
Variance Analysis (Year over Year)							
Number of Customers		-2.0%	-15.4%	-9.1%	10.0%	-18.2%	0.0%
kWh -Actuals		-4.4%	-7.4%	-7.5%	-3.5%	-18.6%	-2.5%
kWh - Weather Normalized		-6.1%	-4.7%	-10.1%	-1.4%	-18.9%	-2.5%
kW -Actuals		-9.6%	-4.2%	-5.2%	-11.8%	-21.1%	-2.6%
kW - Weather Normalized		-11.2%	-1.4%	-7.9%	-9.9%	-21.4%	-2.6%
Sentinel Lights							
Number of Customers	175	170	173	175	175	175	175
kWh -Actuals	461,109	273,180	260,238	261,914	251,879	251,879	251,879
kWh - Weather Normalized	461,109	268,458	263,178	257,447	252,890	251,879	251,879
kW -Actuals	628	739	704	695	680	680	680
kW - Weather Normalized	628	726	712	683	682	680	680
Consumption (kWh) per Customer - Actual	2,637	1,607	1,504	1,497	1,439	1,439	1,439
Consumption (kWh) per Customer - Weather Normalized	2,637	1,579	1,521	1,471	1,445	1,439	1,439
Consumption (kW) per Customer - Actual	15	9	9	9	8	8	8
Consumption (kW) per Customer - Weather Normalized	15	9	9	8	8	8	8
Variance Analysis (Year over Year)							
Number of Customers		-2.8%	1.8%	1.2%	0.0%	0.0%	0.0%
kWh -Actuals		-40.8%	-4.7%	0.6%	-3.8%	0.0%	0.0%
kWh - Weather Normalized		-41.8%	-2.0%	-2.2%	-1.8%	-0.4%	0.0%
kW -Actuals		17.6%	-4.7%	-1.3%	-2.2%	0.0%	0.0%
kW - Weather Normalized		15.6%	-2.0%	-4.0%	-0.1%	-0.4%	0.0%

Table 21 - Summary of Billing Determinants and Average Consumption with Variances of Actual and Forecast Data Consistent with Appendix 2-IB (cont'd)

	2016 Board Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge Year	2021 Test Year
Street Lighting							
Number of Connections	4,649	4,680	4,674	4,778	4,833	4,833	4,833
kWh -Actuals	1,535,681	1,832,979	1,128,400	1,093,732	979,604	979,604	979,604
kWh - Weather Normalized	1,535,681	1,801,296	1,141,146	1,075,079	983,535	979,604	979,604
kW -Actuals	4,282	5,129	3,155	3,043	3,105	3,105	3,105
kW - Weather Normalized	4,282	5,040	3,191	2,991	3,117	3,105	3,105
Consumption (kWh) per Connection - Actual	330	392	241	229	203	203	203
Consumption (kWh) per Connection - Weather Normalized	330	385	244	225	204	203	203
Consumption (kW) per Connection - Actual	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Consumption (kW) per Connection - Weather Normalized	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Variance Analysis (Year over Year)							
Number of Customers		0.7%	-0.1%	2.2%	1.2%	0.0%	0.0%
kWh -Actuals		19.4%	-38.4%	-3.1%	-10.4%	0.0%	0.0%
kWh - Weather Normalized		17.3%	-36.6%	-5.8%	-8.5%	-0.4%	0.0%
kW -Actuals		19.8%	-38.5%	-3.5%	2.0%	0.0%	0.0%
kW - Weather Normalized		17.7%	-36.7%	-6.3%	4.2%	-0.4%	0.0%
Unmetered Scattered Load							
Number of Customers	144	148	152	185	183	183	183
kWh -Actuals	895,971	924,057	934,714	953,473	962,029	962,029	962,029
kWh - Weather Normalized	895,971	908,085	945,272	937,212	965,890	962,029	962,029
Consumption (kWh) per Customer - Actual	6,222	6,244	6,149	5,154	5,257	5,257	5,257
Consumption (kWh) per Customer - Weather Normalized	6,222	6,136	6,219	5,066	5,278	5,257	5,257
Variance Analysis (Year over Year)							
Number of Customers		2.8%	2.7%	21.7%	-1.1%	0.0%	0.0%
kWh -Actuals		3.1%	1.2%	2.0%	0.9%	0.0%	0.0%
kWh - Weather Normalized		1.4%	4.1%	-0.9%	3.1%	-0.4%	0.0%
Totals							
Number of Customers / Connections	27,124	27,110	27,194	27,580	27,719	27,932	28,147
kWh -Actuals	516,203,452	503,249,243	481,228,433	499,443,012	493,960,561	463,663,230	459,373,031
kWh - Weather Normalized	516,203,452	494,550,518	486,664,200	490,925,367	495,943,038	463,663,230	459,373,031
kW -Actuals	669,585	670,402	660,774	663,066	641,485	558,730	543,241
kW - Weather Normalized	669,585	658,814	668,238	651,758	644,060	558,730	543,241
Variance Analysis (Year over Year)							
Number of Customers		-0.1%	0.3%	1.4%	0.5%	0.8%	0.8%
kWh -Actuals		-2.5%	-4.4%	3.8%	-1.1%	-6.1%	-0.9%
kWh - Weather Normalized		-4.2%	-1.6%	0.9%	1.0%	-6.5%	-0.9%
kW -Actuals	-	0.1%	-1.4%	0.3%	-3.3%	-12.9%	-2.8%
kW - Weather Normalized	-	-1.6%	1.4%	-2.5%	-1.2%	-13.2%	-2.8%

1.5.4 RATE BASE AND DSP (EXHIBIT 2) [30]

1.5.4.1 MAJOR DRIVERS OF THE DISTRIBUTION SYSTEM PLAN ("DSP")

The key drivers for all investments in HHHI's DSP are aligned with the asset management objectives as outlined in Section 3.2 of the DSP:

- Safety for employees and the community is the number one priority, always.
- Reliability for supply of electricity, reliable customer service.
- Fair Rates for residential and business customers.
- Financial Metrics, ensuring a stable return on investment for the shareholder, the Town of Halton Hills.
- Conservation, promoting energy conservation programs to help our customers save energy and money.
- Environmental, ensuring HHHI considers the environment in purchasing and operating practices.
- Community Focused and proud to be a part of the Town of Halton Hills, participating in community events and supporting the community.
- Smart Grid Implementation of technology to monitor and maintain the electricity system.

The key metrics used to measure DSP success are identified below. The table below summarizes HHHI's key performance targets.

[30] MFR - Rate Base and DSP - major drivers of DSP, rate base for test year, change from last approved ($ and %), capital expenditures requested for the test year, change in capital expenditures from last approved ($ and %), summary of costs requested for renewable energy connections/expansions, any O.Reg 339/09 planned recovery, capex for test year, change from last approved, costs for any REG-related, smart grid, regional planning projects

Table 22 - HHHI's Key Performance Targets

Performance Indicator	Target
Reliability (SAIDI)	1.32 hours
Reliability (SAIFI)	1.61 Incidents
Customer Satisfaction Index	90%
Billing Accuracy	98%
PEG Report Benchmarking	Maintaining a stretch factor assignment within the top grouping
ESA Reg 22/04	0 Non-Compliance
Substation Loading	Peak Demand <= Nameplate

Drivers of the individual program categories, along with the proposed capital expenditures by category are summarized below:

System Access

These projects include customer connections, new development, renewable generation connections, service upgrades for safety reasons, municipal relocation projects where the utility is required to relocate infrastructure to accommodate road improvement projects. Table 23 - Forecasted System Access Projects with Drivers below shows HHHI's forecasted capital expenditures for System Access projects.

Table 23 - Forecasted System Access Projects with Drivers

Projects	**Driver**	**2021**	**2022**	**2023**	**2024**	**2025**
System Access						
Technical Service Layouts	Customer Services	$538,429	$551,890	$565,687	$579,829	$594,325
Subdivisions	Customer Services	$252,604	$257,656	$262,809	$268,065	$273,427
Renewable Generation	Customer Services	$39,419	$2,000	$2,000	$2,000	$2,000
Wye-Delta Service Upgrades	Customer Services	$79,774	$81,369	$82,997	$84,657	$86,350
Municipally Driven Projects	Municipally Driven	$1,366,230	$702,845	$2,113,350	$1,847,792	$889,212
Make Ready work	Other 3rd Party Driven	$21,834	$22,926	$24,072	$25,276	$26,539
Metering	Mandated Service Obligations	$231,685	$191,684	$191,684	$191,684	$226,684
	Sub-Total	**$2,529,975**	**$1,810,370**	**$3,242,599**	**$2,999,303**	**$2,098,537**
	Contributed Capital	($1,135,176)	($885,392)	($1,479,197)	($1,391,127)	($997,281)
	Total	**$1,394,799**	**$924,978**	**$1,763,402**	**$1,608,176**	**$1,101,256**

Over the historical period, expenditures made for System Access projects revolved primarily around customer driven work that we are mandated to perform (ex. meter exchanges). Spending in this category, as it relates to customer driven work, is not always reflective of when HHHI receives money from customers for their work. In many instances, customers pay for their service work in the year prior to their construction that produces a variance in spending levels as compared to receivables from those customers.

Over the forecast period, HHHI anticipates expenditures for this driver to be similar as to the historical period in that expenses may or may not coincide with the timing of customer driven work. HHHI is forecasting growth in Georgetown through the Vision Georgetown development and intends to have capital funding available to accommodate growth. Furthermore, projects related to municipally driven work are highly subject to the municipality's time. Projects may be deferred or moved up based on timing of the municipal work. Asset performance can be improved when distribution assets are replaced as part of customer driven work such as installing new poles relating to a road widening.

System Renewal

System renewal projects are investments a distributor makes involving replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services. These projects are distributor driven. HHHI's goal with system renewal projects is to ensure the assets used in the delivery of power as well as the supporting infrastructure are in good condition, are safe to operate, and will continue providing reliability to customers. This category includes plans to replace defective, obsolete, and end-of-useful life assets. Table 24 - Forecasted System Renewal Projects with Drivers below shows HHHI's forecasted capital expenditures for System Renewal projects.

Table 24 - Forecasted System Renewal Projects with Drivers

Projects	**Driver**	**2021**	**2022**	**2023**	**2024**	**2025**
System Renewal						
Pole Replacements	End of Life Assets	$624,199	$647,375	$679,744	$713,731	$749,418
Poletrans Replacement Program	Obsolete Equipment	$809,294	$790,157	$165,000	$382,177	$50,000
Porcelain Insulator Replacement Program	End of Life Assets	$51,459	$53,003	$54,593	$56,231	$57,918
Transformer Replacement Program	End of Life Assets	$222,791	$435,329	$187,889	$120,525	$443,241
Pole Line Rebuild Program	End of Life Assets	$0	0	25,000	$378,020	$407,907
Substation Equipment	End of Life Assets	$615,397	$700,253	$242,444	$83,760	$674,760
Distribution Equipment Renewal	End of Life Assets	$38,950	$42,649	$72,600	$41,334	$42,160
Total		**$2,362,090**	**$2,668,766**	**$1,402,270**	**$1,775,778**	**$2,425,404**

Over the historical period investments relating to System Renewal projects were consistent recognizing the importance of key programs such as pole replacements and poletrans replacements. Expenses in this category were higher than System Access and System Service projects during the historical period reflecting the utilities planned and proactive approach to reducing the amount of aged assets we operate.

Over the forecast period, expenses related to System Renewal projects are expected to remain consistent from year-to-year with inflationary increases relating to End of Life Asset programs. In respect of Obsolete Equipment, year-to-year expenses will vary in relation to the type and scope of projects being undertaken. The same can be said for substation equipment replacements where annual expenses will vary and depend on the scope of work for that year. Replacement of aged and obsolete assets results in asset useful lives being essentially reset and returning performance targets to the start of the assets useful life described in HHHI's Asset Management Plan SP20-01 (Exhibit 2).

System Service

System service projects are investments a distributor makes involving modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. These projects are distributor driven; they address system constraints, and promote operational effectiveness. HHHI's goal with system service projects is to ensure the distribution system is free of constraints that may impact system functionality and increases the utilities ability to operate the distribution system. The identified projects demonstrate system planning and the effective execution of the projects will provide system reliability and prepare for long-term growth. Table 25 - Forecasted System Service Projects with Drivers below shows HHHI's forecasted capital expenditures for System Access projects.

Table 25 - Forecasted System Service Projects with Drivers

Projects	**Driver**	**2021**	**2022**	**2023**	**2024**	**2025**
System Service						
Feeder Improvements	Capacity Upgrades	$0	$5,840	$322,380	$317,352	$240,000
Voltage Conversion	Capacity Upgrades	$463,908	$681,385	$619,000	$295,000	$692,189
Substation Upgrades	Capacity Upgrades	$186,770	$186,770	$224,490	$0	$0
Automated Switches & SCADA Integration	Reliability	$231,194	$200,000	$220,000	$315,000	$125,000
Arrestor Program	Safety	$0	$36,672	$38,339	$40,173	$42,190
Total		**$881,872**	**$1,110,667**	**$1,424,209**	**$967,525**	**$1,099,379**

Over this historical period, expenses related to System Service projects were consistent from 2016 to 2018 demonstrating a planned and prioritized approach to projects that enhanced the distribution system making it more resilient.

During the forecast period HHHI will be investing in similar programs as in the historical period with respect to installing devices that will enhance reliability, safety, and provide capacity to supply load growth. During the forecast period spending on specific projects will vary and depend on the scope of work.

General Plant

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities. Table 26 - Forecasted System Service Projects with Drivers below shows HHHI's forecasted capital expenditures for System Access projects.

Table 26 - Forecasted System Service Projects with Drivers

Projects	**2021**	**2022**	**2023**	**2024**	**2025**
General Plant					
Equipment & Tools	$525,000	$265,000	$330,000	$295,000	$435,000
Software & Systems	$233,057	$240,400	$269,940	$397,260	$158,140
Building Equipment	$70,000	$77,000	$184,940	$2,000	$25,000
Total	**$828,057**	**$582,400**	**$784,880**	**$694,260**	**$618,140**

General plant spending is driven by maintaining and replacing equipment and tools, building equipment and software and systems. Projects in this category include information technology upgrades aimed at addressing cyber security risks and complying with Ontario Energy Board (OEB) "Ontario Cyber Security Framework" and reporting requirements set forth in OEB EB-2016-0032.

1.5.4.2 RATE BASE

The last Board Approved Rate Base was established for HHHI in the 2016 Cost of Service Rate Application EB-2015-0074. HHHI has calculated its 2021 Test Year rate base to be $104,249,216. The Rate Base is also used to determine the proposed Revenue Requirement summarized in Exhibit 6. HHHI has provided a summary of Rate Base comparison of 2016 Board Approved to 2021 Test Year Rate Base in Table 27 - Comparison of 2016 Board Approved to 2021 Test Year Rate Base and Working Capital Allowance below.

Table 27 - Comparison of 2016 Board Approved to 2021 Test Year Rate Base and Working Capital Allowance

Description	2016 Board Approved	2021 Test Year	Variance	
Gross Assets				
Opening Balance	60,556,594	115,220,870	54,664,276	90.3%
Closing Balance	68,265,195	120,657,338	52,392,143	76.7%
Accumulated Depreciation				
Opening Balance	7,812,491	16,814,177	9,001,686	115.2%
Closing Balance	9,494,124	20,350,085	10,855,961	114.3%
Net Assets				
Opening Balance	52,744,103	98,406,693	45,662,590	86.6%
Closing Balance	58,771,071	100,307,252	41,536,181	70.7%
Average balance	**55,757,587**	**99,356,973**	**43,599,386**	**78.2%**
Working Capital Allowance	5,664,968	4,892,243	(772,724)	(13.6%)
Rate Base	**61,422,555**	**104,249,216**	**42,826,661**	**69.7%**
Distribution Expenses	**2016 Board Approved**	**2021 Test Year**	**Variance**	
Distribution Expenses - Operation	1,355,647	1,440,803	85,157	6.3%
Distribution Expenses - Maintenance	374,125	458,000	83,875	22.4%
Billing and Collecting	1,559,240	1,177,856	(381,384)	(24.5%)
Community Relations	-	-	-	0.0%
Administrative and General Expenses	2,706,553	4,484,712	1,778,159	65.7%
Donations - LEAP	12,027	18,890	6,863	57.1%
Taxes Other than Income Taxes	104,440	157,546	53,106	50.8%
Less Allocated Depreciation	(173,580)	(304,840)	(131,260)	75.6%
Total Eligible Distribution Expenses	**5,938,452**	**7,432,968**	**1,494,516**	**25.2%**
Power Supply Expenses	69,594,450	57,796,943	(11,797,507)	(17.0%)
Total Working Capital Expenses	**75,532,902**	**65,229,911**	**(10,302,991)**	**(13.6%)**
Working Capital Allowance at 7.5%	**5,664,968**	**4,892,243**	**(772,724)**	**(13.6%)**

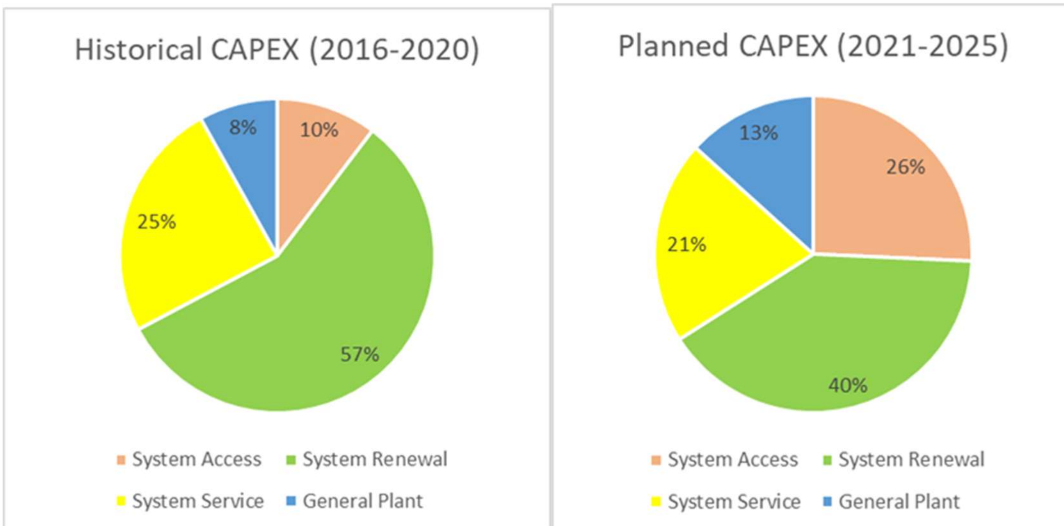
The Rate Base for the 2021 Test Year of $104,249,216 is an increase of $42,826,661 or 69.7% compared to the 2016 Board Approved Rate Base. The variance between the 2021 Test Year and 2016 Board Approved is mainly attributed to:

- An increase in the average net capital assets in service of $43,599,386 from $55,757,587 to $99,356,973 or 78.2% due to the net capital investments in the distribution system, including general plant, over the five (5) year period. Included in the net capital asset increase is $24,475,012 cost of the new HHHI owned transformer station HHHI commissioned in 2019 and deemed in the Decision as a distribution asset in proceeding EB-2018-0328.
- The increase in the average net capital assets in service is partially offset by a decrease in the working capital allowance. The 2021 Test Year Working Capital Allowance of $4,892,243 is $772,724 lower than the 2016 Board Approve of $5,664,968. The reduction in the working capital allowance is mainly due to a decrease in the 2021 Power Supply Expenses of $11,797,507 from $69,594,450 to $57,796,943 or 17.0%, mainly attributable to the decrease in commodity pricing, commencing in July 2017, from the introduction of the *Ontario Fair Hydro Plan*.
- As explained more fully in Exhibit 4, Operating, Maintenance and Administrative ("OM&A") expenses, also used in the calculation, have increase by $1,494,516 from 2016 Board Approved when compared to 2021 Test Year. This increase is partially offset by the reduction of the Power Supply Expense, netting to a total reduction of $772,724 in Working Capital Allowance.

1.5.4.3 CAPITAL EXPENDITURES

A comparison of HHHI's capital expenditures over the historical period and the planned capital expenditures over the forecast period of the DSP is shown in Table 28 - Historical and Planned Capital Expenditures. During the historical period, HHHI invested significantly in System Renewal projects and System Service projects. The previous DSP (EB-2015-0074) forecasted significant investment in System Renewal projects to address the quantity of vintage poles that needed to be replaced having reached or exceeded their useful life. System Renewal investments were also made in replacing vintage, obsolete equipment, Poletrans and padmounted transformers as well as vintage underground cabling and transformers.

Table 28 - Historical and Planned Capital Expenditures



Over the forecast period, HHHI will be reducing System Renewal expenditures by 17% of total planned investments. Reduced spending in System Renewal projects is a result of increased investments during the historical period to replace aged wood poles and reduced spending for underground replacement projects. HHHI's investments in System Service projects will also decrease by 4%. System Access projects will experience the largest increase, 15%, as compared to the other investment categories largely due to municipal and regional road construction projects. System Access expenditures will also include accommodating growth in Halton Hills related to in-fill development and Vision Georgetown. Investments in General Plant will increase by 5% in the forecast period which is reflective of HHHI's need to replace fleet vehicles and office equipment. Table 29 - Historical and Forecasted Capital Expenditures by Category provide a summary of the historical and forecasted costs by category. Further details are provided in Exhibit 2.

Table 29 - Historical and Forecasted Capital Expenditures by Category

Historical Period

Forecast Period (planned)

CATEGORY	**2016**			**2017**			**2018**			**2019**			**2020**			**2021**	**2022**	**2023**	**2024**	**2025**
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Budget**	**Var**					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access	1,161	1,161	(0.0%)	886	1,587	79.1%	3,331	2,182	(34.5%)	967	1,796	85.7%	2,524	2,524	0.0%	2,530	1,810	3,243	2,999	2,099
System Renewal	4,120	4,991	21.2%	4,227	4,601	8.8%	2,818	4,196	48.9%	3,891	3,406	(12.5%)	2,070	2,070	0.0%	2,362	2,669	1,427	1,776	2,425
System Service	2,303	2,035	(11.6%)	2,411	1,574	(34.7%)	2,959	1,747	(41.0%)	3,321	2,000	(39.8%)	1,525	1,525	0.0%	882	1,111	1,424	968	1,099
General Plant	778	491	(36.9%)	479	793	65.4%	421	496	17.9%	425	654	53.8%	621	621	0.0%	828	582	607	694	618
TOTAL EXPENDITURE	**8,361**	**8,678**	**3.8%**	**8,004**	**8,555**	**6.9%**	**9,529**	**8,622**	**(9.5%)**	**8,605**	**7,856**	**(8.7%)**	**6,741**	**6,741**	**0.0%**	**6,602**	**6,172**	**6,701**	**6,437**	**6,241**
Capital Contributions	652	655	0.4%	596	1,451	143.6%	1,741	998	(42.7%)	711	833	17.2%	1,068	1,068	0.0%	1,135	885	1,479	1,391	997
Net Capital Expenditures	**7,709**	**8,023**	**4.1%**	**7,408**	**7,104**	**(4.1%)**	**7,788**	**7,624**	**(2.1%)**	**7,894**	**7,023**	**(11.0%)**	**5,673**	**5,673**	**0.0%**	**5,467**	**5,287**	**5,222**	**5,046**	**5,244**

Table 30 - Change in Capex (Historical to Forecast)

Category	Historical (2016-2019)	Proposed (2021-2025)	Variance
System Access	10%	26%	15.0%
System Renewal	57%	40%	(17.0%)
System Service	25%	21%	(4.0%)
General Plant	8%	13%	5.0%

1.5.4.4 RECOVERY OF COSTS

HHHI is not requesting any recovery of costs for renewable energy connections or expansions, smart grid, regional planning initiatives nor any for Ontario Regulation 330/09.

As part of this application, HHHI has recalculated the ICM revenue requirement based on actual costs. A summary of the OEB Approved ICM revenue requirement based on estimated amounts and actual ICM revenue requirement are show below in Table 31 - Recalculated ICM Revenue Requirement.

Table 31 - Recalculated ICM Revenue Requirement

Description	Capital	Revenue Requirement	Total Revenue Requirement (May 01, 2019 to Apr 30, 2021)
Board Approved Amounts		1,698,085	3,396,170
Projected Over Recovery vs Board Approved Revenue Requirement		(14,677)	(14,461)
ICM Collected/To be collected		**1,683,408**	**3,381,709**
Board Approved Amounts	23,476,441	1,698,085	3,396,170
Variance Between Actual Capital Spending and Board Approved Amounts	998,571	63,529	127,058
Recalculated Amounts	**24,475,012**	**1,761,614**	**3,523,228**
Variance Recalculated Revenue Requirement vs. ICM Revenue Collected - Due from/(Owed to Customer)			**112,597**

HHHI is requesting approval for the true up of the variance of $112,597 from the recalculated revenue requirement. HHHI proposes that the shortfall of $112,597 be recovered from customers through a fixed and volumetric rate rider over two (2) years for all but the Residential class. Residential rate class is proposed to be billed only a fixed rate rider in compliance with OEB policy. The calculation of this incremental capital expenditures rate rider is detailed in Table 32 - Proposed Rate Riders for recovery of ICM True-up.

Table 32 - Proposed Rate Riders for recovery of ICM True-up

Rate Class	**Service Charge Rate Rider**	**Distribution Volumetric Rate kWh Rate Rider**	**Distribution Volumetric Rate kW Rate Rider**
Residential	$0.14	$0.0000	$0.0000
General Service less than 50 kW	$0.15	$0.0001	$0.0000
General Service 50 kW to 999 kW	$0.40	$0.0000	$0.0224
General Service 1,000 kW to 4,999 kW	$1.24	$0.0000	$0.0295
Un-metered Scattered Load	$0.04	$0.0000	$0.0000
Sentinel Lighting	$0.05	$0.0000	$0.2027
Street Lighting	$0.01	$0.0000	$0.0086

1.5.5 OPERATION, MAINTENANCE AND ADMINISTRATION (“OM&A”) EXPENSE (EXHIBIT 4)

OM&A expenses consist of the required expenditures necessary for HHHI to maintain and operate its distribution system assets, safely and reliably, while achieving its strategic imperatives:

i. Safety and Wellness – Always pursue excellence in safety and wellness;
ii. Customers – Anticipate and exceed customer expectations regarding efficiency and reliable delivery of electricity;
iii. People – Develop and support HHHI’s dedicated, talented team who embrace best practices, innovative solutions, and new technologies to deliver present and future

energy needs to our communities while operating within the current COVID-19 "new normal";

iv. Environmental Stewardship – Respect the environment in everything HHHI does including adapting business to address climate change, reduce the impact of operations on the environment and support the Town of Halton Hills initiatives in relation to the Town's declaration of a climate change emergency;

v. Community – Demonstrate HHHI's dedication to the well-being of the communities; and

vi. Value – Invest in quality energy infrastructure while delivering optimal financial returns to HHHI's shareholders.

HHHI believes that its strategic imperatives align to the achievement of the OEB's performance outcomes: (i) Customer Focus; (ii) Operational Effectiveness; (iii) Public Policy Responsiveness; and (iv) Financial Performance; all as outlined in the "*Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach*" ("RRFE"), dated October 18, 2012.

Operating costs include the operations and maintenance of the distribution assets, the costs associated with metering, billing, collecting from customers, costs associated with ensuring all stakeholders' safety (public, employees, etc.) and costs to maintain the distribution business service quality and reliability standards in compliance with the OEB Distribution System Code and other regulatory bodies (Independent Electricity System Operator ("IESO"), Ministry of Energy, Northern Development and Mines, the Electrical Safety Authority ("ESA"), etc.).

1.6.5.1 HHHI TEST YEAR OM&A EXPENSE SUMMARY AND COST TRENDS

HHHI's 2021 Test Year OM&A expenses are $7,561,372 excluding expenditures relating to LEAP and property taxes. A summary of OM&A expenses from 2016 Board Approved to the 2021 Test Year is found in Table 33 - Summary of Operations, Maintenance and Administrative Expenditures below.

Table 33 - Summary of Operations, Maintenance and Administrative Expenditures

Distribution Expenses	**2016 Board Approved**	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Bridge Year**	**2021 Test Year**
Distribution Expenses - Operation	$1,355,646	$1,412,666	$1,374,606	$1,283,640	$1,264,253	$1,211,047	$1,440,803
Distribution Expenses - Maintenance	$374,125	$444,658	$283,003	$317,433	$305,637	$415,550	$458,000
Billing and Collecting	$1,559,240	$1,097,633	$1,130,882	$1,148,641	$1,125,654	$1,171,162	$1,177,856
Administrative and General Expenses	$2,706,553	$3,057,180	$3,187,856	$3,302,510	$3,592,639	$3,608,611	$4,484,712
Total	**$5,995,565**	**$6,012,139**	**$5,976,346**	**$6,052,225**	**$6,288,183**	**$6,406,370**	**$7,561,372**
2021 Test Year vs. 2016 Board Approved							**$1,565,807**
% Increase 2021 Test Year vs. 2016 Board Approved							**26.1%**

HHHI proposed OM&A level of $7,561,372 for the 2021 Test Year is $1,565,807 or 26.1% higher than the 2016 Board Approved of $5,995,565 and $1,549,232 higher or 25.8% higher than the 2016 Actuals.

HHHI continues to prudently manage OM&A costs and for seven (7) consecutive years, HHHI has remained in Group 1 of the PEG report; OEB's Benchmark model most recent report dated August 2019. In the PEG report (dated August 2019), HHHI continually performs under predicted costs and on values related to 2016 to 2018, HHHI is currently operating at 28.4% below predicted costs. It is important to note that even with the 2021 Test Year increases, HHHI is forecasting to remain in Group 1 of the PEG report. The forecasted PEG Benchmarking model is filed in Summary of PEG Forecasted Cost Benchmarking Results in Exhibit 4. A summary of the Forecasted Benchmarking Results is shown in Table 34 - Summary of Forecasted Cost Benchmarking Results below.

Table 34 - Summary of Forecasted Cost Benchmarking Results

Cost Benchmarking Summary	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 (Bridge)	2021 (Test Year)	2022 Forecast	2023 Forecast
Actual Total Cost	17,028,654	16,934,734	17,821,525	15,861,465	16,799,832	17,937,568	18,374,897	18,802,766
Predicted Total Cost	22,429,778	22,492,011	23,853,248	25,155,628	26,545,058	27,795,572	29,086,739	30,411,572
Difference	(5,401,124)	(5,557,277)	(6,031,723)	(9,294,163)	(9,745,226)	(9,858,004)	(10,711,842)	(11,608,807)
Percentage Difference (Cost Performance)	**(27.5%)**	**(28.4%)**	**(29.2%)**	**(46.1%)**	**(46.6%)**	**(42.7%)**	**(45.2%)**	**(47.3%)**
Three-Year Average Performance					(40.6%)	(45.1%)	(44.8%)	(45.1%)
Stretch Factor Cohort								
Annual Result	1	1	1	1	1	1	1	1
Three Year Average	1	1	1	1	1	1	1	1

Overall OM&A Cost Trends summarizes the material costs trends and primary drivers that have influenced the change in HHHI's OM&A expenditures since 2016, up to and including the 2021 Test Year.

The 2016 Board Approved OM&A of $5,995,565, excluding LEAP and property tax amounts, was approved on an envelope approach in HHHI's 2016 Cost of Service application (EB-2015-0074). HHHI has managed its OM&A from 2016 to 2019 on that basis. HHHI's prudent management of OM&A consistently outperforms the predicted costs in the annual PEG report. Table 35 - OM&A Cost Driver Table shows the cost drivers associated with the increased OM&A budget for 2021 Test Year.

Table 35 - OM&A Cost Driver Table

Description	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Bridge Year**	**2021 Test Year**	
Opening Balance (Excluding LEAP & Property Taxes)	**$5,995,565**	**$6,012,139**	**$5,976,346**	**$6,052,225**	**$6,288,183**	**$6,406,370**	**$5,995,565**
Salaries and benefits							
Pay Equity Adjustment			$181,775				$181,775
Increase in FTE				$53,750	$65,373	$250,324	$369,447
Increase in wages and staff progressions						$103,906	$103,906
Increase in benefit costs						$82,967	$82,967
Change in labour burden allocation						$120,698	$120,698
Training and staff development				$58,645	($5,658)		$52,987
Professional Service			$38,500		($115,655)		($77,155)
Bad Debt expense	($114,548)	$107,007	($12,500)				($20,041)
Climate Change (Admin)						$279,700	$279,700
Cybersecurity and IT Training			$13,142	$36,706	$71,293	$91,300	$212,441
Transformer Station (Insurance, Control Room)				$1,086	$138,680	$50,586	$190,352
Mtce Operations (Switch Mtce)						$23,535	$23,535
Trucking costs				$65,730	($20,891)	$37,608	$82,447
Underground cable testing (ENG)					($39,940)	$25,000	($14,940)
Metering (wireless communication costs)						$24,680	$24,680
Regulatory						$16,000	$16,000
Materials and other cost increases					$31,357	$7,138	$38,495
Vegetation Management	$84,855	($181,855)	$6,567	($34,174)	$72,259	$25,000	($27,348)
Other	$46,267	$39,055	($151,605)	$54,215	($78,631)	$16,560	($74,139)
Closing Balance (Excluding LEAP & Property Taxes)	**$6,012,139**	**$5,976,346**	**$6,052,225**	**$6,288,183**	**$6,406,370**	**$7,561,372**	**$7,561,372**

1.6.5.2 INFLATION ASSUMPTIONS

With respect to inflation rate assumptions, HHHI's 2021 Test Year expenditures were budgeted based on the actual expected costs, taking into consideration the current inflation trends as per the consumer price index – Ontario. Assumptions with respect to labour rates are provided in Exhibit 4.

1.6.5.3 COMPENSATION

HHHI's workforce is comprised of unionized and non-unionized employees. Since 2016, wage increases for collective bargaining, pay equity, new hires and benefits have contributed to an increase of $858,793 in operating costs for HHHI.

The cost drivers for salaries and benefits include annual collective agreement wage adjustments, progression and merit increases for union staff and non-union staff. Increases were also realized in benefit costs for OMERs pension and group benefits including health and dental. In addition, HHHI incurred a material pay equity cost increase for which HHHI attempted to recover the pay equity costs as a 'Z-Factor' recovery request (EB-2017-0045). The OEB Decision and Rate Order (EB-2017-0045), dated April 26, 2018 denied HHHI's Z-Factor Pay Equity Application (Exhibit 4).

HHHI's workforce planning is discussed in more detail in Exhibit 4, however, Table 36 - Employee Costs (using FTE Equivalents) (Board Appendix 2-K) below replicates Appendix 2-K of Chapter 2, and summarizes the employee complement, compensation and benefits for 2016 Board Approved, 2016-2019 Actual, 2020 Bridge Year and 2021 Test Year. All compensation is included whether expensed or capitalized. The number of employees ("FTEs") is based on the computation of the number of full-time equivalent positions throughout each of the fiscal years. Employees that were hired during the year or employees that left the organization were pro-rated based on the start and end dates.

Table 36 - Employee Costs (using FTE Equivalents) (Board Appendix 2-K)

	Last Rebasing Year (2016 OEB Approved)	Last Rebasing Year (2016 Actuals)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Number of Employees (FTEs including Part-Time)							
Management (including executive)	12.0	12.0	12.0	13.0	13.0	13.0	13.0
Non-Management (union and non-union)	42.0	41.1	39.7	36.2	37.2	39.8	42.5
Total	**54.0**	**53.1**	**51.7**	**49.2**	**50.2**	**52.8**	**55.5**
Total Salary and Wages including overtime and incentive pay							
Management (including executive)	$1,272,803	$1,441,541	$1,490,328	$1,524,396	$1,708,883	$1,686,887	$1,733,427
Non-Management (union and non-union)	$3,309,796	$3,029,051	$3,036,854	$3,015,966	$2,990,839	$3,142,757	$3,444,252
Total	**$4,582,599**	**$4,470,592**	**$4,527,183**	**$4,540,361**	**$4,699,721**	**$4,829,645**	**$5,177,680**
Total Benefits (Current + Accrued)							
Management (including executive)	$323,315	$374,368	$398,412	$417,433	$437,500	$380,006	$432,753
Non-Management (union and non-union)	$875,226	$763,355	$799,997	$785,152	$782,297	$910,205	$1,009,655
Total	**$1,198,541**	**$1,137,722**	**$1,198,408**	**$1,202,585**	**$1,219,797**	**$1,290,210**	**$1,442,408**
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$1,596,117	$1,815,909	$1,888,740	$1,941,828	$2,146,383	$2,066,893	$2,166,181
Non-Management (union and non-union)	$4,185,023	$3,792,405	$3,836,851	$3,801,118	$3,773,136	$4,052,962	$4,453,907
Total	**$5,781,140**	**$5,608,314**	**$5,725,591**	**$5,742,946**	**$5,919,519**	**$6,119,855**	**$6,620,087**

1.5.6 COST OF CAPITAL (EXHIBIT 5) [31]

HHHI has a current deemed capitalization structure of 56% long term debt with a long term debt cost rate of 2.89%; 4% short term debt with a short term debt cost rate of 1.65%; and 40% common equity with a return of 9.19% as approved in the 2016 Cost of Service ("COS") rate decision, Board proceeding EB-2015-0074.

