Appendices

ADMINISTRATION (2.1.6)

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, 2016.

Applicant's Name:	Halton Hills Hydro Inc.
Applicant's Address for Service:	43 Alice St. Halton Hills (Acton), ON L7J 2A9 (519) 853-3701
	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 Tel: (519) 853-3700, ext. 208 Fax: (519) 853-5592 Email: dsmelsky@haltonhillshydro.com
Primary Application Contact:	David J. Smelsky, CPA, CMA (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	
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1) Introduction

a) 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 within the municipal boundaries of the Town of Halton Hills.

b) The Applicant hereby applies to the Ontario Energy Board (the "Board") pursuant to Section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2016. A list of specific requested approvals is set out in this Exhibit 1.

c) The Application has been prepared pursuant to the Board Renewed Regulatory Framework for Electricity Distributors as detailed in the Report of the Board dated October 18, 2013 (the "RRFE").

d) The Applicant transitioned to MIFRS in its last Cost of Service application in 2012 (EB-2011-0271). HHHI has prepared this 2016 Cost of Service Application entirely on a MIFRS basis.

e) Unless specifically stated otherwise in the Application, the Applicant followed Chapter 2 of the Board's Filing Requirements for Electricity Distribution Rate Applications last revised on July 16, 2015 (the "Filing Requirements") in preparing this Application.

f) The Applicant has prepared a Consolidated Distribution System Plan ("DSP"), filed in Exhibit 2, in accordance with Chapter 5 of the Board's Filing Requirements.

g) This Application has been prepared using the default Working Capital Allowance for the 2016 Rate Year of 7.5% in accordance with the Board Policy recently published on June 3, 2015. Given the fact that this change in Board Policy is relatively recent, HHHI is still in the process of assessing the impact of the policy, and reserves the right to subsequently submit evidence in support of an HHHI-specific working capital allowance, supported by a lead-lag study.

2) Proposed Distribution Rates and Other Charges

a) The Schedule of Rates and Charges proposed in this Application is set out in Exhibit 8, and the material being filed in support of this Application sets out HHHI's approach to its distribution rates and charges.

3) Proposed Effective Date of Rate Order

a) The Applicant requests that the Board make its Rate Order effective May 1, 2016 in accordance with the Filing Requirements.

4) The Proposed Distribution Rates and Other Charges are Just and Reasonable

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

   i) The proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

   ii) The proposed adjusted rates are necessary to meet the Applicant's Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILs") requirements;

   iii) The other service charges proposed by the Applicant are the same as those previously approved by the Board; and

   iv) Such other grounds as may be set out in the material accompanying this Application Summary.

5) Relief Sought

a) The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in Exhibit 8 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2016.

6) Form of Hearing Requested

a) The Applicant requests that this Application be disposed of by way of a written hearing.

DATED at Halton Hills, Ontario, this 28th day of August, 2015.

All of which is respectfully submitted,

Arthur A. Skidmore, CPA, CMA
President & Chief Executive Officer
Halton Hills Hydro Inc.

David J. Smelsky, CPA, CMA
Chief Financial Officer
Halton Hills Hydro Inc.

Specific Approvals Requested

In this proceeding, HHHI is requesting the following approvals:

1. Approval to charge distribution rates effective May 1, 2016 to recover a service revenue requirement of $12,472,736 which includes a revenue deficiency of $2,209,583 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 Exhibit 2.

3. Approval of revised low voltage rates as proposed and described in Exhibit 8.

4. Approval to adjust the Retail Transmission Rates – Network and Connection as detailed in Exhibit 8.

5. Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of HHHI's 2015 Distribution Rates (EB-2014-0079) or updated values as provided by the Board after such time as the Decision and Order was issued.

6. Approval to continue the Specific Service Charges and Transformer Allowance approved in the Board Decision and Order in the matter of HHHI's 2015 Distribution Rates (EB-2014-0079).

7. Approval of the proposed loss factors as detailed in Exhibit 8.

8. Approval of the rate riders for two year disposition of the Group 1 and Group 2 and Other Deferral and Variance Accounts as detailed in Exhibit 9.

9. Approval of the rate riders for two year disposition of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") credit balance for lost revenue from 2012 to 2014 resulting from 2012 to 2014 Independent Electricity System Operator

("IESO") (formerly the Ontario Power Authority ("OPA")) programs as detailed in Exhibit 4.

10. Approval to continue or discontinue Deferral and Variance Accounts as detailed in Exhibit 9.

11. Approval to continue to charge Hydro One Networks Inc. ("HONI"), an Embedded Distributor, the rates for the General Service 1,000 kW to 4,999 kW rate class. The evidence for this proposal is provided in Exhibit 7.

Proposed Effective Date of Rate Order

1. The Applicant requests that the Board make its Rate Order effective May 1, 2016 in accordance with the Filing Requirements.

2. In the event that the Board is unable to provide a Decision and Order in this application for implementation by the Applicant as of May 1, 2016, the Applicant requests that the Board declare its current rates interim, effective May 1, 2016, pending the implementation of the Board's Rate Order for the 2016 rate year.

Form of Hearing

The Applicant requests that this Application be disposed of by way of a written hearing as a written hearing is more cost effective for both HHHI and its customers.

Publication Information

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 at the following internet address:

http://www.haltonhillshydro.com

As HHHI is fully engaged with social media, HHHI will also communicate the internet address to its customers through social media accounts on Facebook, Twitter and LinkedIn at the contacts below:

Facebook: https://www.facebook.com/haltonhillshydro

Twitter: twitter.com/HHHydro

LinkedIn: https://www.linkedin.com/company/halton-hills-hydro

Statement regarding Conditions of Service

The current version of HHHI's Condition of Service is publicly available for on-line viewing, printing and downloading from HHHI's website at www.haltonhillshydro.com. The Conditions of Service are periodically updated to keep current and in accordance with updated regulatory and policy imperatives. There are no changes being proposed to HHHI's Conditions of Service resulting from this Application.

Certification

I, Arthur A. Skidmore, President and Chief Executive Officer of Halton Hills Hydro Inc., certify that the evidence filed is accurate, consistent, and complete to the best of my knowledge.

Arthur A. Skidmore, CPA, CMA
President and Chief Executive Officer

Statement of Deviations

HHHI has not, to the best of its knowledge, deviated from the Board's current version of the Filing Requirements for Electricity Distribution Rate Applications.

Statement of Changes to Methodologies

The pro-forma projections for the 2016 Test Year have been prepared in accordance with HHHI's best practices.

Identification of Board Directives from Previous Board Decisions

<u>2012 COS – EB-2011-0271 – Partial Settlement Agreement</u>

1) Section 2.1, third bullet, of the Partial Settlement Agreement states:

"There shall be an asymmetrical sharing arrangement with respect to capital expenditures for two projects forecast for 2012: (a) the Steeles Avenue – Trafalgar Rd to 5th Line South (Phase 2 – Stage 2)(capital cost of $496,638); and (b) Pole Relocations on Steeles Avenue between Winston Churchill Boulevard and Trafalgar Road (capital cost of $1,047,701) (collectively the "Steeles Avenue Projects"). The Parties have agreed to include the impact of the Steeles Avenue Projects in the Test Year revenue requirement. However, the Parties have also agreed that, in the event that the Steeles Avenue Projects are not closed to rate base in the Test Year, or if the overall capital cost is less than the amount forecasted, the revenue requirement impact will be credited to the asymmetrical variance account established for this purpose (the "Steeles Avenue Capital Addition Variance Account"). This account would provide for the return to customers of the revenue requirement impact related to the difference between the $1,544,339 of forecast capital expenditures on these two projects, and the actual capital expenditures of these two projects closed to rate base in 2012. The Steeles Ave Capital Additions Variance Account would record the difference in all components of annual

> *revenue requirement (including, but not limited to, depreciation, interest, return on equity and PILs) resulting from any under-spending on capital expenditures for these two projects closed to rate base in the Test Year. That is, if the capital expenditures closed to rate base in 2012 are less than $1,544,339 on these two projects, the revenue requirement impact of the shortfall will be calculated and credited to the variance account in each year (between 2012 and HHH's next rebasing application) that the underspending on these two projects persists. For example, if the projects are completed in 2012 but come in under budget by $300,000, then the variance account will capture the revenue requirement impact of removing that $300,000 of capital spending from 2012, including the impact in 2013 to 2015. The account would be subject to disposition in accordance with the Board's normal policies from time to time on the disposition of applicable variance accounts.".*

The Board approved the Partial Settlement Agreement at the Oral Hearing in proceeding EB-2011-0271 (page 1, lines 15 to 18, transcript vol.1). While the Board did not specifically issue a directive, HHHI has treated this section of the Partial Settlement as such. The recording and treatment of the asymmetrical account is discussed in further detail in Exhibit 2.

<u>2013 IRM – EB-2012-0130</u>

There were no Board directives issued in proceeding EB-2012-0130.

<u>2014 IRM – EB-2013-0136</u>

1) Group 1 disposition – The balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the transfer must be the same as the effective date for the associated rates, generally, the start of the rate year.

HHHI will ensure these adjustments are included in the reporting period ending June 30, 2014 (Quarter 2).

HHHI recorded this disposition in May 2014.

2) Shared Tax Savings Adjustment – The Board directed HHHI to record the tax sharing refund of $2,913 in Variance Account 1595 by June 30, 2014 for disposition at a future date.

HHHI recorded this disposition in May 2014.

2014 Z- Factor Application – EB-2014-0211

1) Extraordinary Event Costs – The Board directed HHHI to transfer the final balance from Account 1572 "Extraordinary Event Costs" to separate sub-accounts of Account 1595 applicable to principal and interest carrying charges. The use of Account 1595 "Disposition and Recovery of Regulatory Balances Control Account" will allow the difference between the approved claim and the amount collected from the fixed rate riders to be tracked.

HHHI recorded this disposition in January 2015.

2015 IRM – EB-2014-0079

1) Group 1 disposition –The balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595. Such transfer shall be pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors,* effective January 1, 2012. The date of the transfer must be the same as the effective date for the associated rates, which is, generally, the start of the rate year. Halton Hills Hydro should ensure these adjustments are included in the reporting period ending June 30, 2015 (Quarter 2).

HHHI recorded this disposition in May 2015.

2) Shared Tax Savings Adjustment – The Board directed HHHI to record the tax sharing refund of $4,696 in Variance Account 1595 by June 30, 2015 for disposition at a future date.

EB-2015-0074

HHHI recorded this disposition in May 2015.

MANAGEMENT DISCUSSION AND ANALYSIS (2.1.1)

Strategic Objectives and Key Initiatives

HHHI is a progressive electric distribution utility which owns and operates the electricity distribution system within its licensed service area (280 square kilometres extending to the municipal boundaries of the Town of Halton Hills, of which 255 square kilometres or 91 per cent is a rural distribution system).

HHHI's success is built on the following:

1. "Best in Class"
   Utilizing the Board's Scorecard, HHHI will monitor our performance in key areas as compared to other utilities. HHHI will continue to provide a balanced approach to prudent capital investment, exceptional customer service and meeting shareholder expectations. HHHI will continue to seek partnerships with other utilities where efficiencies, cost savings and benefits to our customers or our employees can be found. HHHI will leverage our partnerships with other utilities to deliver our Conservation Programs through to 2020.

2. "We are Community"
   In 2015, HHHI launched a new tagline: We are Community. This tagline provides a customer facing representation of our mission statement and represents our culture of being leaders in our community by delivering distribution excellence for our employees and our customers. HHHI will continue to build brand recognition that emphasizes our role in supporting the community, our customers and our employees.

3. Risk Management
   HHHI will continue to assess and monitor risks throughout the utility. Risks are reviewed on a quarterly basis with our leadership team. Business Continuity Planning will ensure HHHI is able to continue to serve customers regardless of circumstances. Utilizing HHHI's Safety Management Systems, HHHI is able to track, monitor and address safety risks throughout HHHI's operations.

4. Distribution System Planning
   HHHI's Engineering Department has completed a comprehensive Distribution System Plan which provides a five year strategy for asset management and capital expenditures to ensure HHHI is able to provide reliable supply to meet current customer's needs and accommodate future growth. The plan includes System Access, System Renewal, System Service and General Plant investments.

5. Continuous Improvement
   As HHHI continues to build on Creative and Critical thinking efforts, HHHI will continue our efforts to engage all staff in finding efficiencies and innovation throughout the organization. HHHI will strive for an environment that emphasizes teamwork, innovation and growth.

Our Mission Statement 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 – 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 HHHI provides

Financial Metrics – balancing shareholder and customer expectations, stable rate setting, reasonable rate of return

Conservation – ensuring HHHI is able to meet our energy conservation targets

Environmental – considering the environment in all of our decision making processes, finding ways to reduce waste, conserve and minimize the environmental footprint of our organization

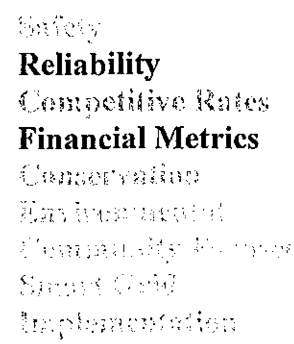
Community Focused – proud part of the Town of Halton Hills, active, visible presence in the community, exceeding customers' expectations

Smart Grid Implementation – building our distribution system with future technology in mind, ensuring HHHI is able to leverage technology for customer service, system reliability and data security

Each of the key initiatives noted below supports or builds upon these Strategic Objectives.

KEY INITIATIVES

1. TRANSFORMER STATION



The most significant capital project to be undertaken by HHHI will be the design, construction and commissioning of a new transformer station connected to the TransCanada Energy generating station.

Halton Hills is experiencing considerable load growth, particularly in south Georgetown. There are a number of development projects underway which will be adding over 1,200 new residential lots by the end of 2017 and continued commercial development in the Steeles Avenue/401 Premier Gateway corridor. As well, the Vision Georgetown project will see 20,000 new residents in Georgetown between 2020 and 2031. HHHI's transformer station project will supply this new load growth. The land purchase and station design is anticipated to be completed in 2015, construction beginning in 2016 with an in-service target date of spring 2018.

The transformer station will ensure reliability of supply for our current and future customers as Halton Hills continues to grow. Prior to undertaking this project, HHHI reviewed several options and have chosen the most cost effective solution by building the transformer station ourselves north of Highway 401. The IESO has noted (as part of the Regional Planning Process) the load growth requirements for HHHI, and in its Northwest GTA Integrated Regional Resource Plan states that: *Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018.*

2. SUCCESSION PLANNING

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

Succession planning continues to be an important focus for HHHI. To ensure successful knowledge transfer and a smooth transition, HHHI is undertaking a knowledge mapping exercise of key positions and individuals throughout the organization.

In HHHI's operations department, a succession planning strategy must include sufficient overlap to allow apprentices time to complete their formal training and gain the necessary experience to be considered as qualified replacements for journeymen linemen. This process takes eight years, so considerable planning is required. Three customer care staff are also eligible for retirement in 2016, and a new collective agreement will need to be negotiated in 2016, so even in the very short term, significant resources need to be dedicated to succession planning.

Along with succession planning, HHHI will continue to look at cross-training of core functions throughout the utility to best leverage existing staff to accomplish work more efficiently and provide greater job satisfaction to employees.

Training and succession planning form a key part of HHHI's overall human resources strategy to ensure we have the right people in the right jobs over the coming years and help us become one of the top employers in Halton Hills and Halton Region.

CONSERVATION AND DEMAND MANAGEMENT

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

In 2014, the Ministry of Energy issued the new 2015-2020 Conservation First Framework. Under this new Framework, HHHI has been allocated a target of 30.9 GWh in energy conservation. To meet this aggressive target, Conservation and Demand Management (CDM) will need to be a focus throughout the utility.

a. CDM FRAMEWORK

In 2015, HHHI filed a comprehensive CDM plan as required under the new Framework rules to achieve the conservation targets by 2020. This plan covers the 2015-2020 timeframe and encompasses a number of the standard programs targeting each of our customer classes. Ongoing training will ensure customer care staff are well-versed on the various programs, and able to promote them effectively to HHHI's customers.

b. CDM COLLABORATION WITH MILTON HYDRO

HHHI will be working in collaboration with Milton Hydro to deliver a robust, cost effective CDM program. By filing a joint application, HHHI has the opportunity for increased incentives from the IESO for achieving our targets and increased budget for program delivery. HHHI will also continue to look for opportunities to market CDM programs in collaboration with the other LDCs.

3. DISTRIBUTION SYSTEM PLAN

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

Foundational to HHHI's strategic planning for the 2016-2020 timeframe is the creation of the Distribution System Plan. This is the first time the utility has created a comprehensive five year plan encompassing asset management and capital expenditures. This plan reviews HHHI's current asset assessment and maintenance strategies and builds a comprehensive expenditure strategy that addresses asset management while planning for future growth and technological advancements and automation.

This plan formed the bases for our 2016 Cost of Service rate application. The plan is built on the principles of excellence, safety and reliability. It takes a prudent, cost effective approach to infrastructure investment and renewal to serve current and future customer preferences and requirements.

4. Customer Billing

The Board is introducing a number of changes to the way HHHI bills customers. These changes will take effect beginning in 2016. HHHI's strategy is to ensure that as these changes are implemented, HHHI communicates effectively with customers to provide them with the information they need to understand the changes and to continue to provide customer service excellence.

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

a. Monthly Billing

Beginning in 2016, HHHI will move to monthly billing for residential and small commercial customers who currently receive bimonthly bills. While there will be increased cost and workload for the utility to accommodate these changes, this will also provide a significant opportunity for increased communication with customers. HHHI will focus on promoting the electronic billing and payment options in conjunction with implementing monthly bills.

b. Restructured Residential distribution rates

The Board is introducing a new fixed rate structure for distribution rates for residential customers. The transition to fixed rate from the current mix of fixed and variable charges will take place over four years beginning in 2016. HHHI will ensure that any significant changes are clearly communicated to the affected customers and options such as equal payment plans are provided. The rate design is anticipated to be revenue neutral to the utility.

5. Creative and Critical Thinking

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

Through all of its initiatives, HHHI will continue its company-wide approach to creative and critical thinking involving all staff in finding efficiencies and innovation. As a number of staff will be retiring over the next five years, succession planning and ensuring an emphasis on teamwork, innovation and growth will be a key to achieving becoming best in class.

Launched in 2015, the "We are Community" tagline will continue to help HHHI build upon its vision as a community-focused, safe and reliable utility for the years to come.

6. Industry Review

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

The Premier's Advisory Council on Government Assets was commissioned to create recommendations on the handling of key provincial assets, including the electricity distribution sector and Hydro One. The initial report of recommendations, known as the Ed Clark Report, was presented to the government in December 2014. Key recommendations included the sale of Hydro One and recommendations for further consolidations of LDC.

In the spring of 2015, the Provincial Government adopted the recommendations of the report including creating a transfer tax exemption for the sale of utilities with less than 30,000 customers and a reduction in the transfer tax for larger utilities.

Continuing to find ways the utility can bend the cost curve will be a priority throughout the term of this strategic plan. This prudent financial approach will continue to position the utility favourably.

7. Empower

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

HHHI's Safety Management System will continue to provide employee knowledge and ongoing engagement in HHHI's safety programs. Nearly 2500 pieces of information have been rolled out so far and overall employee compliance remains above 90%.

In addition to employee compliance, HHHI will continue to roll out its Contractor Compliance program, which tracks documentation such as WSIB and Insurance certificates for contractors doing work for HHHI, and ensures contractors operate with the same high level of safety as the utility.

8. Customer Satisfaction Survey

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

Ensuring HHHI's customers continue to understand the value proposition in HHHI's rates and services is important to the utility's ongoing success. The Board now requires that distributors undertake customer satisfaction surveys on a biennial basis – so HHHI will be conducting surveys in 2016, 2018 and again in 2020.

HHHI will use this information to inform company decisions and planning, and assist in ensuring HHHI is clearly communicating with customers to meet their needs.

9. Customer Information System Review

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

HHHI's Customer Information System is the backbone to billing and communicating with customers. It contains customer billing data, and customer contact information used to track our customer service quality indicators reported to the OEB.

HHHI's current system was installed in 1997, and while it has had numerous updates and upgrades over the years, it seems prudent to undertake a review of competing products to ensure that HHHI has the best system in place. HHHI will review competing systems to look for products that have the flexibility to meet ongoing regulatory reporting requirements as well as provide flexibility to enhance customer self-service options, integration with HHHI's metering and outage management infrastructure and support conservation program tracking.

10. System Integrations in support of Smart Grid

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

Over the next five years, HHHI will undertake a number of projects which will enhance grid automation, outage management and information for customers and crews.

a. GIS Based mapping system

In 2016, HHHI will migrate away from paper based mapping to GIS based mapping throughout the organization. Through the use of tablets for crews in the field, and up to date GIS mapping, HHHI will improve reliability, outage restoration and safety for HHHI's crews.

b. System automation

HHHI will continue to build its electrical infrastructure with system automation as one of the main objectives. This will benefit customers by reducing restoration times, as well as reducing OM&A costs associated with system restoration. Substation automation will be achieved through introduction of new smart equipment when replacing aged assets. An example is the replacement of legacy oil circuit reclosers with new vacuum reclosers and communications ready controllers. Existing electronic protection relays, transformers temperature monitors and load tap changer controllers will be enabled for control through our SCADA system with new SCADA network expansions. Distribution automation will see the enablement of automated switches to allow the control room to reduce outage times.

c. DATA CONVERGENCE

Underground utility locating and GIS will undergo a convergence as new locating equipment incorporates GPS features. Locating activities will also serve to verify underground plant to support the updating of the GIS system.

HHHI will also focus on integrating our AMI data with our GIS data for enhanced outage management capabilities for HHHI's control room. This project will also provide HHHI's engineering team with enhanced data for transformer loading and load forecasting.

RRFE Annual Review and Implementation

HHHI management undertakes an annual review of its business strategy and objectives. The purpose of this review is to ensure a direct alignment between the Board's Renewed Regulatory Framework for Electricity Distributors (RRFE) and HHHI's strategic objectives. The following reflects the outcome of this review.

As noted above, HHHI's eight strategic objectives are:

- Safety; and
- Reliability; and
- Competitive Rates; and
- Financial Metrics; and
- Conservation; and
- Environment; and
- Community Focus; and
- Smart Grid Implementation.

1. ***Safety*** - HHHI has a history of providing a safe work environment for all of its employees and the public. HHHI's goal is to continue to build on HHHI's safety culture, with zero lost time injuries.

1.1 Safety Goals

a. Strive for zero lost time incidents (*RRFE – Operational Effectiveness – Safety*)
b. Provide training and education that enhances the corporate safety culture and employees' personal responsibility through HHHI's EMPOWER-Live Safe program (*RRFE – Operational Effectiveness – Safety*).
c. Remain steadfastly committed to ensure the safety of the public (*RRFE – Operational Effectiveness – Safety*).

1.2 Methodology

1.2.1 Work in partnership to deliver an ongoing safety program and safety culture.

- Conduct monthly Health and Safety meetings for outside staff
- Conduct quarterly Health and Safety meetings for inside staff
- Conduct quarterly "Regional" Health and Safety meetings with neighbouring utilities; Oakville Hydro Distribution Inc., Milton Hydro Distribution Inc.
- Conduct monthly Joint Health and Safety Committee meetings
- Provide appropriate resources and training to all new employees including contract, temporary and co-operative students.
- In late 2013, HHHI launched the "EMPOWER – Live Safe" safety program. Throughout the coming years, HHHI will continue to enhance this program and realize its benefits.
- Continue to partner with local schools within the Town of Halton Hills to offer in-class electricity safety and conservation lessons.
- Continue to provide customers with safety and power outage information through the utility website, social media, bill inserts and other media as appropriate.
- Ensure contractors working for HHHI operate to the same high level of safety standards as the utility through the Contractor Compliance program.

1.2.2 Celebrate HHHI's safety successes.

- Create a safety culture where all incidents are reported to assist in prevention, awareness and education.

1.2.3 Research and adopt new ideas and emerging trends in the industry.

1.2.4 Ensure that HHHI adapts to technological changes and new work methods that help to ensure the safety of employees.

- In 2013, HHHI installed digital signs to provide industry, safety, health and wellness information to staff and customers. HHHI will continue to leverage these signs to provide timely and relevant safety messaging to employees and customers.

- In 2015, tablets were introduced to the crews to ensure they were working with up to date electronic maps in the field.

1.2.5 HHHI will continue to build on the EMPOWER program and will continue to work in conjunction with neighbouring utilities on a region wide safety program to deliver a Best in Class strategy for employees and customers.

1.2.6 HHHI will take all reasonable precautions in the prevention of injuries and accidents in the planning of all projects. The ultimate success and efficiency of HHHI can be measured directly by the effectiveness in eliminating all injuries and losses.

2. ***Reliability*** – HHHI's customers rely on HHHI for a reliable supply of electricity, as well as service and information they can depend upon. Table 1-1 shows HHHI's system reliability measures for the five (5) most recent historical years.

Table 1-1 – Operational Effectiveness – System Reliability – Historical Measures

Service Quality Indices	Board Target	2014	2013	2012	2011	2010	5-year Average
Including Loss of Supply							
SAIDI	1.23 - 1.79	1.25	2.51	1.53	1.55	1.78	1.72
SAIFI	1.22 - 2.75	1.61	1.99	1.90	1.67	2.75	1.99
CAIDI		0.77	1.26	0.80	0.93	0.65	0.88
Excluding Loss of Supply							
SAIDI	1.23 - 1.79	1.21	2.08	1.23	1.38	1.78	1.53
SAIFI	1.22 - 2.75	1.47	1.48	1.34	1.49	2.75	1.70
CAIDI		0.82	1.41	0.91	0.93	0.65	0.94

HHHI will continue to look at ways to improve reliability, outage response and customer communication to an effort to exceed customers' expectations, and meet the 5-year average noted in the above table.

2.1 Reliability Goals

a. Proactively manage the distribution system in an effort to continually improve on reliability metrics (*RRFE – Customer Focus – Service Quality and Customer Satisfaction; Operational Effectiveness – System Reliability*).
b. Create a Distribution System Plan to ensure an ongoing, disciplined approach to capital investments (*RRFE – Operational Effectiveness – Asset Management and Cost Control; Financial Performance – Financial Ratios*).
c. Implement a three (3) year Information Technology Infrastructure strategy to ensure technological reliability and security *(RRFE – Operational Effectiveness – System Reliability; Customer Focus – Customer Satisfaction*).
d. Maximize the benefit of the Control Room partnership with Oakville Hydro Distribution Inc (*RRFE* - Operational *Effectiveness – Safety, System Reliability and Cost Control*).
e. Implement Advanced Metering Infrastructure ("AMI") upgrades, in addition to on-going GIS enhancements, to provide secure, reliable and cost effective outage management tools (*RRFE – Operational Effectiveness – System Reliability and Cost Control*).
f. Ensure staffing strategies are in place to provide continuity and competency through succession planning (*RRFE – Customer Focus – Customer Satisfaction; Operational Effectiveness – Safety, System Reliability, Asset Management and Cost Control*).
g. Track billing accuracy metrics to be used to develop improved strategies to ensure billing reliability for HHHI's customers (*RRFE – Customer Focus – Customer Satisfaction*).

2.2 Methodology

2.2.1 HHHI will plan, design and build the required Transformer Station in the 407 Prestige Industrial Park to service new load requirements.

2.2.2 HHHI will continue to make improvements to communication protocols using the experience gained during the power outages in 2013 and 2014.

2.2.3 HHHI's First Contact Resolution strategies will continue to be reviewed and refined as required.

2.2.4 Maintain compliance with all relevant Electrical Safety Authority ("ESA") standards and guidelines.

2.2.5 Leveraging on past successes from ESA 22/04 Audits, HHHI will continue to improve safety and reliability.

2.2.6 HHHI's Billing Department will track billing accuracy metrics detail to determine reasons for errors and develop processes and training to improve the metric.

2.2.7 Using technology, outage reporting and asset information, HHHI will create a plan that will address specific geographical reliability concerns.

2.2.8 HHHI will optimize its Control Room partnership with Oakville Hydro Distribution Inc. by using the expertise of the in-house GIS Technician to increase the usability of distribution system maps.

2.2.9 HHHI will continue to improve customer communication during power outages to ensure accurate and timely updates are available.

3. ***Competitive Rates*** - Rates and affordability are key issues for HHHI's customers. In a 2014 customer satisfaction survey, seventy percent (70%) of customers agreed that HHHI provided good value for money, a key outcome of the Board's RRFE.

3.1 Goals for Competitive Rates

a. Ensure accurate forecast investment requirements (*RRFE – Operational Effectiveness – Asset Management and Cost Control; Financial Performance – Financial Ratios*).

b. Continue to make improvements to deliver 'Best value' for our customers and to continue to find efficiencies (*RRFE – all outcomes*).

c. Monitor the industry in an effort to achieve growth by organic means, acquisition or regulatory reform (*RRFE – Financial Performance – Financial Ratios*).

3.2 Methodology

3.2.1 A five year Distribution System Plan will be continually updated and analyzed to ensure accurate forecast investment requirements.