For the purposes of preparing this Application, HHHI has used the cost of capital parameters issued by the Board on October 31, 2019, reflecting a Return on Equity ("ROE") of 8.52%, a deemed short term debt rate of 2.75% and long-term debt rate of 3.21%. HHHI will update its cost of

[31] MFR - Cost of Capital - Statement regarding use of OEB's cost of capital parameters; summary of any deviations

capital parameters to reflect future Board issued cost of capital parameters for rates with effective dates in 2021 prior to the issuance of the Board's decision in this Application. HHHI proposes no deviation from the Board's cost of capital methodology.

Historically, HHHI has not achieved the Deemed Regulated Return on Equity. The table below presents HHHI's actual ROE compared to Deemed ROE for the period 2016 through 2019.

Table 37 - Actual ROE compared to Deemed ROE

Financial Ratios		**2016**	**2017**	**2018**	**2019**
Liquidity Ratio		0.91	1.08	0.46	0.86
Leverage Debt to Equity Ratio		1.13	1.31	1.88	2.34
Return on Equity	Deemed	9.19%	9.19%	9.19%	9.19%
	Achieved	6.76%	6.98%	7.07%	4.24%

For 2021, a 5.46% weighted average cost of capital is applied to the rate base of $104,249,216, to determine the regulated return on capital of $5,696,715. This regulated return on capital is included in the proposed revenue requirement and shown in Table 38 - Cost of Capital and Capital Structure – 2021 Test Year.

Table 38 - Cost of Capital and Capital Structure – 2021 Test Year

Year: 2021 Test Year

Line No.	**Particulars**	**Capitalization Ratio**			**Cost Rate**	**Return**
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$58,379,561	3.48%	$2,029,274
2	Short-term Debt	4.00%	(1)	$4,169,969	2.75%	$114,674
3	**Total Debt**	60.0%		$62,549,530	3.43%	$2,143,948
	Equity					
4	Common Equity	40.00%		$41,699,686	8.52%	$3,552,813
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$41,699,686	8.52%	$3,552,813
7	**Total**	100.0%		$104,249,216	5.46%	$5,696,761

1.5.7 COST ALLOCATION AND RATE DESIGN (EXHIBITS 7 & 8) [32]

1.5.7.1 COST ALLOCATION METHODOLOGY

In this application, HHHI has used the 2021 version of the cost allocation model released by the OEB on May 20, 2020 to conduct a 2021 Test Year Cost Allocation study consistent with the OEB's cost allocation policies. The model has been completed with 2021 Test Year costs, customer numbers and demand values for HHHI.

HHHI proposes to use the same method as was used in the 2016 COS Application (EB-2015-0074) to determine the demand data for the 2021 Model. This method involves applying a scaling factor to the 2004 weather normalized volumes supporting the 2004 load profiles to determine an estimate of the 2021 weather normalized load profiles. Then the same method applied by Hydro One to the 2004 load profiles to determine the demand data for the original cost allocation study, is applied to the 2021 load profiles to determine the 2021 demand data.

1.5.7.2 LOAD PROFILE

HHHI is a member of Utilities Standards Forum ("USF"). Currently, a USF member is bringing forth a USF load profiling model in their 2021 COS application. HHHI expects the OEB will thoroughly vet the USF model during the COS process. HHHI intends to utilize the USF load profile model, with any necessary revisions that arise from the COS process, at its next COS.

1.5.7.3 WEIGHTING FACTORS

Distributors are expected to develop their own weighting factors as part of their cost allocation study. In 2016, HHHI developed weighting factors for its 2016 Cost Allocation model (EB-2015-

[32] MFR - Cost Allocation & Rate Design - summary of any deviations from OEB methodologies, significant changes and summary of proposed mitigation plans

0074) based on discussions with Borden, Ladner, Gervais LLP; experts in this subject area. HHHI is applying the same weighting factors in this application as there are no material changes.

1.5.7.4 EMBEDDED DISTRIBUTOR

In preparing its rate application, HHHI advised HONI that it is HHHI's intent to continue to bill HONI as a General Service 1,000 to 4,999 kW customer.

It is HHHI’s view that the embedded HONI connection does not have any distinguishing factors that should result in the HONI account being treated any differently than other HHHI General Service 1,000 to 4,999 kW customers that are similarly connected at the end of the line.

1.5.7.5 UNMETERED SCATTERED LOAD

In relation to this application, HHHI has not communicated with Unmetered Scattered Load customers, including Street Lighting customers, as there is no material change to the level of rates and charges nor the introduction of new rates.

1.5.7.6 CLASS REVENUE REQUIREMENTS

The data used in the updated cost allocation study is consistent with HHHI’s cost data that supports the proposed 2021 revenue requirement outlined in this application. Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the fixed asset continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2021 customer forecast outlined in Exhibit 3.

The allocated cost by rate class for the 2016 COS filing and 2021 updated Model are provided in the following Table 39 - Allocated Cost – (Consistent with RRWF, Tab 11 Cost Allocation, Allocated Costs) which is consistent with RRWF Sheet 11. Cost Allocation.

Table 39 - Allocated Cost – (Consistent with RRWF, Tab 11 Cost Allocation, Allocated Costs)

Rate Class	**Costs Allocated from 2016 Cost Allocation Study (EB-2015-0074)**	**%**	**Costs Allocated in 2021 Test Year**	**%**
Residential	$7,137,223	65.4%	$10,644,454	62.4%
General Service less than 50 kW	$1,161,735	10.6%	$1,684,188	9.9%
General Service 50 to 999 kW	$1,657,050	15.2%	$3,246,944	19.0%
General Service 1,000 to 4,999 kW	$759,279	7.0%	$1,169,371	6.9%
Sentinel Lights	$46,867	0.4%	$55,226	0.3%
Street Lighting	$130,547	1.2%	$170,312	1.0%
Unmetered Scattered Load	$20,436	0.2%	$75,371	0.4%
Total	**$10,913,136**	**100.0%**	**$17,045,865**	**100.0%**

1.5.7.7 REVENUE TO COST RATIOS

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

Table 40 - Revenue to Cost Ratios (Consistent with RRWF, Tab 11 Cost Allocation, Proposed Revenue to Cost Ratios)

Rate Class	2016 Board Approved Cost Allocation Study (EB-2015-0074)	2021 Test Year Updated Cost Allocation Study	2021 Test Year Proposed Ratios	Board Target
Residential	95.09%	105.67%	95.41%	85 -115
General Service less than 50 kW	120.00%	111.54%	120.00%	80 - 120
General Service 50 to 999 kW	96.60%	83.36%	96.60%	80 - 120
General Service 1,000 to 4,999 kW	120.00%	71.35%	120.00%	80 - 120
Sentinel Lights	95.09%	135.15%	95.41%	80 - 120
Street Lighting	120.00%	153.21%	120.00%	80 - 120
Unmetered Scattered Load	95.09%	56.02%	95.41%	80 - 120

The 2021 cost allocation study indicates the revenue to cost ratios for the General Service 1,000 to 4,999 kW class, Street Lighting class, Sentinel Light class and Unmetered Scattered Load class are outside the OEB's range. For 2021 and onward, HHHI proposes to maintain the revenue to cost ratios similar to what was approved in HHHI's 2016 COS (EB-215-0074). This methodology will move the customer classes that are currently outside of the range back within the Board's Target Range. In addition, this adjustment helps to mitigate any large rate increases. Specifically, moving the Residential class from 95.09% to 105.67% would cause a significant rate increase for that class.

1.5.7.8 RATE DESIGN OVERVIEW

HHHI has determined its total service revenue requirement to be $17,045,865. The total revenue offsets in the amount of $1,293,382 reduces HHHI's total service revenue requirement to a base revenue requirement of $15,752,482 which is used to determine the proposed distribution rates. The base revenue requirement is derived from HHHI's capital and operating spending forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The following Table 41 - Proposed Apportionment of Base Revenue to Rate Classes outlines the allocation of the base revenue requirement to the rate classes using the cost allocators shown above.

Table 41 - Proposed Apportionment of Base Revenue to Rate Classes

Rate Class	Proposed Base Revenue
Residential	$ 9,292,387
General Service less than 50 kW	1,899,419
General Service 50 to 999 kW	2,952,052
General Service 1,000 to 4,999 kW	1,333,596
Sentinel Lighting	47,966
Street Lighting	161,526
Unmetered Scattered Load	65,536
Total	**$ 15,752,482**

1.5.7.9. FIXED / VARIABLE PROPORTION

HHHI proposes to maintain the fixed/variable proportions assumed in the current rates to design the proposed monthly service and variable charges. Table 42 - Proposed Fixed / Variable Allocation shows the proposed base revenue, apportioned to rate classes as discussed above, and allocated between fixed monthly service charge and variable charge using the current rate design.

Table 42 - Proposed Fixed / Variable Allocation

Rate Class	Total Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue	Annualized Customer/ Connections	Proposed Monthly Service Charge	Variable Revenue Proportion	Variable Revenue	Annualized kWh or kW as required	Unit of Measure	Proposed Distribution Volumetric Charge before Transformer Allowance
Residential	$9,292,387	100.0%	$9,292,387	249,090	$37.31	0.0%	$0	207,178,634	$/kWh	$0.0000
General Service less than 50 kW	$1,899,419	57.0%	$1,082,950	22,359	$48.43	43.0%	$816,469	46,722,885	$/kWh	$0.0175
General Service 50 to 999 kW	$2,952,052	14.3%	$421,633	2,628	$160.44	85.7%	$2,530,420	371,084	$/kW	$6.8190
General Service 1,000 to 4,999 kW	$1,333,596	4.1%	$55,174	108	$510.87	95.9%	$1,278,422	168,373	$/kW	$7.5928
Sentinel Lighting	$47,966	44.9%	$21,531	2,100	$10.25	55.1%	$26,435	680	$/kW	$38.8900
Street Lighting	$161,526	96.5%	$155,891	57,996	$2.69	3.5%	$5,635	3,105	$/kW	$1.8150
Unmetered Scattered Load	$65,536	77.1%	$50,515	2,196	$23.00	22.9%	$15,021	962,029	$/kWh	$0.0156
Total	**$15,752,482**		**$11,080,080**				**$4,672,402**			

1.5.7.10 STANDBY / CAPACITY RESERVE CHARGE ("CRC")

HHHI is proposing a Standby / CRC charge with this application. This classification would apply to an account with load displacement facilities that contracts with HHHI to provide standby power when its load displacement facilities are not in operation. The level of the billing demand will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation such as name-plate rating of the load displacement facility. The charge would be based on the applicable General Service 50 to 999 kW or General Service 1,000 to 4,999 kW Distribution Volumetric Charge applied to the contracted amount (e.g. nameplate rating of generation facility multiplied by Capacity Factor).

Currently, HHHI would have one (1) customer who will be installing a Combined Heat and Power unit yet would still require reserved capacity. The customer has been notified of this application by HHHI. More details on the Standby / CRC request can be found in Exhibit 8.

1.5.7.11 LOW VOLTAGE ("LV") CHARGE

As HHHI is partially embedded to Hydro One Networks Inc. ("HONI"), HHHI receives step down power at HONI's Sub-Transmission Rates. Part of these rates include Sub-transmission Lines and various rate rider charges. These charges and HHHI recoveries are tracked as Low Voltage. HHHI has used 2019 volumes at current 2020 rates to forecast the Low Voltage costs for 2020 and 2021. The billing determinants, allocation of charges and proposed 2021 Low Voltage rates are provided in Table 43 - Proposed 2021 Low Voltage Rates. More details can be found in Exhibit 8.

Table 43 - Proposed 2021 Low Voltage Rates

Rate Class	Retail TX Connection Rates		Billing Determinants		Allocation of Low Voltage Charges			Low Voltage Charge Rates	
	Per kWh	Per kW	Annualized kWh or kW	Unit of Measure	Retail Tx Connection Revenue - Basis for Allocation ($)	Allocation Percentages	Allocated $	Low Voltage Rates / kWh	Low Voltage Rates / kW
Residential	$0.0059		207,178,634	$/kWh	$1,222,354	44.65%	$905,664	$0.0044	
General Service less than 50 kW	$0.0055		46,722,885	$/kWh	$256,976	9.39%	$190,398	$0.0041	
General Service 50 to 999 kW		$2.3110	371,084	$/kW	$857,575	31.33%	$635,393		$1.7123
General Service 1,000 to 4,999 kW		$2.3110	168,373	$/kW	$389,110	14.21%	$288,298		$1.7123
Sentinel Lighting		$1.6636	680	$/kW	$1,131	0.04%	$838		$1.2326
Street Lighting		$1.6298	3,105	$/kW	$5,060	0.18%	$3,749		$1.2075
Unmetered Scattered Load	$0.0055		962,029	$/kWh	$5,291	0.19%	$3,920	$0.0041	
Total					**$2,737,496**	**100.00%**	**$2,028,261**		

1.5.7.12 OTHER RATES

HHHI has completed the OEB's 2021 Retail Transmission Service Rates ("RTSR") model based on current Uniform Transmission Rates. HHHI bills the RTSR rates, as determined by the model, along with OEB determined Smart Entity Charge, Regulatory Charges (consisting of Wholesale Market Service, Capacity Based Recovery, Rural or Remote Rate Protection) and Standard Supply Service Charge. These charges have been updated accordingly and used to calculate total bill impacts. HHHI understands that these rates may change and will be updated accordingly.

HHHI is not proposing any changes to the Specific Service Charges shown in HHHI's 2020 Tariff of Rates and Charges with the exception of the Specific charge for access to the power poles and Retail Service Charges. As per the Report on Wireline Pole Attachment Charges dated March 22, 2018 and Report of the Ontario Energy Board: Energy Retailer Service Charges dated November 29, 2018, respectively, HHHI proposes to follow the OEB direction that both sets of charges would be increased annual based on the OEB's inflation factor. HHHI has utilized a two percent (2%) inflation factor for the purposes of this application.

HHHI understands and accepts that the Uniform Transmission Rates for the RTSR, the inflation factor for the pole attachment, Retailer Service Charges will be updated with the 2021 rates once approved by the OEB.

1.5.7.13 LOSS ADJUSTMENT FACTOR

HHHI has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2015 to 2019. The calculations are summarized in Table 44 - Proposed Loss Factor Calculation (Chapter 2 Appendix 2-R) and consistent with calculations provided in Appendix 2-R. HHHI is proposing a reduction in Total Loss Factor from 1.056 and 1.0455 for Secondary and Primary Metered customers, respectively, to 1.0400 and 1.0296.

Table 44 - Proposed Loss Factor Calculation (Chapter 2 Appendix 2-R)

		Historical Years					5-Year Average
		2015	2016	2017	2018	2019	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	533,813,769	526,701,336	500,433,348	520,181,401	513,132,840	518,852,539
A(2)	"Wholesale" kWh delivered to distributor (lower value)	520,395,181	513,458,896	487,853,407	507,097,511	500,222,040	505,805,407
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	520,395,181	513,458,896	487,853,407	507,097,511	500,222,040	505,805,407
D	"Retail" kWh delivered by distributor	512,279,689	505,220,809	483,076,156	500,061,363	494,417,598	499,011,123
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-	-	-
F	Net "Retail" kWh delivered by distributor = **D - E**	512,279,689	505,220,809	483,076,156	500,061,363	494,417,598	499,011,123
G	Loss Factor in Distributor's system = **C / F**	1.0158	1.0163	1.0099	1.0141	1.0117	1.0136
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0260	1.0260	1.0260	1.0260	1.0260	1.0260
	Total Losses						
I	Total Loss Factor = **G x H**	1.0423	1.0427	1.0361	1.0404	1.0380	1.0400

1.5.8 DEFERRAL AND VARIANCE ACCOUNTS ("DVA") (EXHIBIT 9) [33]

HHHI has included in this Application, a request for approval for the disposition of Group 1, Group 2 and Other DVAs balances as at December 31, 2019 and the forecasted interest through April 30, 2021.

HHHI has followed the Board's guidance in the Accounting Procedures Handbook and FAQ's (APH) for recording amounts in the deferral and variance accounts. Such guidance also includes the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative ("EDDVAR Report"). HHHI has reconciled the DVAs to the Audited Financial Statements and variances have been explained in detail in Exhibit 9. LRAMVA amounts are detailed in Exhibit 4.

HHHI has not included any references to Account 1509 – Impacts Arising from the COVID-19 Emergency nor any of the sub-accounts. HHHI expects that Account 1509 dispositions will be determined and rate riders calculated outside the usual application process. Additionally, recovery is expected to be completed before the May 1, 2021 rate effective date requested in this application and therefore, is not included in the amounts discussed below or in Exhibit 9.

1.5.8.1 TOTAL DISPOSITION

HHHI is requesting a net disposition of $(903,400) consisting of $(2,281,669) for Group 1, $1,031,364 for Group 2 and $346,905 for LRAMVA to be recovered from or paid to customers. Carrying charges have been computed to April 30, 2021 to align with the proposed effective date for disposition commencing May 1, 2021. Table 45 - Proposed DVA Disposition Amounts summarizes:

[33] MFR - Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested

1

Table 45 - Proposed DVA Disposition Amounts[34]

Account Descriptions	USofA	Principal Adjusted Balances at December 31, 2019	Interest Balance at December 31, 2019	Total Principal and Interest	Forecasted Carrying Charges to April 30, 2021	Total Adjustment Claim for Disposition
Group 1 Accounts						
LV Variance Account	1550	(1,205)	(1,421)	(2,626)	(19)	**(2,645)**
Smart Metering Entity Charge Variance Account	1551	(28,367)	(934)	(29,301)	(444)	**(29,745)**
RSVA - Wholesale Market Service Charge	1580	(212,688)	(12,866)	(225,554)	(3,329)	**(228,883)**
RSVA - Retail Transmission Network Charge	1584	215,404	3,772	219,176	3,371	**222,547**
RSVA - Retail Transmission Connection Charge	1586	74,610	1,048	75,658	1,168	**76,826**
RSVA - Power (excluding Global Adjustment)	1588	502,335	26,198	528,532	7,862	**536,394**
Group 1 Sub-Total		**550,089**	**15,797**	**565,885**	**8,609**	**574,494**
RSVA - Global Adjustment - Class B	1589	(2,779,672)	(32,990)	(2,812,662)	(43,502)	**(2,856,164)**
Group 1 Total		**(2,229,583)**	**(17,193)**	**(2,246,777)**	**(34,893)**	**(2,281,669)**
Group 2 and Other Accounts						
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	(35,443)	29,240	(6,203)	(555)	**(6,758)**
Pole Attachment Revenue Variance	1508	(407,845)	(1,975)	(409,820)	(3,889)	**(413,709)**
Other Regulatory Assets - Sub-Account - OEB Assessment	1508	197,255	3,532	200,787	2,569	**203,355**

[34] MFR - Proposal for disposition of any balances in existing DVAs for renewable generation and smart grid development, if applicable

	Other Regulatory Assets - Sub-Account - Depreciation Adjustment	1508	1,100,879	-	1,100,879	-	**1,100,879**
	Retail Cost Variance Account - Retail	1518	46,024	883	46,907	615	**47,522**
	Retail Cost Variance Account - STR	1548	629	26	655	9	**664**
	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	32,452	66,451	98,903	508	**99,411**
	Group 2 and Other Sub-Total		**933,950**	**98,157**	**1,032,107**	**(743)**	**1,031,364**
	LRAM Variance Account	1568	325,883	15,922	341,805	5,100	**346,905**
Group 2 and Other Total			**1,259,833**	**114,079**	**1,373,912**	**4,357**	**1,378,269**
Total			**(969,750)**	**96,886**	**(872,865)**	**(30,536)**	**(903,400)**

Table 46 - Total Billing Determinants and Allocators for Rate Rider Calculations summarizes the billing determinants and allocators used for the rate rider computations, including the split between RPP and non-RPP customers.

Table 46 - Total Billing Determinants and Allocators for Rate Rider Calculations

Customer Class	# of Customers	Total kWh	Total kW	Non-RPP kWh	Non-RPP kW	Distribution Revenue	WMP kWh	WMP kW
Residential	20,852	207,178,634	-	3,667,062	-	11,248,505		
General Service less than 50 kW	1,876	46,722,885	-	7,041,139	-	1,878,562		
General Service 50 kW to 999 kW	219	132,955,988	371,084	123,197,018	340,098	2,706,645	3,857,378	7,699
General Service 1,000 kW to 4,999 kW	9	70,322,012	168,373	70,322,012	168,373	834,334		
Un-metered Scattered Load	183	962,029	-	962,029	-	42,219		
Sentinel Lighting	175	251,879	680	18,009	50	74,640		
Street Lighting	4,833	979,604	3,105	979,604	3,105	260,941		
TOTAL	**28,147**	**459,373,031**	**543,242**	**206,186,873**	**511,626**	**17,045,846**	**3,857,378**	**7,699**

1.5.8.2 DISPOSITION PERIOD

HHHI is proposing to dispose of DVA balances over a two (2) year period.

1.5.8.3 NEW ACCOUNTS AND REQUESTED DISCONTINUATIONS

HHHI is not requesting any new DVAs.

Table 47 - Deferral and Variance Accounts to be Continued and Discontinued lists all Deferral and Variance Accounts which HHHI will continue and discontinue on a go-forward basis, providing the OEB approves final dispositions.

1 **Table 47 - Deferral and Variance Accounts to be Continued and Discontinued**

Description	USofA	Continue / Discontinue	Reason
Group 1 Accounts			
LV Variance Account	1550	Continue	On-going
LV Variance Account, Sub-account Global Adjustment	1550	Continue	On-going
Smart Metering Entity Charge Variance Account	1551	Continue	On-going
RSVA - Wholesale Market Service Charge	1580	Continue	On-going
RSVA - Retail Transmission Network Charge	1584	Continue	On-going
RSVA - Retail Transmission Connection Charge	1586	Continue	On-going
RSVA - Power (excluding Global Adjustment)	1588	Continue	On-going
RSVA - Global Adjustment	1589	Continue	On-going
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	Continue	On-going
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	Continue	On-going
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	Continue	On-going
Group 2 Accounts			
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	Discontinue	Fully disposed
Pole Attachment Revenue Variance	1508	Discontinue	Fully disposed and included in rates
Other Regulatory Assets - Sub-Account - OEB Assessment	1508	Discontinue	Fully disposed and included in rates
Other Regulatory Assets - Sub-Account - Depreciation Adjustment	1508	Discontinue	Fully disposed and included in rates
Other Regulatory Assets - Sub-Account - Incremental Cap Expenditures	1508	Discontinue	Included in rates
Other Regulatory Assets - Sub-Account - Incremental Cap Expenditures Depreciation Expense	1508	Discontinue	Included in rates
Other Regulatory Assets - Sub-Account - Incremental Cap Expenditures Accumulated Depreciation	1508	Discontinue	Included in rates
Other Regulatory Assets - Sub-Account - Incremental Cap Expenditures Rate Rider Revenues	1508	Discontinue	Included in rates
Other Regulatory Assets - Sub-Account - Incremental Cap Expenditures Carrying Charges	1508	Discontinue	Included in rates
Other Regulatory Assets - Sub-Account - Incremental Cap Expenditures Rate Rider Revenues, Carrying Charges	1508	Discontinue	Included in rates
Retail Cost Variance Account - Retail	1518	Discontinue	Fully disposed and included in rates
Retail Cost Variance Account - STR	1548	Discontinue	Fully disposed and included in rates
Other Accounts			
LRAM Variance Account	1568	Continue	On-going
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	Discontinue	Fully disposed

1.5.9 BILL IMPACTS[35]

Table 48 - Bill Impacts below presents HHHI's proposed distribution rate and total bill impacts, by level of customer consumption per rate class. Impacts are shown using the applicable current approved rates (effective May 1, 2020) and the proposed 2021 rates for distribution, including Rate Riders for the recovery of Deferral and Variance accounts discussed in Exhibit 9. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

Table 48 - Bill Impacts

Rate Class	**Volumes**		**2020 Bill**	**2021 Bill**	**Total Bill Impact**
	kWhs	**kWs**	**$**	**$**	**%**
Residential - Time of Use	750	-	$121.05	$126.49	4.49%
General Service Less Than 50 kW	2,000	-	$298.22	$321.87	7.93%
General Service 50 to 999 kW	328,500	500	$50,916.29	$50,046.17	(1.71%)
General Service 1,000 to 4,999 kW	1,600,000	2,500	$232,630.00	$232,890.86	0.11%
Unmetered Scattered Load	150	-	$20.80	$20.98	0.83%
Sentinel Lighting	650	1	$113.33	$107.66	(5.00%)
Street Lighting	94,033	251	$27,559.97	$27,955.73	1.44%

1.5.10 MITIGATION PLANS

As per the filing guidelines, should any rate class with a total bill increase exceeding 10%, the applicant must file a mitigation plan. HHHI submits that the bill impacts of its proposed electricity distribution rates are below 10% and do not require rate mitigation at this time as changes to rates are possible through the application process. Should bill impacts exceed 10%, HHHI will put forth a mitigation plan.

[35] MFR - Bill Impacts - total impacts ($ and %) for all classes for typical customers

1.6 MATERIALITY THRESHOLD

The materiality threshold used by HHHI in this application is computed based on the Chapter 2 Filing Requirements of 0.5% of the proposed distribution revenue requirement. HHHI has adopted a threshold of $80,000 for variance analysis. The calculation of materiality is set out in Table 49 - Materiality Threshold for Variance Analysis.

Table 49 - Materiality Threshold for Variance Analysis.[36]

Description		2021 Test Year
Distribution Revenue Requirement	$	15,752,482
Materiality Threshold		0.50%
Materiality Calculated		78,762
Materiality Used	**$**	**80,000**

[36] MFR - Materiality threshold; additional details beyond the threshold if necessary

1.7 CUSTOMER ENGAGEMENT

1.7.1 OVERVIEW OF CUSTOMER ENGAGEMENT[37][38][39][40][41][42][43][44]

While HHHI engaged in a modified Customer Engagement survey related to this application, HHHI would like to note that HHHI is constantly engaging with customers and acting on their suggestions and requests within the day to day operations of the utility. Some examples are explained below:

- A pole line on Delrex Blvd. in Georgetown was being replaced as part of a capital project. A pole was in front of a customer's house and the replacement pole was planned to be placed in the same area. The customer approached the crew performing the work and requested that the pole be located between residences, rather than in front of the house. After discussion with the Engineering Department, the design was revised and the pole installed between properties.
- A customer in Acton contacted HHHI about a padmount transformer that was placed near the customer's driveway. The customer indicated that drivers were hitting the transformer. While the transformer was installed correctly as per the subdivision design, it was determined that the developer had paved the driveway incorrectly resulting in the transformer being at risk for impacts. To assist the customer and in agreement with the customer, HHHI installed bollards around the transformer.

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[37] MFR - Overview of customer engagement activities; description of plans and how customer needs, preferences and expectations have been reflected in the application.

[38] MFR - Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates

[39]MFR - Reference to any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities

[40] MFR - Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates

[41] MFR - Discussion of any feedback provided by customers and how the feedback shaped the final application

[42] MFR - Impact of customer engagement activities on the development of the capital plan are to be filed as part of the capital plan requirements in Chapter 5

[43] MFR - Provide relevant customer and local knowledge for (community) meeting planning purposes, preparing presentation and other materials as may be required, attending the meeting and having one or more executives of the distributor available to present the distributor's rate application information and answer customer questions

[44] MFR - Required to advertise the OEB's community meeting(s) on a bill insert developed by the OEB in the next available billing cycle following the filing of the application or sooner. The OEB may require the distributor to advertise the meeting(s) through other channels

These are just a couple of the daily day to day examples of customer engagement in which HHHI and its customers work together to achieve a mutually beneficial conclusion.

1.7.2 ADDRESSING CUSTOMER PREFERENCE

Customer engagement is an important driver for HHHI's planning process. In 2019, the utility launched an innovative, cost effective customer engagement platform. The customer engagement website, HaveYourSay.HaltonHillsHydro.com, provided customers an opportunity to learn about HHHI's distribution system planning process, contribute to idea forums and participate in surveys in support of the DSP and application. The goals of the HaveYourSay customer engagement platform were as follows:

- Inform customers on the distribution system planning process
- Engage customers in the conversation about electricity cost and reliability
- Collaborate with customers through surveys, polls and idea forums to gain an understanding of customer's needs and preferences
- Reach as wide a customer audience as possible
- Achieve statistically relevant survey responses
- Keep customers informed throughout the entire planning process

HHHI found that the customer feedback through the HaveYourSay website was more effective, statistically relevant, more meaningful and more economical than requesting a survey company complete a phone survey. Further details regarding the HaveYourSay website are discussed later in this Exhibit.

Telephone surveys do not provide timely results and are an inconvenience to our customer. Using the HaveYourSay website resulted in statistically relevant results in under two (2) weeks. HHHI would like to note that given the number of hydro scams calls being received by customers and HHHI constantly cautioning customers about the scams, customers are no longer responding to phone surveys.

1.7.3 KEY THEMES / FEEDBACK FROM CUSTOMER ENGAGEMENT

Through the customer engagement activities undertaken in support of this plan, several key themes emerged.

1. Reliability and reasonable rates

Balancing system reliability with affordable rates is a priority driver for HHHI's overall investment strategy.

Voltage conversion programs identified in this plan ensure that capacity from HHHI's municipal transformer station will be available to meet new and growing customer loads, ensuring supply is available for major new developments such as Vision Georgetown. As well, these voltage conversion projects free up capacity to ensure reliable supply for in-fill developments in Georgetown, particularly areas fed from the heavily loaded 44kV system. If these voltage conversion projects did not proceed, HHHI may have to pay for additional capacity from HONI which would result in increased costs for rate payers. Additionally, HHHI is beginning to review planned load transfers to allow for the minimization of "double peak billing" that results from temporarily transferring load from one feeder to another supplied from a different delivery point. Load transfers allow for uninterrupted supply to customers to maintain reliability during peak power periods and during maintenance on the distribution system. When double peak billing occurs, HHHI is billed for the load on both the original feeder and the feeder the load was moved to, resulting in increased costs to customers through the transmission and low-voltage expenses.

2. Customers are strongly in favour of a proactive replacement strategy rather than a run-to-failure approach.

This plan shows a clear focus on proactive replacement programs. Some of the projects outlined in this plan, such as PoleTrans replacements and Live Front transformer replacements remove obsolete equipment from HHHI's distribution system before they fail leading to potentially lengthy power outages because like for like replacements are not available.

Ongoing replacement programs such as pole replacements and porcelain insulator and switch replacements target aged or poor condition assets to prevent future outages. HHHI is also developing a primary cable testing program to develop a health index for underground primary cable to ensure a cable replacement strategy is based on asset condition.

3. Reducing power outages

A number of the programs outlined in this plan are aimed at reducing either the number or the duration of power outages. New poles installed as part of pole replacement projects or installed as part of pole line rebuild or expansion projects are built to current standards that take into account the impacts of severe weather. These new construction methods are more resilient to climate events. HHHI's annual tree trimming program reduces power outages caused by tree contacts.

Projects outlined in this plan that address SCADA integration of automated switches reduce the length of power outages though remote or automated control rather than mobilizing field crews to restore power. In particular, rural customers were twice as likely as other customers to be willing to pay for increased automation to reduce the length of power outages.

While not included in the DSP, HHHI would like to note that it regularly engages with customer in the day to day operations to aid customers with outages. For example, a rural customer had upgraded their service in early 2017. The customer continually exceeded the estimated demand load they had provided by more than 50% resulting in the overloading of the supply transformer, and unplanned outages, and increased O&M costs. In fall 2017, HHHI agreed to undertake a system expansion by upgrading 0.4km of distribution system thereby allowing HHHI to upgrade the transformer and balancing the supplying feeder. By balancing the supplying feeder, all HHHI customers should experience improved power quality, and HHHI's O&M costs have been reduced in respect of this customer.

4. Accommodating renewable energy resources and addressing climate change

Through survey question responses and comments received, customers expressed a strong interest in HHHI modernizing the electricity grid to accommodate renewable energy resources and to address climate change.

As indicated by the programs mentioned earlier in this section, proactive replacement projects, utilizing modern construction methods, having a strong tree trimming program that includes trimming for the best health of the tree, and increased automation are ways HHHI is preparing the grid to be more resilient to climate change.

While only 15% of survey respondents indicated that they were considering installing EV charging stations within the next five (5) years, 31.7% of poll respondents indicated that they were considering installing battery storage to provide back-up power supply to their home or business in the next five (5) years. HHHI will facilitate customers wishing to install EV charging stations and/or battery storage and will review opportunities to invest in EV charging for the community.

HHHI has adequate capacity to accommodate the connection of DERs and works with any customer interested in installing other innovative technologies such as battery backup. HHHI's Renewable Energy Generation & DER Investments 2021-2025 document attached as Appendix C in the DSP, assesses the state of HHHI's existing distribution system, studies the current renewable-connected generation and near-term growth forecast, defines a strategy to accommodate the predicted renewable generation growth and describes HHHI's future Renewable Generation expenditures from 2021 through 2025. As well, the utility is committed to assisting the Town of Halton Hills by providing guidance on the strategic placement of Electric Vehicle charging stations within the distribution system.

1.7.4 CUSTOMER ENGAGEMENT AS PART OF COORDINATED PLANNING WITH THIRD PARTIES

Customer engagement is an important driver for HHHI's planning process. In 2019, the utility launched an innovative, cost effective customer engagement platform. The customer engagement website, HaveYourSay customer engagement platform was promoted extensively through e-mails to customers, HHHI's social media pages on Facebook, Twitter, LinkedIn and Instagram and through Google. The website features discussion forums, quick polls, surveys and an information blog providing information on utility projects and practices. This unique approach to customer engagement provided a meaningful way for customers to contribute to the Distribution System Planning process at a fraction of the cost of conventional customer engagement methods. The Electricity Distributor's Association recognized this innovative customer engagement platform with the 2019 Communications Excellence Award.

HHHI regularly and proactively engages with customers throughout the year. The utility has an active presence on social media with over 33% of its customers engaged through Facebook, Twitter, Instagram and LinkedIn. This is one of the highest following rates of any LDC in Ontario. HaveYourSay.HaltonHillsHydro.com provided customers an opportunity to learn about HHH's distribution system planning process, contribute to idea forums and participate in surveys in support of this plan. Additionally, customers could ask questions and get responses. The goals of the HaveYourSay customer engagement platform were as follows:

- Inform customers on the distribution system planning process
- Engage customers in the conversation about electricity cost and reliability
- Collaborate with customers through surveys, polls and idea forums to gain an understanding of customer's needs and preferences
- Reach as wide a customer audience as possible
- Achieve statistically relevant survey responses
- Keep customers informed throughout the entire planning process

Frequent posts kept customers aware of HHHI activity, projects, power outages and electrical safety information. Customers were able to engage in an ongoing dialogue with the utility throughout the year through these platforms.

HHHI engages with the community at a number of community events throughout the year including Earth Day, Acton Leathertown Festival, Canada Day in Glen Williams and the Acton and Georgetown Santa Claus Parades. Staff throughout the organization participate in these events providing customers a chance to interact directly with their utility.

In 2019, HHHI held its third Community Open House providing customers with a chance to tour their utility, engage with staff and learn about utility operations.