3.2.2 HHHI will endeavor to maximize the tools provided in the new financial reporting system, thus improving the effectiveness of financial analysis.

3.2.3 HHHI has implemented a company-wide "Best in Class" Creative & Critical Thinking initiative that requires all employees to be accountable for continual improvement. Priorities identified through this process are addressed by departmental teams and corporately, as well as used in the Departmental Business Plans. This process was a catalyst for HHHI being awarded the Electricity Distributor Association's Performance Excellence Award for 2013 and will continue to drive improvements.

3.2.4 HHHI will look at utility merger, acquisition and divestiture options that support HHHI's overall strategy and which are aligned with the Town of Halton Hills' financial, reputational and service delivery expectations.

3.2.5 HHHI will continue to investigate and pursue new opportunities for shared services to find increased efficiencies and deliver Best in Class value for customers. An example of this is the collaboration with Oakville Hydro Electricity Distribution Inc. in managing the Control Room Operations for Halton Hills Hydro Inc.

4. ***Financial Metrics*** - Through ongoing Creative and Critical Thinking initiatives, HHHI continues to find efficiencies throughout the organization. Ensuring customers' expectations are continually exceeded while maintaining strong financial strategies will position HHHI as a best in class utility.

4.1 Financial Metrics Goals

a. Ensure the best tools are in place to identify and realize potential opportunities and mitigate potential risks (*RRFE – Financial Performance – Financial Ratios*).

b. Continue to realize financial stability in order to maintain operations, provide just and reasonable rates, allow for proper capitalization and ensure a consistent rate of return to the shareholder (*RRFE – Financial Performance – Financial Ratios*).

c. Leverage cooperative purchasing and shared service opportunities (*RRFE – Operational Effectiveness – Cost Control*).

4.2 Methodology

4.2.1 HHHI intends to utilize the new financial reporting system to improve reporting and integrate key business processes while reducing manual processing procedures.

4.2.2 HHHI will review and analyze Customer Information System ("CIS") options available to determine whether a replacement for the current CIS is required and if so, determine which vendor and product will provide the best value to

HHHI customers and shareholder. This decision will be made in coordination with an iSeries replacement (if required).

4.2.3 Leverage GridSmartCity connections to take advantage of 'Scale and Scope' group purchasing opportunities.

4.2.4 Approximately **twenty-five percent (25%)** of HHHI employees are eligible for retirement by 2020. HHHI will ensure succession planning strategies are in place to address the number of staff throughout the organization who will be eligible for retirement.

4.2.5 HHHI will complete an employee knowledge mapping exercise to ensure a successful transition between new and retiring employees.

4.2.6 HHHI will review restructuring strategies to facilitate succession planning through: regrouping of tasks to create well designed jobs; reorganizing work units to be more efficient, hiring the best people for positions while promoting from within whenever possible.

5. ***Conservation*** - in 2014, the Ministry of Energy issued the new 2015-2020 Conservation First Framework. Under this new Framework, HHHI has been allocated a target of 30.9 GWh in energy conservation. To meet this aggressive target, HHHI will make CDM a focus throughout the utility.

5.1 Conservation Goals

a. Improve conservation program delivery for low-income residential customers (*RRFE – Public Policy Responsiveness – CDM; Customer Focus – Customer Satisfaction*).

b. Engage our customers in a conversation about conservation to facilitate participation in programs (*RRFE – Public Policy Responsiveness – CDM; Customer Focus – Customer Satisfaction*).

c. Meet the annual CDM targets as set out in HHHI's CDM plan (*RRFE – Public Policy Responsiveness – CDM*).

d. Review and revise HHHI's multi-year CDM plan as required (*RRFE – Public Policy Responsiveness – CDM; Customer Focus – Customer Satisfaction*).

5.2 Methodology

5.2.1 HHHI will conduct focus groups, surveys or other means to determine what types of CDM programs customers would be interested in utilizing and the customers' preferred methods of CDM communication and delivery.

5.2.2 HHHI will continue to work with and educate contractors and vendors on the benefits and details of available CDM programs.

5.2.3 HHHI's Customer Care department will actively market CDM programs to customers.

5.2.4 HHHI will partner with other LDC's on CDM Plans, program design and delivery.

5.2.5 HHHI will develop a plan that may include knowledgeable resources to assist with the significant increase to invoicing requirements, cost efficiency testing and program tracking. The plan will also include the technical expertise of consultants and other industry experts to help deliver the initiatives in a cost effective manner.

6. ***Environment*** - Customers expect businesses to demonstrate environmental stewardship as part of their corporate social responsibility. As a community utility, it is important for HHHI to be a local leader in environmental awareness. HHHI promotes environmental awareness and energy conservation through customer communications, web and social media sites.

6.1 Environmental Goals

a. Enhance electronic customer service options (*RRFE – Customer Focus – Customer Satisfaction*).

b. Operate in an environmentally-friendly manner (*RRFE – Public Policy Responsiveness*).

c. Develop a Corporate Social Responsibility Report (*RRFE – Public Policy Responsiveness*).

d. Develop a Corporate Sustainability Strategy.

6.2 Methodology

6.2.1 HHHI will research further opportunities for environmental stewardship.

6.2.2 HHHI will monitor its operational practices including vehicle idling times and material recycling practices in its continuing effort to minimize the impact to the environment.

6.2.3 HHHI will implement suggested initiatives provided by the Corporate Sustainability Committee.

6.2.4 HHHI will actively participate in the Town of Halton Hills Green Plan, the Mayor's Community Energy Plan and the work of the Town Sustainability Advisory Committee.

7. ***Community/Customer Focus*** - HHHI has a recognized valuable "brand" in the community. In 2015, HHHI launched a new taglines to reinforce the utility brand.

   "We are Community" is a vision that was created collaboratively by employees and represents HHHI's mission statement and objectives. This tagline represents HHHI's vision of delivering "Best in Class" performance.

   "We are Reliability" represents HHHI's priorities of safety and reliability. Reliability includes helping customers the first time they call, providing customers with the tools and information they need to understand their energy bills and power usage, providing timely updates on power outages and restoration efforts and providing distribution excellence in a safe and reliable manner.

   "We are Conservation" represents HHHI's commitment to providing energy conservation programs, tools and information to help customers make wise energy choices .

   The 2014 Customer Satisfaction Survey results were comparable to the 2011 survey and at a time when provincial perceptions have created a decline in customer satisfaction, the survey results remained consistent or improved in many key areas. Of particular note, customers' rating of HHHI as a utility that "provides good value for money" increased by 10% over the 2011 results.

   7.1 Community Focus Goals

   a. Maintain a visible presence in the community including participation in community events.

   b. Develop a customer service strategy encompassing enhanced communication methods, biennial customer satisfaction surveys, improved self-service tools (*RRFE – Customer Focus – Customer Satisfaction*).

c. Maintain or exceed 90% of customer satisfaction survey respondents very or fairly satisfied (*RRFE – Customer Focus – Customer Satisfaction*).

d. Enhance brand recognition.

7.2 Methodogy

7.2.1 HHHI will continue to participate in local community events including the local Home Show, Fall Fairs and Festivals.

7.2.2 HHHI will periodically open its doors to customers through Community Open House events.

7.2.3 HHHI will continue to roll out the "We are…" taglines to reinforce HHHI's commitment to customers and the community.

7.2.4 HHHI will conduct its biennial Customer Satisfaction Survey and strive for continued improvement.

7.2.5 HHHI will investigate options to add a Live Chat option to the HHHI website.

7.2.6 HHHI will review the current AccountOnLine tool in an effort to enhance functionality and streamline the customer experience.

7.2.7 HHHI will implement a new Interactive Voice Response system which will provide enhanced self-service options for customers to report payments or moves and find important information on power outages.

8. ***Smart Grid Implementation*** – HHHI has developed a Distribution System Plan with future technology in mind, ensuring HHHI is able to leverage technology for customer service, system reliability, data security and increased efficiencies. HHHI will undertake a number of projects which will enhance grid automation, outage management and information for customers and crews.

8.1 Smart Grid Goals

a. Fully utilize the existing GIS system (*RRFE – Customer Focus – Customer Satisfaction; Operational Effectiveness – Safety, System Reliability, Asset Management and Cost Control*).

b. Continued replacement of aged assets with automation solutions where the solution provides value to customers (*RRFE – Operational Effectiveness – System Reliability, Asset Management and Cost Control*).

c. Ensure internal data is being collected and utilized in a safe, private and effective manner *(RRFE – Operational Effectiveness – System Reliability; Customer Focus – Customer Satisfaction*).

8.2 Methodology

8.2.1 HHHI will migrate away from paper based mapping to GIS based mapping throughout the organization.

8.2.2 HHHI will implement the use of tablets that will enable crews in the field to access up to date GIS mapping, integrate work order processing and timesheet completion.

8.2.3 HHHI will utilize underground utility locating equipment that incorporates GPS features with the resulting convergence used to verify underground plant to support the updating of the GIS system.

8.2.4 HHHI will work towards the integration of AMI data with the GIS system for enhanced outage management capabilities, transformer loading and load forecasting.

8.2.5 HHHI will leverage the information in HHHI's Operational Data Store to analyze customer energy use patterns to better target conservation programs.

8.2.6 HHHI will replace end of life assets with system automation solutions that provide value to customers:

i. The replacement of legacy oil circuit reclosers with new vacuum reclosers and communications ready controllers.

ii. Electronic protection relays, transformers temperature monitors and load tap changer controllers will be enabled for control through the SCADA system with new SCADA network expansions.

iii. Enablement of automated switches.

The RRFE released by the Board on October 18, 2012 is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure distributors provide value for money to their customers. The following outcomes were identified by the Board as appropriate:

- Customer Focus: Services are to be provided in a manner that is responsive to customer preferences.

- Operational Effectiveness: Distributors should achieve continuous improvement in productivity and cost performance, and must deliver on system reliability and quality objectives.

- Public Policy Responsiveness: Distributors must deliver on government mandated initiatives.

- Financial Performance: Distributors must maintain financial viability, and ensure savings from operational effectiveness are sustainable.

HHHI's alignment of the RRFE and HHHI's strategic objectives is noted above. In addition, much of HHHI's success in aligning its business with the RRFE's desired outcomes lies in HHHI's asset management efforts (discussed below). A full copy of HHHI's Distribution System Plan is at Exhibit 2 (Appendix 2-A) of this Application.

Asset Management

HHHI's approach to asset management covers the full implementation of the asset from specification and installation standards, frequency of preventative maintenance during the assets service life, to determination of when the asset should be removed from service. Strategic management of distribution assets is essential to ensuring the longevity, reliability and customer satisfaction with the distribution system.

By collecting and organizing data specific to each asset HHHI aims to ensure investments in assets are made at the right time, address the core necessities of the investment, and provide maximum value to the utility and its customers. Optimal performance improves, system reliability, customer satisfaction, and improves safety factors. The overarching goal of HHHI's asset management plan is to provide a framework for asset management planning from which sustainable levels of capital investments can be made responsibly and optimally and which address the needs of the asset.

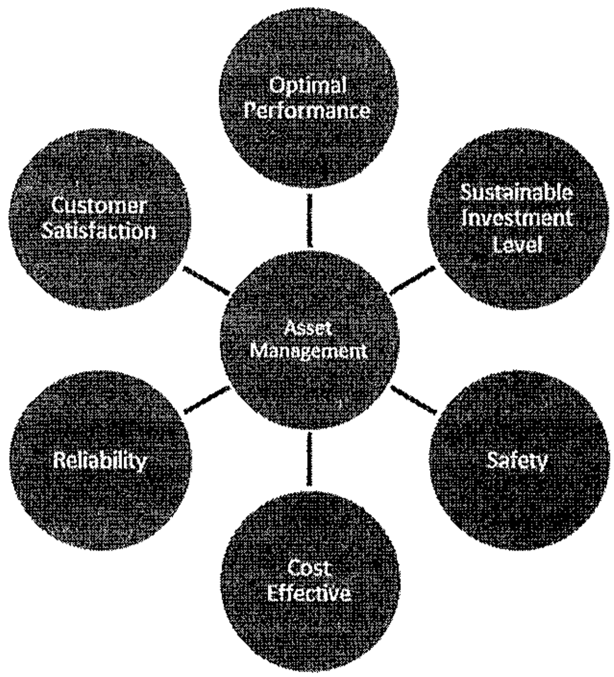


Figure -1 Contributing Elements for Asset Management Investments

As assets age, HHHI makes decisions about the assets to achieve optimal performance, lowest operating cost, and ensure safety. Such decisions often include preventative maintenance timing, the potential for rehabilitation rather than replacement, and where necessary asset replacement. The majority of asset renewal investments is triggered by declining performance, increased operational cost, safety, and anticipated load growth requiring upgrades to increase capacity and/ or reduce system constraints.

This prudent approach to asset management ensures that HHHI's assets are maintained in good condition and that only the necessary investments are made.

HHHI's overall philosophy on maintaining its electrical distribution system assets ties back to many of its strategic objectives, including: (a) meeting HHHI's safety goals; (b) meeting HHHI's reliability targets; (c) financial metrics (achieving the optimal trade-off between maintenance and replacement costs via conditioned-based assessments); and (d) competitive rates and cost control (ensuring prudent capital planning and expenditures).

Information on the quantity, age and capability of existing assets is essential to understand and effectively manage the asset base. HHHI's asset register, the ESRI geographical information system (GIS) and associated databases, store information and technical characteristics for all assets including their location, history and performance. HHHI utilizes Asset Alteration Reports and Mapping Information Update forms to gather changes to our field assets from which we can update our asset information records.

HHHI notes, with reference to the Pacific Economics Group Research, LLC Report (PEG Report) dated July 2015, that HHHI's updated stretch factor was assigned based on a three-year average of actual less predicted cost over the 2011-2014 period, averaging 25% or more below cost resulting in the lowest stretch factor of 0% or Group 1. HHHI is one of six utilities in Group 1, as per the PEG Report – Table 4:

Stretch Factor Assignments by Group

Group I	Group II	Group III	Group IV	Group V
Stretch Factor = 0%	Stretch Factor = 0.15%	Stretch Factor = 0.30%	Stretch Factor = 0.45%	Stretch Factor = 0.60%
E.L.K. Energy Inc.	Cooperative Hydro Embrun Inc.	Bluewater Power Distribution Corporation	Atikokan Hydro Inc.	Algoma Power Inc.
Halton Hills Hydro Inc.	Enersource Hydro Mississauga Inc.	Brantford Power Inc.	Brant County Power Inc.	Hydro One Networks Inc.
Hearst Power Distribution Company Limited	Entegrus Powerlines	Burlington Hydro Inc.	Canadian Niagara Power Inc.	Toronto Hydro-Electric System Limited
Hydro Hawkesbury Inc.	Espanola Regional Hydro Distribution Corporation	Cambridge And North Dumfries Hydro Inc.	Chapleau Public Utilities Corporation	West Coast Huron Energy Inc.
Northern Ontario Wires Inc.	Essex Powerlines Corporation	Centre Wellington Hydro Ltd.	Enwin Utilities Ltd.	Woodstock Hydro Services Inc.
Wassga Distribution Inc.	Grimsby Power Incorporated	Collus Power Corporation	Festival Hydro Inc.	
	Haldimand County Hydro Inc.	Erie Thames Powerlines Corporation	Greater Sudbury Hydro Inc.	
	Kitchener	Fort Frances Power Corporation	Midland Power Utility Corporation	
	Lakefront Utilities Inc.	Guelph Hydro Electric Systems Inc.	Oakville Hydro Electricity Distribution Inc.	
	Lakeland Power Distribution Ltd.	Horizon Utilities Corporation	Peterborough Distribution Incorporated	
	London Hydro Inc.	Hydro 2000 Inc.	PUC Distribution Inc.	
	Milton Hydro Distribution Inc.	Hydro One Brampton Networks Inc.	Renfrew Hydro Inc.	
	Newmarket	Hydro Ottawa Limited	Tillsonburg Hydro Inc.	
	Oshawa PUC Networks Inc.	Innisfil Hydro Distribution Systems Limited	Wellington North Power Inc.	
	Welland Hydro-Electric System Corp.	Kenora Hydro Electric Corporation Ltd.		
		Kingston Hydro Corporation		
		Niagara Peninsula Energy Inc.		
		Niagara-On-The-Lake Hydro Inc.		
		Norfolk Power Distribution Inc.		
		North Bay Hydro Distribution Limited		
		Orangeville Hydro Limited		
		Orillia Power Distribution Corporation		
		Ottawa River Power Corporation		
		Parry Sound Power Corporation		
		Powerstream Inc.		
		Rideau St. Lawrence Distribution Inc.		
		Sioux Lookout Hydro Inc.		
		St. Thomas Energy Inc.		
		Thunder Bay Hydro Electricity Distribution Inc.		
		Veridian Connections Inc.		
		Waterloo North Hydro Inc.		
		Westario Power Inc.		
		Whitby Hydro Electric Corporation		

Financial Viability

Financial viability is one of the performance measurements defined in the Board's RRFE for electricity distributors. The four financial metrics included are liquidity, leverage, deemed return on equity and achieved return on equity. HHHI's metrics for historical years 2010 to 2014 is shown in Table 1-2 below.

Table 1-2: HHHI's Profitability: Liquidity, Leverage and Return on Equity

Performance Metric	2010	2011	2012	2013	2014
Liquidity Ratio	1.15	1.69	1.25	1.06	1.09
Leverage Debt to Equity Ratio	0.75	0.87	0.9	1.04	0.39
Deemed Rate of Return on Equity	8.57%	8.57%	8.82%	8.82%	8.82%
Achieved Rate of Return on Equity	7.59%	8.47%	12.71%	14.97%	12.91%

HHHI's profitability based on the achieved rate of return on equity for historical years 2010 to 2011 are within the allowed dead band of ±300 basis points. The 2012, 2013 and 2014 are above the allowed dead band, the result of tax recovered by HHHI in relation to following *CRA Interpretation Bulletin IT-128R: Capital Cost Allowance – Depreciable Property* to expense amounts capitalized under MIFRS requirements.

EXECUTIVE SUMMARY (2.1.2)

A. Revenue Requirement – Exhibit 6

HHHI is requesting the approval of its proposed revenue requirement of $12,472,736, an increase of $2,692,206 or 27.5% compared with its 2012 approved service revenue requirement, as shown in the Table 1-3 below.

Table 1-3: Calculation of Revenue Deficiency

	2012 Approved	2016 Proposed	2016 vs 2012 Approved
OM&A Expenses	$ 5,793,400	$ 6,754,806	$ 961,406
Amortization/Depreciation	1,319,049	2,356,442	1,037,393
Property Taxes	106,600	104,440	(2,160)
Capital Taxes	-	-	-
Income Taxes (Grossed up)	28,979	(220,666)	(249,645)
Other Expenses	-	-	-
Deemed Interest Expense	1,035,607	1,165,806	130,199
Return on Deemed Equity	1,496,895	2,311,908	815,013
Service Revenue Requirement	$ 9,780,530	$ 12,472,736	$ 2,692,206
Rate Base	$ 42,429,005	$ 62,148,062	$ 19,719,057

Table 1-4 illustrates the main drivers for the 2016 revenue deficiency.

Table 1-4: 2016 Revenue Deficiency Drivers

2016 Cost of Service Rate Application Revenue Deficiency		
Cost Drivers		
OM&A		
Wages and Benefits, including 4 new FTEs	$1,078,481	
Monthly Billing	173,195	
Control Room	155,000	
Health & Safety	64,500	
Tree triming	45,000	
Property Taxes	(2,160)	$ 1,514,016
Rate of Return		
Deemed Interest:		130,199
Return on Equity:		815,013
Taxes Recovery		(249,645)
Total Revenue Deficiency		**$ 2,209,583**

B. Budgeting and Accounting Assumptions

Developing HHHI's budget is a key process as it identifies past successes as well as future initiatives and projections for capital and operating costs. Assumptions provided by the management team for the capital and operating budgets are tested to ensure they support HHHI's core business objectives as well as being prudent and financially sustainable. All budgeting from 2012 to 2016 has been based on MIFRS. HHHI provides detailed explanations in the applicable sections of the application for the major components of the budget; revenue, OM&A and capital. Assumptions and methods of calculation from these exhibits for the 2016 Test Year are as follows:

1) Revenue

a) 2016 distribution revenue, at proposed rates, is $12,472,736 including a revenue deficiency of $2,209,583.
b) The total customer/connections are forecasted to increase based on the forecast by rate class which was determined using a geometric mean analysis.
c) Other revenues were viewed on an item-by-item basis and were either based on a historical indicator or on future strategic initiatives.

2) Operating Maintenance and Administration Expense

a) OM&A expenses have been developed based on the department manager's work plans using a top-down approach in an effort to contain costs but still provide an acceptable level of service and reliability.
b) OM&A expenses also take into consideration costs to implement regulated programs such as LEAP and OESP.
c) Staffing levels are based on the estimated time required to complete the work plans. The 2014 year-end full time employee (FTE) compliment was 51, with the forecast for the 2016 Test Year being 54 FTEs, as more fully described in Exhibit 4. The three new FTEs include a new billing clerk, business analyst and succession planning.

d) Monthly billing will $173, 195 in additional costs, including staffing, postage, etc. on an on-going basis.
e) Union wage increases are based on the union contract which was effective April 1, 2015 and expires on March 31, 2016. The 2016 Test Year assumption is a rate increase effective April 1, 2016 of 2.0%.
f) Non-union management wage assumption in the 2016 Test Year is a rate increase effective January 01, 2016 of 2.0%.
g) Regulatory costs for this application and other one-time costs have been normalized over the five year life of the Application.
h) HHHI used an inflation rate of 2% where the expense increase could not be specifically identified.

3) Amortization

a) Amortization has been calculated based on MIFRS requirements and follows the same IFRS principles as approved in HHHI's 2012 Cost of Service proceeding (EB-2011-0271).

4) Payment-in-lieu of Taxes (PILs)

a) Regulatory PILS have been calculated using the Board-approved model.
b) HHHI is following the tax principles as outlined in ***CRA Interpretation Bulletin IT-128R: Capital Cost Allowance – Depreciable Property*** to expense amounts capitalized under MIFRS requirements.

5) Capital

HHHI has provided a detailed capital expenditure plan which supports asset management, plans for growth, accommodating third party requirements and technological improvements.

The Distribution System Plan (Appendix 2-A) provides a comprehensive strategy for asset management as well as a prudent, cost effective guidance for capital project expenditure over the next five years. HHHI has developed a detailed Asset Management Strategy which informed the Asset Management Process section of the plan and is attached as Appendix A of the Distribution System Plan (DSP).

C. Load Forecast Summary - Exhibit 3

HHHI's load forecast is weather normalized and considers factors such as historical power purchased load, weather, calendar related factors and local economic conditions. As outlined in Exhibit 3, HHHI has used the same regression analysis methodology approved by the Board in Oakville Hydro Distribution Inc.'s 2014 Cost of Service Application (EB-2013-0159). The regression analysis was conducted on historical electricity purchases to produce an equation that will predict weather normalized power purchases in 2016. The weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast which is allocated to rate class using historical billing data by rate class.

Based on the load forecast methodology, the total 2016 Test Year kWh forecast is 509,866,419 kWhs; a 3.21% increase over HHHI's 2012 Board-approved kWh forecast of 494,026,421 kWhs. This increase reflects the impact of CDM savings.

The forecast of customers by rate class was determined using a geometric mean analysis. Based upon the geometric mean analysis, the expected number of customers/connections for the 2016 Test Year is 26,761; an 2.0% increase over HHHI's 2012 Board-approved customers/connections of 26,236.

D. Rate Base and Capital Plan - Exhibit 2

HHHI's Distribution System Plan (DSP) was prepared in accordance with the Ontario Energy Board's Chapter 5 *Consolidated Distribution System Plan Filing Requirements*, and is an integral part of this Application (see Appendix 2-A of Exhibit 2).

The DSP provides a comprehensive strategy for asset maintenance and capital expenditures over the next five years. It is built on the principles of excellence, safety and reliability. It takes a prudent, cost effective approach to infrastructure investment and renewal to serve current and future customer preferences and requirements.

The DSP provides a comprehensive strategy for asset management as well as a prudent, cost effective guidance for capital project expenditure over the next five years. The utility has developed a detailed Asset Management Strategy which informed the Asset Management Process section of the DSP. The utility has also provided a detailed capital expenditure plan which supports asset management, accommodates third party requirements and plans for growth and technological improvements.

The Capital Expenditure portion of the DSP provides an analysis of the historical 5 year period leading up to the planning time frame, as well as forecasted costs for the life of the DSP. Projects are categorized into four major categories: System Access, System Renewal, System Service and General Plant. Within each category and across categories, projects are assigned a risk ranking and a priority to help the utility with resource planning and budgeting.

This comprehensive plan will provide the utility with a prudent strategy for investment for the years to come.

HHHI's capital spending requirements, after contributed capital, will average $8.2 million per year over the five year period of 2016 to 2020. This does not include the building of the transformer station, anticipated in 2018. These capital expenditures are grouped in four categories (as seen in Table 1-5 below): System Renewal, System Access, System Service and General Plant.

Table 1-5: Capital Expenditures by Category

	Year					
OEB Category	2016	2017	2018	2019	2020	Total
System Access	$2,472,588	$866,314	$3,330,938	$967,143	$1,038,920	$8,695,904
System Renewal	$3,790,671	$4,226,861	$2,818,292	$4,220,233	$5,464,607	$20,520,664
System Service	$2,302,791	$1,854,882	$3,535,241	$4,567,366	$1,856,956	$14,117,266
General Plant	$777,613	$479,416	$421,000	$425,000	$374,000	$2,477,029
Net Totals:	**$9,343,663**	**$7,447,472**	**$10,105,471**	**$10,179,742**	**$8,734,513**	**$45,810,862**
Contributed Capital	$1,132,703	$595,554	$1,740,960	$711,103	$782,510	$4,962,830
Annual Totals:	**$8,210,960**	**$6,851,919**	**$8,364,511**	**$9,468,640**	**$7,952,003**	**$40,848,033**

HHHI is experiencing significant growth in the southern regions of their service territory, primarily in south Georgetown. The utility is also seeing a number of in-fill developments in Georgetown and Acton. These developments in Georgetown will contribute an additional 1,242 new residential lots anticipated by the end of 2017. In addition, the Town of Halton Hills has established a Vision Georgetown Plan which, once implemented, will add about 20,000 people starting in 2021 to an area of 1,000 acres in southern Georgetown. Vision Georgetown is the product of provincial growth targets for the Greater Golden Horseshoe area which started in 2006 with the *Places to Grow Act, 2005*. This legislation allocated an additional 130,000 people and 50,000 jobs between 2021 and 2031 in the Halton Region. Included in the HHHI's DSP are system service projects that will expand our 16.0/27.6kV distribution system to bring capacity from the Steeles Avenue corridor and our planned transformer station to the southern region of Georgetown to accommodate this growth.

There is steady growth in Halton Hills related to new service requests and service upgrades. There is a new 56 unit apartment building in development in Georgetown as well as ongoing commercial development in the Steeles Avenue/401 Premier Gateway corridor.

Presently, HHHI has capacity to manage known developments presently under construction. HHHI is able to assess demand for new services and developments using in-house software to determine impacts on the distribution system and what changes may be needed to accommodate the development. Such information is used to determine scope of work related to supplying the development and may translate into capital work where distribution expansions are required. HHHI has internal resources to address and prepare for load growth through the use of system planning tools that are used assess system capacity and potential shortfalls/ constraints and how such limiting factors can be mitigated.

These tools allow HHHI to determine and prepare for the additional capacity needs that will be required by proposed developments not yet under construction but are identified in the municipal development maps. Such capacity will need to be supplied from our 16.0/27.6kV distribution system for which additional circuits/ feeders will be necessary to support the load growth.

While the 27.6kV and 8.32kV distribution systems can accommodate load growth, HHHI is more vigilant in assessing capacity required for in-fill development on our 4.16kV system to ensure system will not be constrained. Because of the anticipated growth in Georgetown south the 5 year forecast period includes reasonable system service investments relating to our 27.6kV distribution system that will see the system developed to accommodate the growth of Vision Georgetown as well as in-fill development around the Town of Halton Hills municipal building. Such proactive projects will ensure that HHHI can meet its system access requirements as these developments begin construction and distribution services to the developments occur.

System renewal projects include replacing defective and aged poles, feeder reinforcements to ensure urban 4.16kV distribution systems can support current load and future in-fill development, and the removal of obsolete equipment (Poletrans transformers) that present difficulties for operation.

The DSP includes expenditures aimed at further developing HHHI's smart grid deployment by increasing the number of automated switches employed on our 16.0/27.6kV. Over the course of the next five (5) years HHHI will install ten (10) additional automated switches on our 16.0/27.6kV distribution system at strategic locations to improve system reliability, enhanced system performance and data collected from the field, and reduce O&M costs related to field crews performing manual switching operations. This work will coincide with expanding the 16.0/27.6kV distribution system to accommodate the provincially regulated growth Georgetown is and will be experiencing.