Some of the key messages heard from customer feedback include:

- Proactive replacement strategy – Customer response is strongly in favour of a proactive asset replacement strategy to improve reliability even if it results in increased costs. In particular, commercial customer responses reflected a strong preference for proactive replacement strategies.
- Reliability vs Cost - Balancing system reliability with affordable rates continues to be a priority for customers.
- Accommodating renewable energy resources and addressing climate change: Preparing to integrate distributed energy resources and other new technologies is important as HHHI plans for the future. HHHI's customers agree. Over 70% of responses are in favour of HHHI investing to be prepared for new technologies. There were a number of customer comments related to grid modernization, particularly in the context of climate change and the environment. Comments focused on the need for solar power/renewable energy as a way to reduce greenhouse gases and address climate change.
- Customers trust HHHI to make the right decisions, and trust HHHI to maintain its existing investment strategy.
- The lessons learned through the customer engagement strategy have informed the DSP and HHHI operations.

Details of the customer engagement feedback are outlined in Appendix B of the DSP.

1.7.5 CUSTOMER ENGAGEMENT ACTIVITIES

HHHI undertook an innovative customer engagement process to obtain an understanding of customer preference as it pertains to distribution system planning. The utility launched a customer engagement portal, HaveYourSay.HaltonHillsHydro.com as a tool to engage customers in a conversation about their utility. Customer engagement activities were undertaken entirely in house including all marketing, design, customer outreach, surveys and analysis. A third party, Bang the Table was utilized to host the HaveYourSay website. Through this approach, the utility realized substantial savings compared to traditional customer engagement methods while realizing extensive customer feedback. This is an example whereby HHHI continually and prudently manages costs and being innovative is achieving customer satisfaction.

A customer panel was utilized to provide input into the customer engagement website prior to its launch. This panel was also engaged to review survey questions prior to survey launch. The panel consisted of eight (8) members of the community; a mix of residential and commercial customers. During HHHI's 2018 customer satisfaction survey, customers were asked if they would be interested in participating in future panels or focus groups. These eight (8) customers were engaged as a result of that survey.

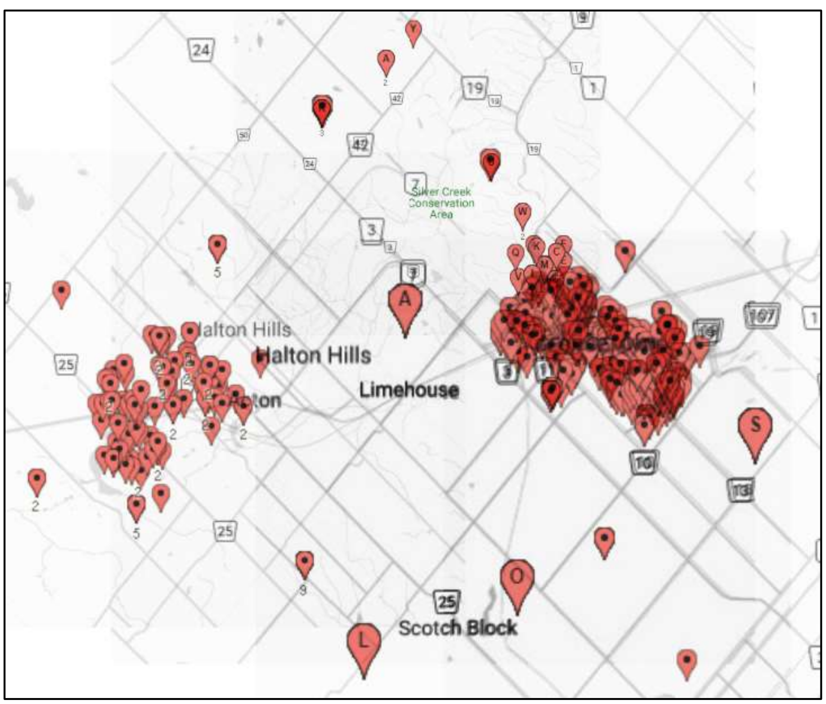
Through the customer engagement platform, customers had the opportunity to read blogs about such topics as cyber security, burying powerlines, how automation helps reduce outage times, proactive vs run to failure equipment replacement, overviews of HHHI, the Ontario electricity system and electricity bills. As well, customers could engage in idea forums on future planning, submit questions and participate in quick polls.

The site also featured two surveys, one focusing on power outages and reliability, while the other focused on planning and spending. The Planning survey had 561 responses, providing a 4.05% margin of error at a 95% confidence level. The Power Outages & Reliability survey had 461 responses, providing a 4.52% margin of error at a 95% confidence level. Full details of survey findings can be found in Appendix B of the DSP. In 2018, HHHI conducted its biennial customer satisfaction survey. While this survey focused on overall customer satisfaction, there were a number of questions that were relevant to the DSP process. Those results were analyzed in conjunction with the specific customer engagement surveys.

The site was promoted extensively through HHHI's social media sites, website, customer account portal, local BIA newsletters and Google. As well, surveys were available to be completed at the Acton Leathertown festival, HHHI's Community Open House and at the customer front counter. All customers with e-mail information on file were contacted with a direct link to participate in the surveys as well.

Survey responses were well distributed throughout HHHI's service territory including urban centres and rural customers. The map below marks the locations of survey responses throughout HHHI's territory.

Table 50 - Survey Response Distribution

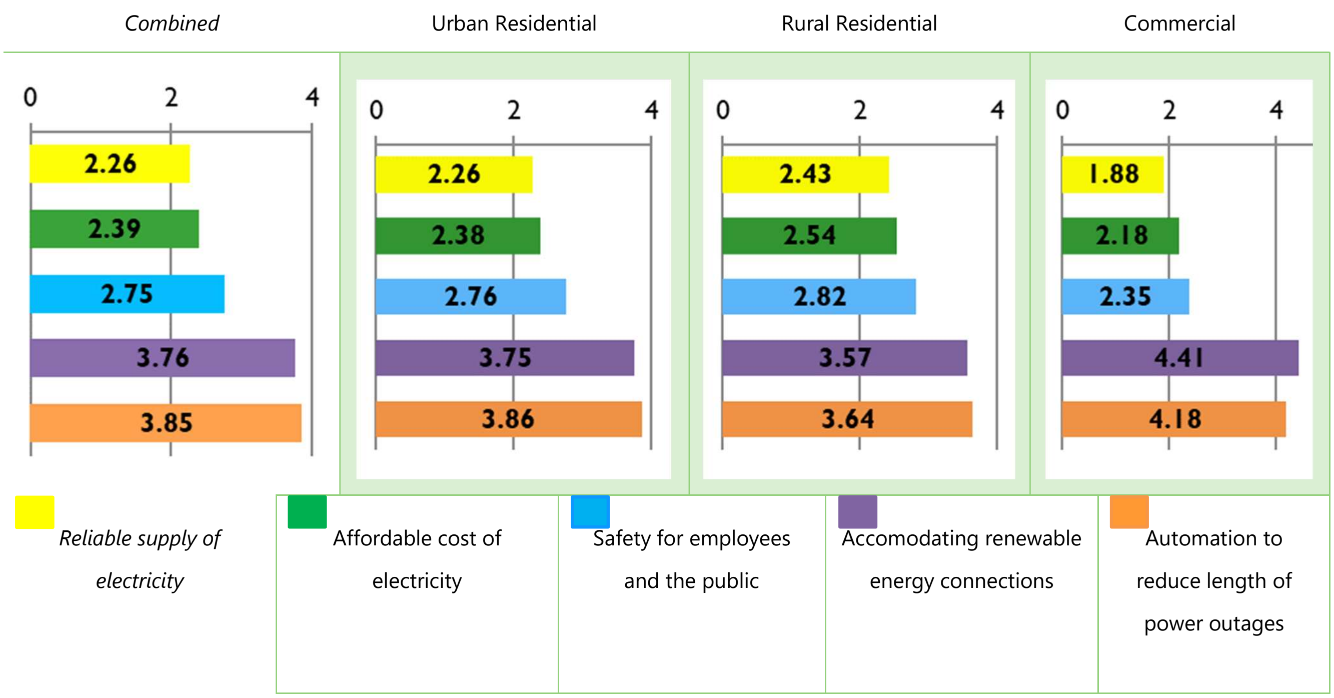


A complete list of customer engagement activities including all social media posts can be found in Appendix B of the DSP.

A number of projects within this Distribution System Plan support the feedback received through customer engagement.

Table 51 - Customer Priority Ranking below summarizes customer's priority ranking (1 is the highest priority, 5 is the lowest). The averaged scores show the relative weighting of responses.

Table 51 - Customer Priority Ranking



In particular, customers showed a strong preference for a proactive replacement instead of run to failure. HHH's System Renewal programs, in particular, porcelain insulator replacement, defective transformer replacement, pole replacements and poletrans replacement programs, directly address this preference.

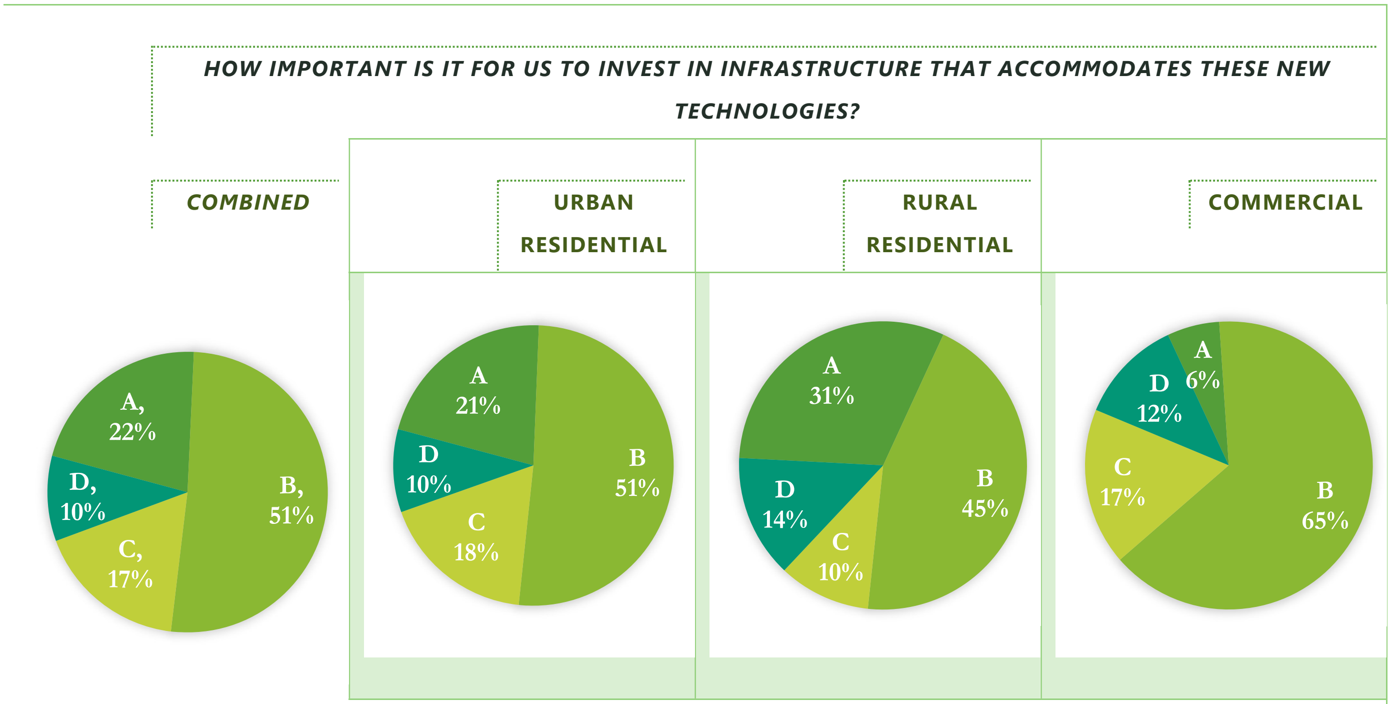
Voltage conversion projects improve reliability, support grid modernization, provide support for DERs and provide increased system hardening to address climate change.

Customer engagement on grid modernization

Through HHHI's customer engagement activities, customers were asked about the importance of grid modernization to accommodate new technologies. The question and charts below show customer perceptions related to grid modernization.

Table 52 - Customer Grid Modernization Survey Results

The electricity industry is evolving. New technologies are making it easier for homes and businesses to install smart devices such as internet connected thermostats and switches, renewable energy generation, such as solar panels, and battery backup power supply. Electric vehicles and their charging stations will also play an increasingly important role in our electricity grid. As these technologies become more common place, utilities will need to adapt to new customer expectations.



A: Very important, HHHI should start investing now to be prepared for these new technologies and I am willing to pay more.

B: Important, Halton Hills should start investing now but at no additional cost.

C: Important but HHHI should wait a few years until these technologies are more common place.

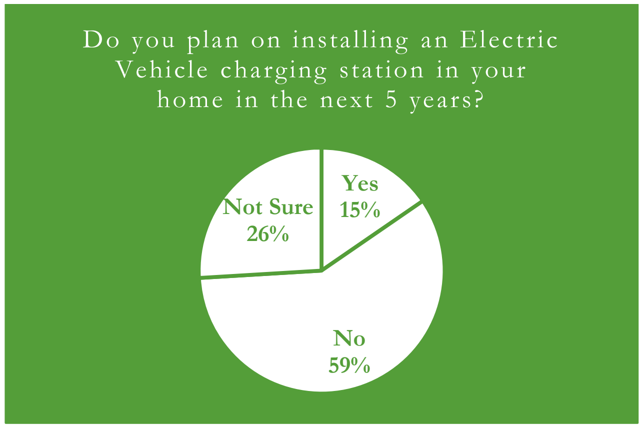
D: Not important. HHHI should focus on keeping the existing system safe and reliable.

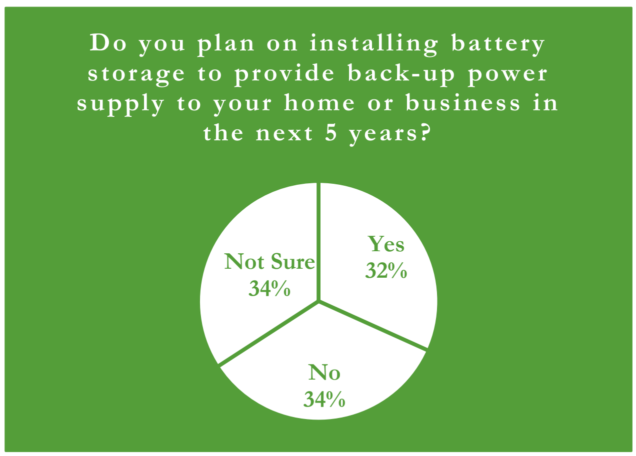
DER Accommodation

As part of our customer engagement activities to understand customer preference around DERs, we asked two (2) quick poll questions related to electric vehicle charging and battery storage to gain an understanding of customers' plans to adopt these technologies.

Only 15% of respondents are considering installing an electric vehicle charging station in the next five (5) years. However, 31.7% of poll respondents plan on installing battery storage to provide back-up power supply to their home or business in the next five (5) years.

Table 53 - Customer DER interest





HHHI has adequate capacity to accommodate the connection of DERs and works with any customer interested in installing other innovative technologies such as battery backup, combined heat and power, solar panels. HHHI's Renewable Energy Generation & DER Investments 2021-2025 document is included in the DSP in Exhibit 2.

Smart Grid

Through HHHI's customer engagement activities, the utility received a number of customer comments related to grid modernization, particularly in the context of climate change and the environment. Comments focused on the need for solar power/renewable energy as a way to reduce greenhouse gases and address climate change.

Throughout the term of the DSP, HHHI plans to automate switches and other devices and integrate those devices into the SCADA system. This automation helps create a more resilient grid in the event of climate change impacts and to accommodate DERs.

1.7.6 CUSTOMER ENGAGEMENT WORKBOOK

HHHI has completed Appendix 2-AC – Customer Engagement Worksheet which identifies ongoing customer engagement activities and the impacts those activities have on distribution system planning.

1.8 LETTERS OF COMMENT

1.8.1 LETTER OF COMMENT

There have been no letters of comment filed with OEB as of the submission date as part of this Application. [45]

[45] MFR - All responses to matters raised in letters of comment filed with the OEB.

1.9 PERFORMANCE MEASUREMENT

1.9.1 OVERVIEW[46]

HHHI strives for continuous improvement in all aspects of the organization. As such, HHHI has a number of processes and metrics in place to monitor performance. These metrics review planning from a number of perspectives: Customer oriented performance, cost efficiency and effectiveness and system performance. Additionally, HHHI also monitors and strives for continuous improvement in the OEB performance outcomes: Customer Focus, Operation Effectiveness, Public Policy Responsiveness, and Financial Performance.

Below, HHHI discusses the performance of each OEB Scorecard measure over the last five (5) years in addition to HHHI specific measures. HHHI would like to note that it has utilized the years 2015 to 2019 where available and as the Scorecard measures provide by the OEB are not available for 2019, HHHI has used 2014 to 2018.

1.9.2 CUSTOMER FOCUS

These excellent results in customer focus are reflective of HHHI's strong commitment to customer service. HHHI expects metrics in this area to continue to exceed targets. The Customer Focus section of the OEB Scorecard for HHHI is shown below:

[46] MFR - Discussion of performance for each of the distributor's scorecard measures over the last five years; drivers for its performance, plans for continuous improvement, identify performance improvement targets, forecast of efficiency assessment using the PEG forecasting model for the test year, discussion on how distributor's self-assessment has informed its business plan and the application

Table 54 - Customer Focus Scorecard Results

Performance Outcomes	Performance	Measures	2015	2016	2017	2018	2019
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%
		Scheduled Appointments Met On Time	100.00%	100.00%	100.00%	99.98%	97.66%
		Telephone Calls Answered On Time	93.10%	94.40%	95.85%	96.63%	96.43%
	Customer Satisfaction	First Contact Resolution	99.99%	99.98%	99.99	99.98%	99.98%
		Billing Accuracy	99.96%	99.84%	99.77%	99.89%	99.88%
		Customer Satisfaction Survey Results	90%	88%	88%	95%	95%

1.9.3 SERVICE QUALITY

New Residential/Small Business Services Connected – HHHI continues to achieve 100% for New Residential/ Small Business Services Connected. HHHI endeavours to connect customers the same day they call for service, providing all other necessary requirements have been met.

Scheduled Appointments Met on Time - HHHI endeavours to meet customers on time. As a result of significantly increased locate requests where HHHI's sole locator has been requested to provide service, HHHI's appointments met on time has decreased. To mitigate this issue, HHHI has implemented a new scheduling system to better manage the requests.

Telephone Calls Answered on Time – HHHI continually exceeds the OEB minimum target of 65% of calls answered within thirty (30) seconds. As can be seen in the above table, HHHI continually maintains a target above 90%.

1.9.4 CUSTOMER SATISFACTION

First Contact Resolution – HHHI tracks unresolved first contacts using the following method: All escalated calls from Customer Care are directed to the Customer Care Supervisor (CCS). The CCS determines whether the escalation is due to no resolution or if the customer is not willing to accept the resolution (i.e. customer has a high bill, confirms consumption but still wants to discuss with the CCS). If the CCS determines that the call was not resolved, then a specific call type is entered in Contact Management. If a complaint is filed with the OEB, a call is immediately entered into Contact Management and counted in the metric. All OEB complaints count as unresolved.

HHHI had three (3) unresolved first contacts in 2018. Of these three (3) unresolved first contacts, the OEB deemed HHHI to be compliant in two (2) of the cases. The other case involved stray voltage and HHHI was able to find a resolution that satisfied the customer.

<u>Billing Accuracy</u> - Since the utility bill is one of the principal forms of communications with the customer, ensuring accurate billing improves customer satisfaction. The Billing Accuracy metric looks at the number of bills that have had to be cancelled or corrected in a given year. In 2019, HHHI issued 276,856 bills (2018 – 277,895, 2017 – 271,641, 2016 – 245,642) and achieved a billing accuracy of 99.88% (2018 – 99.89%, 2017 – 99.77%, 2016 – 99.84%). This compares favourably to the prescribed OEB target of 98%.

HHHI continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

<u>Customer Satisfaction Survey Results</u> - Customer satisfaction is an important measure of customer loyalty and trust. In an environment where the electricity sector receives a high amount of attention in the media, maintaining customer satisfaction is a priority for HHHI. HHHI engages our customers throughout the year at community events, online through social media and through bill inserts and website messaging. HHHI strives to maintain customer satisfaction through ongoing efforts to communicate relevant and timely customer information. Customers (residential and commercial) are engaged to provide high level feedback on their perceptions of HHHI performance and where they think HHHI could improve service. HHHI's target is maintain an Overall Customer Satisfaction Index score of 90% or higher. The overall results of the 2018 Customer Service Survey reported 95% of customers were "very or fairly" satisfied and is above the National and Ontario average of 91%.

Some of the key findings from the 2018 Customer Satisfaction Survey:

- Provides consistent, reliable energy: 94%
- Quickly handles outages and restores power: 94%

- Customer Centric Engagement Index: 87%
- Overall Customer Satisfaction: 95%

The table below shows HHHI's Customer Satisfaction Report Card for the past four (4) survey periods. These scores reflect the utility's culture of continuous improvement.

Table 55 - Customer Satisfaction Survey Summary

Report Card	2018	2016	2014	2011
Customer Care	A	B+	B+	B+
Price and Value	B+	C+	B+	C+
Customer Service	A	A	A	A
Company Image	A	A	A	A
Company Leadership	A	A	A	A
Corporate Stewardship	A	A	A	A
Management Operations	A+	A	A	A
Operational Effectiveness	A+	A	A	A
Power Quality & Reliability	A+	A+	A	A
Overall Score	**A**	**A**	**A**	**A**

1.9.5 OPERATIONAL EFFECTIVENESS

The Operational Effectiveness section of the OEB Scorecard for HHHI is shown below:

Table 56 - Operational Effectiveness Scorecard Results

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			83.00%	83.00%	85.00%	85.00%	83.00%
		Level of Compliance with Ontario Regulation 22/04 [1]			C	C	C	C	C
		Serious Electrical Incident Index	Number of General Public Incidents		0	0	0	0	0
			Rate per 10, 100, 1000 km of line		0.000	0.000	0.000	0.000	0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]			2.58	1.38	1.65	1.48	1.60
		Average Number of Times that Power to a Customer is Interrupted [2]			3.02	1.65	1.13	1.60	1.70
	Asset Management	Distribution System Plan Implementation Progress			On-track	Over budget	Over-budget	123.38%	114.56%
	Cost Control	Efficiency Assessment		1	1	1	1	1	
		Total Cost per Customer [3]		$701	$744	$770	$763	$794	
		Total Cost per Km of Line [3]		$9,886	$10,490	$10,557	$10,295	$10,860	

1.9.6 SAFETY

Level of Public Awareness - The Public Awareness of Electrical Safety measure is determined by public survey. The purpose of the survey is to monitor the effort and impact LDCs are having on improving public electrical safety for the Distribution Network. This public safety survey is intended to be conducted every two (2) years. This survey differs from HHHI's customer satisfaction survey in that it targets the general public regardless of whether they were an LDC customer. The questions on the survey are standardized across the province.

HHHI's Public Awareness of Electrical Safety survey result was 83% and was conducted in early 2020.

Level of Compliance with Ontario Regulation 22/04 - The past nine (9) annual Ontario Regulation 22/04 Audits have concluded that HHHI is compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety, and adherence to company procedures & policies. Ontario Regulation 22/04 - Electrical Distribution Safety 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, specifications and inspection of construction before they are put into service.

Serious Electrical Incident Index – Number of General Public Incidents and Rate per 1,000km of line - HHHI has had zero (0) Serious Electrical Incidents and works diligently with staff and the public to maintain the highest degree of safety and education.

1.9.7 SYSTEM RELIABILITY

Average Number of Hours that Power to a Customer is Interrupted (SAIDI) & Average Number of Times that Power to a Customer is Interrupted (SAIFI) - The table below shows all power outages by cause for the historical period of 2015 to 2019. HHHI calculates Major Event incidents using the OEB approved methodology of calculating a daily threshold based on a five (5) year historical average. Based on this methodology, the only event that met the Major Event threshold for HHHI was a freezing rai storm on March 24, 2016. This event has been removed from the table above.

Table 57 - Interruptions by Cause (2015 to 2019)

		2015			2016			2017		
Cause Code	**Description**	**Number of Incidents**	**Number of Customer Interruptions**	**Number of Customer Hours of Interruptions**	**Number of Incidents**	**Number of Customer Interruptions**	**Number of Customer Hours of Interruptions**	**Number of Incidents**	**Number of Customer Interruptions**	**Number of Customer Hours of Interruptions**
0	Unknown	3	68	66	7	789	553	3	3,646	372
1	Scheduled Outage	14	384	723	32	746	1,839	42	796	1,825
2	Loss of Supply	-	-	-	8	10,054	8,407	3	10,846	766
3	Tree Contacts	11	14,996	5,186	6	212	293	5	992	587
4	Lightning	7	1,019	1,475	1	280	75	3	4,350	7,215
5	Defective Equipment	28	22,513	24,983	37	10,740	10,680	22	4,404	6,925
6	Adverse Weather	6	5,091	1,711	32	35,323	50,561	14	3,256	4,343
7	Adverse Environment	8	18,789	20,767	3	539	1,437	1	21	5
8	Human Element	1	362	253	3	1,974	172	-	-	-
9	Foreign Interference	10	3,502	1,715	24	11,645	4,190	16	8,172	15,963
	Annual Total	**88**	**66,724**	**56,879**	**153**	**72,302**	**78,207**	**109**	**36,483**	**38,001**

		2018			2019		
Cause Code	**Description**	**Number of Incidents**	**Number of Customer Interruptions**	**Number of Customer Hours of Interruptions**	**Number of Incidents**	**Number of Customer Interruptions**	**Number of Customer Hours of Interruptions**
0	Unknown	6	2,082	774	7	14,858	5,612
1	Scheduled Outage	32	632	1,661	9	172	594
2	Loss of Supply	2	2,982	1,378	1	3,003	200
3	Tree Contacts	14	1,660	1,551	11	2,935	2,278
4	Lightning	-	-	-	1	11	76
5	Defective Equipment	26	13,022	15,096	12	4,540	6,121
6	Adverse Weather	18	13,910	13,464	6	7,700	9,258
7	Adverse Environment	1	10	5	-	-	-
8	Human Element	-	-	-	1	502	50
9	Foreign Interference	7	5,209	1,112	15	8,427	12,952
	Annual Total	**106**	**39,507**	**35,039**	**63**	**42,148**	**37,141**

Reliability statistics for 2015 and 2016 were restated based on the change in Major Event reporting methodology. This negatively affected reliability statistics in those two (2) years.

In 2016, the longest outages were related to adverse weather. A freezing rain storm on March 24, 2016 was excluded from reporting as it met the Major Event threshold. However, an additional March freezing rain storm was included in the reporting as it did not meet the threshold. This second storm accounted for over 11,000 customer hours of outage over a couple of days. If this second storm was also excluded, the SAIDI number for 2016 would be reduced from 1.38 to 0.88, well below the five (5) year average.

The second longest outages were related to defective equipment. HHHI would like to note, however, that the total number of outage hours related to defective equipment was less than half the previous year's total.

The restated statistics resulted in an increase in incidents in 2015. In 2015, HHHI had multiple pole fires over the course of two (2) days due to salt spray. HHHI had removed these from the reporting as a Major Event due to the number of customers affected and the duration of the outage (over

10% of customers). As each of these pole fires were considered separate incidents and were over a couple of days, the new methodology, using a calculated daily threshold, indicated these pole fires did not qualify as a Major Event and therefore should be included in the reporting. Had the salt spray incidents been deemed a Major Event, the SAIDI reported would have decreased from 2.58 to 1.67.

1.9.7.1 ASSET MANAGEMENT

Distribution System Plan Implementation Progress - Monitoring actual spending compared to budgets established in the DSP is another important measure of cost efficiency. There are a number of external factors that can significantly affect actual costs within a given year. In particular, System Access projects are driven by third parties, municipalities and customers. The timing on these projects can be unpredictable since they are outside of HHHI's control. As well, extreme weather events, vehicle accidents and other external events can affect actual costs.

HHHI continues to monitor projects and programs included in the DSP and will continue to compare actual capital spending to the approved capital budget. The table below shows the historical planned and actual expenditures for HHHI for the previous DSP time period. 2020 has been excluded as it is the filing year and therefore still in progress. The overall annual historical DSP spend has been within the spending variance target.

Table 58 - Summary of Historical Capital Expenditures (DSP to Actual) 2016 to 2020 Bridge Year

	2016			2017			2018			2019			2020 Bridge Year
Projects	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**
	$'000s			**$'000s**			**$'000s**			**$'000s**			**$'000s**
System Access	509	638	25%	291	203	(30%)	1,590	1,206	(24%)	256	1,024	300%	1,456
System Renewal	4,120	4,896	19%	4,227	4,534	7%	2,818	4,149	47%	3,891	3,345	(14%)	2,070
System Service	2,303	1,999	(13%)	2,411	1,574	(35%)	2,959	1,772	(40%)	3,321	2,000	(40%)	1,525
General Plant	778	491	(37%)	479	761	59%	421	496	18%	425	654	54%	621
Total	**7,709**	**8,023**	**4%**	**7,408**	**7,073**	**(5%)**	**7,788**	**7,624**	**(2%)**	**7,894**	**7,023**	**(11%)**	**5,673**
O&M	1,730	1,905	10%	1,730	1,706	(1%)	1,730	1,636	(5%)	1,730	1,570	(9%)	1,708

1.9.7.2 COST CONTROL

Efficiency Assessment - A key metric in utility cost efficiency and effectiveness is the annual Pacific Economics Group (PEG) performance benchmarking report. This report evaluates all Ontario LDCs to determine their stretch factor assignments in relation to the next rate year. The report assigns LDCs into one of five (5) groups with stretch factors ranging from 0% for the most efficient (Group 1) to 0.6% for the least efficient (Group 5). HHHI has maintained one of the top cost efficiency ratings of LDC's in the Province and has established a target to remain within Group 1.

Table 59 - HHHI Cost Benchmarking Results below shows HHHI's Cost Benchmarking Results from 2016 through to Forecasted 2023.

Table 59 - HHHI Cost Benchmarking Results

Summary of Cost Benchmarking Results

Total Gross Capital Additions

Cost Benchmarking Summary	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 (Bridge)	2021 (Test Year)	2022 Forecast	2023 Forecast
Actual Total Cost	17,028,654	16,934,734	17,821,525	15,861,465	16,799,832	17,937,568	18,374,897	18,802,766
Predicted Total Cost	22,429,778	22,492,011	23,853,248	25,155,628	26,545,058	27,795,572	29,086,739	30,411,572
Difference	(5,401,124)	(5,557,277)	(6,031,723)	(9,294,163)	(9,745,226)	(9,858,004)	(10,711,842)	(11,608,807)
Percentage Difference (Cost Performance)	**(27.5%)**	**(28.4%)**	**(29.2%)**	**(46.1%)**	**(46.6%)**	**(42.7%)**	**(45.2%)**	**(47.3%)**
Three-Year Average Performance					(40.6%)	(45.1%)	(44.8%)	(45.1%)
Stretch Factor Cohort								
Annual Result	1	1	1	1	1	1	1	1
Three Year Average	1	1	1	1	1	1	1	1

Total Cost per Customer – Total cost per customer is calculated as the sum of HHHI's capital and operating costs and dividing this cost figure by the total number of customers that HHHI serves. The cost performance result for 2018 is $794 per customer (2017 - $763, 2016 - $770). Similar to all distributors in the province, HHHI has experienced increases in its total costs required to deliver quality and reliable services to customers. Province wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in aggressive line clearing programs, new information systems technology, cyber-security and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs. HHHI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts as demonstrated in both HHHI's 2016 and 2021 rate applications. Additionally, HHHI completed a number of capital projects that enhanced reliability and efficiencies related to the building of HHHI's new municipal Transformer Station. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on HHHI's capital spending plans.

HHHI has actively engaged staff through the Creative and Critical Thinking initiative to find additional cost efficiencies throughout the LDC. A new program that HHHI began in 2017 focused on "Relentless Incrementalism" – small steps that make a difference and help pave the way for more significant change – involves all staff members examining processes and procedures and implementing changes that would create cost savings, efficiencies or benefit customers.

Total Cost per km of Line – Total cost per km of Line is calculated as the sum of HHHI's capital and operating costs and dividing this cost figure by the total kilometer of line. The 2018 total km of lines in HHHI's distribution system was 1,641 km (2017 – 1,645, 2016 - 1,613 km). The cost performance result for 2018 is $10,860/km of line (2017 – 10,295, 2016 - $10,557).

Similar to all distributors in the province, HHHI has experienced increases in its total costs required to deliver quality and reliable services to customers. Province wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in line clearing programs, new information systems technology, cyber-security and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs. HHHI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts as demonstrated in HHHI's 2016 and 2021 rate applications. Additionally, HHHI completed a number of capital projects that enhanced reliability and efficiencies related to the building of HHHI's new municipal Transformer Station. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on HHHI's capital spending plans.

HHHI has actively engaged staff through the Creative and Critical Thinking initiative to find additional cost efficiencies throughout the LDC. A new program that HHHI began in 2017 focused on "Relentless Incrementalism" – small steps that make a difference and help pave the way for more significant change – involves all staff members examining processes and procedures and implementing changes that would create cost savings, efficiencies or benefit customers.

1.9.8 PUBLIC POLICY RESPONSIVENESS

The Public Policy Responsiveness section of the OEB Scorecard for HHHI is shown below:

Table 60 - Public Policy Responsiveness Scorecard Results

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		17.78%	33.84%	63.29%	77.00%	84.00%
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time	100.00%	100.00%	100.00%	100.00%	100.00%	

1.9.8.1 CONSERVATION AND DEMAND MANAGEMENT

Up until March 21, 2019, LDCs had been delivering conservation programs under the Conservation First Framework (CFF). The CFF required the IESO to coordinate, support and fund the delivery of Conservation and Demand Management (CDM) programs through LDCs to achieve a total of seven (7) TWhs of reductions in electricity consumption between January 1, 2015 and December 31, 2020. LDCs could deliver their CDM obligations through useof IESO province-wide programs and/or their own (or regional) programs (both of which are IESO funded); and were permitted to do so individually or in a joint plan with one or more LDCs. HHHI entered into a Joint CDM Plan with Milton Hydro and Burlington Hydro to deliver 30.94 net GWh in total energy savings over the CFF.

On March 21, 2019, the Minister of Energy, Northern Development and Mines introduced Bill 87 – *Fixing the Hydro Mess Act*, which, among other regulatory initiatives, refocused and uploaded electricity conservation programs to the IESO. The Minister issued a Ministerial Directive terminating the CFF and the Energy Conservation Agreements (ECAs) with LDCs. Upon termination of the CFF, the IESO was directed to provide centralized delivery of a reduced scope of programs under an Interim Framework.

Cancellation of the ECA relieved HHHI of its obligation to deliver its 30.94 GWh savings target, although HHHI was on track to exceed its target. To the end of 2019, HHHI had achieved 84% of its six (6) year target and was on target to exceed the 30.94 GWh savings in 2020.

1.9.8.2 CONNECTION OF RENEWABLE GENERATION

<u>Renewable Generation Connection Impact Assessments Completed on Time</u> - With the end of the Feed-in-Tariff program, Connection Impact Assessments (CIAs) request reporting is no longer required after 2016

<u>New Micro-embedded Generation Facilities Connected on Time</u> - HHHI's workflow to connect these projects is very streamlined and transparent for customers. HHHI works closely with its customers and their contractors to tackle any connection issues to ensure the project is connected on time. It is expected that with the end of the Feed-in-Tariff program, micro-embedded generation connection requests will be minimal in the future.

1.9.9 FINANCIAL PERFORMANCE

1.9.9.1 FINANCIAL RATIOS

The Financial Ratios section of the OEB Scorecard for HHHI is shown below:

Table 61 - Financial Rations Scorecard Results

Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.95	0.91	1.08	0.46	0.86
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.07	1.13	1.31	1.88	2.34
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.82%	9.19%	9.19%	9.19%	9.19%
			Achieved	6.70%	6.76%	6.98%	7.07%	4.24%

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. HHHI’s Liquidity for 2019 is 0.86. The change is the result of recognizing the construction loan for the new transformer station as a current liability. Upon completion of construction, the construction loan will be termed out and reflected accordingly on the balance sheet.