HHHI has enough remaining station capacity and distribution infrastructure to accommodate the demand for renewable energy projects anticipated from 2016 to 2020. There are no large projects anticipated in the service territory. Should a large connection or a concentrated number of connections in a specific area occur, HHHI will assess any potential system limitations and work with the applicants to enable renewable energy connections provided such connections would not adversely affect the distribution system.

Based on a calculated remaining maximum capacity and the projected generation projects HHHI has the capacity in place to accept future renewable generation projects. As such, there are no specific investments planned to accommodate renewable energy connections.

Proposed capital expenditures by category are set out in more detail in the tables below.

Table 1-6: System Access (Planned) Capital Expenditures

Project Category	2016	2017	2018	2019	2020
Make Ready Upgrades	$17,424	$17,772	$18,128	$18,490	$18,860
microFIT/ FIT	$43,732	$44,609	$45,501	$46,411	$47,340
Subdivisions	$207,000	$244,260	$288,227	$340,108	$401,327
Technical Service Layouts	$376,036	$384,684	$393,532	$402,584	$411,843
Municipal Road Widening	$1,668,844	$0	$2,426,000	$0	$0
Metering	$159,550	$194,988	$159,550	$159,550	$159,550
Subtotals	$2,472,588	$886,314	$3,330,938	$967,143	$1,038,920
Capital Contributions	$1,132,703	$595,554	$1,740,960	$711,103	$782,510
Total	**$1,339,885**	**$290,760**	**$1,589,978**	**$256,040**	**$256,410**

System Access projects include customer connections, new development, renewable generation connections, and can also include municipal relocation projects where the utility is required to relocate infrastructure to accommodate road improvement projects.

Table 1-7: System Renewal (Planned) Capital Expenditures

Project Category	2016	2017	2018	2019	2020
Vintage System Replacements	$963,062	$1,250,781	$726,867	$900,086	$900,698
Feeder Renewal Projects	$0	$22,728	$0	$506,452	$1,349,951
Substation Improvements	$736,184	$953,352	$0	$813,695	$1,122,532
Metering Retail/Interval PMU replacements	$91,425	$0	$91,425	$0	$91,425
Total System Renewal	**$3,790,671**	**$4,226,861**	**$2,818,292**	**$4,220,233**	**$5,464,607**

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, to ensure the assets used in the delivery of power are in good condition, safe to operate, and continue to provide reliable service. This category includes plans to replace defective, obsolete, and end-of-useful life assets.

Table 1-8: System Service (Planned) Capital Expenditures

Project Category	2016	2017	2018	2019	2020
SCADA projects	$135,562	$86,579	$0	$0	$0
Automated Switches	$301,851	$150,406	$157,568	$164,730	$171,892
Feeder Upgrade & Reinforcement	$375,239	$497,853	$497,853	$0	$0
Voltage Conversion Projects	$1,334,510	$847,518	$1,594,351	$3,268,153	$1,685,094
Municipal Substation Upgrades	$155,629	$272,525	$1,111,000	$936,224	$0
Total System Service	**$2,302,791**	**$1,854,882**	**$3,535,241**	**$4,567,366**	**$1,856,986**

System service projects are investments a distributor makes to ensure the distribution system continues to meet operational objectives while addressing anticipated future customer electricity service requirements. These projects are distributor driven – they address system constraints, and promote operational effectiveness. The 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 1-9: General Plant (Planned) Capital Expenditures

Project Category	2016	2017	2018	2019	2020
Vehicles & Tools	$177,000	$322,000	$259,000	$298,000	$312,000
IT Infrastructure	$77,800	$38,840	$100,000	$65,000	$0
SCADA Outage Mgmt System Interfaces	$67,813	$0	$0	$0	$0
Interactive Voice Response (IVR)	$100,000	$0	$0	$0	$0
Building Upgrades	$355,000	$118,576	$62,000	$62,000	$62,000
Total General Plant	**$777,613**	**$479,416**	**$421,000**	**$425,000**	**$374,000**

General Plant projects are investments that support the ongoing business operations and efficiency of the utility. These projects are distributor driven and include fleet management as well as IT infrastructure, tools, equipment and general building and facility maintenance and improvements.

E. Operations, Maintenance and Administration Expense - Exhibit 4

Through distribution rates, HHHI is proposing to recover $6,859,246 in Operating, Maintenance and Administration (OM&A) costs for the 2016 Test Year.

OM&A expenditures in the 2016 Test Year of $6,859,246 represent an increase of $959,246 or 16.3% over the 2012 Board-approved OM&A expenditures of $5,900,000. The following Table 1-10 summarizes the changes.

Table 1-10: OM&A Comparison Between 2012 Board Approved and 2016 Proposed

Description	2012 Board Approved	2016 Test Year
Distribution Expenses - Operation	1,049,101	1,355,647
Distribution Expenses - Maintenance	933,985	374,125
Billing and Collecting	1,226,281	1,890,937
Community Relations	-	-
Administrative and General Expenses	2,584,033	3,134,097
Sub-Total	5,793,400	6,754,806
Property Tax	106,600	104,440
Total	**5,900,000**	**6,859,246**
		16.3%

The proposed OM&A expenditures for the 2016 Test Year have been derived through a detailed budgeting and business planning process aligned to meet HHHI's strategic objectives and OEB performance outcomes. These expenditures are required to allow HHHI to maintain distribution system service quality and reliability standards in compliance with the Distribution System Code and other regulatory imperatives (IESO, OPA, Ministry of Energy, ESA, etc.). The OM&A costs in the 2016 Test Year reflect the resourcing mix and investments required to meet customer and broader public policy requirements for the duration of the 4th Generation IRM plan term. The resourcing and investments, outlined in this application will enable HHHI to meet the expectations of HHHI customers.

There main drivers for the increase in OM&A expenditures is discussed fully at Exhibit 4, but include an increase in FTEs, wages and increased operational requirements including monthly billing, etc.

F. Cost of Capital - Exhibit 5

HHHI has prepared its Application in accordance with the Board's guidelines provided in the Report of the Board on Cost of Capital for Ontario's Regulated Utilities (the "2010 Report") issued on December 11, 2010. For the purposes of preparing this Application, HHHI has used the cost of capital parameters issued by the Board on November 20, 2014. HHHI will update its cost of capital parameters for rates with effective dates in 2016 prior to the issuance of the Board's decision for its Application.

G. Cost Allocation and Rate Design - Exhibits 7 and 8

Cost Allocation: The data used in the updated cost allocation study is consistent with HHHI's cost data that supports the proposed 2016 revenue requirement outlined in this Application. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to HHHI, its engineering records, and its customer and financial information systems.

HHHI has continued to use its utility specific weighting factors as approved in its 2012 Cost of Service Application (EB-2011-0271) and in accordance with both the Report of the Board "Review of Electricity Distribution Cost Allocation Policy, dated March 31, 2012" and the Board letter on new cost allocation policy for street lighting rate class, dated June 12, 2015. The NCP factor has been incorporated into the CA model for street lights.

As shown in Table 1-11, the 2016 cost allocation study indicates the revenue-to-cost ratios for General Service less than 50kW, General Service 1,000 to 4,999 kW and Street Lighting are outside the Board's range. For 2016, it is proposed these ratios be brought within the Board's range and the Residential and Unmetered Scattered Load (USL) adjusted upward to maintain revenue neutrality.

Table 1-11: Revenue to Cost Ratios

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	96.00	90.02	92.48	85 - 115
General Service less than 50 kW	110.00	120.81	120.00	80 - 120
General Service 50 to 999 kW	96.00	110.55	110.55	80 - 120
General Service 1,000 to 4,999 kW	120.00	124.64	120.00	80 - 120
Street Lighting	120.00	231.39	120.00	80 - 120
Sentinel Lighting	96.00	89.51	92.48	80 - 120
Unmetered Scattered Load (USL)	120.00	102.99	102.99	80 - 120
Embedded distributor class				

Rate Design: HHHI proposes to maintain the fixed/variable proportions assumed in the current rates to design the proposed monthly service charges for all rate class except the residential. This proposal is consistent with the Board's Decisions in the following cases:

- Centre Wellington Hydro Ltd. - 2014 Cost of Service Rate (EB-2013-0113);
- Atikokan Hydro Inc. - 2013 Cost of Service Rate (EB-2012-0293);
- Espanola Regional Hydro Distribution Corporation - 2013 Cost of Service Rate (EB-2012-0319);
- Horizon Utilities Corporation - 2012 Cost of Service application (EB-2011-0131);
- Hydro One Brampton Networks Inc. - 2012 Cost of Service application (EB-2011-0132); and
- Kenora Hydro Electric Corporation Ltd.- 2012 Cost of Service application (EB-2011-0135).

In addition, on April 2, 2015, the Board released its *Board Policy: A New Distribution Rate Design for Residential Electricity Customers* (EB-2014-0210), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. This policy change is expected to be implemented over a period of four (4) years, beginning in 2016. The approach to the implementation of the policy, including mitigation expectations, was described in a Board letter dated July 16, 2015. HHHI is expected to propose changes to residential rates consistent with this policy.

Table 1-12 outlines a comparison of the 2015 current to the 2016 proposed distribution rates.

Table 1-12: Proposed 2016 Distribution Charges

RATES SCHEDULE

Schedule of Distribution Rates and Charges
Effective May 1, 2016

Customer Class	Item Description	Unit	Rate ($)
Residential			
	Monthly Service Charge	per month	19.45
	Distribution Volumetric Rate	per kWh	0.0115
	Low Voltage Rider	per kWh	0.0026
GS < 50 kW			
	Monthly Service Charge	per month	33.96
	Distribution Volumetric Rate	per kWh	0.0105
	Low Voltage Rider	per kWh	0.0024
GS >50 to 999 kW			
	Monthly Service Charge	per month	96.42
	Distribution Volumetric Rate	per kW	4.2701
	Low Voltage Rider	per kW	1.0516
GS >1000 to 4999 kW			
	Monthly Service Charge	per month	215.16
	Distribution Volumetric Rate	per kW	3.7012
	Low Voltage Rider	per kW	1.0516
Sentinels			
	Monthly Service Charge	per month	6.52
	Distribution Volumetric Rate	per kW	24.7051
	Low Voltage Rider	per kW	0.7570
Street Lighting			
	Monthly Service Charge	per month	1.36
	Distribution Volumetric Rate	per kW	18.3515
	Low Voltage Rider	per kW	0.7416
Unmetered and Scattered			
	Monthly Service Charge	per month	8.40
	Distribution Volumetric Rate	per kW	0.0056
	Low Voltage Rider	per kW	0.0024

H. Deferral and Variance Accounts - Exhibit 9

As outlined in Exhibit 9 (and shown in Table 1-13 below), HHHI is requesting approval for the disposition of Group 1, Group 2 and Other Deferral and Variance Accounts in the amount of $805,202 . HHHI is proposing a two year disposition period for all Deferral and Variance Accounts.

Table 1-13: Deferral and Variance Accounts

Account Descriptions	USofA	Principal (Dec. 31, 2014)	Interest (Dec. 31, 2014)	Total (Principal & Interest)	Dispositions and Adjustments	Forecasted Carrying Charges to Apr. 30/16	Total Adjustment Claim for Disposition
Group 1 Accounts							
LV Variance Account	1550	158,674	2,037	160,711	135,624	2,470	27,557
Smart Metering Entity Charge Variance Account	1551	5,948	499	6,447	17,899	93	(11,359)
RSVA - Wholesale Market Service Charge	1580	(423,092)	(7,013)	(430,105)	(324,124)	(6,586)	(112,567)
RSVA - Retail Transmission Network Charge	1584	646,594	10,390	656,984	750,276	10,065	(83,227)
RSVA - Retail Transmission Connection Charge	1586	282,045	4,330	286,375	444,162	4,391	(153,396)
RSVA - Power (excluding Global Adjustment)	1588	318,740	19,068	337,808	575,733	4,962	(232,963)
RSVA - Global Adjustment	1589	672,329	853	673,181	19,597	10,466	664,050
Group 1 Sub-Total		**1,661,238**	**30,164**	**1,691,401**	**1,619,167**	**25,860**	**98,094**
Group 2 and Other Accounts							
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	661,665	45,486	707,151	15,000	10,533	732,684
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	-	(2,896)	(2,896)	-	-	(2,896)
Other Regulatory Assets - Sub-Account - Other	1508	-	(3,290)	(3,290)	-	-	(3,290)
Retail Cost Variance Account - Retail	1518	6,207	(53)	6,154	-	97	6,251
Retail Cost Variance Account - STR	1548	449	36	485	-	7	492
LRAM Variance Account	1568	(108,200)	-	(108,200)	65,763	(2,333)	(44,770)
Extra-Ordinary Event Costs	1572	1,555,863	23,934	1,579,797	1,561,372	212	18,637
Group 2 and Other Sub-Total		**2,115,984**	**63,217**	**2,179,201**	**1,642,135**	**8,516**	**707,108**
Total		**3,777,222**	**93,381**	**3,870,602**	**3,261,302**	**34,376**	**805,202**

I. Bill Impacts

In preparing this Application, HHHI has considered and sought to minimize any rate impacts. A comprehensive discussion of HHHI's customer engagement efforts, the customer feedback and preferences identified as a result of these efforts, and the steps HHHI is taking to ensure that customer preferences are being addressed as part of its business activities, is set out at Tab 4 of this Exhibit 1.

Table 1-14 below provides the proposed distribution bill impacts, based on consumption levels for a typical customer in each rate class.

A typical residential customer using 800 kWh per month will see a total billing increase of $8.29 or 5.85% per month.

Table 1-14: Bill Impacts

Residential - Time of Use

Customer Class	Res				
RPP/non-RPP	RPP	**RPP Tier One**	600 kWh		
Consumption	800 kWh				
Demand	- kW				
Current Loss Factor	1.0602			**Average HOEP**	
Proposed Loss Factor	1.0560	1 **Connections**		**Average GA**	
OCEB eligible?	Yes	30 **Days**		1 **# Units**	

	CURRENT ESTIMATED BILL			Proposed 2016 BILL					
Charge Description	**Volume**	**Current Rate ($)**	**Current Charge ($)**	**Volume**	**Proposed Rate ($)**	**Proposed Charge ($)**	**Change ($)**	**Change (%)**	**% of Total TOU Bill**
Energy First Tier (kWh)	0.00	0.0940	0.00	0.00	0.0940	0.00			
Energy Second Tier (kWh)	0.00	0.1100	0.00	0.00	0.1100	0.00			
TOU - Off Peak	512	0.0800	40.96	512	0.0800	40.96	0.00	0.00%	27.32%
TOU - Mid Peak	144	0.1220	17.57	144	0.1220	17.57	0.00	0.00%	11.72%
TOU - On Peak	144	0.1610	23.18	144	0.1610	23.18	0.00	0.00%	15.46%
Total: Electricity			**81.71**			**81.71**	**0.00**	**0.00%**	**54.49%**
Monthly Service Charge	1	12.72	12.72	1	19.45	19.45	6.73	52.91%	12.97%
Distribution Volumetric Rate	800	0.0120	9.60	800	0.0115	9.20	(0.40)	(4.17)%	6.14%
Fixed Rate Riders	1	4.67	4.67	1	2.33	2.33	(2.34)	(50.11)%	1.55%
Volumetric Rate Riders	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Sub-Total: Distribution (excluding pass through)			26.99			30.98	3.99	14.78%	20.66%
Line Losses	48	0.1203	5.80	45	0.1198	5.37	(0.43)	(7.36)%	3.58%
Total Deferral/Variance Account Rate Riders - Volumetric	800	0.0033	2.64	800	(0.0005)	(0.40)	(3.04)	(115.15)%	(0.27)%
Total Deferral/Variance Account Rate Riders - Fixed	1	0.0000	0.00	1	0.5900	0.59	0.59	0.00%	0.39%
Low Voltage Service Charge	800	0.0012	0.96	800	0.0026	2.08	1.12	116.67%	1.39%
Smart Meter Entity Charge	1	0.79	0.79	1	0.79	0.79	0.00	0.00%	0.53%
Sub-Total: Distribution (including pass through)			37.18			8.43	(28.75)	(77.33)%	5.62%
Retail Transmission Rate - Network Service Rate	800	0.0074	5.92	800	0.0068	5.44	0.85	14.36%	3.63%
Retail Transmission Rate - Line and Transformation Connection Service Rate	800	0.0051	4.08	800	0.0052	4.16	0.34	8.33%	2.77%
Sub-Total: Retail Transmission			10.00			9.60	(0.40)	(4.00%)	6.40%
Total: Delivery			**47.18**			**40.58**	**(6.60)**	**(13.99%)**	**27.06%**
Wholesale Market Service Rate	800	0.0044	3.52	800	0.0044	3.52	0.00	0.00%	2.35%
Rural Rate Protection Charge	800	0.0013	1.04	800	0.0013	1.04	0.00	0.00%	0.69%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.17%
Ontario Electricity Support Program (OESP)*		0.00	0.00		0.00	0.00	0.00	0.00%	0.00%
Total: Regulatory			**4.81**			**4.81**	**0.00**	**0.00%**	**3.21%**
Debt Retirement Charge (DRC)	**800**	**0.00700**	**5.60**	**800**	**0.0070**	**5.60**	**0.00**	**0.00%**	**3.73%**
Total Bill on TOU (before taxes)			139.30			132.70	(6.60)		
HST		13%	18.11		13%	17.25	(0.86)		11.50%
Total Bill (including HST)			157.41			149.95	(7.46)		
Ontario Clean Energy Benefit (OCEB)		(10%)	(15.74)		0%	0.00	15.74		0.00%
Total Bill on TOU (including OCEB)			**141.67**			**149.95**	**8.29**	**5.85%**	**100.00%**

* Rate and Unit of Measure still to be determined

CUSTOMER ENGAGEMENT (2.1.3)

A Reflection of Customer Feedback and Preferences

It is the responsibility of HHHI to manage the business outcomes and serve the customer taking a consumer–centric approach with effective and ongoing consultation and engagement with our customers. It is with sound planning, meaningful customer engagement, benefits to customer and a strong corporate governance all of which support this application.

A comprehensive discussion of HHHI's customer engagement efforts, the customer feedback and preferences identified as a result of these efforts, and the steps HHHI is taking to ensure that customer preferences are being addressed as part of its business activities.

HHHI actively engages with customers throughout the year for input and feedback. HHHI participates in approximately twenty (20) community events each year to provide information to customers on programs and solicit feedback. HHHI regularly engages with customers on social media, through HHH's website and in person at community events. Twenty percent (20%) of HHHI's customers follow on social media, placing HHHI amongst the top three in the province for customer engagement. In addition, HHHI's President & CEO attends a minimum of two public Town Council meetings per year to provide current affairs update. These presentations to council are broadcast on local cable T.V.

Customer satisfaction surveys are conducted by telephone every two (2) years using an independent third party. This survey of residential and commercial customers seeks feedback on a number of issues including reliability, operational effectiveness, outage management, value for money, cost effectiveness and affordability. Over the past two survey periods, HHHI has consistently received an A rating from its customers and exceeding the provincial averages in all major areas of performance.

HHHI customers have participated in two (2) random telephone surveys over the past five (5) years. These surveys were conducted by an independent third party with results compared across the province and country. The survey was conducted with both residential and small commercial customers as these two classes represent ninety-nine percent (99%) of HHHI's customer base. Customers have responded positively and as indicated in Table 1-15, HHHI receives high ratings for providing excellent quality services and for providing consistent, reliable energy.

Table 1-15 Customer Survey Results – 2014

Customer Service Quality			
Top 2 boxes, 'strongly + somewhat agree'	Halton Hills Hydro	National	Ontario
Deals professionally with customers' problems	85%	82%	78%
Pro-active in communicating changes and issues affecting Customers	80%	74%	73%
Quickly deals with issues that affect customers	82%	79%	74%
Customer-focused and treats customers as if they're valued	82%	74%	72%
Is a company that is 'easy to do business with'	85%	79%	75%
Cost of electricity is reasonable when compared to other utilities	60%	60%	55%
Provides good value for money	70%	67%	63%
Delivers on its service commitments to customers	85%	84%	82%

Base: total respondents with an opinion

Source: Simul Corporation 2014 UtilityPulse survey.

Town Hall meetings are held by HHHI for customer input on specific projects. HHHI held a public information session on January 20, 2015 prior to implementing its 2015 vegetation management program. In attendance at the public meeting was HHHI staff as well as the contracted arborist and tree trimmers. The purpose of this session was to provide information about the tree trimming program as well as to answer customer questions and concerns, including review of specific trees and likely tree trimming outcomes. The session was held in the Village of Glen Williams in the area where the 2015 tree trimming would be occurring. Twelve (12) residents attended. The residents that attended supported HHHI's tree trimming initiative and were pleased to see it commence.

In preparation for this application, a 2015 Electric Utility Customer Engagement Survey (Included as Appendix I of the Distribution System Plan) was completed to obtain customer preferences related to spending.

A random telephone survey of four hundred twenty-six **(426)** was conducted in the month of May 2015. In addition to the telephone survey, an online survey was offered and HHHI received nine hundred thirty **(930)** responses. The combined responses from one thousand, three hundred fifty-six **(1356)** customers represents a margin of error of +/-2.6%, nineteen (19) times out of twenty (20). The telephone survey was conducted by contacting random residential and commercial customers. The online survey was promoted on HHHI's website and social media. A link to the online survey was also emailed to the four thousand, three hundred thirty-five (4635) customers for whom HHHI had e-mail addresses on file and who elected to receive information electronically. E-mails were also sent to customers requesting their participation in focus groups. Twenty **(20)** residential customers participated in the Residential Focus Group and seven **(7)** commercial customers attended the Business Customer Focus Group.

Sixty-two percent (62%) of customer surveyed felt that HHHI spending should focus on both reducing the number of unplanned outages and the duration of unplanned outages. Outage management is addressed in this plan through a number of feeder renewal and reinforcement projects as well as through SCADA upgrades including Outage Management System (OMS) integrations.

The top communication method preferred for power outage information is through accessing recorded telephone messages. In 2016, HHHI will be implementing an Interactive Voice Response (IVR) system to address this preference.

Sixty-two percent (62%) of HHHI customers prefer a pro-active asset management replacement strategy over run-to-failure asset management options. In a 2015 Focus Group, UtilityPULSE asked Halton Hills Hydro customers: "As it relates to replacing equipment electric utilities typically follow two main practices which are:

i. let equipment run-to-failure OR
ii. pro-actively replace equipment.

Which of the following best represents your view on equipment replacement?"

The results are listed in Table 1-16 below:

Table 1-16: Responses re Equipment Replacement

	Halton Hills Hydro Inc.		Ontario LDC	
Pro-active replacement, even though it may cost more, should ensure reliability	62.0%		65.0%	
Run-to-Failure when there are limited customers affected ensures full-value is received from the equipment	37.0%		27.0%	
Don't know	1.0%		8.0%	

Base: Extract from 2015 UtilityPULSE 17th Annual Customer Satisfaction Survey Ontario LDCs / total respondents

Source: Simul Corporation 2015 UtilityPulse Focus Group – Halton Hills Hydro Inc.

When asked about increased rates to pay for capital expenditures, seventy-one percent (71%) of customers were willing to pay more for replacing aging equipment to improve safety and reliability. The DSP Appendix I addresses a number of system renewal projects focused on replacing aging equipment including a strategic pole replacement program to remove aging poles from HHHI's distribution system.

Customers were more receptive to paying more when there is a direct benefit to the customer. Looking at operational expenditures, fifty-three percent (53%) of respondents said they would be willing to pay more for tree-trimming. Tree trimming remains a focus of HHHI for the next five years.

Overall, customers show reluctance to pay for growth and are more willing to pay for items that they feel directly impact or improve their own service, even though HHHI is obligated to service growth.

From the focus groups, it was clear that residential customers were not aware that HHHI's portion of the electricity bill represents only twenty percent (20%) of the overall bill. Likewise, the Commercial Customers were not aware that that HHHI's portion of the electricity bill represents only 10% to 15% of the overall bill. Many participants believed the percentage was much higher and did not understand the impact of 'Provincial Charges' on the total bill. HHHI will continue to educate customers about their bills in an effort to facilitate more understanding.

The complete report from the customer engagement survey is shown in Appendix I of the DSP.

Performance Overview

Past Performance Measures

Performance Excellence Award

Halton Hills Hydro wins industry performance excellence award

HALTON HILLS, ON – Halton Hills Hydro has won the LDC (Local Distribution Company) Performance Excellence Award.

The award, which was presented on March 31, 2014 is one of the most prestigious given by the Electricity Distributors Association (EDA). The EDA is the trade association of Ontario's LDCs. The award is sponsored by Ontario Power Generation.

"This is a team effort and we are very grateful for this award. I accept it on behalf of all of our employees and our board," said Art Skidmore, President & CEO, Halton Hills Hydro. "We believe it is our obligation to provide our community with excellent service and to do it safely and in a reliable manner. This award is validation that our strategies and efforts are on the right track."

Halton Hills Hydro was cited for its performance excellence in five key areas – occupational health & safety, operational excellence, financial operations, conservation & demand management (CDM) and contribution to the community.

Halton Hills Hydro introduced a number of initiatives over the last several years to enhance its performance, including capital investments into the community, CDM programs, a leading edge health and safety program (EMPOWER), a shared control room with a neighbouring LDC (Oakville Hydro), strong dividends to the Town of Halton Hills, and strong customer service and reliability.

"Congratulations to Halton Hills Hydro for this outstanding achievement. We believe we have one of the best locally-owned electrical utilities in the province and they do a great job serving our community," said Mayor Rick Bonnette.

Pacific Economics Group Research, LLC Report (PEG Report) - July 2015

HHHI notes, with reference to the Pacific Economics Group Research, LLC Report (PEG Report) dated July 2015, that HHHI's updated stretch factor was assigned based on a three-year average of actual less predicted cost over the 2011-2014 period, averaging 25% or more below cost resulting in the lowest stretch factor of 0% or Group I. HHHI is one of six utilities in Group I, as per the PEG Report , three years in a row.

Customer Focus

Service Quality

Table 1-17 shows HHHI's service quality measures for the five (5) most recent historical years.

Table 1-17: Customer Focus – Service Quality (Historical Measures)

Service Quality	Board Target	2014	2013	2012	2011	2010
Connection of New Services - Low Voltage (LV)	90%	100.00%	100.00%	100.00%	100.00%	100.00%
Connection of New Services - High Voltage (HV)	90%	0.00%	0.00%	0.00%	0.00%	0.00%
Appointment Scheduling	90%	100.00%	100.00%	100.00%	100.00%	100.00%
Appointments Met	90%	100.00%	100.00%	100.00%	96.00%	99.20%
Rescheduling a missed appointment	100%	100.00%	100.00%	100.00%	100.00%	100.00%
Telephone Accessibility	65%	89.70%	83.20%	87.70%	85.50%	86.20%
Telephone Call Abandon Rate	10%	1.00%	1.70%	1.40%	3.10%	2.00%
Written Responses to Enquiries	80%	100.00%	99.90%	100.00%	100.00%	100.00%
Emergency Response Urban	80%	100.00%	100.00%	98.81%	100.00%	100.00%
Emergency Response Rural	80%	100.00%	100.00%	89.60%	100.00%	100.00%
Reconnection Performance Standard	85%	100.00%	100.00%	100.00%		

HHHI places a strong focus on providing customers with distribution excellence. This includes maintaining exceptional levels of customer service. HHHI has continuously exceeded the OEB's minimum standards.

The connection of New Services – High Voltage target is not applicable for HHHI as HHHI has no high voltage connections.

In all areas, HHHI has met or exceeded its targets in 2014. Historical achievements have always exceeded the Board targets. In particular, it should be noted that for the past three years, all appointments have been met and all connections for new services completed, one hundred percent (100%) of the time.

HHHI notes that telephone accessibility is a high priority for its customers. The telephone is still, by far, the preferred method of contact for the vast majority of HHHI's customers. In HHHI's 2014 customer service survey, it was noted that eighty-eight percent (88%) of customers prefer to use the telephone to contact HHHI. HHHI still believes there is room for improvement and with reference to the general capital plan, the utility will be implementing an Interactive Voice Response (IVR) system to provide customers with added features and flexibility to better respond to their needs.

Customer Satisfaction

Table 1-18 shows HHHI's Target Customer Satisfaction measures with recent historical years.

Table 1-18: Customer Focus – Customer Satisfaction (Historical Measures)

Customer Satisfaction Measures	Board Target	2014	2013	2012	2011	2010
First Contact Resolution	Not Available	100.00%				
Billing Accuracy	98%	99.95%	99.91%			
Customer Satisfaction Survey Results	Not Available	90.00%	93.00%			

Service Quality measures consist of new measures recently introduced by the Board. In January 2015, HHHI implemented tools within the CIS system to monitor and report on First Contact Resolution.

HHHI understands that billing accuracy is imperative for all customers. The bill is the primary way most customers interact with their utility and they expect the bill to be correct. HHHI will be moving to monthly billing in 2016 and as such, continued billing accuracy is paramount. HHHI has achieved 99.9% billing accuracy.

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.

HHHI will be moving to monthly billing in 2016. This means that customers will receive twice as many bills from the utility so ensuring that those bills are accurate is an important part of maintaining customer satisfaction and trust.