Leverage: Total 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.

HHHI's 2019 debt to equity ratio is 2.34 and reflects the borrowing required for the construction of the Municipal Transformer Station (MTS1). HHHI expects the debt to equity ratio to remain above the 1.5 until 2023.

Profitability: Regulated Return on Equity - HHHI's profitability, based on the achieved rate of return on equity for historical years 2016 to 2018, are below the Deemed Return on Equity of 9.19%, but are within the allowed dead band of ±300 basis points. The achieved 2019 Return on Equity is 4.24% and is (4.95%) below the Deemed Return on Equity or (195) basis points below the allowed dead band. Historically, HHHI has not achieved the Deemed Regulated Return on Equity.

1.9.10 ADDITIONAL HHHI SPECIFIC METRICS

1.9.10.1 METRICS USED TO MONITOR DISTRIBUTION SYSTEM PLANNING PROCESS PERFORMANCE

HHHI established an Enterprise Risk Management Framework in 2012, which provides a risk-based approach to strategic planning and decision-making. Effective risk management occurs through consistent monitoring, communication and reporting of those risks that might have a material impact on operations, financial performance, regulatory compliance and the reputation of HHHI. Risk management is incorporated into the corporation's strategic and business planning processes and supports major decisions throughout the organization. Power outages by cause are analyzed and this information assists in prioritizing capital programs and Operating and Maintenance programs such as vegetation management.

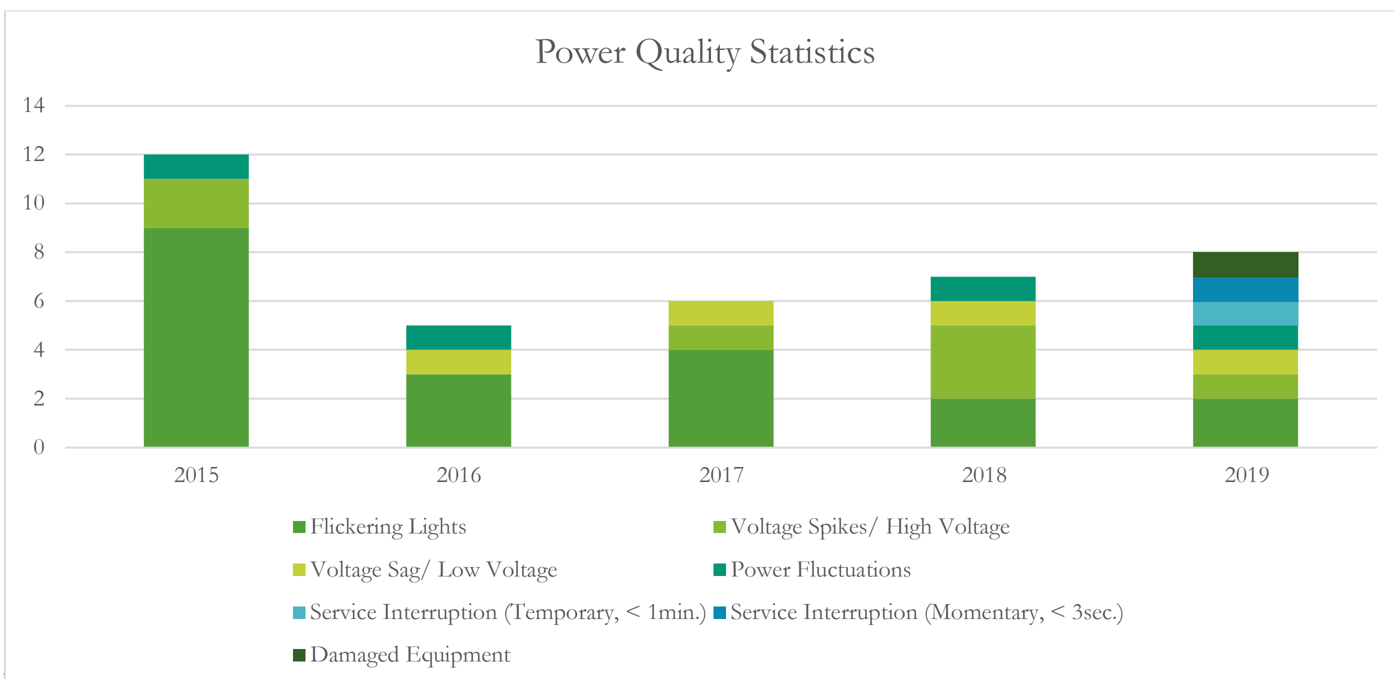
1.9.10.2 POWER QUALITY

HHHI strives to provide its customers with a reliable and safe supply of power of a consistent power quality. When a customer contacts HHHI to report a power quality problem, HHHI installs a power quality monitoring device at the customer's service entrance, or as close as possible to the service entrance, if safe to do so. Depending on the type of service and location of installation, HHHI can monitor voltage, current, harmonics, voltage sag/ swell, transients, demand, and other power quality factors. A report is provided to the affected customer that summarizes the reported problem, the findings of the power quality survey, corrective actions and recommendations.

A subset of ensuring consistent power quality is monitoring supply voltage metrics.

While HHHI makes every effort to deliver power within normal operating conditions, variation in voltage resulting from external forces such as operating practices of an upstream distributor or transmitter, exceptionally high loads, and severe weather conditions can impact power quality. HHHI's target is to maintain one (1) or less instances of voltage variations outside of the band of extreme operating conditions and five (5) or less instances per year of voltage variations outside of the band of normal operating conditions but within the extreme band. A customer contacting HHHI with a voltage complaint does not constitute a voltage issue until HHHI has installed a voltage monitoring device and verified the complaint. These metrics are included in the overall power quality metrics. The chart below shows HHHI's power quality statistics over the past five (5) years.

Table 62 - Power Quality Statistics

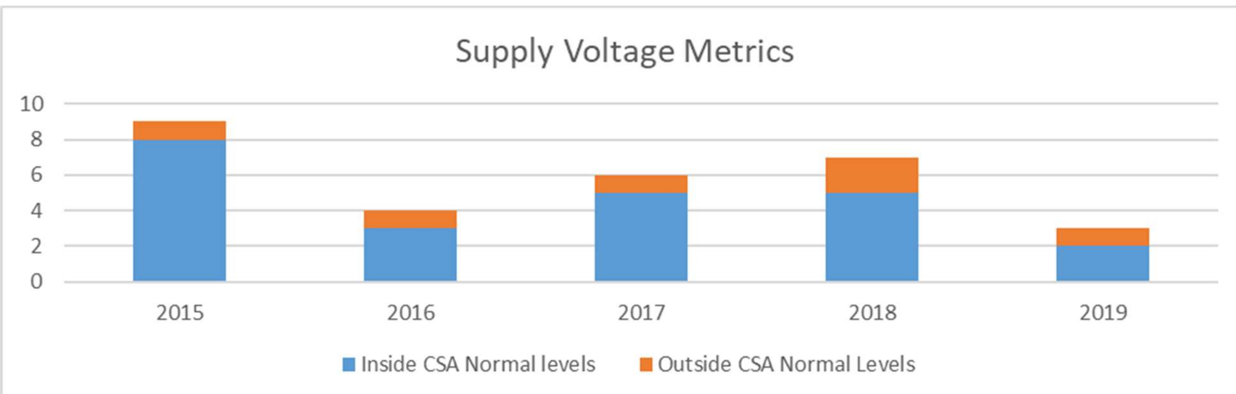


An important component of power quality is maintaining supply voltage within the levels established

Where the voltage deviates outside the band of normal operating conditions but remains within the band of extreme operating conditions HHHI makes improvements or takes corrective action on a planned and programmed basis. Where the supply voltage deviates outside of the band of extreme operating conditions HHHI takes corrective action as soon as possible.

The chart below shows HHHI's supply voltage metrics for the past five (5) years.

Table 63 - Supply Voltage Metrics



1.9.10.3 DISTRIBUTION SYSTEM LOSSES

HHHI system losses are monitored annually. System design and operation is managed such that system losses are maintained within OEB thresholds as defined in the OEB Practices Relating to Management of System Losses. HHHI's maintains a target for distribution system losses of less than 5% while continuing to further reduce losses as applicable.

1.10 FINANCIAL INFORMATION[47] [48] [49] [50] [51] [52] [53]

1.10.1 NON-CONSOLIDATED AUDITED FINANCIAL STATEMENTS ("AFS")

HHHI has included the non-consolidated Audited Financial Statements for the years 2018 and 2019. The statements are found in Appendix 1-4 and Appendix 1-5.

1.10.2 RECONCILIATION OF AFS WITH REGULATORY FINANCIAL RESULTS

Detailed reconciliation between the AFS and regulatory financial results filed in the application are included in Appendix 1-6 and Appendix 1-7. HHHI has no deviations.

1.10.3 ANNUAL REPORT AND MD&A

HHHI, nor its parent company, Halton Hills Community Energy Corporation, produce publicly available annual reports or MD&As.

1.10.4 RATING AGENCY REPORTS

HHHI does not have any rating agency reports and there are no plans for public issuances.

[47] MFR - Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals)
[48] MFR - Detailed reconciliation of AFS with regulatory financial results filed in the application, with identification of any deviations that are being proposed
[49] MFR - Annual Report and MD&A for most recent year of distributor and parent company, if applicable
[50] MFR - If a distributor has acquired or amalgamated with another distributor, identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement.
[51] MFR - Description of actual savings as a result of consolidation compared to what was in the approved consolidation application and explanation of how savings are sustainable and the efficacy of any rate plan approved as part of the MAADs application
[52] MFR - Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base.
[53] MFR - Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances

1.10.5 CHANGE IN TAX STATUS

HHHI has not, nor is planning any future change in tax status.

1.10.6 EXISTING ACCOUNTING ORDERS

HHHI does not have any specific Board Approved Accounting Orders other than directions which stemmed from previous Board Decisions that can be found at Section 1.3.10.

1.10.7 ACCOUNTING STANDARDS

HHHI is reporting under Modified International Financial Reporting Standards (MIFRS) for all years in this Application. MIFRS was adopted in 2015 with 2014 being restated.

1.10.8 NON-UTILITY BUSINESS

HHHI confirms that only utility business is included in rate regulated activities.

1.11 DISTRIBUTOR CONSOLIDATION

1.11.1 AMALGAMATIONS

HHHI has no amalgamations in this application and therefore, no amalgamation incentives or actual savings resulting from amalgamations or consolidations are discussed.

1.11.2 APPROVED ICM

On December 3, 2018, HHHI filed an application (EB-2018-0328) requesting proposed Incremental Capital Module ("ICM") funding in the amount of $23,476,441 for the construction of a new municipal transformer station (TS) in the Town of Halton Hills. HHHI stated that the new TS is required to serve future growth in HHHI's service area. HHHI also requested the OEB deem the new TS as a distribution asset pursuant to section 84(a) of the *Ontario Energy Board Act, 1998* ("OEB Act").

On April 4, 2019, the OEB issued a Decision and Rate Order approving the ICM funding of $23.48 million related to the construction of the new municipal TS in the Town of Halton Hills. The OEB was satisfied that the evidence demonstrated the need and prudence for the new TS. The OEB found that the project also met the project-specific materiality threshold and the ICM materiality threshold based on the OEB's ICM formula in the ACM Report. Regarding the cost of the new TS, the OEB found that HHHI provided sufficient evidence of its due diligence and that the cost estimates provided were reasonable.

Further details are found in Exhibit 2.

APPENDICES

APPENDIX 6-1: 2020 CORPORATE BUSINESS PLAN

APPENDIX 6-2: 2019 DRAFT SCORECARD

APPENDIX 6-3: LIST OF APPROVALS

APPENDIX 6-4: 2018 AUDITED FINANCIAL STATEMENTS

APPENDIX 6-5: 2019 AUDITED FINANCIAL STATEMENTS

APPENDIX 6-6: 2018 AUDITED FINANCIAL STATEMENTS RECONCILIATION TO REGULATORY FINANCIAL RESULTS

APPENDIX 6-7: 2019 AUDITED FINANCIAL STATEMENTS RECONCILIATION TO REGULATORY FINANCIAL RESULTS

APPENDIX 1-1: 2020 CORPORATE BUSINESS PLAN

2020 Corporate Business Plan

Halton Hills HYDRO

Advancing Innovation

Executive Summary

Our 2020 Business Plan is built on the objectives and key success factors outlined in our 2016-2020 Corporate Strategic Plan and forms the basis for our 2020 Capital and Operating Budgets. Building on our successes in innovation and collaboration, this plan continues to focus on finding efficiencies and process improvements.

Supporting this plan are departmental business plans from each of our major business units and the Distribution System Plan that was created as part of our 2016 Cost of Service filing. As this is the final year in the current strategic plan, the focus is both one of wrapping up initiatives planned within that window and forward looking in preparation for the next 5-year planning period.

Together, these documents create a strong plan in support of our corporate mission and strategic goals and present a strong value proposition for our customers and shareholder.

Our Mission and Strategic Objectives

Our mission statement is to Provide Halton Hills with Electricity Distribution Excellence in a safe and reliable manner. It is supported by the following eight strategic objectives.

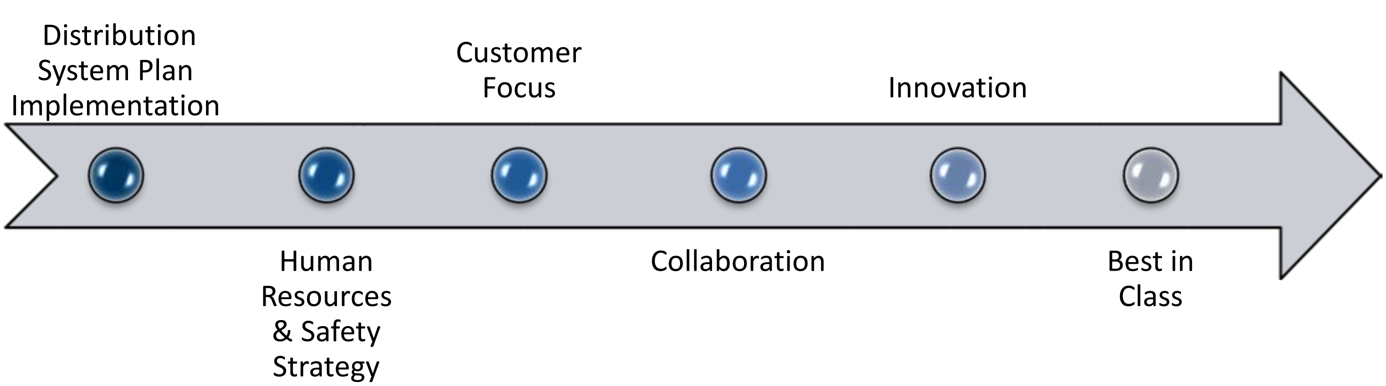
Safety
Reliability
Competitive Rates
Financial Metrics
Conservation
Environmental
Community Focused
Smart Grid Implementation

- **Safety** – for our customers, our employees and the general public.
- **Reliability** – reliability of electricity supply, reliability of service, reliability of customer care.
- **Competitive Rates** – our customers understand the value proposition in fair and reasonable rates for the services we provide.
- **Financial Metrics** – balancing shareholder and customer expectations, stable rate setting, and reasonable rate of return.
- **Conservation** – investigating conservation opportunities for the utility and its customers – considering climate & environment in decisions. Wrapping up CDM program ended in 2019.
- **Environmental** –finding ways to minimize the environmental footprint of our organization. Recognizing the importance of planning and preparing for climate change and associated extreme weather events.
- **Community Focused** – proud part of the Town of Halton Hills, active, visible presence in the community, exceeding our customers' expectations.
- **Smart Grid Implementation** – building our distribution system with future technology in mind, ensuring we are able to leverage technology for customer service, system reliability and data security.

Key Success Factors

The following five key success factors were outlined in our 2016-2020 strategic plan and are addressed through a number of initiatives in this plan. Together, they help create a best in class utility.

1. Completion of our 5-Year Distribution System Plan – This comprehensive engineering plan outlines our asset management strategy and capital expenditure plans. We are completing implementation of this plan, with some reprioritization of projects. This year we will also be finalizing the creation of the Distribution System Plan for the next five-year planning period.
2. Human Resources and Safety Strategy – Succession planning, employee growth and engagement will ensure we have the right people in the right jobs over the coming years. Sound human resources and safety policies will position us as one of the top employers in Halton Hills and Halton Region.
3. Customer Focus – In 2020, we will once again be reaching out to our customers through our biennial customer satisfaction survey. We will also be conducting our third public safety awareness survey measuring safety awareness in the general public. These surveys form part of our OEB Performance Scorecard.
4. Collaboration – We will continue to build on our partnerships with other Local Distribution Companies (LDCs) and other organizations to strengthen our utility. Cost savings continue to be realized through equipment standardization and joint purchases through the GridSmart city cooperative.
5. Innovation – Building on the strong culture of innovation we have created throughout the organization, we will continue to engage all staff to look for ways to improve efficiency and reduce cost through innovation.



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2020 Business Plan

Our 2020 Business plan focuses on the theme of innovation. This theme, which embraces the principle of relentless incrementalism, guides us in finding efficiencies and opportunities throughout our business.

This plan covers the key initiatives planned by each department and across departments in 2020. Other initiatives are detailed in the individual department plans and budgets. Together these documents set out a plan for continuous improvement and ongoing efficiencies throughout the company.

The following are the Key Initiatives highlighted in this plan:

1. Enterprise Risk Management
2. Innovation
3. Safety
4. Cost of Service Rate Application
5. Customer Focus
6. Succession Planning

Key Initiatives

Enterprise Risk Management

Enterprise Risk Management continues to be a top priority at Halton Hills Hydro. The corporate risk register will continue to be reviewed by the leadership team on a quarterly basis to ensure that risks with a potential to affect the organization from a safety, reputation, financial or personnel perspective are identified and addressed.

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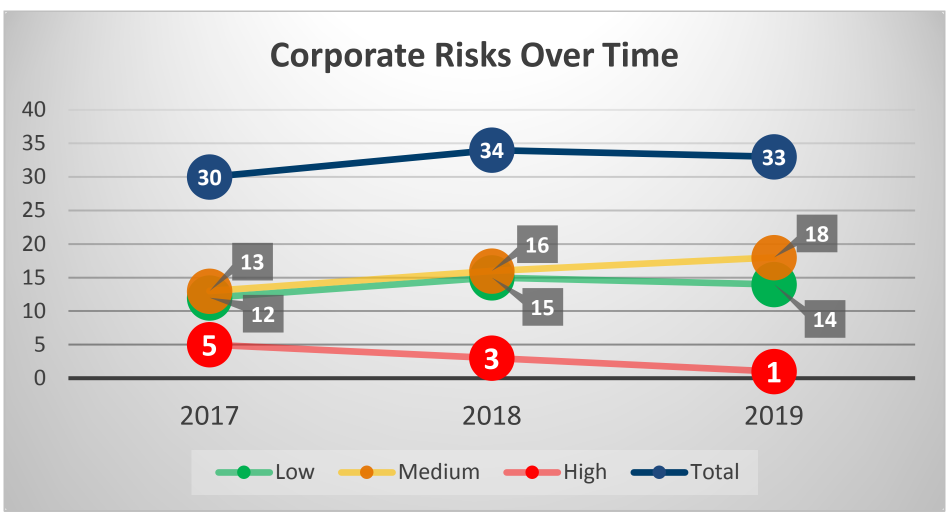


The primary focus in 2020 will be completing the Cybersecurity implementation plan developed in 2018 to meet the requirements of the Ontario Energy Board (OEB) Cyber Security Framework.

Cyber Security

The majority of the requirements of the Ontario Energy Board (OEB) cybersecurity framework were implemented in 2019. By the end of 2020, Halton Hills Hydro expects to be 99% compliant with the framework.

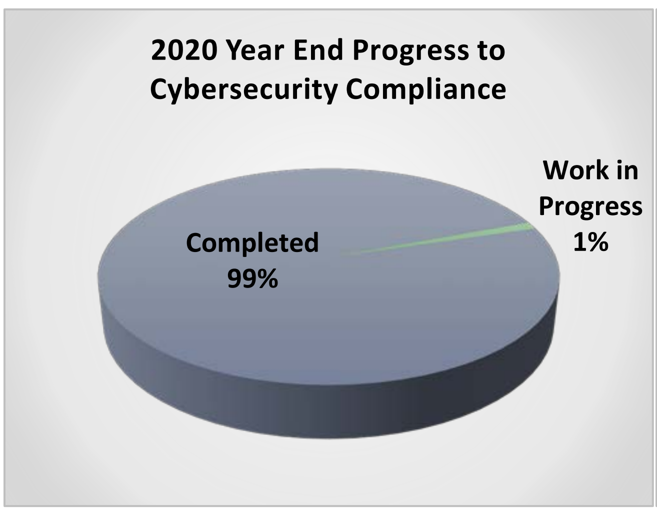
The following are the three focus areas for cyber security in 2020:

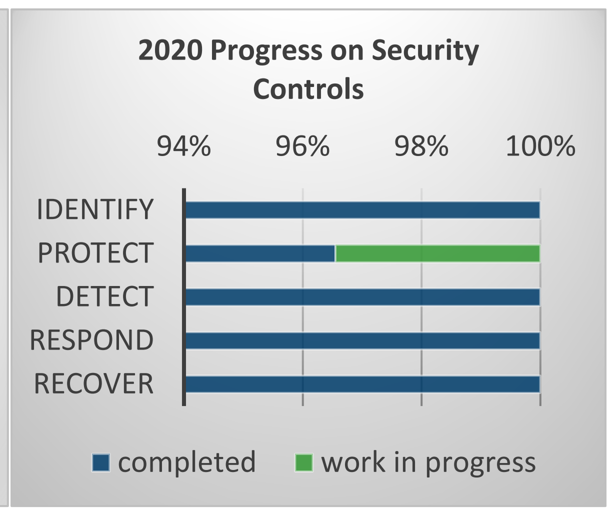
Business Process & Data Mapping – This important process identifies critical workflows throughout the organization and identifies both systems and individuals involved. We will identify critical information and systems that need to be protected and establishes the timeframes in which they need to be restored. We will also gain a clearer understanding critical business functions from a human resources perspective while ensuring legal, statutory, regulatory, and contractual compliance.

Business Continuity Plan and ***Disaster Recovery Plan*** – These plans limit the immediate impact of an incident and set out steps for recovery. The business continuity plan ensures the utility can continue to operate during an incident while the disaster recovery plan establishes the procedures for properly recovering from an event.

Incident Response Plan – An incident response plan defines the roles, responsibilities, procedures and reporting requirements required to respond to and recover from an information security incident.

2020 Cybersecurity Implementation Plan





Climate Change

Understanding the impacts of climate change, particularly the increase of extreme weather events, on system reliability is an important part of our corporate risk management strategy. We will look at ways to harden our system to withstand adverse weather through our continued vegetation management program and adding automated switches to key locations on our distribution system.

Halton Hills Hydro will continue to evaluate smart grid technologies to accommodate renewable generation, battery storage and other connected devices as they become more prevalent as customers seek ways to prepare their homes or businesses for the effects of climate change.

We will explore and evaluate emerging technologies and utility concepts that we can leverage to build increased climate resilience for our utility and our community.

In 2018, we added an electric vehicle to our fleet. We will assess its performance to quantify financial benefits. Through firsthand experience with electric vehicles and their charging, we will gain insight into the impact of these technologies on our distribution system. Halton Hills Hydro will assist the Town as it rolls out public Electric Vehicle charging stations within the community including providing guidance on the strategic placement of charging stations within our distribution system.

We will continue to implement environmental best practices in our operations through reducing vehicle idle times and through re-using or recycling materials where possible.

Innovation

Innovation continues to drive planning throughout the utility. Building on the innovation processes begun in 2017, each department now meets regularly to discuss and build on innovative ideas. Ideas presented provide improvements in all aspects of the business including efficiency, time and cost savings and safety and wellness improvements.

Since implementing innovation tracking at the department level in 2018, there have been 162 Innovation ideas created by staff. Innovation ideas have created $222,000 in cost savings and 2300 hours in productivity improvements.

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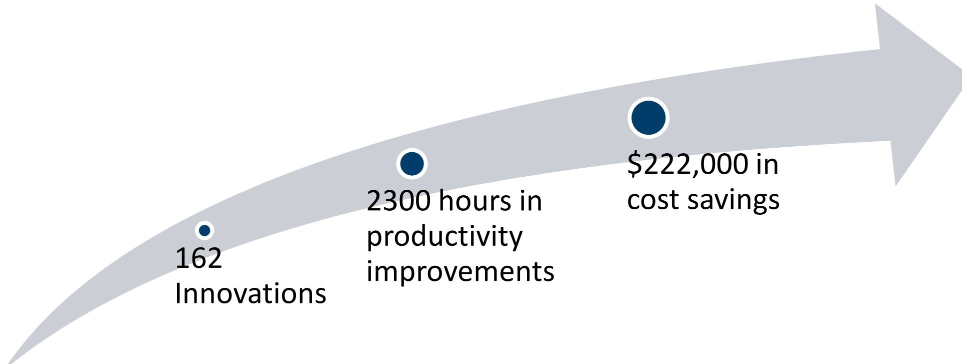

The Engineering Department is continuing its move to paperless workflows resulting in increased efficiencies and reliability of information collected. In 2020, the department will launch electronic interim records of inspection. These tools will be further rolled out to both the Operations department and contract inspectors later in the year. Improved data accuracy for asset management will come from electronic tracking of pole replacements.

Through evaluating new distribution system materials, significant cost savings can be achieved. One example is a review of alternatives to traditional switches that will operate as automated switches at a much lower cost than traditional switches.

Our operations department will be utilizing contract service providers for utility locates during high volume periods to reduce overtime-labour costs. There have been significant Fibre-to-the-Home installations over the past year, which are expected to continue in 2020. This work has resulted in a 40% increase in locate volume. Our operations department will be expanding maintenance programs; bringing underground inspections, infrared inspections and air-break switch maintenance work in house.

Continuing to engage all staff in innovative thinking creates a mindset of finding efficiencies, questioning spending and looking for better ways to improve processes and reduce costs, thereby creating a culture of Best in Class.

GridSmart City

Halton Hills Hydro is realizing innovation through collaboration through our ongoing participation in the GridSmart City Cooperative, where we will continue to find cost savings through collaborative purchasing opportunities.

Through the purchasing and materials committees, the Cooperative member LDCs will be looking at expanding the list of bulk purchased items where opportunities for savings can be achieved. In 2020, the cooperative will be looking at standardizing pole line hardware to drive further cost savings. Revised transformer specifications have a potential for significant cost savings.

GRIDSMART CITY CUMULATIVE SAVINGS THROUGH JOINT PURCHASES AND EQUIPMENT STANDARDIZATION 2018

PURCHASING EVALUATION FACTS AND FIGURES

Cumulative Savings	$1.2M on Wood Poles, Cables & Wires and Transformers
Avoided costs for re-negotiated contracts	$0.6M

Source: The Power of Cooperation 2018-2019 GridSmart City Cooperative Report

Safety

Safety is always a top priority in our plans and budgets. This includes both safety for the public and the safety and wellness of our employees.

In 2019, Halton Hills Hydro hired a Human Resources Manager. The addition of this position has allowed the utility the opportunity to bring many of the safety programs in house. A consultant will continue to deliver operations safety programs, however, inside safety programs and management of incident reporting and other training initiatives will be handled internally in 2020. Delivery of inside safety programs in house will result in cost savings in 2020 and an opportunity to better tailor program delivery specific to our employees.

Safety
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In 2020, we will continue to focus on the importance of reporting near-miss incidents. Better monitoring of these types of incidents will help in identifying potential improvements to processes, tools or equipment to prevent future incidents.

Over the past few years, Halton Hills Hydro has seen an improvement in our safety record. At the time of writing this plan, we have exceeded 1000 days no lost time injuries. We will be focusing on continuing this trend towards increased safety.

Lost Time Incidents - Number of Days				
2015	2016	2017	2018	2019 Q2
4	3	1	0	0

Public Safety

Every two years, Halton Hills Hydro is required to conduct a public safety survey to gather information on electrical safety awareness in the public. This survey addresses the public safety criteria on the OEB performance scorecard and gauges the impact of continued electrical safety education on public perceptions.

Throughout the year, Halton Hills Hydro will promote awareness of overhead powerline safety, downed powerline hazards and the importance of obtaining underground cable locates before digging. This messaging will be promoted through Halton Hills Hydro's website and social media channels throughout the year. Messaging will include promotion of various province wide campaigns such as Dig Safe Month in April and Powerline Safety Week in May.

We will be conducting our third public safety awareness survey in early 2020. We will be taking an innovative approach to the survey this year, utilizing our Have Your Say customer engagement website to conduct the survey online rather than utilizing a third party to conduct telephone surveys. This will provide considerable cost savings while continuing to utilize the same questions and scoring methodology to ensure consistent reporting.

2020 Distribution System Plan

Through 2020, we will be completing the projects identified in our 2016-2020 Distribution System Plan.

System Access projects focus on connecting new customers and relocating infrastructure in support of municipal road improvement projects.

System Renewal projects include annual pole testing & replacements, and replacement of obsolete pole-trans transformers. Significant repair work will take place at the Norval substation to replace equipment damaged by weather events. Metering systems, reclosers and feeder switches will all be replaced.

Safety
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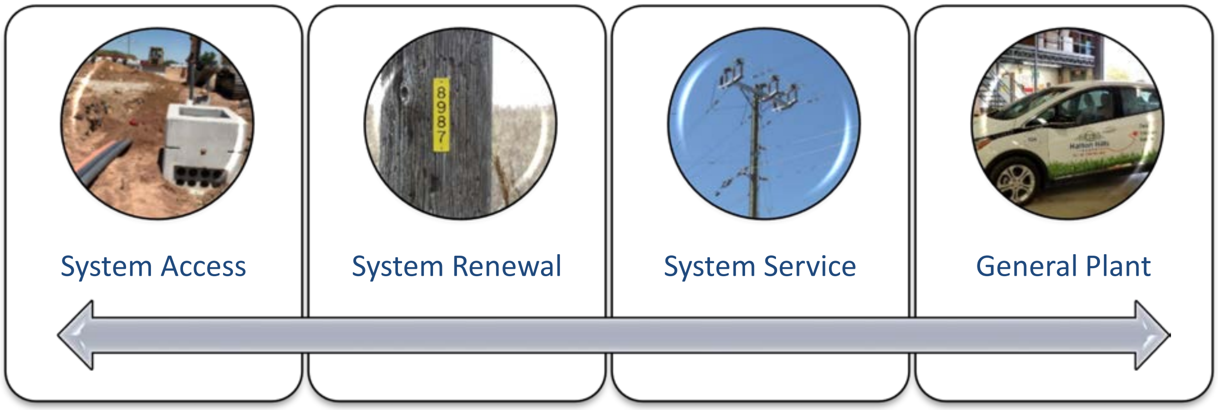
System Service projects address system constraints and promote operational effectiveness. These projects include switch automation to allow control room operation of remote switches, leading to improved reliability and outage response times. A number of voltage conversion and feeder upgrade projects are planned to extend the 27.6kV system bringing supply from the new transformer station to the Steeles Ave. corridor and Georgetown South.

General Plant projects include software, fleet tools and equipment. In 2020, we will implement a major upgrade to the head end software for our AMI system. The vendor no longer supports the current software. In fleet, a single bucket truck will be replaced this year.



2021 Cost of Service Rate Application

A major undertaking throughout the organization in 2020 will be the preparation and filing of the 2021 Cost of Service Rate Application including an updated Asset Management Plan and new 5 year Distribution System Plan.

Asset Management – Halton Hills Hydro will be utilizing a new asset management "Decision Support System" (DSS) to assist in budgeting and prioritizing of spending on a number of key assets. For the purposes of this rate application, this DSS will be utilized for poles, transformers and substation equipment. Other utility assets will be added in future years. This tool will confirm appropriate budget levels for these key assets and provide the impact of changes in spending on asset condition.

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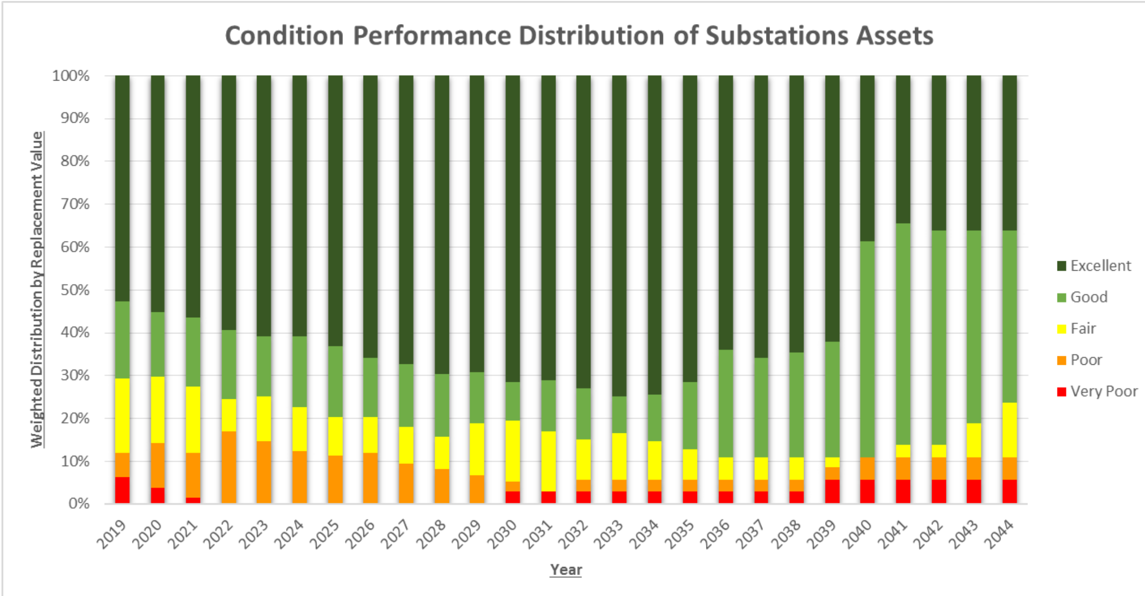

SAMPLE CONDITION ASSESSMENT – SUBSTATION ASSETS

Distribution system plan – Creation of a new Distribution System Plan will identify the major capital projects planned throughout the organization for the next 5 years. It will follow the established project categories of System Access, System Renewal, System Service and General Plant and will support the rate application to be filed in 2020.

Customer engagement – Ensuring we understand our customers' preferences and views is an important component of building our Distribution System Plan. Halton Hills Hydro has utilized an online customer engagement platform, HaveYourSay.HaltonHillsHydro.com to conduct polls and surveys and provide information on utility plans. Leveraging the information gathered from this tool will ensure that projects outlined in the Distribution System Plan align with customer views. Feedback will be provided to customers through this site to demonstrate how their input helped shape the plan.

Customer Focus

In the fall of 2020, we will conduct our biennial Customer Satisfaction Survey. We will use the results of this survey as a basis for customer communication and customer service improvements in 2021 and beyond.

In 2020, our customer service team will focus on promoting paperless billing to increase enrollment. This will provide cost savings to the utility as well as increased opportunities to communicate with customers.

Safety
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Building on the customer engagement activities for the cost of service rate application, we will leverage the Have Your Say site to continue to inform and engage our customers.

Succession Planning

Apprentice training is critical to the success of our operations department. The utility currently has four apprentices: three line staff and one metering apprentice. Monitoring the progress of these individuals prepares the utility to continue to deliver best in class services in future years.

Focus on ensuring we have the right staff in the right roles will be important in 2020 as we prepare for a number of staff retirements. Expected retirements include both members of staff and the leadership team.

Conclusion

Halton Hills Hydro's 2020 corporate business plan addresses the goals from the 2016-2020 strategic plan while continuing to look forward at new opportunities and challenges. The innovative projects outlined in this plan continue to position us as a best in class utility today and for the future. The mindset of relentless incrementalism embraced by the utility ensures we will continue to bend the cost curve as we deliver distribution excellence for our customers.

APPENDIX 1-2: 2019 DRAFT SCORECARD

Scorecard - Halton Hills Hydro Inc.