HHHI maintains a strong presence in the community and uses its participation in community events as an opportunity for customer outreach. HHHI participates in over twenty (20) community events each year including fall fairs, farmers markets and other local events. As well, HHHI actively engages with its customers online. Over twenty percent (20%) of HHHI's customers follow HHHI via Facebook and/or Twitter. All of these opportunities to engage with the community help build customer's trust.

In the 2014 Customer Satisfaction Survey HHHI's customer's satisfaction level was 90%. This survey was conducted in March 2014, with very recent memories of the December 2013 Ice-Storm.

FINANCIAL INFORMATION (2.1.4)

Audited Financial Statements

Copies of HHHI's 2012, 2013 and 2014 Audited Financial Statements are provided in Appendices 1-D.

Reconciliation Between Audited Financial Statements and Regulatory Accounting

Reconciliations of HHHI's Audited Financial Statements to the annual RRR 2.1.7 Trial Balance for 2012, 2013 and 2014 are provided as Appendix 1-E.

Statement of Accounting Standard Used

Existing/Proposed Accounting Orders

The Accounting Standard Board ("AcSB") deferred mandatory adoption of IFRS for qualifying rate-regulated entities to January 1, 2015. However, per the 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, 2014. HHHI confirms it implemented all MIFRS changes including depreciation expense, capitalization policies, componentization and revised useful lives, during its 2012 fiscal year and in accordance with EB-2012-0271. HHHI has prepared the 2016 Cost of Service Application entirely on an MIFRS basis.

Accounting Standard used in Application

HHHI confirms it implemented all MIFRS changes including depreciation expense, capitalization policies, componentization and revised useful lives, during its 2012 fiscal year. HHHI has prepared this 2016 Cost of Service Application (including historical, bridge and test year information) entirely on an MIFRS basis.

As HHHI transitioned to MIFRS in 2012 (EB-2011-0271), HHHI has not completed any CGAAP to MIFRS charts or Board Appendices in this application.

Compliance with the Uniform System of Accounts

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

Accounting Treatment of Non-Utility Businesses

HHHI is engaged in the delivery of the IESO's conservation and demand management programs. The accounting for these activities is segregated from HHHI's rate regulated activities in accordance with the Board's Accounting Procedures Handbook For Electricity Distributors.

Annual Report and MD&A for Parent Company

Halton Hills Community Energy Corporation Inc. does not publish a public annual report or an MD&A. As a result, this requirement is not applicable.

Rating Agency Reports

Not applicable.

Prospectus or Information Circulars

Not applicable.

Changes in Tax Status

HHHI has not had a change in tax status since its last Cost of Service Application.

MATERIALITY THRESHOLDS (2.1.5)

Chapter 2 of the Filing Requirements issued by the Board sets out the materiality levels based on the magnitude of a utility's revenue requirement. HHHI's revenue requirement is greater than $10 million and less than $200 million, therefore its materiality level is 0.5% of HHHI's distribution revenue requirement. HHHI's materiality threshold for the 2016 Test Year is $62,364 as provided in Table 1-19 below. HHHI has used a lower threshold of $65,000 for assessing materiality for the purposes of this Application.

Table 1-19: 2016 Test Year Materiality Calculation

Description	2016 Test Year
Distribution Revenue Requirement	$ 12,472,736
Materiality Threshold	0.50%
Calculated Materiality	$ 62,364
Materiality Used	$ 65,000

APPLICANT OVERVIEW (2.1.7)

HHHI, 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 within the Town of Halton Hills.

Service Description

HHHI distributes electricity within the municipal boundaries of the Town of Halton Hills. The service territory covers approximately 280 sq. km comprised of approximately 26 sq. km of urban area and 255 sq. km of rural territory. The urban areas encompass the towns of Acton and Georgetown as well as several smaller rural hamlets, namely Ashgrove, Ballinafad, Crewson's Corners, Glen Williams, Hornby, Limehouse, Norval, Silver Creek, Stewarttown and Terra Cotta. HHHI's distribution network consists of 12 municipal substations and 1,527 km of underground and overhead distribution lines. HHHI is owned by Halton Hills Community Energy Corporation Inc., which is wholly owned by the Corporation of the Town of Halton Hills. HHHI services approximately 22,000 customers. Approximately 19,625 of those customers are residential, 1,700 small commercial, 112 renewable generation connections and the remaining customers spread across the remaining customer classes.

HHHI maintains 1,527 kilometers of medium- and low-voltage distribution circuits that distribute electricity from the provincial transmission grid. The utility receives primary supply from HONI at three locations as follows:

- Three-phase three-wire 44 kV sub-transmission: HHHI has three (3) feeder positions (designated 42M23, 42M25 and 42M28) from Pleasant transformer station ("TS").
- Three-phase three-wire 44 kV sub-transmission: HHHI shares a feeder position with Milton Hydro, and Guelph Hydro (73M04) that emanates from Fergus TS.
- Three-phase four-wire 16/27.6Y kV distribution: HHHI has three (3) feeder positions (designated 41M21, 41M29 and 41M30) from Halton TS.

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

There are twelve (12) municipal substations strategically located throughout the service territory that provide 2.4/4.16Y kV primary distribution voltages in the urban areas (i.e. Acton and Georgetown) and 4.8/8.32Y kV primary distribution voltages in the rural parts of the service territory.

COMMUNITY SERVED:	Town of Halton Hills
TOTAL SERVICE AREA:	280 sq. km
RURAL SERVICE AREA:	255 sq. km
DISTRIBUTION TYPE:	Electricity Distribution
SERVICE AREA POPULATION:	60,882
MUNICIPAL POPULATION:	60,882

A map of HHHI's distribution service territory is provided in Appendix 1-B.

List of Neighbouring Utilities

HHHI's service area is bounded by HONI on its north and north-west border, Hydro One Brampton on its east border, Enersource Hydro Mississauga on its south-east corner and Milton Hydro Distribution Inc. on its south and west borders.

Identification of Embedded or Host Utilities

HHHI is embedded to HONI at three points. HONI feeds HHHI through the following points:

- one feeder at Fergus TS to the west of HHHI and located outside the boundaries of HHHI;
- three feeders at Pleasant TS to the east of HHHI and located outside the boundaries of HHHI; and
- three feeders at Halton TS to the south of HHHI and located outside the boundaries of HHHI.

HHHI includes, in its distribution rates, Low Voltage Charges and requests the continuation of Low Voltage rates in its distribution rates as detailed in Exhibit 8.

Statement regarding Distribution Assets

HHHI does not have any transmission or high voltage asset (>50kV) that have been previously deemed by the Board as distribution assets, and does not have any such assets for which HHHI is seeking Board approval to be deemed as distribution assets in this Application.

CORPORATE GOVERNANCE (2.1.8)

Utility Organizational Structure

A copy of HHHI's utility organizational chart is provided in Appendix 1-J, together with a description of each of the HHHI operational units.

Utility Corporate Entities Organizational Structure

HHHI is a wholly-owned subsidiary of Halton Hills Community Energy Corporation Inc. which is wholly-owned by The Corporation of the Town of Halton Hills. A corporate organization chart is provided in Appendix 1-J.

Planned Changes in Corporate and Operational Structure

HHHI is not planning on any changes to its corporate or operational structure.

Board of Directors

HHHI has seven (7) members of the HHHI Board of Directors (the "HHHI Board"). Four (4) members of the current HHHI Board are independent.

HHHI Board Mandate

The HHHI Board's mandate, as set out in Halton Hills Community Energy Corporation Inc. (and its subsidiaries') Shareholder Direction is detailed below.

> "STANDARDS OF GOVERNANCE
>
> The Shareholder expects the Board and each Director of the Corporation to observe principles of good corporate governance, including the following:
>
> (a) The Board should have in place a Corporate Governance Committee;
>
> (b) The Board should have in place an Audit Committee;
>
> (c) The Board should have in place a Compensation Committee;

(d) The Board should establish, and review from time to time, a written mandate for each of the foregoing committees that sets out each such committee's purpose, responsibilities, membership and manner of reporting to the Board; and

(e) The Board shall establish and maintain a Code of Conduct to guide each Director of the Corporation and the Affiliates, the Chief Executive Officer (or equivalent), the Chief Financial Officer (or equivalent) and any other key executives of the Corporation and the Affiliates as to (i) practices necessary to maintain confidence in the integrity of each of the Corporation and the Affiliates, and (ii) the responsibility and accountability of individuals for reporting and investigating unethical practices and reviewed on a periodic basis."

HHHI has in place Corporate Governance, Audit and Compensation Committees. The Corporate Governance and Compensation Committees are populated by members of the Halton Hills Community Energy Corporation Inc. Board. The HHHI Audit Committee consists of the Chair and Vice-Chair of the HHHI Board, along with the Chair and Vice-Chair of SouthWestern Energy Inc., an affiliate corporation. The Chair of the Audit Committee is a Chartered Professional Accountant (CPA). The other members of the audit committee are also well versed in financial and utility matters, and include the former CEO of Hydro One Brampton, and the CAO of the Town of Halton Hills.

"NUMBER AND QUALIFICATIONS OF DIRECTORS

(a) The Board for Halton Hills Community Energy Corporation Inc. (the 'Parent') will have five to seven Directors, consisting of the Mayor of the Town of Halton Hills, the Chief Administrative Officer for the Town of Halton Hills, the Chair and Vice-Chair of Halton Hills Hydro Inc. and the Chair and Vice-Chair of SouthWestern Energy Inc. (affiliate).

(b) The Board of Directors of each of the Affiliates will each have five to seven Directors with either the Mayor of the Town of Halton Hills or the Town's Chief Administrative Officer serving as a Director.

(c) The Board of Halton Hills Hydro needs to satisfy the Affiliate Relationship Code requirements of the Board.

(d) Subject to Section 6 hereof, the Directors of the Corporation and its Affiliates will be appointed by the Town.

(e) The Directors of the Corporation and of the Board of Directors of each of the Affiliates will reside in and have good knowledge of Halton Hills and will have a reputation for honesty and integrity. Each of the members of the Board will have experience in at least one of the following areas and all will collectively have experience in all of the following areas:

(i) Electricity distribution and generation;
(ii) Government and regulatory agencies;
(iii) Corporate governance and structure;
(iv) Corporate finance and accounting;
(v) Private sector senior management experience;
(vi) Human resource management;
(vii) Practice of corporate law;
(viii) Corporate sales and marketing;
(ix) Energy industry experience; and
(x) Community awareness and involvement."

The HHHI Board meets the directed number and qualifications for its Board of Directors.

"SELECTION OF DIRECTORS

(a) A Selection Committee will be established by the Town to recruit and recommend to Town Council the persons to be the Directors of the Corporation and its Affiliates. The Selection Committee will:

(i) Be comprised of the Corporate Affairs Committee of Town Council or, other Committee as directed by Council;

(ii) Seek input from the current Board, and

(iii) Have regard to the qualifications of Directors set forth in section 5(e) hereof and recognized, recommended practices of corporate governance, including with respect to independence of Directors.

(b) The Selection Committee is authorized to proceed as needed from time to time with the recruitment of the Directors of the Corporation and its Affiliates and to report back to Town Council with the Selection Committee's recommendations.

(c) Town Council may accept or reject, but not substitute for, any person recommended to Town Council by the Selection Committee to be a Director of the Corporation and its Affiliates.

(d) The Board and the Corporation, as the case may be, will appoint or elect, or cause to be appointed or elected, as Directors of the Corporation and each Affiliate, the persons contemplated by sections 5 and 6 hereof.

(e) Persons appointed to the Board of the Corporation and its Affiliates initially shall be appointed for 1, 2 or 3 year terms, subject to the pleasure of Town Council, to enable rotational membership on the Boards to be established. Thereafter, persons appointed are appointed for a 3 year term subject to the pleasure of Town Council. In any case, no person shall be appointed for more than 3 terms, except the Mayor and the CAO."

The HHHI Board members have been appointed in accordance with the Shareholder Direction.

SHAREHOLDER EXPECTATIONS

The Shareholder expects that the Directors of the Corporation and of each Affiliate will:

(a) Supervise the management of the business and affairs of the Corporation and cause the Corporation, as Shareholder, to oversee the business and affairs of each Affiliate;

(b) Cause the business of the Corporation to be conducted in accordance with this General Shareholder Direction, all other Shareholder's Directions, prudent business practice, and all requirements of the Ontario Energy Board, of all other regulatory or governmental authorities having jurisdiction over the Corporation or the Affiliates, and of all applicable laws, regulations, rules, codes, licenses and orders;

(c) Develop and maintain a prudent financial and capitalization structure consistent with relevant industry norms, sound financial principles and applicable laws, regulations, rules, codes, licenses and orders;

(d) Establish just and reasonable rates for the regulated distribution business of Hydro which take into consideration:

(i) the other provisions of this General Shareholder Direction and the provisions of all other Shareholder's Directions;
(ii) the rates in other municipalities in comparable areas and circumstances;
(iii) an intention to maintain and/or enhance the value of Hydro and the Corporation;

(iv) the encouragement of economic development and activity within the Town of Halton Hills;

(v) where possible, moderating increases and decreases in rates by phasing in the increases and decreases; and

(vi) applicable laws, regulations, rules, codes, licenses and orders.

(e) Develop for Shareholder approval and implement a long range strategic plan for the Corporation and the Affiliates (the "Long-Range Strategic Plan") which is consistent with:

(i) The guiding considerations contemplated by section 1 hereof;

(ii) The maintenance of a viable and competitive business;

(iii) Preserving and enhancing the value of the business;

(iv) Sustaining physical infrastructure;

(v) Ensuring long-term reliability of service to customers; and

(vi) Adhering to the policies listed in this Shareholder direction.

(f) Develop on a timely basis prior to the end of each fiscal year of the Corporation for Shareholder approval all necessary or desirable strategic documents, including an annual business plan and capital budget (the "Annual Business Plan and Capital Budget"), and implement the same; and

(g) Appoint the officers of the Corporation and the Affiliates and provide for an orderly succession of such officers."

The HHHI Board complies with the Shareholder expectations.

Board Meetings

The following are the 2015 scheduled meetings of the HHHI Board:

- March 6th, 2015
- April 16th, 2015
- June 19th, 2015
- August 5th, 2015
- October 29th, 2015
- November 26th, 2015

Orientation and Continuing Education

The HHHI Board receives continuing education and professional development training through Board Reports, Board Meetings and attendance at subject-related conferences. From time-to-time, external subject matter experts are utilized to assist with the education process. HHHI Board members, through their professional careers are also active in industry-related issues and receive continuous education through this experience.

Code of Conduct

Halton Hills Community Energy Corporation Inc. and its subsidiaries, including HHHI, have adopted a written corporate-wide Code of Conduct. It is an annual requirement for all Directors, Officers of the Corporation, and Employees to sign the 'Code of Conduct - Certificate of Compliance'. The Code of Conduct is shown in Appendix 1-H. Compliance is monitored on a complaints basis.