6/8/2020

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%	100.00%	99.98%	97.66%		90.00%	
		Telephone Calls Answered On Time		93.10%	94.40%	95.85%	96.63%	96.43%		65.00%	
	Customer Satisfaction	First Contact Resolution		99.99%	99.98%	99.99	99.98%	99.98%			
		Billing Accuracy		99.96%	99.84%	99.77%	99.89%	99.88%		98.00%	
		Customer Satisfaction Survey Results		90%	88%	88%	95%	95%			
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		83.00%	83.00%	85.00%	85.00%	83.00%			
		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]		2.58	1.38	1.65	1.48	1.60			1.32
		Average Number of Times that Power to a Customer is Interrupted [2]		3.02	1.65	1.13	1.60	1.70			1.61
	Asset Management	Distribution System Plan Implementation Progress		On-track	Over budget	Over-budget	123.38%	114.56%			
	Cost Control	Efficiency Assessment		1	1	1	1				
		Total Cost per Customer [3]		$744	$770	$763	$794				
		Total Cost per Km of Line [3]		$10,490	$10,557	$10,295	$10,860				
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]		17.78%	33.84%	63.29%	77.00%	84.00%			30.94 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%						
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	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)		0.95	0.91	1.08	0.46	0.86			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.07	1.13	1.31	1.88	2.34			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.82%	9.19%	9.19%	9.19%	9.19%			
			Achieved	6.70%	6.76%	6.98%	7.07%	4.24%			

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 1-3: LIST OF APPROVALS

List of Approvals Requested

1. Approval to charge distribution rates effective May 1, 2021 to recover a service revenue requirement of $17,045,865 which includes a gross revenue deficiency of $7,377,397 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8.

2. Approval of the Distribution System Plan as outlined in Appendix 2-1 of Exhibit 2.

3. Approval to adjust the Retail Transmission Rates (Network and Connection) as detailed in Exhibit 8.

4. Approval to continue to charge Wholesale Market (including CBR) and Rural Rate Protection Charges as directed by the Board.

5. Approval to continue the Specific Service Charges and tranformer allowance approved in the Decision and Order in EB-2019-0039 (2020 IRM).

6. Approval of adjusted Deferral and Variance Account disposition amounts as presented in the 2021 DVA Continuity Schedule in the form of rate riders over two years as detailed in Exhibit 9.

7. Approval of Incremental Capital True up amounts provided in Exhibit 2 in the form of a two year rate rider.

8. Approval to deem the full cost (including incremental) of the Municipal Tranformer Station as a distribution asset.

9. Approval to leave USofA 1592 available to HHHI for expected future use.

10. Approval of Standby/Capacity Reserve Charge detailed in Exhibit 8.

11. Approval for Low Voltage Rates as detailed in Exhbit 8.

12. Approval for a revised total loss factor as detailed in Exhibit 8.

APPENDIX 1-4: 2018 AUDITED FINANCIAL STATEMENTS

Financial Statements of

HALTON HILLS HYDRO INC.

Year ended December 31, 2018

KPMG LLP
Commerce Place
21 King Street West, Suite 700
Hamilton Ontario L8P 4W7
Canada
Telephone (905) 523-8200
Fax (905) 523-2222

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Halton Hills Hydro Inc.:

Opinion

We have audited the financial statements of Halton Hills Hydro Inc., (the "Company"), which comprise:

- the statement of financial position as at December 31, 2018
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company 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 "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other 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.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

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 Company'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 Company or to cease operations, or has no realistic alternative but to do so.

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

Auditors' 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 auditors' 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 the 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 Company'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 Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' 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 auditors' report. However, future events or conditions may cause the Company 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.
- 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.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada
April 23, 2019

HALTON HILLS HYDRO INC.

Financial Statements

Year ended December 31, 2018

Financial Statements

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HALTON HILLS HYDRO INC.

Statement of Financial Position

Year ended December 31, 2018, with comparative information for 2017

	Note	2018	2017
Assets			
Current assets			
Accounts receivable	5	$ 6,307,238	$ 6,277,414
Unbilled revenue		6,232,787	6,759,150
Income taxes receivable		17,593	13,044
Materials and supplies	6	1,203,168	1,294,966
Due from related companies	7	2,591,285	1,552,093
Prepaid expenses		543,553	503,805
Total current assets		16,895,624	16,400,472
Non-current assets			
Property, plant and equipment	9	97,733,243	75,106,536
Deferred income taxes	13	2,096,805	2,880,129
Total non-current assets		99,830,048	77,986,665
Total assets		116,725,672	94,387,137
Regulatory balances	8	6,761,777	8,010,864
Total assets and regulatory balances		$ 123,487,449	$ 102,398,001
Liabilities			
Current liabilities			
Bank overdraft		$ 6,824,777	$ 3,715,449
Accounts payable and accrued liabilities	10	13,347,941	12,549,340
Customer deposits		884,157	667,943
Current portion of bank term loans	19	18,610,817	5,392,371
Total current liabilities		39,667,692	22,325,103
Non-current liabilities			
Bank term loans	19	20,197,503	15,999,871
Note payable	11	16,141,970	16,141,970
Employee future benefits	12	922,997	902,826
Deferred revenue		4,769,141	3,972,659
Deferred income taxes	13	6,784,992	7,167,434
Total non-current liabilities		48,816,603	44,184,760
Total liabilities		88,484,295	66,509,863
Equity			
Share capital	14	16,161,663	16,161,663
Retained earnings		16,897,161	15,631,095
Accumulated other comprehensive loss		(201,997)	(201,997)
Total equity		32,856,827	31,590,761
Total liabilities and equity		121,341,122	98,100,624
Regulatory balances	8	2,146,327	4,297,377
Total liabilities, equity and regulatory balances		$ 123,487,449	$ 102,398,001

See accompanying notes to the financial statements.

On behalf of the Board:

_____________ Director _____________ Director

HALTON HILLS HYDRO INC.

Statement of Comprehensive Income

Year ended December 31, 2018, with comparative information for 2017

	Note	2018	2017
Revenue			
Distribution revenue		$ 10,676,661	$ 10,107,104
Other income	15	2,373,529	2,906,445
		13,050,190	13,013,549
Sale of electricity		60,469,502	62,536,126
Total revenue	17	73,519,692	75,549,675
Operating expenses			
Employee salaries and benefits	16	4,079,271	3,886,774
Material costs		22,851	37,124
Contract services		1,041,942	823,298
Property costs		775,817	817,687
Other costs		932,450	1,573,019
Communication costs		481,219	497,014
Depreciation		2,359,877	2,226,549
		9,693,427	9,861,465
Cost of power purchased		60,673,385	61,732,303
Total expenses		70,366,812	71,593,768
Income from operating activities		3,152,880	3,955,907
Finance income		80,373	28,473
Finance costs		(1,499,142)	(1,158,749)
Income before income taxes		1,734,111	2,825,631
Income tax expense	13	(466,294)	(536,769)
Net income for the year		1,267,817	2,288,862
Net movement in regulatory balances, net of tax			
Net movement in regulatory balances		235,411	(752,231)
Income tax		666,552	566,486
		901,963	(185,745)
Net income for the year, net movement in regulatory balances and total comprehensive income		2,169,780	2,103,117
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurement of employee future benefits	12	-	(112,005)
Tax on re-measurements		-	29,681
Other comprehensive income for the year		**-**	(82,324)
Total comprehensive income for the year		$ 2,169,780	$ 2,020,793

See accompanying notes to the financial statements.

HALTON HILLS HYDRO INC.

Statement of Changes in Equity

Year ended December 31, 2018, with comparative information for 2017

	Note	Share capital	Retained earnings	Accumulated other comprehensive loss	Total
Balance at January 1, 2017		$ 16,161,663	$ 14,731,978	$ (119,673)	$ 30,773,968
Net income and net movement in regulatory balances		-	2,103,117	-	2,103,117
Other comprehensive income		-	-	(82,324)	(82,324)
Dividends	14	-	(1,204,000)	-	(1,204,000)
Balance at December 31, 2017		$ 16,161,663	$ 15,631,095	$ (201,997)	$ 31,590,761
Balance at January 1, 2018		$ 16,161,663	$ 15,631,095	$ (201,997)	$ 31,590,761
Net income and net movement in regulatory balances		-	2,169,780	-	2,169,780
Dividends	14	-	(903,714)	-	(903,714)
Balance at December 31, 2018		$ 16,161,663	$ 16,897,161	$ (201,997)	$ 32,856,827

See accompanying notes to the financial statements.

HALTON HILLS HYDRO INC.

Statement of Cash Flows

Year ended December 31, 2018, with comparative information for 2017

	2018	2017
Operating activities		
Net Income and net movement in regulatory balances	$ 2,169,780	$ 2,103,117
Adjustments for:		
Depreciation	2,576,260	2,419,582
Amortization of deferred revenue	(306,583)	(275,609)
Employee future benefits	20,171	27,653
Income tax expense	466,294	536,769
Net finance costs	1,418,769	1,130,276
Change in non-cash operating working capital:		
Accounts receivable	(29,824)	(223,339)
Unbilled revenue	526,363	639,089
Materials and supplies	91,798	(409,617)
Due from related companies	(1,039,192)	(647,246)
Prepaid expenses	(39,748)	128,271
Accounts payable and accrued liabilities	798,601	(233,835)
Customer deposits	216,214	127,477
Capital contributions	1,103,065	1,495,511
Regulatory balances	(901,963)	185,745
Income tax paid	(69,961)	(29,729)
Interest paid	(1,499,142)	(1,158,749)
Interest received	80,373	28,473
Net cash from operating activities	5,581,275	5,843,839
Investing activities		
Purchase of property, plant and equipment	(25,202,967)	(11,095,939)
Net cash used by investing activities	(25,202,967)	(11,095,939)
Financing activities		
Dividends paid	(903,714)	(1,204,000)
Issuance of long-term debt	18,070,645	9,134,755
Repayment of long-term debt	(654,567)	(820,582)
Net cash from financing activities	16,512,364	7,110,173
Change in bank overdraft	(3,109,328)	1,858,073
Bank overdraft, beginning of year	(3,715,449)	(5,573,522)
Bank overdraft, end of year	$ (6,824,777)	$ (3,715,449)

See accompanying notes to the financial statements.

1. Reporting entity:

Halton Hills Hydro Inc., (the “Company”) is a rate regulated, municipally owned electricity distribution company incorporated under the laws of the Province of Ontario, Canada. The Company is located in the Town of Acton in the Town of Halton Hills. The address of the Company’s registered head office is 43 Alice St., Acton, Ontario.

The Company delivers electricity and related energy services to residential and commercial customers in the Town of Halton Hills. The Company is wholly owned by Halton Hills Community Energy Corporation and the ultimate parent company is the Corporation of The Town of Halton Hills.

The financial statements are for the Company as at and for the year ended December 31, 2018.

2. Basis of presentation:

(a) Statement of compliance:

The Company's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 23, 2019.

(b) Basis of measurement:

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

(d) Use of estimates and judgments:

(i) Assumptions and estimation uncertainty:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

2. Basis of presentation (continued):

(d) Use of estimates and judgments (continued):

(i) Assumptions and estimation uncertainty (continued):

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Note 3(b) – measurement of unbilled revenue

(ii) Note 3(f) – recognition and measurement of regulatory balances

(iii) Notes 3(d), 9 – estimation of useful lives of its property, plant and equipment

(iv) Note 12(b) – measurement of defined benefit obligations: key actuarial assumptions

(v) Note 18 – recognition and measurement of commitments and contingencies

(ii) Judgements:

Information about judgements made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following notes:

(i) Note 3(b) – determination of the performance obligation for contributions from customers and the related amortization period

(e) Rate regulation:

The Company is regulated by the Ontario Energy Board (“OEB”), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies (“LDCs”), such as the Company, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Company is required to bill customers for the debt retirement charge set by the province for certain customer classes. Effective March 31, 2018, the debt retirement charge is no longer charged to customers in the province. The Company may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation (“OEFC”) once each year.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

Rate setting:

(i) Distribution revenue:

For the distribution revenue, the Company files a “Cost of Service” (“COS”) rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder’s equity required to support the Company’s business. The Company estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application (“IRM”) is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year’s rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand (“GDP IPI-FDD”) net of a productivity factor and a “stretch factor” determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers.

The company filed an application with the Ontario Energy Board (OEB) on October 15, 2018 for rates pursuant to the OEB’s Price Cap IR framework for electricity rates effective May 01, 2019. On December 3, 2018, the company also submitted an application for proposed incremental revenue requirement recovery as it relates to the building of a Municipal Transformer Station (TS), through rate riders effective May 1, 2019, requesting that the Board deem the TS to be a distribution asset and therefore allow recovery of incremental OM&A costs related to the TS”.

The Company filed applications with the Ontario Energy Board (OEB) on September 25, 2017, October 23, 2017 and December 1, 2017 for rates pursuant to the OEB’s Price Cap IR framework, for the establishment and disposition of a variance account to account for and remedy an error related to depreciation expense and for recovery of costs incurred as a result of a pay equity settlement agreement (Z factor), respectively. The applications were filed under section 78 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B) and under the OEB’s Filing Requirements for Incentive Regulation Rate Applications seeking approval for changes to Halton Hills Hydro’s electricity distribution rates to be effective May 1, 2018. The OEB approved the Price Cap IR and depreciation recovery applications but denied the requested Z-factor application for recovery of pay equity settlement costs.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

Rate setting (continued):

(i) Electricity rates:

Historically, the OEB set electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. As a result of the Ontario Fair Hydro Plan Act, the OEB was instructed to freeze those electricity prices until April 30, 2018. The rate was adjusted on May 1, 2018 but will not exceed the rate of inflation. All remaining consumers pay the market price for electricity. The Company is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments:

All financial assets and all financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(h). The Company has not entered into any derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

(b) Revenue recognition:

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Company has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

3. Significant accounting policies (continued):

(b) Revenue recognition (continued):

Customer billings for debt retirement charges are recorded on a net basis as the Company is acting as an agent for this billing stream.

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Company's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Company has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered. Amounts received in advance of these milestones are presented as deferred revenue.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. Cash contributions are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Company's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Government grants and the related performance incentive payments under Conservation and Demand Management (CDM) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

3. Significant accounting policies (continued):

(c) Material and supplies:

Materials and supplies, the majority of which are consumed by the Company in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

Net realizable value is the estimated selling price in the ordinary course of business, less estimated selling expenses.

(d) Property, plant and equipment:

Items of property, plant and equipment ("PP&E") used in rate-regulated activities are measured at deemed cost established on the transition date less accumulated depreciation. All other items of PP&E measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Company's borrowings. Qualifying assets are considered to be those that take in excess of 6 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Company and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Company has concluded it does not have any legal or constructive obligation to remove PP&E.

3. Significant accounting policies (continued):

(d) Property, plant and equipment (continued):

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

Asset	Rate
Distribution system	25 - 50 years
Plant	20 - 42 years
Fleet	8 - 15 years
Other equipment	5 - 20 years
Computer equipment and software	1 - 5 years
General office	5 years
Stores equipment	10 years
Contributed capital	20 - 50 years

(e) Employee future benefits:

The Company pays certain life insurance benefits, under unfunded defined benefit plans, on behalf of its retired employees and extended health and dental benefits under unfunded defined benefit plans, on behalf of early retirees.

(i) Pension plan:

The Company provides a pension plan for its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and 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. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

3. Significant accounting policies (continued):

(e) Employee future benefits (continued):

(i) Pension plan (continued):

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Company to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Company is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension:

The Company provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(f) Regulatory balances:

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Company.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

3. Significant accounting policies (continued):

(f) Regulatory balances (continued):

When the Company is required to refund amounts to ratepayers in the future, the Company recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(g) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the “Tax Acts”). Under the *Electricity Act*, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (“OEFC”). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

3. Significant accounting policies (continued):

(h) Impairment:

(i) Financial assets measured at amortized cost:

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

A financial asset 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 is calculated as the difference between an asset's 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. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. 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. An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

3. Significant accounting policies (continued):

(i) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

(j) Provisions:

A provision is recognized if, as a result of a past event, the Company 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 pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(k) Finance income and finance costs:

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents.

Finance costs comprise interest expense on borrowings. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

4. Changes in accounting policy:

IFRS 15 Revenue from Contracts with Customers and IFRS 9 Financial Instruments

The Company has initially applied IFRS 15 *Revenue from Contracts with Customers* and IFRS 9 *Financial Instruments* from January 1, 2018 on a retrospective basis. The following practical expedients have been used in the initial application of these new standards:

For completed contracts, the Company did not restate contracts that:

(i) Began and ended within the same annual reporting period; or

(ii) Were completed at the beginning of January 1, 2016.

There have been no material changes to the Company's comparative figures as a result of this implementation.

Leases

In January 2016, IASB issued IFRS 16 to establish 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 it is effective for annual periods beginning on or after January 1, 2019. The standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. This standard substantially carries forward the lessor accounting requirements of IAS 17, while requiring enhanced disclosures to be provided by the lessor. Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning January 1, 2019. The Company does not expect the standard to have a material impact on the financial statements.

Uncertainty over Income Tax Treatments

The IASB issued IFRIC 23 to clarify how to apply the recognition and measurement requirements in IAS 12 *Income Taxes*. The IFRIC is effective for annual periods beginning on or after January 1, 2019. The Company has assessed their uncertain tax treatments and concluded that it is probable that the tax authorities will accept the treatment.

5. Accounts receivable:

	2018	2017
Electric service revenue	$ 4,168,726	$ 3,957,475
Recoverable work	1,546,549	1,302,275
Others	710,687	1,159,593
Town of Halton Hills	74,576	1,387
Less: allowance for doubtful accounts	(193,300)	(143,316)
	$ 6,307,238	$ 6,277,414

The accounts receivable from the Town of Halton Hills arose in the normal course of operations and are due under normal terms of trade.

6. Materials and supplies:

The Company has included certain major standby equipment as in-service fixed assets and amortizes these assets over their useful lives. The Company has reclassified $1,020,971 (2017 - $954,087) to capital assets during the year.

The amount of inventory consumed by the Company and recognized as an expense during 2018 was $22,851 (2017 - $37,124). No amount of inventory has been written down due to obsolescence (2017 - $nil).

7. Due from (to) related companies:

(a) Parent and ultimate controlling party:

The sole shareholder of the Company is Halton Hills Community Energy Corporation which in turn is wholly-owned by the Corporation of The Town of Halton Hills. The Town produces consolidated financial statements that are available for public use.

(b) Outstanding balances with related parties:

Amounts due from related companies are unsecured, non-interest bearing have no specific terms of repayment and are as follows:

	2018	2017
SouthWestern Energy Inc.	$ 1,708,195	$ 1,037,509
Halton Hills Community Energy Corporation	683,634	359,878
2008949 Ontario Ltd.	199,456	154,706
	$ 2,591,285	$ 1,552,093

7. Due from (to) related companies (continued):

(c) Transactions with affiliates:

Included in other income are administrative services provided by the Company to companies under common control during the year and measured at the exchange amount are as follows:

	2018	2017
SouthWestern Energy Inc.	$ 355,595	$ 326,894
2008949 Ontario Ltd.	14,182	12,023
	$ 369,777	$ 338,917

Included in contract services is $23,980 (2017 - $5,248) paid to SouthWestern Energy Inc. for electrical contracting services and smart meter repairs.

(d) Transactions with parent:

Included in other income are administrative services provided by the Company to the parent during the year and measured at the exchange amount are as follows:

	2018	2017
Halton Hills Community Energy Corporation	$ 7,090	$ 6,012

7. Due from (to) related companies (continued):

(e) Transactions with ultimate parent, the Town of Halton Hills

The following summarizes the Company's related party transactions, recorded at the exchange amount, and balances with the Town of Halton Hills for the years ended December 31:

	2018	2017
Transactions:		
Revenue		
Distribution revenue	$ 265,559	$ 258,403
Sale of electricity	1,448,845	1,580,634
Expenses		
Property taxes	125,785	125,648
Interest	655,049	655,049
Balances:		
Accounts receivable	74,576	1,387

The Company delivers electricity to the Town throughout the year for the electricity needs of the Town and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB.

(f) Key management personnel:

The key management personnel of the Company have been defined as members of its board of directors and management team members. The compensation paid or payable is as follows:

	2018	2017
Salaries, director's fee, bonuses and other short-term benefits	$ 1,917,049	$ 1,769,079
Post-employment benefits	9,479	12,586
	$ 1,926,528	$ 1,781,665

8. Regulatory balances:

Reconciliation of the carrying amount for each regulatory account

Regulatory deferral account debit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining recovery/ reversal years
Other regulatory assets	$ 64,913	$ 356,060	$ -	$ 420,973	1 -3 yrs
RCVA retail services	26,207	7,248	-	33,455	1 -3 yrs
RCVA service transaction request	425	77	-	502	1 -3 yrs
Low voltage variance	859,695	(210,293)	(649,402)	-	1 -3 yrs
LRAM variance account	265,625	36,900	-	302,525	3-5 yrs
Smart meter capital & recovery	97,567	607	-	98,174	1 -3 yrs
Extraordinary events	180,818	(180,818)	-	-	1 -2 yrs
RSVA network services	60,373	87,877	(105,306)	42,944	1 -3 yrs
RSVA connection services	136,099	3,965	(140,064)	-	1 -3 yrs
Global adjustment	1,538,259	(1,350,080)	227,590	415,769	1 -3 yrs
Deferred income taxes	4,780,883	666,552	-	5,447,435	-
	$ 8,010,864	$ (581,905)	$ (667,182)	$ 6,761,777	

Regulatory deferral account debit balances	January 1, 2017	Additions	Recovery/ reversal	December 31, 2017	Remaining recovery/ reversal years
Other regulatory assets	$ 22,888	$ 42,025	$ -	$ 64,913	1 -3 yrs
RCVA retail services	16,379	9,828	-	26,207	1 -3 yrs
RCVA service transaction request	277	148	-	425	1 -3 yrs
Low voltage variance	842,035	17,660	-	859,695	1 -3 yrs
LRAM variance account	139,659	125,966	-	265,625	4-6 yrs
Smart meter capital & recovery	97,167	400	-	97,567	1 -3 yrs
Extraordinary events	107,656	73,162	-	180,818	1 -3 yrs
RSVA network services	104,196	(43,823)	-	60,373	1 -3 yrs
RSVA connection services	233,742	(97,643)	-	136,099	1 -3 yrs
Global adjustment	-	1,762,050	(223,791)	1,538,259	1 -3 yrs
Disposition and refund regulatory balance	113,909	(303,329)	189,420	-	1 -3 yrs
Deferred income taxes	4,214,397	566,486	-	4,780,883	-
	$ 5,892,305	$ 2,152,930	$ (34,371)	$ 8,010,864	

The deferred income taxes balances will be recovered over the lives of the related capital assets.

8. Regulatory balances (continued):

Regulatory deferral account credit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining recovery/ reversal years
Low voltage variance	$ -	$ (210,293)	$ 3,468	$ (206,825)	1 -3 yrs
Smart metering entity charge	(18,651)	(22,800)	13,302	(28,149)	1 -3 yrs
RSVA wholesale market services	(2,022,040)	(81,959)	1,525,309	(578,690)	1 -3 yrs
RSVA connection services	-	3,965	(100,835)	(96,870)	1 -3 yrs
RSVA power	(2,067,266)	903,163	261,577	(902,526)	1 -3 yrs
Disposition and refund regulatory balance	(189,420)	685,464	(829,311)	(333,267)	1 -3 yrs
	$ (4,297,377)	$1,277,540	$ 873,510	$ (2,146,327)	

Regulatory deferral account credit balances	January 1, 2017	Additions	Recovery/ reversal	December 31, 2017	Remaining recovery/ reversal years
Smart metering entity charge	$ (13,084)	$ (5,567)	$ -	$ (18,651)	1 -3 yrs
RSVA wholesale market services	(1,499,120)	(522,920)	-	(2,022,040)	1 -3 yrs
RSVA power	(257,078)	(1,810,188)	-	(2,067,266)	1 -3 yrs
Global adjustment	(223,791)	1,762,050	(1,538,259)	-	1 -3 yrs
Disposition and refund regulatory balance	-	(303,329)	113,909	(189,420)	1 -3 yrs
	$ (1,993,073)	$ (879,954)	$(1,424,350)	$ (4,297,377)	

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy, weather and conservation. The Company has received approval from the OEB to establish its regulatory balances.

Settlement of the deferral accounts is done on an annual basis through application to the OEB. The 2017 IRM application, made to the OEB, did not meet the minimum requirement for disposition and therefore, no disposition was sought or approved for the 2017 rate year.

The OEB requires the Company to estimate its income taxes when it files a cost of service rate application to set its rates. As a result, the Company has recognized a regulatory debit account for the amount of deferred taxes that will ultimately be recovered from its customers. This balance will fluctuate as the Company's deferred tax balance fluctuates. Costs in the other regulatory assets account are related to increased OEB Assessment costs as per OEB direction.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points. In 2018, the rate was 1.10% for the period January 2018 to September 2018 and 1.50% for the period October 2018 to December 2018.

9. Property, plant and equipment:

	January 1, 2018	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2018
Cost					
Distributions system	$ 61,080,253	$ 6,856,062	$ -	$ -	$ 67,936,315
Plant	10,222,740	71,249	-	-	10,293,989
Fleet	2,106,742	175,169	-	-	2,281,911
Other equipment	1,711,954	321,710	-	-	2,033,664
Computer equipment and software	1,399,969	101,349	-	-	1,501,318
General office	220,470	2,677	-	-	233,147
Store equipment	4,732	-	-	-	4,732
Construction in process	7,316,917	17,674,751	-	-	24,991,668
	84,063,777	25,202,967	-	-	109,266,744
Accumulated Depreciation					
Distributions system	5,649,510	2,012,013	-	-	7,661,523
Plant	1,081,614	89,017	-	-	1,170,631
Fleet	636,409	216,381	-	-	852,790
Other equipment	383,833	128,795	-	-	512,628
Computer equipment and software	1,045,081	105,728	-	-	1,150,809
General office	156,062	24,326	-	-	180,388
Store equipment	4,732	-	-	-	4,732
Construction in process	-	-	-	-	-
	8,957,241	2,576,260	-	-	11,533,501
Carrying amount	$ 75,106,536	$ 22,626,707	$ -	$ -	$ 97,733,243

	January 1, 2017	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2017
Cost					
Distributions system	$ 53,740,262	$ 7,339,991	$ -	$ -	$ 61,080,253
Plant	10,164,565	58,175	-	-	10,222,740
Fleet	1,665,597	441,145	-	-	2,106,742
Other equipment	1,299,665	412,289	-	-	1,711,954
Computer equipment and software	1,251,933	148,036	-	-	1,399,969
General office	219,932	538	-	-	220,470
Store equipment	4,732	-	-	-	4,732
Construction in process	4,621,152	2,695,765	-	-	7,316,917
	72,967,838	11,095,939	-	-	84,063,777
Accumulated Depreciation					
Distributions system	3,776,408	1,873,102	-	-	5,649,510
Plant	994,138	87,476	-	-	1,081,614
Fleet	443,376	193,033	-	-	636,409
Other equipment	274,727	109,106	-	-	383,833
Computer equipment and software	913,660	131,421	-	-	1,045,081
General office	130,618	25,444	-	-	156,062
Store equipment	4,732	-	-	-	4,732
Construction in process	-	-	-	-	-
	6,537,659	2,419,582	-	-	8,957,241
Carrying amount	$ 66,430,179	$ 8,676,357	$ -	$ -	$ 75,106,536

Interest capitalized in property, plant and equipment for 2018 was $452,956 (2017 - $64,320).

At December 31, 2018, property, plant and equipment with a carry value of $97,733,243 (2017 - $75,106,536) are subject to a general security agreement.

10. Accounts payable and accrued liabilities:

	2018	2017
Accounts payable – energy purchases	$ 11,263,573	$ 9,977,315
Debt retirement charge payable to OEFC	-	149,692
Payroll payable	323,776	371,055
Other	1,760,592	2,051,278
	$ 13,347,941	$ 12,549,340

11. Note payable:

The note payable is due to the Town of Halton Hills, bears interest at a prescribed rate set annually by the Town and is due December 31, 2020. In 2018, the prescribed rate was 4.12%. (2017 - 4.12%).

The Company incurred interest expense in respect of the note payable of $655,049 (2017 - $655,049). The note payable has been postponed in favour of the financial institution described in note 19.

12. Employee future benefits:

(a) OMERS pension plan

The Company provides a pension plan for its full-time employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2018, the Company made employer contributions of $466,685 to OMERS (2017 - $441,812), of which $303,262 (2017 - $295,283) has been capitalized as part of PP&E and the remaining amount of $163,423 (2017 - $146,529) has been recognized in profit or loss. The Company estimates that a contribution of $515,075 to OMERS will be made during the next fiscal year.

As at December 31, 2018, OMERS had approximately 496,000 members, of whom 52 are current employees of the Company. The most recently available OMERS annual report is for the year ended December 31, 2018, which reported that the plan was 96% (2017 - 94%) funded, with an unfunded liability of $4.2 billion (2017 - $5.4 billion). This unfunded liability is likely to result in future payments by participating employers and members.

12. Employee future benefits (continued):

(b) Employee future benefits other than pension

The Company pays certain medical and life insurance benefits on behalf of some of its retired employees. The Company recognizes these post-employment benefits in the year in which employees' services were rendered. The Company is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans.

Reconciliation of the obligation	2018	2017
Defined benefit obligation, beginning of year	$ 902,826	$ 763,168
Included in profit or loss:		
Current service cost	27,910	21,283
Interest cost	30,054	30,421
	960,790	814,872
Benefits paid	(37,793)	(24,051)
Included in OCI		
Actuarial loss	-	112,005
Defined benefit obligation, end of year	$ 922,997	$ 902,826

Actuarial assumptions	2018	2017
General inflation	2.00%	2.00%
Discount (interest) rate	3.40%	3.40%
Salary levels	2.70%	2.70%
Medical costs	6.20%	6.20%
Dental costs	4.50%	4.50%

13. Income tax expense:

Current tax expense

	2018	2017
Current year	$ 53,177	$ 52,958
Adjustment for prior years	12,235	(19,880)
	$ 65,412	$ 33,078

Deferred tax expense

	2018	2017
Change in recognized deductible temporary differences	$ 400,882	$ 503,691

Reconciliation of effective tax rate

	2018	2017
Income before taxes	$ 1,734,111	$ 2,825,631
Canada and Ontario statutory Income tax rates	26.50%	26.50%
Expected tax provision on income at statutory rates	459,539	748,792
Increase (decrease) in income taxes resulting from:		
Permanent differences	1,110	1,221
Under (over) provided in prior periods	43,187	(6,003)
Other adjustments	(845)	(7,900)
Other adjustments – regulatory movements	(36,697)	(199,341)
Income tax expense	$ 466,294	$ 536,769

Significant components of the Company’s deferred tax balances

	2018	2017
Deferred tax assets (liabilities):		
Property, plant and equipment	$(6,784,992)	$ (7,167,434)
Cumulative eligible capital	10,747	10,747
Post employment benefits	244,594	239,249
Deferred revenue	1,092,404	914,095
Non-capital losses	234,408	1,362,629
Corporate minimum tax	463,428	320,928
Other	51,224	32,481
	$(4,688,187)	$ (4,287,305)

14. Capital stock:

	2018	2017
Authorized:		
Unlimited number of preference shares		
Unlimited number of common shares		
Issued and fully paid:		
1,152 common shares	$ 16,161,663	$ 16,161,663

Dividends

The Company has established a dividend policy to pay 50% of budgeted net income with consideration given to the cash position, the working capital requirements and the net capital expenditures requirements.

The Company paid aggregate dividends in the year on common shares of $784 per share (2017 - $1,045), which amount to total dividends paid in the year of $903,714 (2017 - $1,204,000).

15. Other income:

	2018	2017
Rendering of services	$ 916,398	$ 892,753
Contributions received from customers	306,583	275,609
Government grants under CDM programs	773,681	1,161,104
Performance incentive payments under CDM programs	-	232,050
Recovery from related company	376,867	344,929
	$ 2,373,529	$ 2,906,445

16. Employee salaries and benefits:

	2018	2017
Salaries, wages and benefits	$ 3,846,211	$ 3,665,167
CPP and EI remittances	49,466	47,425
Contributions to OMERS	163,423	146,529
Post-employment benefit plans	20,171	27,653
	$ 4,079,271	$ 3,886,774

17. Revenue from contracts with customers

The Company generates revenue primarily from the sale and distribution of electricity to its customers. Other sources of revenue include performance incentive payments under CDM programs.

	2018	2017
Revenue from contracts with customers	$ 71,146,163	$ 72,643,230
Other revenue:		
CDM programs	773,681	1,161,766
Other	1,599,848	1,744,679
Total revenue	$ 73,519,692	$ 75,549,675

In the following table, revenue from contracts with customers is disaggregated by type of customer.

	2018	2017
Residential	$ 29,721,483	$ 29,994,517
Commercial	41,033,751	42,177,284
Other	390,929	471,429
Total revenue	$ 71,146,163	$ 72,643,230

18. Commitments and contingencies:

General

From time to time, the Company is involved in various litigation matters arising in the ordinary course of its business. The Company has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Company's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2018, no assessments have been made.

19. Credit facilities:

(a) Credit limit:

The Company has available an operating credit facility from a financial institution in the amount of $9,000,000 (2017 - $9,000,000). Credit is available to the Company in the form of prime based loans, bankers' acceptances, letters of credit or stand-by letters of guarantee. At year end, the letter of credit described in b) below is outstanding and the operating line utilized is $6,850,000 (2017 - $3,260,000). Security is in the form of a first charge over the Company's assets and undertakings and an assignment of liability and fire insurance has been provided. Amounts under this facility are due on demand.

(b) Security on electricity purchases:

As of May 2002, in order for the Company to obtain the electricity it requires to distribute to its customers, the Company is required to provide security to the Independent Electricity System Operator based on its estimated usage. The security obtained was a letter of credit issued in the amount of $1,754,315 (2017 - $1,754,315) from a financial institution.

19. Credit facilities (continued):

(c) Term loans:

Security on the following term loans is in the form of a first charge over the Company's assets and undertakings and an assignment of liability and fire insurance has been provided.

	2018	2017
Smart Meter Term Loan: Fixed rate term loan due May 25, 2021 bearing interest at 3.63% per year repayable monthly $12,418, principal and interest. Interest of $85,593 (2017-$62,373) was paid and expensed during the year.	$ 2,302,297	$ 2,456,762
Capital Term Loan 1: Fixed rate term loan due May 25, 2021 bearing interest at 3.71% repayable monthly in the amounts of $7,952, principal and interest	1,522,193	1,592,155
Capital Term Loan 2: Fixed rate term loan due May 25, 2021 bearing interest at 3.71% repayable monthly in the amounts of $10,094, principal and interest	1,957,578	2,038,910
Capital Term Loan 3: Fixed rate term loan due May 25, 2021 bearing interest at 3.76% repayable monthly in the amounts of $12,554, principal and interest	2,479,864	2,576,170
Capital Term Loan 4: Fixed rate term loan due May 25, 2021 bearing interest at 3.83% repayable monthly in the amounts of $17,412, principal and interest	3,522,177	3,646,826
Capital Term Loan 5: Fixed rate term loan due May 25, 2021 bearing interest at 3.86% repayable monthly in the amounts of $22,268, principal and interest	4,630,380	4,746,666
Facility 6: $23,000,000 construction loan due on demand. Interest is at a floating prime rate and payable interest only. Subsequent to December 31, 2018, the Company has entered into an interest rate SWAP on this facility to fix the interest rate exposure when fully drawn. The interest rate on this instrument is 4.095%	18,155,398	4,334,753
Capital Term Loan 7: Fixed rate term loan due May 25, 2021 bearing interest at 3.91% repayable monthly in the amounts of $20,022, principal and interest	4,238,433	-
	$ 38,808,320	$ 21,392,242

19. Credit facilities (continued):

Principal payments on the term loans are as follows:

2019	$ 455,419
2020	470,819
2021	491,116
2022	510,046
2023	529,704
2024 – 2028	36,351,216
	38,808,320
Less: current portion	(18,610,817)
Long-term portion of loan	$ 20,197,503

20. Financial instruments:

The carrying value of the accounts receivable and unbilled revenue, bank overdraft, accounts payable and accrued liabilities, and consumer deposits all approximate fair value because of the short maturity of these instruments.

The bank term loans have a carrying value that approximates fair value as the loans bear interest at current rates.

The fair value of the note payable at December 31, 2018 is $14,300,590. The fair value is calculated based on the present value of future cash flows, discounted at the current rate of interest at the report date. The interest rate used to calculate the fair value at December 31, 2018 is 4.12%.

The Company understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Company's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk

Financial assets carry credit risk, in that a counter-party will fail to discharge an obligation, resulting in a financial loss. Financial assets, such as accounts receivable, expose the Company to credit risk. The Company earns its revenue from a broad base of customers located in the Town of Halton Hills. No single customer accounts for revenue in excess of 2% of the respective reported balances.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts. The amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of accounts receivable previously provisioned are credited to the statement of comprehensive income. The balance of the allowance for impairment at December 31, 2018 is $193,300 (2017 - $143,316). An impairment loss of $45,813 (2017 - $73,780) was recognized during the year.

20. Financial instruments (continued):

(a) Credit risk (continued):

The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2018, approximately $143,435 (2017 - $91,491) is considered 90 days past due. The Company has approximately 22,982 customers, the majority of which are residential. Credit risk is managed through collection of security deposits from customers in accordance with direction provided by the OEB. As at December 31, 2018, the Company holds security deposits in the amount of $884,157 (2017 - $667,943).

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Customer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Company. Interest expense of $16,664 (2017 - $4,055) was incurred on customer deposits.

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Company currently does not have any material commodity or foreign exchange risk. The Company is exposed to fluctuations in interest rates as the regulated rate of return for the Company's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

(c) Liquidity risk:

The Company monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing demands. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing any interest expense. The Company has access to a line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. The majority of accounts payable, as reported on the balance sheet, are due within 60 days.

(d) Capital disclosures:

The main objectives of the Company when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to any credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on the regulated distribution business, and to deliver the appropriate financial returns.

The Company's definition of capital includes shareholder's equity, bank term loans, and note payable. As at December 31, 2018, shareholder's equity amounts to $32,856,827 (2017 - $31,590,761), bank term loans amounts to $38,808,320 (2017 - $21,392,242) and note payable amounts to $16,141,970 (2017 - $16,141,970).

APPENDIX 1-5: 2019 AUDITED FINANCIAL STATEMENTS

Financial Statements of

HALTON HILLS HYDRO INC.

And Independent Auditors' Report thereon

Year ended December 31, 2019

KPMG LLP
Commerce Place
21 King Street West, Suite 700
Hamilton Ontario L8P 4W7
Canada
Telephone (905) 523-8200
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Halton Hills Hydro Inc.:

Opinion

We have audited the financial statements of Halton Hills Hydro Inc., (the "Company"), which comprise:

- the statement of financial position as at December 31, 2019
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies
  (Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2019, 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 "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other 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.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

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 Company'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 Company or to cease operations, or has no realistic alternative but to do so.

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

Auditors' 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 auditors' 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 the 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 Company'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 Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' 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 auditors' report. However, future events or conditions may cause the Company 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.
- 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.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada
April 23, 2020

HALTON HILLS HYDRO INC.

Financial Statements

Year ended December 31, 2019

Financial Statements

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HALTON HILLS HYDRO INC.

Statement of Financial Position

Year ended December 31, 2019, with comparative information for 2018

	Note	2019	2018
Assets			
Current assets			
Accounts receivable	5	$ 7,218,868	$ 6,307,238
Unbilled revenue		7,205,808	6,232,787
Income taxes receivable		204,053	17,593
Materials and supplies	6	1,107,020	1,203,168
Due from related companies	7	2,602,450	2,591,285
Prepaid expenses		607,810	543,553
Total current assets		18,946,009	16,895,624
Non-current assets			
Property, plant and equipment	9	105,461,163	97,733,243
Deferred income taxes	13	5,192,078	2,096,805
Total non-current assets		110,653,241	99,830,048
Total assets		129,599,250	116,725,672
Regulatory balances	8	6,598,695	6,761,777
Total assets and regulatory balances		$ 136,197,945	$ 123,487,449
Liabilities			
Current liabilities			
Bank overdraft		$ 7,514,177	$ 6,824,777
Accounts payable and accrued liabilities	10	12,109,515	13,347,941
Customer deposits		669,580	884,157
Current portion of bank term loans	19	961,904	18,610,817
Current portion of note payable	11	3,141,970	-
Total current liabilities		24,397,146	39,667,692
Non-current liabilities			
Bank term loans	19	46,614,471	20,197,503
Note payable	11	13,000,000	16,141,970
Employee future benefits	12	940,114	922,997
Deferred revenue		5,027,955	4,769,141
Derivative liability	20	2,274,169	-
Deferred income taxes	13	9,629,622	6,784,992
Total non-current liabilities		77,486,331	48,816,603
Total liabilities		101,883,477	88,484,295
Equity			
Share capital	14	16,161,663	16,161,663
Retained earnings		15,441,164	16,897,161
Accumulated other comprehensive loss		(201,997)	(201,997)
Total equity		31,400,830	32,856,827
Total liabilities and equity		133,284,307	121,341,122
Regulatory balances	8	2,913,638	2,146,327
Subsequent event	21		
Total liabilities, equity and regulatory balances		$ 136,197,945	$ 123,487,449

See accompanying notes to the financial statements.

On behalf of the Board:

Director

Director

HALTON HILLS HYDRO INC.

Statement of Comprehensive Income

Year ended December 31, 2019, with comparative information for 2018

	Note	2019	2018
Revenue			
Distribution revenue		$ 12,050,552	$ 10,676,661
Other income	15	2,349,129	2,373,529
		14,399,681	13,050,190
Sale of electricity		60,208,617	60,469,502
Total revenue	17	74,608,298	73,519,692
Operating expenses			
Employee salaries and benefits	16	4,078,557	4,079,271
Material costs		5,237	22,851
Contract services		1,042,708	1,041,942
Property costs		875,758	775,817
Other costs		986,285	932,450
Communication costs		510,343	481,219
Depreciation		2,881,715	2,359,877
		10,380,603	9,693,427
Cost of power purchased		59,807,204	60,673,385
Total expenses		70,187,807	70,366,812
Income from operating activities		4,420,491	3,152,880
Finance income		24,699	80,373
Finance costs			
Interest		(1,856,099)	(1,499,142)
Fair value adjustment on derivative	20	(2,274,169)	-
Total finance costs		(4,130,268)	(1,499,142)
Income before income taxes		314,922	1,734,111
Income tax recovery (expense)	13	253,790	(466,294)
Net income		**568,712**	**1,267,817**
Net movement in regulatory balances, net of tax			
Net movement in regulatory balances	8	(1,286,015)	235,411
Income tax	8	355,622	666,552
		(930,393)	901,963
Net (loss) income and net movement in regulatory balances, being total comprehensive income		$ **(361,681)**	$ **2,169,780**

See accompanying notes to the financial statements.

HALTON HILLS HYDRO INC.

Statement of Changes in Equity

Year ended December 31, 2019, with comparative information for 2018

	Note	Share capital	Retained earnings	Accumulated other comprehensive loss	Total
Balance at January 1, 2018		$ 16,161,663	$ 15,631,095	$ (201,997)	$ 31,590,761
Net income and net movement in regulatory balances		-	2,169,780	-	2,169,780
Dividends	14	-	(903,714)	-	(903,714)
Balance at December 31, 2018		$ 16,161,663	$ 16,897,161	$ (201,997)	$ 32,856,827
Balance at January 1, 2019		$ 16,161,663	$ 16,897,161	$ (201,997)	$ 32,856,827
Net income and net movement in regulatory balances		-	(361,681)	-	(361,681)
Dividends	14	-	(1,094,316)	-	(1,094,316)
Balance at December 31, 2019		$ 16,161,663	$ 15,441,164	$ (201,997)	$ 31,400,830

See accompanying notes to the financial statements.

HALTON HILLS HYDRO INC.

Statement of Cash Flows

Year ended December 31, 2019, with comparative information for 2018

	2019	2018
Operating activities		
Net (loss) income and net movement in regulatory balances	$ (361,681)	$ 2,169,780
Adjustments for:		
Depreciation	3,101,176	2,576,260
Amortization of deferred revenue	(329,195)	(306,583)
Employee future benefits	17,117	20,171
Income tax (recovery) expense	(253,790)	466,294
Net finance costs	1,831,400	1,418,769
Fair value adjustment on derivative liability	2,274,169	-
Change in non-cash operating working capital:		
Accounts receivable	(911,630)	(29,824)
Unbilled revenue	(973,021)	526,363
Materials and supplies	96,148	91,798
Due from related companies	(11,165)	(1,039,192)
Prepaid expenses	(64,257)	(39,748)
Accounts payable and accrued liabilities	(1,512,005)	798,601
Customer deposits	(214,577)	216,214
Capital contributions	588,009	1,103,065
Regulatory balances	930,393	(901,963)
Income tax paid	(183,313)	(69,961)
Interest paid	(1,856,099)	(1,499,142)
Interest received	24,699	80,373
Net cash from operating activities	2,192,378	5,581,275
Investing activities		
Purchase of property, plant and equipment	(10,829,096)	(25,202,967)
Net cash used by investing activities	(10,829,096)	(25,202,967)
Financing activities		
Dividends paid	(820,737)	(903,714)
Issuance of long-term debt	9,361,532	18,070,645
Repayment of long-term debt	(593,477)	(654,567)
Net cash from financing activities	7,947,318	16,512,364
Change in bank overdraft	(689,400)	(3,109,328)
Bank overdraft, beginning of year	(6,824,777)	(3,715,449)
Bank overdraft, end of year	$ (7,514,177)	$ (6,824,777)

See accompanying notes to the financial statements.

1. Reporting entity:

Halton Hills Hydro Inc., (the “Company”) is a rate regulated, municipally owned electricity distribution company incorporated under the laws of the Province of Ontario, Canada. The Company is located in the Town of Acton in the Town of Halton Hills. The address of the Company’s registered head office is 43 Alice St., Acton, Ontario.

The Company delivers electricity and related energy services to residential and commercial customers in the Town of Halton Hills. The Company is wholly owned by Halton Hills Community Energy Corporation and the ultimate parent company is the Corporation of The Town of Halton Hills.

The financial statements are for the Company as at and for the year ended December 31, 2019.

2. Basis of presentation:

(a) Statement of compliance:

The Company's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 23, 2020.

(b) Basis of measurement:

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

(d) Use of estimates and judgments:

(i) Assumptions and estimation uncertainty:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

2. Basis of presentation (continued):

(d) Use of estimates and judgments (continued):

(i) Assumptions and estimation uncertainty (continued):

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Note 3(b) – measurement of unbilled revenue

(ii) Note 3(f) – recognition and measurement of regulatory balances

(iii) Notes 3(d), 9 – estimation of useful lives of its property, plant and equipment

(iv) Note 3(e)(ii), 12(b) – measurement of defined benefit obligations: key actuarial assumptions

(v) Note 3(j), 18 – recognition and measurement of commitments and contingencies

(ii) Judgements:

Information about judgements made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following notes:

(i) Note 3(b) – determination of the performance obligation for contributions from customers and the related amortization period

(e) Rate regulation:

The Company is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Company, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

Rate setting:

(i) Distribution revenue:

For the distribution revenue, the Company files a "Cost of Service" ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Company's business. The Company estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers.

On October 15th, 2018 the company filed an application with the Ontario Energy Board (OEB), for rates pursuant to the OEB's Price Cap IR framework for electricity rates effective May 01, 2019, the rates were approved on March 28, 2019.

On December 3, 2018, the company submitted an application for proposed incremental revenue requirement recovery as it relates to the building of a Municipal Transformer Station (TS), through rate riders effective May 1, 2019. On April 04, 2019 the OEB approved the ICM funding of $23.4 million related to the construction of the transformer station. In its decision, the OEB denied Halton Hills Hydro an exception to the ICM policy to recover incremental operating, maintenance and administration costs arising from the operation of the new transformer station. Halton Hills Hydro has appealed this OEB decision through Divisional Court, Ontario Supreme Court of Justice; the appeal decision remains outstanding.

The company filed an application with the Ontario Energy Board (OEB) on November 25, 2019 for rates pursuant to the OEB's Price Cap IR framework for electricity rates effective May 01, 2020. The Company last filed a COS application on October 02, 2015 for rates effective May 01, 2016.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

Rate setting:

(i) Distribution revenue:

The Company filed applications with the Ontario Energy Board (OEB) on September 25, 2017, October 23, 2017 and December 1, 2017 for rates pursuant to the OEB's Price Cap IR framework, for the establishment and disposition of a variance account to account for and remedy an error related to depreciation expense and for recovery of costs incurred as a result of a pay equity settlement agreement (Z factor), respectively. The applications were filed under section 78 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B) and under the OEB's Filing Requirements for Incentive Regulation Rate Applications seeking approval for changes to Halton Hills Hydro's electricity distribution rates to be effective May 1, 2018. The OEB approved the Price Cap IR and depreciation recovery applications but denied the requested Z-factor application for recovery of pay equity settlement costs. The rate rider for the recovery of depreciation expenses is effective from May 01, 2018 to April 30, 2021.

(ii) *Electricity rates:*

The OEB sets electricity prices for certain low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity or pursuant to their contract with a retailer. The Company is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

The OEB issued an Accounting Guidance on February 21, 2019 to standardize the accounting processes used by electricity distributors to improve the accuracy of settlements with the IESO for low-volume consumers. The standardization seeks to facilitate the accurate disposition of commodity pass-through variance account balances. The Company implemented these procedures by the due date of August 31, 2019 retroactive to January 1, 2019 as required by the OEB.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments:

All financial assets and all financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Derivatives are classified as financial liabilities at fair value through profit or loss. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(h).

Hedge accounting has not been used in the preparation of these financial statements.

3. Significant accounting policies (continued):

(b) Revenue recognition:

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Company has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Company has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Company is acting as an agent for this billing stream.

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Company's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Company has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

3. Significant accounting policies (continued):

(b) Revenue recognition (continued):

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered. Amounts received in advance of these milestones are presented as deferred revenue.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. Cash contributions are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Company's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Government grants and the related performance incentive payments under Conservation and Demand Management (CDM) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Material and supplies:

Materials and supplies, the majority of which are consumed by the Company in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

Net realizable value is the estimated selling price in the ordinary course of business, less estimated selling expenses.

(d) Property, plant and equipment:

Items of property, plant and equipment (“PP&E”) used in rate-regulated activities are measured at deemed cost established on the transition date less accumulated depreciation. All other items of PP&E measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Company’s borrowings. Qualifying assets are considered to be those that take in excess of 6 months to construct.

3. Significant accounting policies (continued):

(d) Property, plant and equipment (continued):

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Company and its cost can be measured reliably.

In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Company has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

Asset	Rate
Distribution system	25 - 50 years
Plant	20 - 42 years
Fleet	8 - 15 years
Other equipment	5 - 20 years
Computer equipment and software	1 - 5 years
General office	5 years
Stores equipment	10 years
Contributed capital	20 - 50 years

3. Significant accounting policies (continued):

(e) Employee future benefits:

The Company pays certain life insurance benefits, under unfunded defined benefit plans, on behalf of its retired employees and extended health and dental benefits under unfunded defined benefit plans, on behalf of early retirees.

(i) Pension plan:

The Company provides a pension plan for its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and 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.

To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Company to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Company is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension:

The Company provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management’s best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(f) Regulatory balances:

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Company.

3. Significant accounting policies (continued):

(f) Regulatory balances (continued):

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance.

The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Company is required to refund amounts to ratepayers in the future, the Company recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(g) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the “Tax Acts”). Under the *Electricity Act*, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (“OEFC”). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used.

3. Significant accounting policies (continued):

(g) Income taxes (continued):

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

(h) Impairment:

(i) Financial assets measured at amortized cost:

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the impairment requirements are no longer met.

A financial asset 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.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. 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. An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

3. Significant accounting policies (continued):

(i) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

(j) Provisions:

A provision is recognized if, as a result of a past event, the Company 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 pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(k) Finance income and finance costs:

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash balances.

Finance costs comprise interest expense on borrowings and customer deposits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(l) Leased assets:

At inception of a contract, the Company assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Company with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Company recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

3. Significant accounting policies (continued):

(l) Leased assets (continued):

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Company's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Company has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Company recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

(m) Cash and cash equivalents:

Cash and cash equivalents is comprised of cash balances as well as bank overdraft amounts.

4. Change in accounting policy:

The Company has applied IFRS 16 *Leases* with a date of initial application of January 1, 2019.

The details of the changes in accounting policies are disclosed below.

Except for the changes below, the Company has consistently applied the accounting policies to all periods presented in these financial statements.

Previously, the Company determined, at contract inception, whether an arrangement is or contains a lease under IFRIC 4. Under IFRS 16, the Company assesses whether a contract is or contains a lease based on the definition of a lease, as explained in Note 3(l). On transition to IFRS 16, the Company elected to apply the practical expedient to grandfather the assessment of which contracts are leases. It applied IFRS 16 only to contracts that were previously identified as leases. Contracts that were not identified as leases under IAS 17 and IFRIC 4 were not reassessed for whether they contained a lease. Therefore, the definition of a lease under IFRS 16 was applied only to contracts entered into or changed on or after January 1, 2019.

4. Change in accounting policy (continued):

As a lessee, the Company previously classified leases as operating or finance leases based on its assessment of whether the lease transferred significantly all of the risks and rewards incidental to ownership of the underlying asset to the Company. Under IFRS 16, the Company recognizes right-of-use assets and lease liabilities for most leases – i.e. these leases are on-balance sheet. The Company has decided to apply recognition exemptions to short-term leases and leases for which the value of the underlying asset is of low value.

The Company used the following practical expedients and recognition exemptions when applying IFRS 16 to leases previously classified as operating leases under IAS 17.

— Applied the exemption not to recognize right-of-use assets and liabilities for leases with less than 12 months of lease term;

— Applied the exemption not to recognize right-of-use assets and liabilities for leases for which the underlying asset is of low value;

— Applied this standard to all contracts that were previously identified as leases by applying IAS 17 Leases and IFRIC 4 Determining whether and Arrangement contains a Lease.

Leases previously classified as finance leases

For leases that were classified as finance leases under IAS 17, the carrying amount of the right-of-use asset and the lease liability at January 1, 2019 are determined at the carrying amount of the leased asset and lease liability under IAS 17 immediately before that date.

Impacts on financial statements

There are no transitional impacts to report as the Company does not enter into leasing arrangements and has determined that there are no arrangements that contain a lease.

5. Accounts receivable:

	2019	2018
Electric service revenue	$ 3,969,947	$ 4,168,726
Recoverable work	1,731,501	1,546,549
Others	1,712,709	710,687
Town of Halton Hills	2,190	74,576
Less: allowance for doubtful accounts	(197,479)	(193,300)
	$ 7,218,868	$ 6,307,238

The accounts receivable from the Town of Halton Hills arose in the normal course of operations and are due under normal terms of trade.

6. Materials and supplies:

The Company has included certain major standby equipment as in-service fixed assets and amortizes these assets over their useful lives. The Company has reclassified $750,178 (2018 - $1,020,971) to capital assets during the year.

The amount of inventory consumed by the Company and recognized as an expense during 2019 was $5,237 (2018 - $22,851). No amount of inventory has been written down due to obsolescence (2018 - $nil).

7. Due from related companies:

(a) Parent and ultimate controlling party:

The sole shareholder of the Company is Halton Hills Community Energy Corporation which in turn is wholly-owned by the Corporation of The Town of Halton Hills. The Town produces consolidated financial statements that are available for public use.

(b) Outstanding balances with related parties:

Amounts due from related companies are unsecured, non-interest bearing, have no specific terms of repayment and are as follows:

	2019	2018
SouthWestern Energy Inc.	$ 1,575,245	$ 1,708,195
Halton Hills Community Energy Corporation	897,780	683,634
2008949 Ontario Ltd.	129,425	199,456
	$ 2,602,450	$ 2,591,285

Included in accounts payable and accrued liabilities is an amount of $273,579 that is due to Halton Hills Community Energy Corporation for dividends declared.

7. Due from related companies (continued):

(c) Transactions with affiliates:

Included in other income are administrative services provided by the Company to companies under common control during the year and measured at the exchange amount are as follows:

	2019	2018
SouthWestern Energy Inc.	$ 355,595	$ 355,595
2008949 Ontario Ltd.	14,377	14,182
	$ 369,972	$ 369,777

Included in contract services is $96,074 (2018 - $23,980) paid to SouthWestern Energy Inc. for electrical contracting services and smart meter repairs.

(d) Transactions with parent:

Included in other income are administrative services provided by the Company to the parent during the year and measured at the exchange amount are as follows:

	2019	2018
Halton Hills Community Energy Corporation	$ 7,151	$ 7,090

7. Due from related companies (continued):

(e) Transactions with ultimate parent, the Town of Halton Hills

The following summarizes the Company's related party transactions, recorded at the exchange amount, and balances with the Town of Halton Hills for the years ended December 31:

	2019	2018
Transactions:		
Revenue		
Distribution revenue	$ 299,166	$ 265,559
Sale of electricity	1,556,678	1,448,845
Expenses		
Property taxes	139,899	125,785
Interest	655,049	655,049
Balances:		
Accounts receivable	2,190	74,576

The Company delivers electricity to the Town throughout the year for the electricity needs of the Town and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB.

(f) Key management personnel:

The key management personnel of the Company have been defined as members of its board of directors and management team members. The compensation paid or payable is as follows:

	2019	2018
Salaries, director's fee, bonuses and other short-term benefits	$ 1,889,701	$ 1,917,049
Post-employment benefits	7,931	9,479
	$ 1,897,632	$ 1,926,528

8. Regulatory balances:

Reconciliation of the carrying amount for each regulatory account

Regulatory deferral account debit balances	January 1, 2019	Additions	Recovery/ reversal	December 31, 2019	Remaining recovery/ reversal years
Other regulatory assets	$ 420,973	$ (564,882)	$ 143,909	$ -	1 -3 yrs
RCVA retail services	33,455	3,763	-	37,218	1 -3 yrs
RCVA service transaction request	502	51	-	553	1 -3 yrs
LRAM variance account	302,525	61,607	-	364,132	1 -3 yrs
Smart meter capital & recovery	98,174	729	-	98,903	1 -3 yrs
RSVA network services	42,944	130,147	46,083	219,174	1 -3 yrs
RSVA connection services	-	69,118	6,540	75,658	1 -3 yrs
Global adjustment	415,769	(2,736,843)	2,321,074	-	1 -3 yrs
Deferred income taxes	5,447,435	355,622	-	5,803,057	*
	$ 6,761,777	$(2,680,688)	$ 2,517,606	$6,598,695	

Regulatory deferral account debit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining recovery/ reversal years
Other regulatory assets	$ 64,913	$ 356,060	$ -	$ 420,973	1 -3 yrs
RCVA retail services	26,207	7,248	-	33,455	1 -3 yrs
RCVA service transaction request	425	77	-	502	1 -3 yrs
Low voltage variance	859,695	(210,293)	(649,402)	-	1 -3 yrs
LRAM variance account	265,625	36,900	-	302,525	3 -5 yrs
Smart meter capital & recovery	97,567	607	-	98,174	1 -3 yrs
Extraordinary events	180,818	(180,818)	-	-	1 -2 yrs
RSVA network services	60,373	87,877	(105,306)	42,944	1 -3 yrs
RSVA connection services	136,099	3,965	(140,064)	-	1 -3 yrs
Global adjustment	1,538,259	(1,350,080)	227,590	415,769	1 -3 yrs
Deferred income taxes	4,780,883	666,552	-	5,447,435	*
	$ 8,010,864	$ (581,905)	$ (667,182)	$ 6,761,777	

*The deferred income taxes balances will be recovered over the lives of the related capital assets.

8. Regulatory balances (continued):

Regulatory deferral account credit balances	January 1, 2019	Additions	Recovery/ reversal	December 31, 2019	Remaining recovery/ reversal years
Other Regulatory Assets	$ -	$ (564,878)	$ 420,974	$ (143,904)	1 -3 yrs
Low voltage variance	(206,825)	207,863	(3,663)	(2,625)	1 -3 yrs
Smart metering entity charge	(28,149)	(6,640)	5,487	(29,302)	1 -3 yrs
RSVA wholesale market services	(578,690)	(156,569)	509,706	(225,553)	1 -3 yrs
RSVA connection services	(96,870)	69,118	27,752	-	1 -3 yrs
RSVA power	(902,526)	58,825	817,274	(26,427)	1 -3 yrs
Global adjustment	-	(1,918,890)	(338,813)	(2,257,703)	1 -3 yrs
Disposition and refund regulatory balance	(333,267)	828,861	(723,718)	(228,124)	1 -3 yrs
	$ (2,146,327)	$(1,482,310)	$ 714,999	$ (2,913,638)	

Regulatory deferral account credit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining recovery/ reversal years
Low voltage variance	$ -	$ (210,293)	$ 3,468	$ (206,825)	1 -3 yrs
Smart metering entity charge	(18,651)	(22,800)	13,302	(28,149)	1 -3 yrs
RSVA wholesale market services	(2,022,040)	(81,959)	1,525,309	(578,690)	1 -3 yrs
RSVA connection services	-	3,965	(100,835)	(96,870)	1 -3 yrs
RSVA power	(2,067,266)	903,163	261,577	(902,526)	1 -3 yrs
Disposition and refund regulatory balance	(189,420)	685,464	(829,311)	(333,267)	1 -3 yrs
	$ (4,297,377)	$1,277,540	$ 873,510	$ (2,146,327)	

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy, weather and conservation. The Company has received approval from the OEB to establish its regulatory balances.

Settlement of the deferral accounts is done on an annual basis through application to the OEB. The 2019 IRM application, made to the OEB, met the minimum requirement for disposition, however, the OEB only approved interim disposition on the 2017 balances. The Company did not ask for disposition of 2018 balances in the 2020 IRM application as the Company intends to ask for final disposition on all 2017, 2018 and 2019 audited balances (both Group 1 and Group 2) with the 2021 Cost of Service application.

The OEB requires the Company to estimate its income taxes when it files a cost of service rate application to set its rates. As a result, the Company has recognized a regulatory debit account for the amount of deferred taxes that will ultimately be recovered from its customers. This balance will fluctuate as the Company's deferred tax balance fluctuates. Costs in the other regulatory debit balances are related to increased OEB Assessment costs, increased pole attachment revenue, depreciation adjustment tracking and MTS incremental capital costs and recoveries, as per OEB direction.

8. Regulatory balances (continued):

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points. In 2019, the rate was 2.45% for the period January 2019 to March 2019 and 2.18% for the period April 2019 to December 2019.

9. Property, plant and equipment:

	January 1, 2019	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2019
Cost					
Distributions system	$ 67,936,315	$ 9,907,569	$ 20,361,852	$ -	$ 98,205,736
Plant	10,293,989	100,493	-	-	10,394,482
Fleet	2,281,911	92,120	-	-	2,374,031
Other equipment	2,033,664	231,254	-	-	2,264,918
Computer equipment and software	1,501,318	258,425	-	-	1,759,743
General office	223,147	472	-	-	223,619
Store equipment	4,732	-	-	-	4,732
Construction in process	24,991,668	238,763	(20,361,852)	-	4,868,579
	109,266,744	10,829,096	-	-	120,095,840
Accumulated Depreciation					
Distributions system	7,661,523	2,521,727	-	-	10,183,250
Plant	1,170,631	91,062	-	-	1,261,693
Fleet	852,790	219,461	-	-	1,072,251
Other equipment	512,628	137,532	-	-	650,160
Computer equipment and software	1,150,809	107,039	-	-	1,257,848
General office	180,388	24,355	-	-	204,743
Store equipment	4,732	-	-	-	4,732
Construction in process	-	-	-	-	-
	11,533,501	3,101,176	-	-	14,634,677
Carrying amount	$ 97,733,243	$ 7,727,920	$ -	$ -	$ 105,461,163

9. Property, plant and equipment (continued):

	January 1, 2018	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2018
Cost					
Distributions system	$ 61,080,253	$ 6,856,062	$ -	$ -	$ 67,936,315
Plant	10,222,740	71,249	-	-	10,293,989
Fleet	2,106,742	175,169	-	-	2,281,911
Other equipment	1,711,954	321,710	-	-	2,033,664
Computer equipment and software	1,399,969	101,349	-	-	1,501,318
General office	220,470	2,677	-	-	223,147
Store equipment	4,732	-	-	-	4,732
Construction in process	7,316,917	17,674,751	-	-	24,991,668
	84,063,777	25,202,967	-	-	109,266,744
Accumulated Depreciation					
Distributions system	5,649,510	2,012,013	-	-	7,661,523
Plant	1,081,614	89,017	-	-	1,170,631
Fleet	636,409	216,381	-	-	852,790
Other equipment	383,833	128,795	-	-	512,628
Computer equipment and software	1,045,081	105,728	-	-	1,150,809
General office	156,062	24,326	-	-	180,388
Store equipment	4,732	-	-	-	4,732
Construction in process	-	-	-	-	-
	8,957,241	2,576,260	-	-	11,533,501
Carrying amount	$ 75,106,536	$ 22,626,707	$ -	$ -	$ 97,733,243

Interest capitalized in property, plant and equipment for 2019 was $543,584 (2018 - $452,956).

At December 31, 2019, property, plant and equipment with a carrying value of $105,461,163 (2018 - $97,733,243) are subject to a general security agreement.

10. Accounts payable and accrued liabilities

	2019	2018
Accounts payable – energy purchases	$ 9,626,932	$ 11,263,573
Payroll payable	357,204	323,776
Other	2,125,379	1,760,592
	$ 12,109,515	$ 13,347,941

11. Note payable:

The note payable is due to the Town of Halton Hills and bears interest at a prescribed rate set annually by the Town. In 2019, the prescribed rate was 4.12% (2018 - 4.12%). On December 17, 2019 the Town of Halton Hills agreed to a change in the repayment schedule of the loan with repayments commencing in 2020 due on or before April 1 each calendar year with a maturity date of no later than April 1, 2025.

Principal payments on the note payable are as follows:

2020	$	3,141,970
2021		2,800,000
2022		2,800,000
2023		2,800,000
2024		2,800,000
2025		1,800,000
		16,141,970
Less: current portion		(3,141,970)
Long-term portion of loan	$	13,000,000

The Company incurred interest expense in respect of the note payable of $655,049 (2018 - $655,049).

12. Employee future benefits:

(a) OMERS pension plan

The Company provides a pension plan for its full-time employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2019, the Company made employer contributions of $453,351 to OMERS (2018 - $466,685), of which $289,928 (2018 - $303,262) has been capitalized as part of PP&E and the remaining amount of $163,423 (2018 - $163,423) has been recognized in profit or loss. The Company estimates that a contribution of $471,864 to OMERS will be made during the next fiscal year.

As at December 31, 2019, OMERS had approximately 500,000 members, of whom 51 are current employees of the Company. The most recently available OMERS annual report is for the year ended December 31, 2019, which reported that the plan was 97% (2018 - 96%) funded, with an unfunded liability of $3.4 billion (2018 - $4.2 billion). This unfunded liability is likely to result in future payments by participating employers and members.

12. Employee future benefits (continued):

(b) Employee future benefits other than pension

The Company pays certain medical and life insurance benefits on behalf of some of its retired employees. The Company recognizes these post-employment benefits in the year in which employees' services were rendered. The Company is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans.

Reconciliation of the obligation	2019	2018
Defined benefit obligation, beginning of year	$ 922,997	$ 902,826
Included in profit or loss:		
Current service cost	26,851	27,910
Interest cost	30,695	30,054
	980,543	960,790
Benefits paid	(40,429)	(37,793)
Defined benefit obligation, end of year	$ 940,114	$ 922,997

Actuarial assumptions	2019	2018
General inflation	2.00%	2.00%
Discount (interest) rate	3.40%	3.40%
Salary levels	2.70%	2.70%
Medical costs	5.96%	6.20%
Dental costs	4.50%	4.50%

13. Income tax expense:

Current tax expense

	2019	2018
Current year	$ -	$ 53,177
Adjustment for prior years	(3,147)	12,235
	$ (3,147)	$ 65,412

Deferred tax expense

	2019	2018
Origination and reversal of temporary differences	$ (250,643)	$ -
Change in recognized deductible temporary differences	-	400,882
	$ (250,643)	$ 400,882

Reconciliation of effective tax rate

	2019	2018
Income before taxes	$ 314,922	$ 1,734,111
Canada and Ontario statutory Income tax rates	26.50%	26.50%
Expected tax provision on income at statutory rates	83,454	459,539
Increase (decrease) in income taxes resulting from:		
Permanent differences	2,340	1,110
Under (over) provided in prior periods	7,090	43,187
Other adjustments	(5,880)	(845)
Other adjustments – regulatory movements	(340,794)	(36,697)
Income tax expense	$ (253,790)	$ 466,294

Significant components of the Company’s deferred tax balances

	2019	2018
Deferred tax assets (liabilities):		
Property, plant and equipment	$(9,629,622)	$ (6,784,992)
Cumulative eligible capital	-	10,747
Post employment benefits	249,130	244,594
Deferred revenue	1,226,034	1,092,404
Non-capital losses	2,600,534	234,408
Corporate minimum tax	463,427	463,428
Other	50,298	51,224
Fair value adjustment on derivative liability	602,655	-
	$(4,437,544)	$ (4,688,187)

14. Capital stock:

	2019	2018
Authorized:		
Unlimited number of preference shares		
Unlimited number of common shares		
Issued and fully paid:		
1,152 common shares	$ 16,161,663	$ 16,161,663

Dividends

The Company has established a dividend policy to pay 50% of budgeted net income with consideration given to the cash position, the working capital requirements and the net capital expenditures requirements.

The Company declared aggregate dividends in the year on common shares of $950 per share (2018 - $784), which amounted to total dividends declared in the year of $1,094,316 (2018 - $903,714).

15. Other income:

	2019	2018
Rendering of services	$ 956,085	$ 916,398
Contributions received from customers	329,195	306,583
Government grants under CDM programs	686,726	773,681
Recovery from related company	377,123	376,867
	$ 2,349,129	$ 2,373,529

16. Employee salaries and benefits:

	2019	2018
Salaries, wages and benefits	$ 3,843,388	$ 3,846,211
CPP and EI remittances	54,629	49,466
Contributions to OMERS	163,423	163,423
Post-employment benefit plans	17,117	20,171
	$ 4,078,557	$ 4,079,271

17. Revenue from contracts with customers

The Company generates revenue primarily from the sale and distribution of electricity to its customers. Other sources of revenue include performance incentive payments under CDM programs.

	2019	2018
Revenue from contracts with customers	$ 72,259,169	$ 71,146,163
Other revenue:		
CDM programs	686,726	773,681
Other	1,662,403	1,599,848
Total revenue	$ 74,608,298	$ 73,519,692

In the following table, revenue from contracts with customers is disaggregated by type of customer.

	2019	2018
Residential	$ 29,210,758	$ 29,721,483
Commercial	42,643,450	41,033,751
Other	404,961	390,929
Total revenue	$ 72,259,169	$ 71,146,163

18. Commitments and contingencies:

General

From time to time, the Company is involved in various litigation matters arising in the ordinary course of its business. The Company has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Company's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2019, no assessments have been made.

19. Credit facilities:

(a) Credit limit:

The Company has available an operating credit facility from a financial institution in the amount of $9,000,000 (2018 - $9,000,000). Credit is available to the Company in the form of prime based loans, bankers' acceptances, letters of credit or stand-by letters of guarantee. At year end, the letter of credit described in b) below is outstanding and the operating line utilized is $7,530,000 (2018 - $6,850,000). Security is in the form of a first charge over the Company's assets and undertakings and an assignment of liability and fire insurance has been provided. Amounts under this facility are due on demand.

(b) Security on electricity purchases:

As of May 2002, in order for the Company to obtain the electricity it requires to distribute to its customers, the Company is required to provide security to the Independent Electricity System Operator based on its estimated usage. The security obtained was a letter of credit issued in the amount of $1,754,315 (2018 - $1,754,315) from a financial institution.

19. Credit facilities (continued):

(c) Term loans:

Security on the following term loans is in the form of a first charge over the Company's assets and undertakings and an assignment of liability and fire insurance has been provided.

	2019	2018
Smart Meter Term Loan: Fixed rate term loan due May 25, 2021 bearing interest at 3.63% per year repayable monthly $12,418, principal and interest.	$ 2,235,730	$ 2,302,297
Capital Term Loan 1: Fixed rate term loan due May 25, 2021 bearing interest at 3.71% repayable monthly in the amounts of $7,952, principal and interest	1,482,550	1,522,193
Capital Term Loan 2: Fixed rate term loan due May 25, 2021 bearing interest at 3.71% repayable monthly in the amounts of $10,094, principal and interest	1,908,225	1,957,578
Capital Term Loan 3: Fixed rate term loan due May 25, 2021 bearing interest at 3.76% repayable monthly in the amounts of $12,554, principal and interest	2,421,429	2,479,864
Capital Term Loan 4: Fixed rate term loan due May 25, 2021 bearing interest at 3.83% repayable monthly in the amounts of $17,412, principal and interest	3,446,777	3,522,177
Capital Term Loan 5: Fixed rate term loan due May 25, 2021 bearing interest at 3.86% repayable monthly in the amounts of $22,268, principal and interest	4,540,260	4,630,380
Capital Transformer Station Loan: Capital transformer station loan bearing interest at prime rate due September 1, 2049 repayable monthly in the amounts of $111,069 principal and interest,	22,901,922	-
Capital Term 6 loan: $23,000,000 on construction loan due on demand. Interest is at floating prime rate and payable interest only,	-	18,155,398
Capital Term Loan 7: Fixed rate term loan due May 25, 2021 bearing interest at 3.91% repayable monthly in the amounts of $20,022, principal and interest	4,162,044	4,238,433
Capital Term Loan 8: Fixed rate term loan due May 25, 2021 bearing interest at 3.35% repayable monthly in the amounts of $19,803.	4,477,438	-
	$ 47,576,375	$ 38,808,320

The Company has entered into an interest rate swap agreement to pay a fixed rate of interest of 4.095%, exclusive of bank transaction fees, in lieu of prime rate on its capital transformer station loan to effectively reduce interest rate risk associated with the floating rate debt of the Company.

19. Credit facilities (continued):

(c) Term loans (continued):

The interest rate swap agreement was effective September 6, 2019 with the initial notional amount of CAD $23,000,000. Payments are made monthly on the 1st of each month commencing on October 1, 2019 up to and including the Termination Date of August 1, 2049.

Principal payments on the term loans are as follows:

2020	$ 961,904
2021	1,002,436
2022	1,041,991
2023	1,083,113
2024	1,123,538
2025 – 2049	42,363,393
	47,576,375
Less: current portion	(961,904)
Long-term portion of loan	$ 46,614,471

20. Financial instruments:

The carrying value of the accounts receivable, unbilled revenue, due from related companies, bank overdraft, accounts payable and accrued liabilities, and customer deposits all approximate fair value because of the short maturity of these instruments.

The fair value of the note payable at December 31, 2019 is $14,257,000. The fair value is calculated based on the present value of future cash flows, discounted at the current rate of interest at the report date. The interest rate used to calculate the fair value at December 31, 2019 is 4.12%.

The remaining term loans fair value at December 31, 2019 are as follows:

Loan	Rate	Carrying Value	Fair Value
Smart Meter Term Loan	3.63%	$ 2,235,730	$ 2,230,000
Capital Term Loan 1	3.71%	1,482,550	1,482,000
Capital Term Loan 2	3.71%	1,908,225	1,297,000
Capital Term Loan 3	3.76%	2,421,429	2,343,000
Capital Term Loan 4	3.83%	3,446,777	2,506,000
Capital Term Loan 5	3.86%	4,540,260	4,539,000
Capital Term Loan 7	3.91%	4,162,044	4,118,000
Capital Term Loan 8	3.35%	4,477,438	4,337,000
		$ 24,674,453	$ 22,852,000

20. Financial instruments (continued):

The Company understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Company's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk:

Financial assets carry credit risk, in that a counter-party will fail to discharge an obligation, resulting in a financial loss. Financial assets, such as accounts receivable, expose the Company to credit risk. The Company earns its revenue from a broad base of customers located in the Town of Halton Hills. No single customer accounts for revenue in excess of 2% of the respective reported balances.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts. The amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of accounts receivable previously provisioned are credited to the statement of comprehensive income. The balance of the allowance for impairment at December 31, 2019 is $197,479 (2018 - $193,300). An impairment loss of $70,528 (2018 - $45,813) was recognized during the year.

The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2019, approximately $186,339 (2018 - $211,737) is considered 60 days past due. The Company has approximately 23,066 customers, the majority of which are residential. Credit risk is managed through collection of security deposits from customers in accordance with direction provided by the OEB. As at December 31, 2019, the Company holds security deposits in the amount of $669,580 (2018 - $884,157).

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Customer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Company. Interest expense of $13,715 (2018 - $16,664) was incurred on customer deposits.

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Company currently does not have any material commodity or foreign exchange risk. The Company is exposed to fluctuations in interest rates as the regulated rate of return for the Company's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

The Company is exposed to interest rate risk on its prime rate capital transformer station loan. The Company has mitigated its risk through an interest rate swap agreement as described in note 19(c).

20. Financial instruments (continued):

(b) Market risk (continued):

Interest is paid on customer deposits at a market rate reset quarterly as directed by the Ontario Energy Board. A credit facility loan bears interest at a floating rate and thus, the carrying value approximates fair value. However, the Company has entered into an interest rate swap transaction, derivative instrument, the effect of which is to fix the interest rate on the term facility loan at 4.095%. The potential replacement cost to the Company of the interest rate swaps, representing estimated fair value as presented on the balance sheet, was $2,274,169 (2018 - $nil), which was in the favour of institution outlined in note 19. The Company entered into this interest rate swap transaction to fix the interest rate over the long-term and intends to hold this to maturity at which time there should be no replacement cost.

(c) Liquidity risk:

The Company monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing demands. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing any interest expense. The Company has access to a line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. The majority of accounts payable, as reported on the balance sheet, are due within 60 days.

(d) Capital disclosures:

The main objectives of the Company when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to any credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on the regulated distribution business, and to deliver the appropriate financial returns.

The Company's definition of capital includes shareholder's equity, bank term loans, and note payable. As at December 31, 2019, shareholder's equity amounts to $31,400,830 (2018 - $32,856,827), bank term loans amounts to $47,576,375 (2018 - $38,808,320) and note payable amounts to $16,141,970 (2018 - $16,141,970).

21. Subsequent event:

Subsequent to December 31, 2019, the COVID-19 outbreak was declared a pandemic by the World Health Organization. This has resulted in governments worldwide, including the Canadian and Ontario governments, enacting emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally and in Ontario resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions however the success of these interventions is not currently determinable. The current challenging economic climate may lead to adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct impact on the Company's operating results and financial position in the future. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and our business are not known at this time.

APPENDIX 1-6: 2018 AUDITED FINANCIAL RECONCILIATION TO STATEMENTS REGULATORY FINANCIAL RESULTS

Balance Sheet

USofA	Cash and Equivalents	Accounts receivable	Unbilled Revenue	Income taxes receivable	Materials & Supplies	Due from related companies	Prepaid expenses	Regulatory Assets	Regulatory Assets	PP&E
	Current Assets									
	0	1	2	3	4	5	6	7A	7B	8
1005	25,223.00	-	-	-	-	-	-	-	-	-
1060	-	-	-	-	-	-	-	-	-	-
1100	-	4,209,130	-	-	-	-	-	-	-	-
1104	-	1,546,549	-	-	-	-	-	-	-	-
1110	-	744,861	-	-	-	-	-	-	-	-
1120	-	-	6,232,787	-	-	-	-	-	-	-
1130	-	(193,300)	-	-	-	-	-	-	-	-
1180	-	-	-	561,146	-	-	-	-	-	-
1200	-	-	-	-	-	2,591,285	-	-	-	-
1330	-	-	-	-	1,203,168	-	-	-	-	-
1495	-	-	-	-	-	-	-	5,447,433	-	-
1508	-	-	-	-	-	-	-	420,974	-	-
1518	-	-	-	-	-	-	-	33,455	-	-
1521	-	-	-	-	-	-	-	-	-	-
1525	-	-	-	-	-	-	-	-	-	-
1548	-	-	-	-	-	-	-	503	-	-
1550	-	-	-	-	-	-	-	-	(206,825)	-
1551	-	-	-	-	-	-	-	-	(28,149)	-
1555	-	-	-	-	-	-	-	1,181,558	(1,083,384)	-
1556	-	-	-	-	-	-	-	-	-	-
1562	-	-	-	-	-	-	-	-	-	-
1568	-	-	-	-	-	-	-	302,525	-	-
1572	-	-	-	-	-	-	-	-	-	-
1575	-	-	-	-	-	-	-	-	-	-
1580	-	-	-	-	-	-	-	-	(578,690)	-
1582	-	-	-	-	-	-	-	-	-	-
1584	-	-	-	-	-	-	-	42,944	-	-
1586	-	-	-	-	-	-	-	-	(96,870)	-
1588	-	-	-	-	-	-	-	-	(902,525)	-
1589	-	-	-	-	-	-	-	415,769	-	-
1590	-	-	-	-	-	-	-	-	-	-
1592	-	-	-	-	-	-	-	-	-	-
1595	-	-	-	-	-	-	-	273,088	(606,356)	-
1606	-	-	-	-	-	-	-	-	-	192,292
1611	-	-	-	-	-	-	-	-	-	1,128,301
1612	-	-	-	-	-	-	-	-	-	4,738
1820	-	-	-	-	-	-	-	-	-	1,332,941
1830	-	-	-	-	-	-	-	-	-	26,804,665
1835	-	-	-	-	-	-	-	-	-	9,557,133
1840	-	-	-	-	-	-	-	-	-	1,288,278
1845	-	-	-	-	-	-	-	-	-	12,390,850
1850	-	-	-	-	-	-	-	-	-	18,409,061
1855	-	-	-	-	-	-	-	-	-	628,152
1860	-	-	-	-	-	-	-	-	-	3,995,228
1905	-	-	-	-	-	-	-	-	-	1,571,819
1908	-	-	-	-	-	-	-	-	-	2,875,593
1915	-	-	-	-	-	-	-	-	-	223,148
1920	-	-	-	-	-	-	-	-	-	373,017
1930	-	-	-	-	-	-	-	-	-	2,281,911
1940	-	-	-	-	-	-	-	-	-	576,437
1955	-	-	-	-	-	-	-	-	-	641,215
1990	-	-	-	-	-	-	-	-	-	300
1995	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	1,325
2055	-	-	-	-	-	-	-	-	-	24,990,341
2105	-	-	-	-	-	-	-	-	-	(8,444,039)
2120	-	-	-	-	-	-	-	-	-	-
2160	-	-	-	-	-	-	-	-	-	(3,089,462)
2205	-	-	-	-	-	-	-	-	-	-
2220	-	-	-	-	-	-	-	-	-	-
2225	-	-	-	-	-	-	-	-	-	-
2250	-	-	-	-	-	-	-	-	-	-
2260	-	-	-	-	-	-	-	-	-	-
2290	-	-	-	-	-	-	-	-	-	-
2292	-	-	-	-	-	-	-	-	-	-
2312	-	-	-	-	-	-	-	-	-	-
2335	-	-	-	-	-	-	-	-	-	-
2350	-	-	-	-	-	-	-	-	-	-
2440	-	-	-	-	-	-	-	-	-	-
2525	-	-	-	-	-	-	-	-	-	-
2550	-	-	-	-	-	-	-	-	-	-
3005	-	-	-	-	-	-	-	-	-	-
3045	-	-	-	-	-	-	-	-	-	-
3049	-	-	-	-	-	-	-	-	-	-
9999	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-
	25,223.00	**6,307,240**	**6,232,787**	**561,146**	**1,203,168**	**2,591,285**	**-**	**8,118,249**	**(3,502,799)**	**97,733,244**

Balance Sh

	Liabilities and Shareholder's Equity											
USofA	Bank overdraft 9	Operating Loan 10	AP and Accrued Liabilities 11	Current portion of bank term loans 12	Customer deposits 13	Bank term loans 14	Note Payable 15	Future benefits 16	Deferred Revenue 20	Deferred income taxes 17	Share Capital 18	Retained Earnings 19
1005	-	-	-	-	-	-	-	-	-	-	-	-
1060	-	-	-	-	-	-	-	-	-	-	-	-
1100	-	-	-	-	-	-	-	-	-	-	-	-
1104	-	-	-	-	-	-	-	-	-	-	-	-
1110	-	-	-	-	-	-	-	-	-	-	-	-
1120	-	-	-	-	-	-	-	-	-	-	-	-
1130	-	-	-	-	-	-	-	-	-	-	-	-
1180	-	-	-	-	-	-	-	-	-	-	-	-
1200	-	-	-	-	-	-	-	-	-	-	-	-
1330	-	-	-	-	-	-	-	-	-	-	-	-
1495	-	-	-	-	-	-	-	-	-	-	-	-
1508	-	-	-	-	-	-	-	-	-	-	-	-
1518	-	-	-	-	-	-	-	-	-	-	-	-
1521	-	-	-	-	-	-	-	-	-	-	-	-
1525	-	-	-	-	-	-	-	-	-	-	-	-
1548	-	-	-	-	-	-	-	-	-	-	-	-
1550	-	-	-	-	-	-	-	-	-	-	-	-
1551	-	-	-	-	-	-	-	-	-	-	-	-
1555	-	-	-	-	-	-	-	-	-	-	-	-
1556	-	-	-	-	-	-	-	-	-	-	-	-
1562	-	-	-	-	-	-	-	-	-	-	-	-
1568	-	-	-	-	-	-	-	-	-	-	-	-
1572	-	-	-	-	-	-	-	-	-	-	-	-
1575	-	-	-	-	-	-	-	-	-	-	-	-
1580	-	-	-	-	-	-	-	-	-	-	-	-
1582	-	-	-	-	-	-	-	-	-	-	-	-
1584	-	-	-	-	-	-	-	-	-	-	-	-
1586	-	-	-	-	-	-	-	-	-	-	-	-
1588	-	-	-	-	-	-	-	-	-	-	-	-
1589	-	-	-	-	-	-	-	-	-	-	-	-
1590	-	-	-	-	-	-	-	-	-	-	-	-
1592	-	-	-	-	-	-	-	-	-	-	-	-
1595	-	-	-	-	-	-	-	-	-	-	-	-
1606	-	-	-	-	-	-	-	-	-	-	-	-
1611	-	-	-	-	-	-	-	-	-	-	-	-
1612	-	-	-	-	-	-	-	-	-	-	-	-
1820	-	-	-	-	-	-	-	-	-	-	-	-
1830	-	-	-	-	-	-	-	-	-	-	-	-
1835	-	-	-	-	-	-	-	-	-	-	-	-
1840	-	-	-	-	-	-	-	-	-	-	-	-
1845	-	-	-	-	-	-	-	-	-	-	-	-
1850	-	-	-	-	-	-	-	-	-	-	-	-
1855	-	-	-	-	-	-	-	-	-	-	-	-
1860	-	-	-	-	-	-	-	-	-	-	-	-
1905	-	-	-	-	-	-	-	-	-	-	-	-
1908	-	-	-	-	-	-	-	-	-	-	-	-
1915	-	-	-	-	-	-	-	-	-	-	-	-
1920	-	-	-	-	-	-	-	-	-	-	-	-
1930	-	-	-	-	-	-	-	-	-	-	-	-
1940	-	-	-	-	-	-	-	-	-	-	-	-
1955	-	-	-	-	-	-	-	-	-	-	-	-
1990	-	-	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-
2105	-	-	-	-	-	-	-	-	-	-	-	-
2120	-	-	-	-	-	-	-	-	-	-	-	-
2160	-	-	-	-	-	-	-	-	(831,615)	-	-	-
2205	-	-	5,800,741	-	-	-	-	-	-	-	-	-
2220	-	-	5,557,434	-	-	-	-	-	-	-	-	-
2225	-	6,850,000	-	-	-	-	-	-	-	-	-	-
2250	-	-	-	-	-	-	-	-	-	-	-	-
2260	-	-	-	455,419	-	-	-	-	-	-	-	-
2290	-	-	(33,208)	-	-	-	-	-	-	-	-	-
2292	-	-	323,776	-	-	-	-	-	-	-	-	-
2312	-	-	-	-	-	-	-	922,997	-	-	-	-
2335	-	-	1,754,374	-	828,941	-	-	-	-	-	-	-
2350	-	-	-	-	-	-	-	-	-	4,688,187	-	-
2440	-	-	25,804	-	-	-	-	-	5,574,953	-	-	-
2525	-	-	-	-	-	38,352,901	-	-	-	-	-	-
2550	-	-	-	-	-	-	16,141,969	-	-	-	-	-
3005	-	-	-	-	-	-	-	-	-	-	16,161,663	-
3045	-	-	-	-	-	-	-	-	-	-	-	21,819,007
3049	-	-	-	-	-	-	-	-	-	-	-	(7,293,583)
9999	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
	-	6,850,000	13,428,921	455,419	828,941	38,352,901	16,141,969	922,997	4,743,338	4,688,187	16,161,663	14,525,424

Balance Sh					
USofA	Totals	2.1.7	Difference between AFS and 2.1.7	Re-allocation for AFS presentation	Reference
1005	25,223	-	25,223	(25,223)	H
1060	-	-	-	-	
1100	4,209,130	4,209,130	0	0	
1104	1,546,549	1,546,549	0	-	
1110	744,861	744,859	2	-	
1120	6,232,787	6,232,787	-	-	
1130	(193,300)	(193,300)	(0)	-	
1180	561,146	561,146	(0)	-	
1200	2,591,285	2,591,285	(0)	-	
1330	1,203,168	1,203,168	(0)	-	
1495	5,447,433	5,447,433	-	-	
1508	420,974	420,974	(0)	-	
1518	33,455	33,455	0	-	
1521	-	-	-	-	
1525	-	-	-	-	
1548	503	503	0	-	
1550	(206,825)	(206,825)	0	-	
1551	(28,149)	(28,149)	(0)	-	
1555	98,174	98,174	(0)	-	
1556	-	-	-	-	
1562	-	-	-	-	
1568	302,525	302,525	(0)	-	
1572	-	-	-	-	
1575	-	-	-	-	
1580	(578,690)	(578,690)	0	-	
1582	-	-	-	-	
1584	42,944	42,944	(0)	-	
1586	(96,870)	(96,870)	0	-	
1588	(902,525)	(902,525)	(0)	-	
1589	415,769	415,769	0	-	
1590	-	-	-	-	
1592	-	-	-	-	
1595	(333,268)	(333,269)	1	-	
1606	192,292	192,292	(0)	-	
1611	1,128,301	1,128,301	(0)	-	
1612	4,738	4,738	(0)	-	
1820	1,332,941	1,332,941	(0)	-	
1830	26,804,665	26,804,665	0	-	
1835	9,557,133	9,557,133	(0)	-	
1840	1,288,278	1,288,278	(0)	-	
1845	12,390,850	12,390,850	(0)	-	
1850	18,409,061	18,409,060	1	-	
1855	628,152	628,152	(0)	-	
1860	3,995,228	3,995,228	0	-	
1905	1,571,819	1,571,819	(0)	-	
1908	2,875,593	2,875,593	(0)	-	
1915	223,148	223,148	0	-	
1920	373,017	373,017	(0)	-	
1930	2,281,911	2,281,910	1	0	
1940	576,437	576,437	0	-	
1955	641,215	641,215	(0)	-	
1990	300	300	(0)	-	
1995	-	-	-	-	
2050	1,325	-	1,325	(1,325)	E
2055	24,990,341	24,991,666	(1,325)	1,325	E
2105	(8,444,039)	(8,444,040)	(1)	-	
2120	-	-	-	-	
2160	(3,921,077)	(3,089,464)	831,613	(831,615)	M
2205	5,800,741	(5,800,741)	(0)	-	
2220	5,557,434	(5,557,434)	(0)	-	
2225	6,850,000	(6,824,777)	(25,223)	25,223	H
2250	-	-	-	-	
2260	455,419	(18,610,817)	(18,155,398)	(18,155,398)	A
2290	(33,208)	33,207	(1)	-	
2292	323,776	(323,775)	1	-	
2312	922,997	(922,997)	(0)	-	
2335	2,583,315	(2,583,315)	(0)	-	
2350	4,688,187	(4,688,187)	-	-	
2440	5,600,757	(4,769,142)	(831,615)	831,615	M
2525	38,352,901	(20,197,502)	18,155,399	18,155,398	A
2550	16,141,969	(16,141,969)	(0)	-	
3005	16,161,663	(16,161,663)	(0)	-	
3045	21,819,007	(21,819,007)	(0)	-	
3049	(7,293,583)	7,293,583	-	-	
9999	-	-	-	-	
	-	-	-	-	
	236,369,303	2,169,779	(2)	-	0

BALANCE SHEET

Balance Sh

USofA	Balance Sheet	Mapping		Adjustments for presentation		AFS		Variance	
	Current Assets	Accounts receivable	6,307,240		6,307,240	Accounts Receeivabe	6,307,238	2	1
1005		Unbilled Revenue	6,232,787		6,232,787	Unbilled Revenue	6,232,787	-	2
1060		PILS receivable	561,146	(543,553)	17,593	Income Taxes receivable	17,593	-	3
1100		Inventory	1,203,168		1,203,168	Materials and Supplies	1,203,168	-	4
1104		Due from related companies	2,591,285		2,591,285	Due from related companies	2,591,285	-	5
1110		Prepaid exp and dep	-	543,553	543,553	Prepaid expenses	543,553	-	6
1120	Total Current Assets		*16,895,626*		*16,895,626*		*16,895,624*	2	
1130		Capital Assets	97,733,244		97,733,244	Property, plant and equipment	97,733,243	1	8
1180				2,096,805	2,096,805	Deferred Income taxes	2,096,805	-	
1200			97,733,244		99,830,049		99,830,048		
1330	Total Assets		*114,628,870*		*116,725,675*		*116,725,672*	3	
1495		Regulatory Assets	4,615,450	2,146,327	6,761,777	Regulatory Balances	6,761,777	-	7A
1508		Regulatory Assets			-			-	
1518		Total Regulatory Assets	4,615,450		6,761,777		6,761,777	-	
1521	Total Assets and regulatory balances		*119,244,320*		*123,487,452*		*123,487,449*	3	
1525	Liabilities	Bank indebtedness	-		-	Bank overdraft	6,824,777	(6,824,777)	9
1548		Operating Loan	6,850,000	(25,223)	6,824,777			6,824,777	
1550		AP and Accrued Liabilities	13,428,921		13,428,921	AP and Accrued Liabilities	13,347,941	80,980	11
1551		Current portion of bank term loans	455,419	18,155,398	18,610,817	Current portion of bank term lo	18,610,817	-	12
1555		Current Portion of Consumer Deposits	828,941		828,941	Customer deposits	884,157	(55,216)	13
1556	Total Current Liabilities		*21,563,281*		*39,693,456*		*39,667,692*	25,764	
1562		Bank term loans	38,352,901	(18,155,398)	20,197,503	Bank term loans	20,197,503	-	14
1568		Note Payable	16,141,969		16,141,969	Note Payable	16,141,970	(1)	15
1572		Employee Future benefits	922,997		922,997	Employee Future benefits	922,997	-	16
1575		Deferred Revenue	4,743,338		4,743,338	Deferred Revenue	4,769,141	(25,803)	20
1580		Future Income taxes	4,688,187	2,096,805	6,784,992	Deferred Income taxes	6,784,992	-	17
1582	Total non-current liabilities		*64,849,392*		*48,790,799*		*48,816,603*	(25,804)	
1584	Total liabilities		*86,412,673*		*88,484,255*		*88,484,295*	(40)	
1586	Shareholder's Equity	Capital Stock	16,161,663	-	16,161,663	Share Capital	16,161,663	-	18
1588		Retained Earnings	14,525,424		14,525,424	Retained Earnings	16,897,161	(2,371,737)	19
1589					-	Accumulated other comprehensive income (loss)	(201,997)	201,997	
1590	Total Equity		*30,687,087*		*30,687,087*		*32,856,827*	(2,169,740)	
1592	Total liabilities and equity		*117,099,760*		*119,171,342*		*121,341,122*	(2,169,780)	
1595				2,146,327	2,146,327	Regulatory Balances	2,146,327	-	7B
1606	**Total liabilities, equity and regulatory balances**		**117,099,760**		**121,317,669**		**123,487,449**	(2,169,780)	
1611									
1612									
1820									
1830									
1835									
1840									
1845									
1850									
1855									
1860									
1905									
1908									
1915									
1920									
1930									
1940									
1955									
1990									
1995									
2050									
2055									
2105									
2120									
2160									
2205									
2220									
2225									
2250									
2260									
2290									
2292									
2312									
2335									
2350									
2440									
2525									
2550									
3005									
3045									
3049									
9999									

Income Statement												
	Revenue				Operating Expenses							
USofA	Sale of Electricity	Distribution:	CDM:	Other Income:	Cost of Power Purchase:	Salaries and benefits:	Contract Services:	Material costs:	Communication costs:	Property costs:	Other costs:	Depreciation:
	1	2	3	4	5	6	7	8	9	10	11	12
4000	-	-	-	-	-	-	-	-	-	-	-	-
4006	18,296,887	-	-	-	-	-	-	-	-	-	-	-
4010	20,869,895	-	-	-	-	-	-	-	-	-	-	-
4015	10,113,634	-	-	-	-	-	-	-	-	-	-	-
4025	128,338	-	-	-	-	-	-	-	-	-	-	-
4030	22,161	-	-	-	-	-	-	-	-	-	-	-
4035	(145)	-	-	-	-	-	-	-	-	-	-	-
4060	1,052,269	-	-	-	-	-	-	-	-	-	-	-
4062	2,031,177	-	-	-	-	-	-	-	-	-	-	-
4066	3,456,454	-	-	-	-	-	-	-	-	-	-	-
4068	2,968,120	-	-	-	-	-	-	-	-	-	-	-
4075	1,363,137	-	-	-	-	-	-	-	-	-	-	-
4076	167,575	-	-	-	-	-	-	-	-	-	-	-
4080	-	10,676,660	-	-	-	-	-	-	-	-	-	-
4082	-	-	-	10,061	-	-	-	-	-	-	-	-
4084	-	-	-	96	-	-	-	-	-	-	-	-
4086	-	-	-	67,384	-	-	-	-	-	-	-	-
4210	-	-	-	208,641	-	-	-	-	-	-	-	-
4225	-	-	-	159,359	-	-	-	-	-	-	-	-
4235	-	-	-	306,110	-	-	-	-	-	-	-	-
4355	-	-	-	15,487	-	-	-	-	-	-	-	-
4375	-	-	773,681	446,074	-	-	-	-	-	-	-	-
4380	-	-	-	-	-	-	-	-	-	-	-	-
4385	-	-	-	38,791	-	-	-	-	-	-	-	-
4390	-	-	-	39,227	-	-	-	-	-	-	-	-
4398	-	-	-	2,035	-	-	-	-	-	-	-	-
4405	-	-	-	-	-	-	-	-	-	-	-	-
4705	-	-	-	-	25,384,688	-	-	-	-	-	-	-
4707	-	-	-	-	23,916,262	-	-	-	-	-	-	-
4708	-	-	-	-	1,969,357	-	-	-	-	-	-	-
4714	-	-	-	-	3,544,079	-	-	-	-	-	-	-
4716	-	-	-	-	2,972,579	-	-	-	-	-	-	-
4720	-	-	-	-	1,592,398	-	-	-	-	-	-	-
4751	-	-	-	-	145,226	-	-	-	-	-	-	-
4750	-	-	-	-	1,148,797	-	-	-	-	-	-	-
5005	-	-	-	-	-	389,819	-	-	-	-	-	-
5012	-	-	-	-	-	-	-	-	-	56,367	-	-
5016	-	-	-	-	-	54,581	133,285	-	-	-	-	-
5017	-	-	-	-	-	-	-	563	19,691	-	-	-
5020	-	-	-	-	-	492,299	-	-	-	-	-	-
5025	-	-	-	-	-	-	33,421	16,503	-	-	8,571	-
5035	-	-	-	-	-	40,729	1,173	2,281	-	-	-	-
5040	-	-	-	-	-	29,338	-	-	-	-	-	-
5045	-	-	-	-	-	-	8,157	1,544	-	-	189	-
5065	-	-	-	-	-	32,761	28,204	755	11,811	-	40	-
5085	-	-	-	-	-	-	-	-	-	16,000	-	-
5114	-	-	-	-	-	-	11,965	-	-	-	-	-
5120	-	-	-	-	-	-	23,984	-	-	-	-	-
5125	-	-	-	-	-	-	-	-	-	-	590	-
5135	-	-	-	-	-	-	236,941	126	-	-	-	-
5150	-	-	-	-	-	-	43,801	-	-	-	-	-
5175	-	-	-	-	-	-	-	27	-	-	-	-
5305	-	-	-	-	-	138,075	-	-	-	-	-	-
5310	-	-	-	-	-	-	17,910	-	-	-	-	-
5315	-	-	-	-	-	323,976	108,938	-	272,647	48,043	-	-
5320	-	-	-	-	-	493,455	6,039	-	25,094	-	-	-
5325	-	-	-	-	-	-	-	-	-	-	-	-
5330	-	-	-	-	-	-	-	-	-	-	6,783	-
5335	-	-	-	-	-	-	-	-	-	-	70,000	-
5405	-	-	-	-	-	-	-	-	-	-	151,710	-
5415	-	-	-	-	-	-	-	-	-	-	615,927	-
5420	-	-	-	-	-	-	386	-	-	-	-	-
5605	-	-	-	-	-	675,800	-	-	-	-	-	-
5610	-	-	-	-	-	517,029	-	-	-	-	-	-
5615	-	-	-	-	-	691,867	32,998	1,054	58,019	42,632	555	-
5620	-	-	-	-	-	2,067	-	-	19,800	31,552	52,317	-
5630	-	-	-	-	-	-	181,479	-	-	-	-	-
5635	-	-	-	-	-	-	-	-	-	32,745	-	-
5640	-	-	-	-	-	-	-	-	-	85,187	-	-
5645	-	-	-	-	-	15,381	-	-	35,758	-	-	-
5655	-	-	-	-	-	-	-	-	-	-	185,173	-
5660	-	-	-	-	-	-	-	-	-	-	11,988	-
5665	-	-	-	-	-	27,853	-	-	26,805	208,739	162,404	-
5675	-	-	-	-	-	2,537	-	-	-	254,553	13,604	-
5695	-	-	-	-	-	-	-	-	-	-	-	-
5705	-	-	-	306,583	-	-	-	-	-	-	-	2,359,877
6005	-	-	-	-	-	-	-	-	-	-	-	-
6035	-	-	-	-	-	-	-	-	-	-	-	-
6110	-	-	-	-	-	-	-	-	-	-	-	-
6115	-	-	-	-	-	-	-	-	-	-	-	-
6205	-	-	-	-	-	-	-	-	-	-	12,511	-
7010	-	-	-	-	-	-	-	-	-	-	-	-
7030	-	-	-	-	-	-	-	-	-	-	-	-
9040	-	-	-	-	-	-	-	-	-	-	-	-
9070	-	-	-	-	-	-	-	-	-	-	(23,347)	-
9090	-	-	-	-	-	-	-	-	-	-	-	-
3045	-	-	-	-	-	-	-	-	-	-	-	-
	60,469,503	**10,676,662**	**773,684**	**1,599,852**	**60,673,391**	**3,927,573**	**868,688**	**22,861**	**469,634**	**775,828**	**1,269,026**	**2,359,889**

Income Sta	Other								
USofA	Finance Income:	Finance Costs:	Income Tax Expense:	Net Movement in Regulatory	Totals	2.1.7	Difference between AFS and 2.1.7	Re-allocation for AFS presentation	Reference
	13	14	15	16					
4000	-	-	-	-	-	-	-		
4006	-	-	-	-	18,296,887	(14,832,655)	3,464,232	3,464,231	Z
4010	-	-	-	-	20,869,895	(20,869,894)	1	-	
4015	-	-	-	-	10,113,634	(10,113,634)	-	-	
4025	-	-	-	-	128,338	(128,339)	(1)	-	
4030	-	-	-	-	22,161	(22,161)	(0)	-	
4035	-	-	-	-	(145)	145	(0)	-	
4060	-	-	-	-	1,052,269	-	1,052,269	1,052,269	Z
4062	-	-	-	-	2,031,177	(1,969,357)	61,820	61,819	Z
4066	-	-	-	-	3,456,454	(3,456,454)	(0)	-	
4068	-	-	-	-	2,968,120	(2,968,120)	(0)	-	
4075	-	-	-	-	1,363,137	(1,148,797)	214,340	214,341	Z
4076	-	-	-	-	167,575	(145,226)	22,349	22,349	Z
4080	-	-	-	-	10,676,660	(10,676,661)	(1)	-	
4082	-	-	-	-	10,061	(10,061)	0	-	
4084	-	-	-	-	96	(96)	1	-	
4086	-	-	-	-	67,384	(67,384)	0	-	
4210	-	-	-	-	208,641	(193,924)	14,717	14,716	X
4225	-	-	-	-	159,359	(159,359)	0	-	
4235	-	-	-	-	306,110	(306,111)	(1)	-	
4355	-	-	-	-	15,487	(15,487)	0	-	
4375	-	-	-	-	1,219,755	(1,219,755)	(0)	-	
4380	-	-	-	-	-	1,129,276	1,129,276	1,129,276	C/K
4385	-	-	-	-	38,791	(38,791)	(0)	-	
4390	-	-	-	-	39,227	(39,227)	(0)	-	
4398	-	-	-	-	2,035	(2,035)	0	-	
4405	(80,373)	-	-	-	(80,373)	(80,373)	(0)	-	
4705	-	-	-	-	25,384,688	25,384,688	(0)	-	
4707	-	-	-	-	23,916,262	20,581,850	3,334,412	(3,334,412)	Z
4708	-	-	-	-	1,969,357	1,969,357	(0)	-	
4714	-	-	-	-	3,544,079	3,456,454	87,625	(87,625)	Z
4716	-	-	-	-	2,972,579	2,968,120	4,459	(4,459)	Z
4720	-	-	-	-	1,592,398	-	1,592,398	(1,592,398)	Z
4751	-	-	-	-	145,226	145,226	0	-	
4750	-	-	-	-	1,148,797	1,148,797	0	-	Z
5005	-	-	-	-	389,819	389,815	4	-	
5012	-	-	-	-	56,367	33,284	23,083	(23,083)	B
5016	-	-	-	-	187,866	187,866	(0)	-	
5017	-	-	-	-	20,254	21,334	(1,080)	1,079	B/R
5020	-	-	-	-	492,299	492,299	0	-	
5025	-	-	-	-	58,495	34,540	23,955	(23,953)	B/R
5035	-	-	-	-	44,183	31,655	12,528	(12,528)	B/R
5040	-	-	-	-	29,338	29,338	(0)	-	
5045	-	-	-	-	9,890	18,403	(8,513)	8,513	B/R
5065	-	-	-	-	73,571	79,710	(6,139)	6,140	R
5085	-	-	-	-	16,000	-	16,000	(16,000)	B
5114	-	-	-	-	11,965	11,965	(0)	-	
5120	-	-	-	-	23,984	23,984	(0)	-	
5125	-	-	-	-	590	590	-	-	
5135	-	-	-	-	237,067	237,067	0	-	
5150	-	-	-	-	43,801	43,801	0	-	
5175	-	-	-	-	27	27	0	-	
5305	-	-	-	-	138,075	138,076	(1)	-	
5310	-	-	-	-	17,910	17,909	1	-	
5315	-	-	-	-	753,604	391,285	362,319	(362,319)	K/Z
5320	-	-	-	-	524,588	524,588	(0)	-	
5325	-	-	-	-	-	-	-	-	
5330	-	-	-	-	6,783	6,783	(0)	-	
5335	-	-	-	-	70,000	70,000	0	-	
5405	-	-	-	-	151,710	-	151,710	(151,709)	C
5415	-	-	-	-	615,927	-	615,927	(615,928)	C
5420	-	-	-	-	386	386	-	-	
5605	-	-	-	-	675,800	675,801	(1)	-	
5610	-	-	-	-	517,029	517,025	4	-	
5615	-	-	-	-	827,125	863,607	(36,482)	36,484	R
5620	-	-	-	-	105,736	105,734	2	-	
5630	-	-	-	-	181,479	181,478	1	-	
5635	-	-	-	-	32,745	32,745	(0)	-	
5640	-	-	-	-	85,187	85,187	(0)	-	
5645	-	-	-	-	51,139	51,139	0	-	
5655	-	-	-	-	185,173	145,658	39,515	(39,516)	X
5660	-	-	-	-	11,988	5,837	6,151	(6,151)	C
5665	-	-	-	-	425,801	425,909	(108)	107	C
5675	-	-	-	-	270,694	270,694	(0)	-	
5695	-	-	-	-	-	-	-	-	
5705	-	-	-	-	2,053,294	2,053,294	0	-	
6005	-	1,300,082	-	-	1,300,082	1,300,082	(0)	-	
6035	-	199,060	-	-	199,060	199,060	0	-	
6110	-	-	65,412	-	65,412	65,412	-	-	
6115	-	-	400,882	-	400,882	(265,670)	666,552	(666,552)	Y/Z
6205	-	-	-	-	12,511	12,511	(0)	-	
7010	-	-	-	-	-	-	-	-	
7030	-	-	-	-	-	-	-	-	
9040	-	-	-	-	-	-	-	-	
9070	-	-	-	-	(23,347)	-	(23,347)	23,347.62	R
9090	-	-	-	-	-	-	-	-	
3045	-	-	-	(901,959)	(901,959)	(21,819,007)	20,917,048	901,959	X/Y/Z
	(80,360)	1,499,156	466,309	(901,943)	2,169,765	(2,169,779)	(14)	-	

Income Sta INCOME STATEMENT

USofA	Income Statement	Mapping		Adjustments for presentation		AFS		Variance
	Revenue	Energy Sales:	60,469,502		60,469,502	Service Revenue	60,469,502	-
4000		Distribution:	10,676,660		10,676,660	Distribution Revenue	10,676,661	1
4006		CDM:	773,681		773,681			(773,681)
4010		Other Income:	1,599,848		1,599,848	Other Income	2,373,529	773,681
4015			*73,519,691*	-	*73,519,691*		*73,519,692*	1
4025	Operating Expenses	Cost of Power Purchase:	60,673,386		60,673,386	Cost of power purchased	60,673,385	(1)
4030		Salaries and benefits:	3,927,567	151,707	4,079,274	Employee salaries and benefits	4,079,271	(3)
4035		Contract Services:	868,681	173,261	1,041,942	Contract Services	1,041,942	-
4060		Material costs:	22,853		22,853	Material Costs	22,851	(2)
4062		Communication costs:	469,625	11,594	481,219	Communication Costs	481,219	-
4066		Property costs:	775,818		775,818	Property Costs	775,817	(1)
4068		Other costs:	1,269,015	(336,562)	932,453	Other Costs	932,450	(3)
4075		Depreciation:	2,359,877		2,359,877	Depreciation	2,359,877	-
4076			*70,366,822*	-	*70,366,822*		*70,366,812*	(10)
4080	Income from operating activities		*3,152,869*		*3,152,869*		*3,152,880*	11
4082	Other	Finance Income:	80,373		80,373	Finance income	80,373	-
4084		Finance Costs:	(1,499,142)		(1,499,142)	Finance costs	(1,499,142)	-
4086	Income before income taxes		1,734,100		1,734,100		1,734,111	11
4210		Income Tax Expense:	466,294		466,294	Income Tax expense	466,294	-
4225	Net income for the year		1,267,806		1,267,806		1,267,817	11
4235		Net Movement in Regulatory Balances:	901,959		901,959	Net Movement in Regulatory Balances, net of tax	901,963	4
4355	Net income for the year and net movement in Regulatory balance		2,169,765		2,169,765		2,169,780	15
4375		Other Comprehensive Income	-		-	Other Comprehensive Income		-
4380	Total Comprehensive income for the year				2,169,765		2,169,780	15
4385								
4390								
4398								
4405								
4705								
4707								
4708								
4714								
4716								
4720								
4751								
4750								
5005								
5012								
5016								
5017								
5020								
5025								
5035								
5040								
5045								
5065								
5085								
5114								
5120								
5125								
5135								
5150								
5175								
5305								
5310								
5315								
5320								
5325								
5330								
5335								
5405								
5415								
5420								
5605								
5610								
5615								
5620								
5630								
5635								
5640								
5645								
5655								
5660								
5665								
5675								
5695								
5705								
6005								
6035								
6110								
6115								
6205								
7010								
7030								
9040								
9070								
9090								
3045								

APPENDIX 1-7: 2019 AUDITED FINANCIAL RECONCILIATION TO STATEMENTS REGULATORY FINANCIAL RESULTS

Balance Sheet

USofA	Current Assets														
	Cash and Equivalents	Accounts receivable	Unbilled Revenue	Income taxes receivable	Materials & Supplies	Due from related companies	Prepaid expenses	Regulatory Assets	Regulatory Assets	PP&E	Bank overdraft	Operating Loan	AP and Accrued Liabilities	Current portion of bank term loans	Customer deposits
	0	1	2	3	4	5	6	7A	7B	8	9	10	11	12	13
1005	15,566.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1060	258.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1100	-	4,008,859	-	-	-	-	-	-	-	-	-	-	-	-	-
1104	-	1,731,503	-	-	-	-	-	-	-	-	-	-	-	-	-
1110	-	1,675,987	-	-	-	-	-	-	-	-	-	-	-	-	-
1120	-	-	7,205,808	-	-	-	-	-	-	-	-	-	-	-	-
1130	-	(197,479)	-	-	-	-	-	-	-	-	-	-	-	-	-
1180	-	-	-	204,053	-	-	607,810	-	-	-	-	-	-	-	-
1200	-	-	-	-	-	2,602,451	-	-	-	-	-	-	-	-	-
1330	-	-	-	-	1,107,020	-	-	-	-	-	-	-	-	-	-
1495	-	-	-	-	-	-	-	5,803,055	-	-	-	-	-	-	-
1508	-	-	-	-	-	-	-	1,063,606	(1,207,510)	-	-	-	-	-	-
1518	-	-	-	-	-	-	-	37,218	-	-	-	-	-	-	-
1521	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1525	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1548	-	-	-	-	-	-	-	553	-	-	-	-	-	-	-
1550	-	-	-	-	-	-	-	-	(2,625)	-	-	-	-	-	-
1551	-	-	-	-	-	-	-	-	(29,302)	-	-	-	-	-	-
1555	-	-	-	-	-	-	-	1,181,558	(1,082,655)	-	-	-	-	-	-
1556	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1562	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1568	-	-	-	-	-	-	-	364,132	-	-	-	-	-	-	-
1572	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1575	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1580	-	-	-	-	-	-	-	-	(225,553)	-	-	-	-	-	-
1582	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1584	-	-	-	-	-	-	-	219,176	-	-	-	-	-	-	-
1586	-	-	-	-	-	-	-	75,658	-	-	-	-	-	-	-
1588	-	-	-	-	-	-	-	-	(26,427)	-	-	-	-	-	-
1589	-	-	-	-	-	-	-	-	(2,257,703)	-	-	-	-	-	-
1590	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1592	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1595	-	-	-	-	-	-	-	-	(228,123)	-	-	-	-	-	-
1606	-	-	-	-	-	-	-	-	-	192,292	-	-	-	-	-
1611	-	-	-	-	-	-	-	-	-	1,307,622	-	-	-	-	-
1612	-	-	-	-	-	-	-	-	-	4,738	-	-	-	-	-
1805	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1815	-	-	-	-	-	-	-	-	-	23,494,533	-	-	-	-	-
1820	-	-	-	-	-	-	-	-	-	1,335,509	-	-	-	-	-
1830	-	-	-	-	-	-	-	-	-	28,093,976	-	-	-	-	-
1835	-	-	-	-	-	-	-	-	-	11,182,304	-	-	-	-	-
1840	-	-	-	-	-	-	-	-	-	1,475,190	-	-	-	-	-
1845	-	-	-	-	-	-	-	-	-	13,610,648	-	-	-	-	-
1850	-	-	-	-	-	-	-	-	-	20,221,878	-	-	-	-	-

Income Statement

USofA	Revenue				Operating Expenses								Other				Totals	2.1.7	Difference between AFS and 2.1.7	Re-allocation for AFS presentation	Reference
	Sale of Electricity	Distribution:	CDM:	Other Income:	Cost of Power Purchase:	Salaries and benefits:	Contract Services:	Material costs:	Communication costs:	Property costs:	Other costs:	Depreciation:	Finance Income:	Finance Costs:	Income Tax Expense:	Net Movement in Regulatory Balances:					
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16					
4000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
4006	19,290,032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19,290,032	(19,290,032)	(0)	-	Z
4010	23,180,528	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23,180,528	(20,466,832)	2,713,696	2,713,695	Z
4015	10,300,488	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,300,488	(10,300,488)	(0)	-	Z
4025	141,737	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	141,737	(141,737)	(0)	-	Z
4030	23,441	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23,441	(23,441)	0	-	Z
4035	276	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	276	(276)	-	-	Z
4060	(2,257,544)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2,257,544)	-	(2,257,544)	(2,257,544)	Z
4062	2,005,018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,005,018	(1,854,148)	150,870	150,870	Z
4066	3,262,014	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,262,014	(3,262,014)	(0)	-	Z
4068	2,788,060	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,788,060	(2,788,060)	(0)	-	Z
4075	1,319,938	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,319,938	(1,319,938)	0	-	Z
4076	154,628	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	154,628	(148,606)	6,022	6,022	Z
4080	-	12,050,550	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12,050,550	(10,896,636)	1,153,914	1,153,917	V/DD
4082	-	-	-	14,510	-	-	-	-	-	-	-	-	-	-	-	-	14,510	(14,510)	0	3	
4084	-	-	-	139	-	-	-	-	-	-	-	-	-	-	-	-	139	(139)	(0)	-	
4086	-	-	-	68,310	-	-	-	-	-	-	-	-	-	-	-	-	68,310	(68,310)	(0)	-	
4210	-	-	-	358,735	-	-	-	-	-	-	-	-	-	-	-	-	358,735	(195,051)	163,684	163,684	X
4225	-	-	-	162,094	-	-	-	-	-	-	-	-	-	-	-	-	162,094	(162,094)	0	-	
4235	-	-	-	235,887	-	-	-	-	-	-	-	-	-	-	-	-	235,887	(224,049)	11,838	11,838	DD
4245	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(329,196)	(329,196)	(329,196)	BB
4355	-	-	-	-	-	-	-	-	-	-	(1,000)	-	-	-	-	-	(1,000)	(1,000)	(2,000)	-	
4375	-	-	686,726	409,767	-	-	-	-	-	-	-	-	-	-	-	-	1,096,493	(1,096,492)	1	-	
4380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,042,321	1,042,321	1,042,321	C/K
4385	-	-	-	39,175	-	-	-	-	-	-	-	-	-	-	-	-	39,175	(39,175)	0	-	
4390	-	-	-	45,402	-	-	-	-	-	-	-	-	-	-	-	-	45,402	(45,402)	0	-	
4398	-	-	-	(812)	-	-	-	-	-	-	-	-	-	-	-	-	(812)	812	0	-	
4405	-	-	-	-	-	-	-	-	-	-	-	-	(24,699)	-	-	-	(24,699)	(24,699)	(0)	-	
4705	-	-	-	-	29,104,878	-	-	-	-	-	-	-	-	-	-	-	29,104,878	28,559,829	545,049	(545,049)	Z
4707	-	-	-	-	21,662,977	-	-	-	-	-	-	-	-	-	-	-	21,662,977	21,662,977	(0)	-	Z
4708	-	-	-	-	1,854,148	-	-	-	-	-	-	-	-	-	-	-	1,854,148	1,854,148	0	-	Z
4714	-	-	-	-	3,389,793	-	-	-	-	-	-	-	-	-	-	-	3,389,793	3,262,014	127,779	(127,779)	Z
4716	-	-	-	-	2,858,210	-	-	-	-	-	-	-	-	-	-	-	2,858,210	2,788,060	70,150	(70,150)	Z
4720	-	-	-	-	(744,487)	-	-	-	-	-	-	-	-	-	-	-	(744,487)	-	(744,487)	744,487	Z
4751	-	-	-	-	148,606	-	-	-	-	-	-	-	-	-	-	-	148,606	148,606	0	-	Z
4750	-	-	-	-	1,533,078	-	-	-	-	-	-	-	-	-	-	-	1,533,078	1,319,938	213,140	(213,140)	Z
5005	-	-	-	-	-	379,502	-	-	-	-	-	-	-	-	-	-	379,502	379,503	(1)	-	
5012	-	-	-	-	-	-	-	-	-	74,764	-	-	-	-	-	-	74,764	21,352	53,412	(53,411)	AA
5015	-	-	-	-	-	-	-	-	1,086	-	-	-	-	-	-	-	1,086	1,086	(0)	-	
5016	-	-	-	-	-	45,046	135,769	-	-	-	-	-	-	-	-	-	180,815	180,815	0	-	
5017	-	-	-	-	-	-	-	264	29,572	-	-	-	-	-	-	-	29,836	43,143	(13,307)	13,308	R
5020	-	-	-	-	-	403,310	-	-	-	-	-	-	-	-	-	-	403,310	403,310	0	-	
5025	-	-	-	-	-	-	16,677	2,417	-	-	721	-	-	-	-	-	19,815	19,798	17	(17)	DD
5035	-	-	-	-	-	31,227	1,438	-	-	-	-	-	-	-	-	-	32,665	37,694	(5,029)	5,029	R
5040	-	-	-	-	-	49,063	-	-	-	-	-	-	-	-	-	-	49,063	49,063	0	-	
5045	-	-	-	-	-	-	6,654	218	-	-	-	-	-	-	-	-	6,872	33,385	(26,513)	26,513	R
5065	-	-	-	-	-	34,603	32,454	786	22,301	-	-	-	-	-	-	-	90,144	95,106	(4,962)	4,962	R
5085	-	-	-	-	-	-	-	-	-	17,507	-	-	-	-	-	-	17,507	-	17,507	(17,507)	R
5114	-	-	-	-	-	-	7,532	-	-	-	-	-	-	-	-	-	7,532	7,532	-	-	
5120	-	-	-	-	-	1,542	140	-	-	-	-	-	-	-	-	-	1,682	1,682	(0)	-	
5125	-	-	-	-	-	-	-	-	-	-	90	-	-	-	-	-	90	90	-	-	
5135	-	-	-	-	-	-	202,741	151	-	-	-	-	-	-	-	-	202,892	202,893	(1)	-	
5150	-	-	-	-	-	-	93,440	-	-	-	-	-	-	-	-	-	93,440	93,440	(0)	-	
5175	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5305	-	-	-	-	-	139,766	-	-	-	-	-	-	-	-	-	-	139,766	139,769	(3)	-	
5310	-	-	-	-	-	-	21,547	-	-	-	-	-	-	-	-	-	21,547	21,546	1	-	
5315	-	-	-	-	-	298,683	123,124	-	273,971	51,842	-	-	-	-	-	-	747,620	389,031	358,589	(358,591)	K/Z
5320	-	-	-	-	-	477,519	6,162	-	13,478	-	-	-	-	-	-	-	497,159	497,159	(0)	-	
5325	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5330	-	-	-	-	-	-	-	-	-	-	8,149	-	-	-	-	-	8,149	8,149	(0)	-	
5335	-	-	-	-	-	-	-	-	-	-	70,000	-	-	-	-	-	70,000	70,000	0	-	
5405	-	-	-	-	-	-	-	-	-	-	134,114	-	-	-	-	-	134,114	-	134,114	(134,115)	C
5415	-	-	-	-	-	-	-	-	-	-	552,611	-	-	-	-	-	552,611	-	552,611	(552,610)	C
5420	-	-	-	-	-	-	(386)	-	-	-	-	-	-	-	-	-	(386)	-	(386)	386	F
5605	-	-	-	-	-	760,103	-	-	-	-	-	-	-	-	-	-	760,103	760,104	(1)	-	
5610	-	-	-	-	-	520,768	-	-	-	-	-	-	-	-	-	-	520,768	520,769	(1)	-	
5615	-	-	-	-	-	702,400	35,859	1,401	66,359	50,810	905	-	-	-	-	-	857,734	929,944	(72,210)	72,211	R
5620	-	-	-	-	-	2,198	-	-	-	30,982	75,696	-	-	-	-	-	108,876	108,875	1	-	
5630	-	-	-	-	-	-	216,917	-	-	-	-	-	-	-	-	-	216,917	216,532	385	(386)	F
5635	-	-	-	-	-	-	-	-	-	53,323	-	-	-	-	-	-	53,323	53,323	-	-	
5640	-	-	-	-	-	-	-	-	-	80,905	-	-	-	-	-	-	80,905	80,905	(0)	-	
5645	-	-	-	-	-	57,893	-	-	51,891	-	-	-	-	-	-	-	109,784	109,784	0	-	
5655	-	-	-	-	-	-	-	-	-	-	169,244	-	-	-	-	-	169,244	130,481	38,763	(38,763)	X
5660	-	-	-	-	-	-	-	-	-	-	1,400	-	-	-	-	-	1,400	1,400	-	-	
5665	-	-	-	-	-	38,296	2,139	-	46,507	250,071	120,535	-	-	-	-	-	457,548	457,566	(18)	17	DD

Income Statement

USofA	Revenue				Operating Expenses								Other				Totals	2.1.7	Difference between AFS and 2.1.7	Re-allocation for AFS presentation	Reference
	Sale of Electricity	Distribution:	CDM:	Other Income:	Cost of Power Purchase:	Salaries and benefits:	Contract Services:	Material costs:	Communication costs:	Property costs:	Other costs:	Depreciation:	Finance Income:	Finance Costs:	Income Tax Expense:	Net Movement in Regulatory Balances:					
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16					
5675	-	-	-	-	-	2,517	-	-	-	265,556	16,013	-	-	-	-	-	**284,086**	222,956	**61,130**	(61,128)	AA
5695	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**	-	-	-	
5705	-	-	-	329,196	-	-	-	-	-	-	-	2,881,714	-	-	-	-	**2,552,518**	2,556,788	**(4,270)**	4,270	W/BB
6005	-	-	-	-	-	-	-	-	-	-	-	-	-	1,574,926	-	-	**1,574,926**	3,770,942	**(2,196,016)**	2,196,016	W/CC
6035	-	-	-	-	-	-	-	-	-	-	-	-	-	2,555,342	-	-	**2,555,342**	281,173	**2,274,169**	(2,274,169)	CC
6105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**	114,540	**(114,540)**	114,540	AA
6110	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,147)	-	**(3,147)**	(3,147)	-	-	
6115	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(250,643)	-	**(250,643)**	(606,265)	**355,622**	(355,622)	Y
6205	-	-	-	-	-	-	-	-	-	-	13,086	-	-	-	-	-	**13,086**	13,086	**(0)**	-	
7010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**	-	-	-	
7030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**	-	-	-	
9040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**	-	-	-	
9070	-	-	-	-	-	-	-	-	-	-	104,516	-	-	-	-	-	**104,516**	-	**104,516**	(104,515)	R
9090	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**	-	-	-	
3045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	930,392	**930,392**	(23,988,787)	**24,919,179**	(930,392)	V/W/X/Y/Z
	60,208,616	**12,050,550**	**686,726**	**1,662,403**	**59,807,203**	**3,944,436**	**902,207**	**5,237**	**505,165**	**875,760**	**1,266,080**	**2,881,714**	**(24,699)**	**4,130,268**	**(253,790)**	**930,392**	**(363,678)**	**361,681**	**(1,997)**	**3**	
				74,608,295								**70,187,802**				**4,782,171**					

Income Stat INCOME STATEMENT

USofA	Income Statement	Mapping		Adjustments for presentation		AFS		Variance
4000	Revenue	Energy Sales:	60,208,616		60,208,616	Sale of electricity	60,208,617	1
4006		Distribution:	12,050,550		12,050,550	Distribution Revenue	12,050,552	2
4010		CDM:	686,726	(686,726)	0			(0)
4015		Other Income:	1,662,403	686,726	2,349,129	Other Income	2,349,129	0
4025			***74,608,295***	-	***74,608,295***		***74,608,298***	3
4030	Operating Expenses	Cost of Power	59,807,203		59,807,203	Cost of power purchased	59,807,204	1
4035		Salaries and benefits:	3,944,436	134,115	4,078,551	Employee salaries and benefi	4,078,557	6
4060		Contract Services:	902,207	140,499	1,042,706	Contract Services	1,042,708	2
4062		Material costs:	5,237		5,237	Material Costs	5,237	-
4066		Communication costs:	505,165	5,181	510,346	Communication Costs	510,343	(3)
4068		Property costs:	875,760		875,760	Property Costs	875,758	(2)
4075		Other costs:	1,266,080	(279,795)	986,285	Other Costs	986,285	0
4076		Depreciation:	2,881,714		2,881,714	Depreciation	2,881,715	1
4080			***70,187,802***	-	***70,187,802***		***70,187,807***	5
4082	Income from operating activities		***4,420,493***		***4,420,493***		***4,420,491***	(2)
4084	Other	Finance Income:	24,699		24,699	Finance income	24,699	-
4086		Finance Costs:	(4,130,268)		(4,130,268)	Finance costs	(4,130,268)	-
4210	Income before income taxes		**314,924**		**314,924**		**314,922**	(2)
4225		Income Tax Expense: -	253,790		(253,790)	Income Tax expense	(253,790)	-
4235	Net income for the year		**568,714**		**568,714**		**568,712**	(2)
4245		Net Movement in Regulatory Balances:	(930,392)		(930,392)	Net Movement in Regulatory Balances, net of	(930,393)	(1)
4355	Net income for the year and net movement in Regul -		**361,678**		**(361,678)**		**(361,681)**	(3)
4375		Other Comprehensive Ir	-		-	Other Comprehensive Income		-
4380	**Total Comprehensive income for the year**				**(361,678)**		**(361,681)**	(3)
4385								-
4390								
4398								
4405								
4705								
4707								
4708								
4714								
4716								
4720								
4751								
4750								
5005								
5012								
5015								
5016								
5017								
5020								
5025								
5035								
5040								
5045								
5065								
5085								
5114								
5120								
5125								
5135								
5150								
5175								
5305								
5310								
5315								
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5330								
5335								
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5640								
5645								
5655								
5660								
5665								

Balance Sheet

USofA	Cash and Equivalents	Accounts receivable	Unbilled Revenue	Income taxes receivable	Materials & Supplies	Due from related companies	Prepaid expenses	Regulatory Assets	Regulatory Assets	PP&E	Bank overdraft	Operating Loan	AP and Accrued Liabilities	Current portion of bank term loans	Customer deposits
	Current Assets														
	0	1	2	3	4	5	6	7A	7B	8	9	10	11	12	13
1855	-	-	-	-	-	-	-	-	-	796,614	-	-	-	-	-
1860	-	-	-	-	-	-	-	-	-	4,633,540	-	-	-	-	-
1905	-	-	-	-	-	-	-	-	-	1,571,819	-	-	-	-	-
1908	-	-	-	-	-	-	-	-	-	2,976,086	-	-	-	-	-
1915	-	-	-	-	-	-	-	-	-	223,620	-	-	-	-	-
1920	-	-	-	-	-	-	-	-	-	452,122	-	-	-	-	-
1930	-	-	-	-	-	-	-	-	-	2,374,031	-	-	-	-	-
1940	-	-	-	-	-	-	-	-	-	612,506	-	-	-	-	-
1955	-	-	-	-	-	-	-	-	-	667,939	-	-	-	-	-
1990	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	1,325	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	4,867,252	-	-	-	-	-
2105	-	-	-	-	-	-	-	-	-	(10,996,155)	-	-	-	-	-
2120	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2160	-	-	-	-	-	-	-	-	-	(3,638,523)	-	-	-	-	-
2205	-	-	-	-	-	-	-	-	-	-	-	-	4,036,988	-	-
2215	-	-	-	-	-	-	-	-	-	-	-	-	273,579	-	-
2220	-	-	-	-	-	-	-	-	-	-	-	-	5,667,294	-	-
2225	-	-	-	-	-	-	-	-	-	-	-	7,530,000	-	-	-
2250	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2260	-	-	-	-	-	-	-	-	-	-	-	-	-	961,904	-
2290	-	-	-	-	-	-	-	-	-	-	-	-	(28,128)	-	-
2292	-	-	-	-	-	-	-	-	-	-	-	-	357,207	-	-
2312	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2335	-	-	-	-	-	-	-	-	-	-	-	-	1,734,630	-	669,580
2350	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2440	-	-	-	-	-	-	-	-	-	-	-	-	67,906	-	-
2520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2525	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2550	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3005	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9999	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	15,824.00	7,218,870	7,205,808	204,053	1,107,020	2,602,451	607,810	8,744,956	(5,059,898)	105,461,166	-	7,530,000	12,109,476	961,904	669,580
							18,961,836			128,108,060					21,270,960

Balan

Liabilities and Shareholder's Equity

USofA	Bank term loans 14	Note Payable 15	Employee Future benefits 16	Deferred Revenue 20	Derivative Liability 21	Deferred income taxes 17	Share Capital 18	Retained Earnings 19	Totals	2.1.7	Difference between AFS and 2.1.7	Re-allocation for AFS presentation	Reference
1005	-	-	-	-	-	-	-	-	15,566	-	15,566	(15,565)	H
1060	-	-	-	-	-	-	-	-	258	-	258	(258)	H
1100	-	-	-	-	-	-	-	-	4,008,859	4,008,859	(0)	0	
1104	-	-	-	-	-	-	-	-	1,731,503	1,731,503	0	-	
1110	-	-	-	-	-	-	-	-	1,675,987	1,675,985	2	-	
1120	-	-	-	-	-	-	-	-	7,205,808	7,205,808	-	-	
1130	-	-	-	-	-	-	-	-	(197,479)	(197,479)	0	-	
1180	-	-	-	-	-	-	-	-	811,863	811,863	0	-	
1200	-	-	-	-	-	-	-	-	2,602,451	2,602,450	1	-	
1330	-	-	-	-	-	-	-	-	1,107,020	1,107,039	(19)	19	DD
1495	-	-	-	-	-	-	-	-	5,803,055	5,803,055	-	-	
1508	-	-	-	-	-	-	-	-	(143,904)	(143,904)	(0)	-	
1518	-	-	-	-	-	-	-	-	37,218	37,218	0	-	
1521	-	-	-	-	-	-	-	-	-	-	-	-	
1525	-	-	-	-	-	-	-	-	-	-	-	-	
1548	-	-	-	-	-	-	-	-	553	553	0	-	
1550	-	-	-	-	-	-	-	-	(2,625)	(2,625)	0	-	
1551	-	-	-	-	-	-	-	-	(29,302)	(29,302)	(0)	-	
1555	-	-	-	-	-	-	-	-	98,903	98,903	(0)	-	
1556	-	-	-	-	-	-	-	-	-	-	-	-	
1562	-	-	-	-	-	-	-	-	-	-	-	-	
1568	-	-	-	-	-	-	-	-	364,132	364,132	(0)	-	
1572	-	-	-	-	-	-	-	-	-	-	-	-	
1575	-	-	-	-	-	-	-	-	-	-	-	-	
1580	-	-	-	-	-	-	-	-	(225,553)	(225,553)	0	-	
1582	-	-	-	-	-	-	-	-	-	-	-	-	
1584	-	-	-	-	-	-	-	-	219,176	219,176	(0)	-	
1586	-	-	-	-	-	-	-	-	75,658	75,658	0	-	
1588	-	-	-	-	-	-	-	-	(26,427)	(26,427)	(0)	-	
1589	-	-	-	-	-	-	-	-	(2,257,703)	(2,257,703)	0	-	
1590	-	-	-	-	-	-	-	-	-	-	-	-	
1592	-	-	-	-	-	-	-	-	-	-	-	-	
1595	-	-	-	-	-	-	-	-	(228,123)	(228,124)	1	-	
1606	-	-	-	-	-	-	-	-	192,292	192,292	(0)	-	
1611	-	-	-	-	-	-	-	-	1,307,622	1,307,622	0	-	
1612	-	-	-	-	-	-	-	-	4,738	4,738	(0)	-	
1805	-	-	-	-	-	-	-	-	-	980,479	(980,479)	980,479	EE
1815	-	-	-	-	-	-	-	-	23,494,533	23,494,533	(0)	-	
1820	-	-	-	-	-	-	-	-	1,335,509	1,335,509	0	-	
1830	-	-	-	-	-	-	-	-	28,093,976	28,093,976	(0)	-	
1835	-	-	-	-	-	-	-	-	11,182,304	11,182,303	(1)	-	
1840	-	-	-	-	-	-	-	-	1,475,190	1,475,190	0	-	
1845	-	-	-	-	-	-	-	-	13,610,648	13,610,647	(1)	-	
1850	-	-	-	-	-	-	-	-	20,221,878	20,221,878	0	-	

Balan

USofA	Bank term loans	Note Payable	Employee Future benefits	Deferred Revenue	Derivative Liability	Deferred income taxes	Share Capital	Retained Earnings	Totals	2.1.7	Difference between AFS and 2.1.7	Re-allocation for AFS presentation	Reference
	Liabilities and Shareholder's Equity												
	14	15	16	20	21	17	18	19					
1855	-	-	-	-	-	-	-	-	796,614	796,614	0	-	
1860	-	-	-	-	-	-	-	-	4,633,540	4,633,541	1	-	
1905	-	-	-	-	-	-	-	-	1,571,819	591,341	980,478	(980,479)	EE
1908	-	-	-	-	-	-	-	-	2,976,086	2,976,086	(0)	-	
1915	-	-	-	-	-	-	-	-	223,620	223,620	0	-	
1920	-	-	-	-	-	-	-	-	452,122	452,122	0	-	
1930	-	-	-	-	-	-	-	-	2,374,031	2,374,030	1	0	
1940	-	-	-	-	-	-	-	-	612,506	612,506	0	-	
1955	-	-	-	-	-	-	-	-	667,939	667,939	(0)	-	
1990	-	-	-	-	-	-	-	-	300	300	(0)	-	
1995	-	-	-	-	-	-	-	-	-	-	-	-	
2050	-	-	-	-	-	-	-	-	1,325	-	1,325	(1,325)	E
2055	-	-	-	-	-	-	-	-	4,867,252	4,868,577	(1,325)	1,325	E
2105	-	-	-	-	-	-	-	-	(10,996,155)	(10,996,157)	(2)	-	
2120	-	-	-	-	-	-	-	-	-	-	-	-	
2160	-	-	-	(1,160,811)	-	-	-	-	(4,799,334)	(3,638,523)	1,160,811	(1,160,811)	M
2205	-	-	-	-	-	-	-	-	4,036,988	(4,036,988)	0	-	
2215	-	-	-	-	-	-	-	-	273,579	(273,579)	-	-	
2220	-	-	-	-	-	-	-	-	5,667,294	(5,667,313)	19	(19)	DD
2225	-	-	-	-	-	-	-	-	7,530,000	(7,514,177)	(15,823)	15,823	H
2250	-	-	-	-	-	-	-	-	-	-	-	-	
2260	-	-	-	-	-	-	-	-	961,904	(4,103,874)	(3,141,970)	3,141,970	A
2290	-	-	-	-	-	-	-	-	(28,128)	28,128	(0)	-	
2292	-	-	-	-	-	-	-	-	357,207	(357,206)	1	-	
2312	-	-	940,114	-	-	-	-	-	940,114	(940,114)	(0)	-	
2335	-	-	-	-	-	-	-	-	2,404,210	(2,404,209)	1	-	
2350	-	-	-	-	-	4,437,544	-	-	4,437,544	(4,437,544)	-	-	
2440	-	-	-	6,188,766	-	-	-	-	6,256,672	(5,095,861)	(1,160,811)	1,160,811	M
2520	-	-	-	-	-	-	-	-	-	(2,274,169)	(2,274,169)	2,274,169	CC
2525	46,614,471	-	-	-	-	-	-	-	46,614,471	(46,614,471)	(0)	-	
2550	-	16,141,969	-	-	2,274,169	-	-	-	18,416,138	(12,999,999)	5,416,139	(5,416,139)	A/CC
3005	-	-	-	-	-	-	16,161,663	-	16,161,663	(16,161,663)	(0)	-	
3045	-	-	-	-	-	-	-	23,988,787	23,988,787	(23,988,787)	0	-	
3049	-	-	-	-	-	-	-	(8,387,899)	(8,387,899)	8,387,899	-	-	
9999	-	-	-	-	-	-	-	-	-	-	-	-	
	-	-	-	-	-	-	-	-	-	-	-	-	
	46,614,471	16,141,969	940,114	5,027,955	2,274,169	4,437,544	16,161,663	15,600,888	256,577,793	(361,680)	5	-	
						75,436,222		31,762,551					

Balan BALANCE SHEET

USofA

	Balance Sheet	Mapping		Adjustments for presentation		AFS		Variance
1005	Current Assets	Accounts receivable	7,218,870		7,218,870	Accounts Receivable	7,218,868	2
1060		Cash and Equivalents	15,824	(15,824)	-			-
1100		Unbilled Revenue	7,205,808		7,205,808	Unbilled Revenue	7,205,808	-
1104		PILS receivable	204,053		204,053	Income Taxes receivable	204,053	-
1110		Inventory	1,107,020		1,107,020	Materials and Supplies	1,107,020	-
1120		Due from related companies	2,602,451		2,602,451	Due from related companies	2,602,450	1
1130		Prepaid exp and dep	607,810		607,810	Prepaid expenses	607,810	-
1180	Total Current Assets		*18,961,836*		*18,946,012*		*18,946,009*	3
1200		Capital Assets	105,461,166		105,461,166	Property, plant and equipment	105,461,163	3
1330				5,192,078	5,192,078	Deferred Income taxes	5,192,078	-
1495			105,461,166		110,653,244		110,653,241	
1508	Total Assets		*124,423,002*		*129,599,256*		*129,599,250*	6
1518		Regulatory Assets	3,685,058	2,913,638	6,598,696	Regulatory Balances	6,598,695	1
1521		Regulatory Assets			-			-
1525		Total Regulatory Assets	3,685,058		6,598,696		6,598,695	1
1548	Total Assets and regulatory balances		*128,108,060*		*136,197,952*		*136,197,945*	7
1550	Liabilities	Bank indebtedness	-		-	Bank overdraft	7,514,177	(7,514,177)
1551		Operating Loan	7,530,000	(15,824)	7,514,176			7,514,176
1555		AP and Accrued Liabilities	12,109,476		12,109,476	AP and Accrued Liabilities	12,109,515	(39)
1556		Current portion of bank term loans	961,904	3,141,970	4,103,874	Current portion of bank term loans	4,103,874	-
1562		Current Portion of Consumer Deposits	669,580		669,580	Customer deposits	669,580	-
1568	Total Current Liabilities		*21,270,960*		*24,397,106*		*24,397,146*	(40)
1572		Bank term loans	46,614,471		46,614,471	Bank term loans	46,614,471	-
1575		Note Payable	16,141,969	(3,141,970)	12,999,999	Note Payable	13,000,000	(1)
1580		Employee Future benefits	940,114		940,114	Employee Future benefits	940,114	-
1582		Deferred Revenue	5,027,955		5,027,955	Deferred Revenue	5,027,955	-
1584				2,274,169	2,274,169	Derivative Liability	2,274,169	-
1586		Future Income taxes	4,437,544	5,192,078	9,629,622	Deferred Income taxes	9,629,622	-
1588	Total non-current liabilities		*73,162,053*		*77,486,330*		*77,486,331*	(1)
1589	Total liabilities		*94,433,013*		*101,883,436*		*101,883,477*	(41)
1590	Shareholder's Equity	Capital Stock	16,161,663	-	16,161,663	Share Capital	16,161,663	-
1592		Retained Earnings	15,600,888		15,600,888	Retained Earnings	15,441,164	159,724
1595					-	Accumulated other comprehensive income (loss)	(201,997)	201,997
1606	Total Equity		*31,762,551*		*31,762,551*		*31,400,830*	361,721
1611	Total liabilities and equity		*126,195,564*		*133,645,987*		*133,284,307*	361,680
1612				2,913,638	2,913,638	Regulatory Balances	2,913,638	-
1805	Total liabilities, equity and regulatory balances		**126,195,564**		**136,559,625**		**136,197,945**	361,680

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1830
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1850