LETTERS OF COMMENT (2.4.9)

No letters of comment have been filed with the Board during the course of this proceeding.

APPENDIX 1-A

SCHEDULE OF PROPOSED RATES AND CHARGES

File Number:	EB-2015-0074
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-Z
Proposed Tariff of Rates and Charges

For each class, Applicants are required to copy and paste the class descriptions (located directly under the class name) and the description of the applicability of those rates (description is found under the class name and directly under the word "APPLICATION"). By using the drop-down lists located under the column labeled "Rate Description", please select the descriptions of the rates and charges that BEST MATCHES the descriptions on your most recent Board-Approved Tariff of Rates and Charges. **If the description is not found in the drop-down list,** please enter the description in the green shaded cells under the correct class exactly as it appears on the tariff. Please do not enter more than one "Service Charge" for each class for which a base monthly fixed charge applies. All rate rider descriptions should begin with "Rate Rider for...".

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, including the MicroFit Class.

How many classes are listed on your most recent Board-Approved Tariff of Rates and Charges? 8

Identify Your Rate Classes in the **Blue Cells** below. Rate class names can be selected from the pull-dwon menu. Please ensure that a rate class is assigned to each shaded cell.

List of Rate Classes
RESIDENTIAL - TIME OF USE
GENERAL SERVICE LESS THAN 50 KW
GENERAL SERVICE 50 TO 999 KW
GENERAL SERVICE 1,000 TO 4,999 KW
UNMETERED SCATTERED LOAD
SENTINEL LIGHTING
STREET LIGHTING
microFIT

Once all blue shaded cells above are filled out, press the following button to create your tariff template

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2015-0074

RESIDENTIAL - TIME OF USE SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. The customer will be supplied at one service entrance only. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	19.45
Rate Rider for Smart Metering Entity Charge - effective until October 31,2018	$	0.79
Rate Rider for Ice Storm Recovery - effective until October 31, 2016	$	2.33
Distribution Volumetric Rate	$/kWh	0.0115
Low Voltage Service Rate	$/kWh	0.0026
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2018	$/kWh	(0.0005)
Rate Rider for Disposition of Deferral/Variance Group 2 Account (2016) - effective until April	$	0.59
Rate Rider for Disposition of LRAMVA Account (2016) - effective until April 30, 2018	$/kWh	0.0000
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018		
Applicable only for Non-RPP Customers	$/kWh	0.0013
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program (OESP)		TBD
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	33.96
Rate Rider for Smart Metering Entity Charge - effective until October 31,2018	$	0.79
Rate Rider for Ice Storm Recovery - effective until October 31, 2016	$	5.08
Distribution Volumetric Rate	$/kWh	0.0105
Low Voltage Service Rate	$/kWh	0.0024
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2018	$/kWh	0.0002
Rate Rider for Disposition of LRAMVA Account (2016) - effective until April 30, 2018	$/kWh	(0.0001)
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018		
Applicable only for Non-RPP Customers	$/kWh	0.0013
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program (OESP)		TBD
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 50 kW over the past twelve months, or is forecast to be equal to or greater than 50 kW, but less than 1,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST. Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts with the exception of the Retail Transmission Rate-Network Service Rate, which is billed on a $/kW basis only.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	96.42
Rate Rider for Ice Storm Recovery - effective until October 31, 2016	$	53.52
Distribution Volumetric Rate	$/kW	4.2701
Low Voltage Service Rate	$/kW	1.0516
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2018	$/kW	0.0634
Rate Rider for Disposition of LRAMVA Account (2016) - effective until April 30, 2018	$/kW	(0.0264)
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018		
Applicable only for Non-RPP Customers	$/kW	0.4552
Retail Transmission Rate - Network Service Rate	$/kW	2.6426
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1070

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program (OESP)		TBD
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 1,000 kW over the past twelve months, or is forecast to be equal to or greater than 1,000 kW, but less than 5,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the installed transformer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST. Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts with the exception of the Retail Transmission Rate-Network Service Rate, which is billed on a $/kW basis only.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	215.16
Rate Rider for Ice Storm Recovery - effective until October 31, 2016	$	511.97
Distribution Volumetric Rate	$/kW	3.7012
Low Voltage Service Rate	$/kW	1.0516
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2018	$/kW	0.0664
Rate Rider for Disposition of LRAMVA Account (2016) - effective until April 30, 2018	$/kW	0.0029
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018		
Applicable only for Non-RPP Customers	$/kW	0.4896
Retail Transmission Rate - Network Service Rate	$/kW	2.6426
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1070

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program (OESP)		TBD
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian X-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	8.40
Rate Rider for Ice Storm Recovery - effective until October 31, 2016	$	1.00
Distribution Volumetric Rate	$/kWh	0.0056
Low Voltage Service Rate	$/kWh	0.0024
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2018	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018		
Applicable only for Non-RPP Customers	$/kWh	0.0000
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program (OESP)	$/kWh	TBD
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6.52
Rate Rider for Ice Storm Recovery - effective until October 31, 2016	$	1.31
Distribution Volumetric Rate	$/kW	24.7051
Low Voltage Service Rate	$/kW	0.7570
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2018	$/kW	0.1264
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018		
Applicable only for Non-RPP Customers	$/kW	0.9319
Retail Transmission Rate - Network Service Rate	$/kW	1.8853
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5168

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program (OESP)		[TBD]
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street lighting equipment owned by or operated for the Municipality, the Region or the Province of Ontario shall be classified as Street Lighting Service. Street Lighting plant, facilities, or equipment owned by the customer are subject to the Electrical Safety Authority (ESA) requirements and Halton Hills Hydro specifications. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1.36
Rate Rider for Ice Storm Recovery - effective until October 31, 2016	$	0.66
Distribution Volumetric Rate	$/kW	18.3515
Low Voltage Service Rate	$/kW	0.7416
Rate Rider for Disposition of Deferral/Variance Accounts (2016) - effective until April 30, 2018	$/kW	0.0618
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2018		
Applicable only for Non-RPP Customers	$/kW	0.4552
Retail Transmission Rate - Network Service Rate		1.8766
Retail Transmission Rate - Line and Transformation Connection Service Rate		1.4859

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program (OESP)		TBD
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate		
Rural Rate Protection Charge		
Ontario Electricity Support Program (OESP)		
Standard Supply Service - Administrative Charge (if applicable)		

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.5000)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.0000)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/Credit Check (plus credit agency costs)	$	15.00
Returned Cheque Charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account Set Up Charge/Change of Occupancy Charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Meter Dispute Charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment Charge – per month	%	1.5000
Late Payment Charge – per annum	%	19.5600
Collection of Account Charge – no disconnection	$	30.00
Collection of Account Charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00

Other

Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles - per pole/year	$	22.35
Interval Meter Charge	$	20.00

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.5000
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.3000
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.3000)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

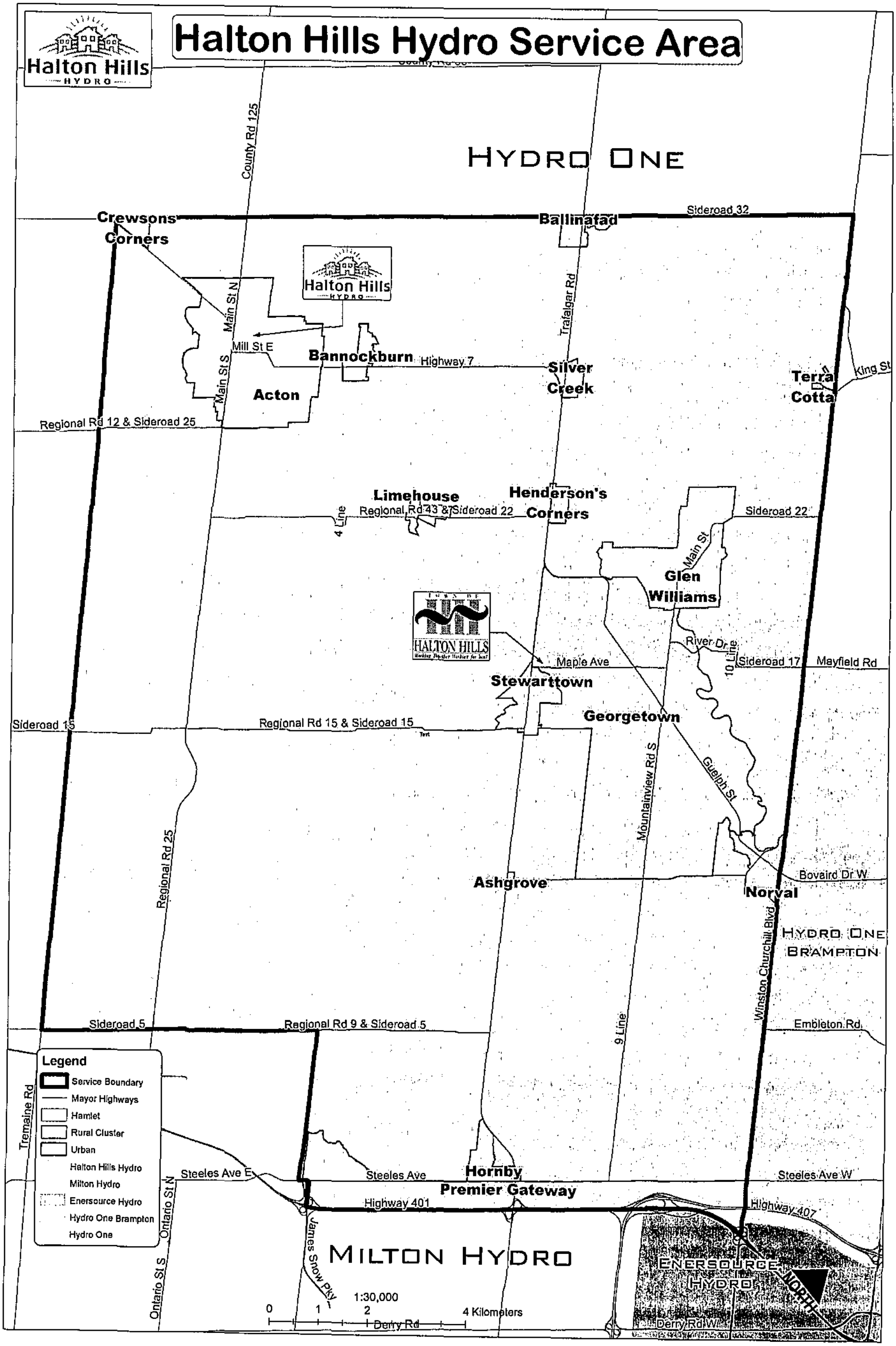
If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.05605
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.04549

APPENDIX 1-B

MAP OF DISTRIBUTION SERVICE TERRITORY

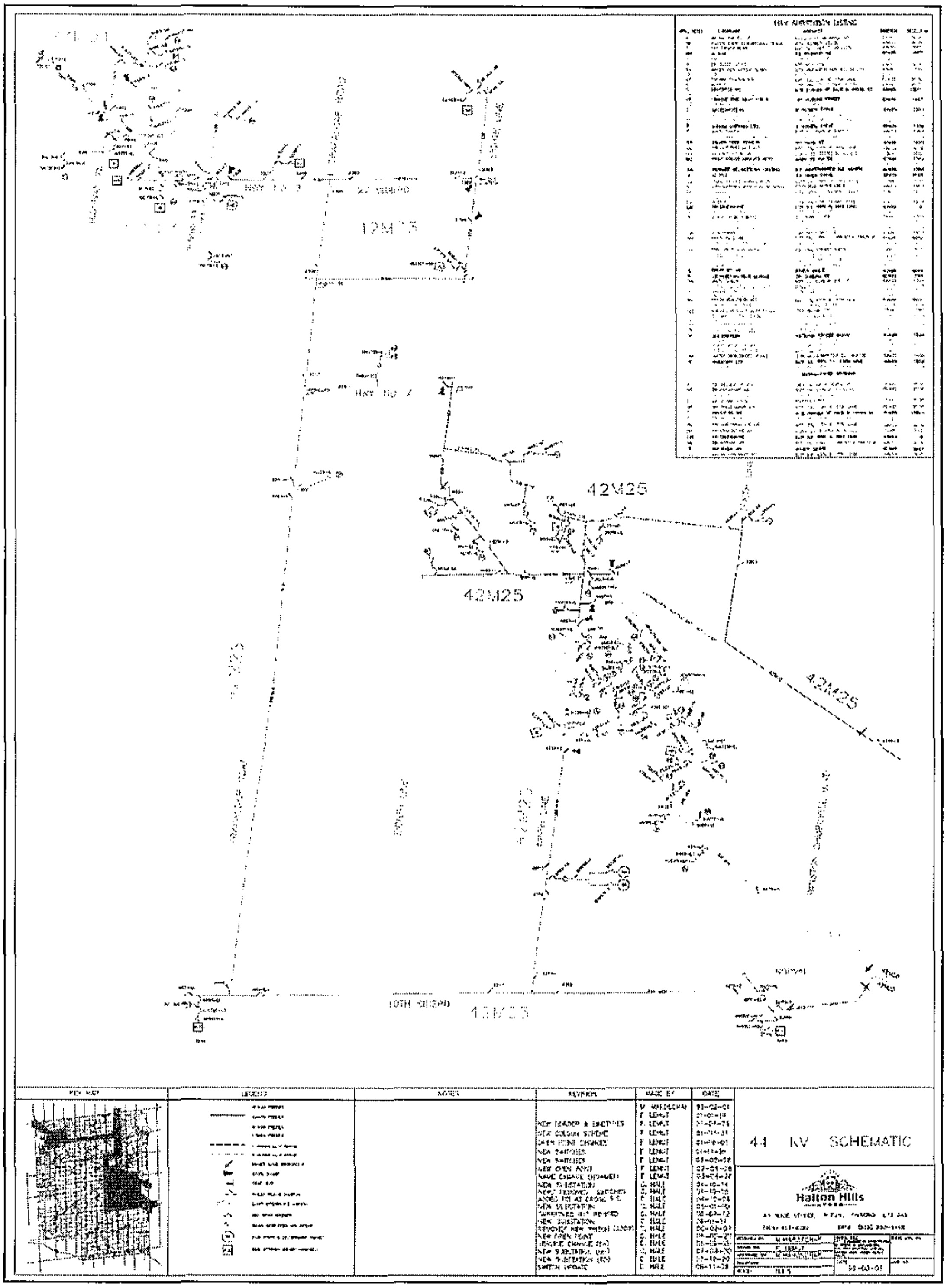
Halton Hills Hydro Service Area



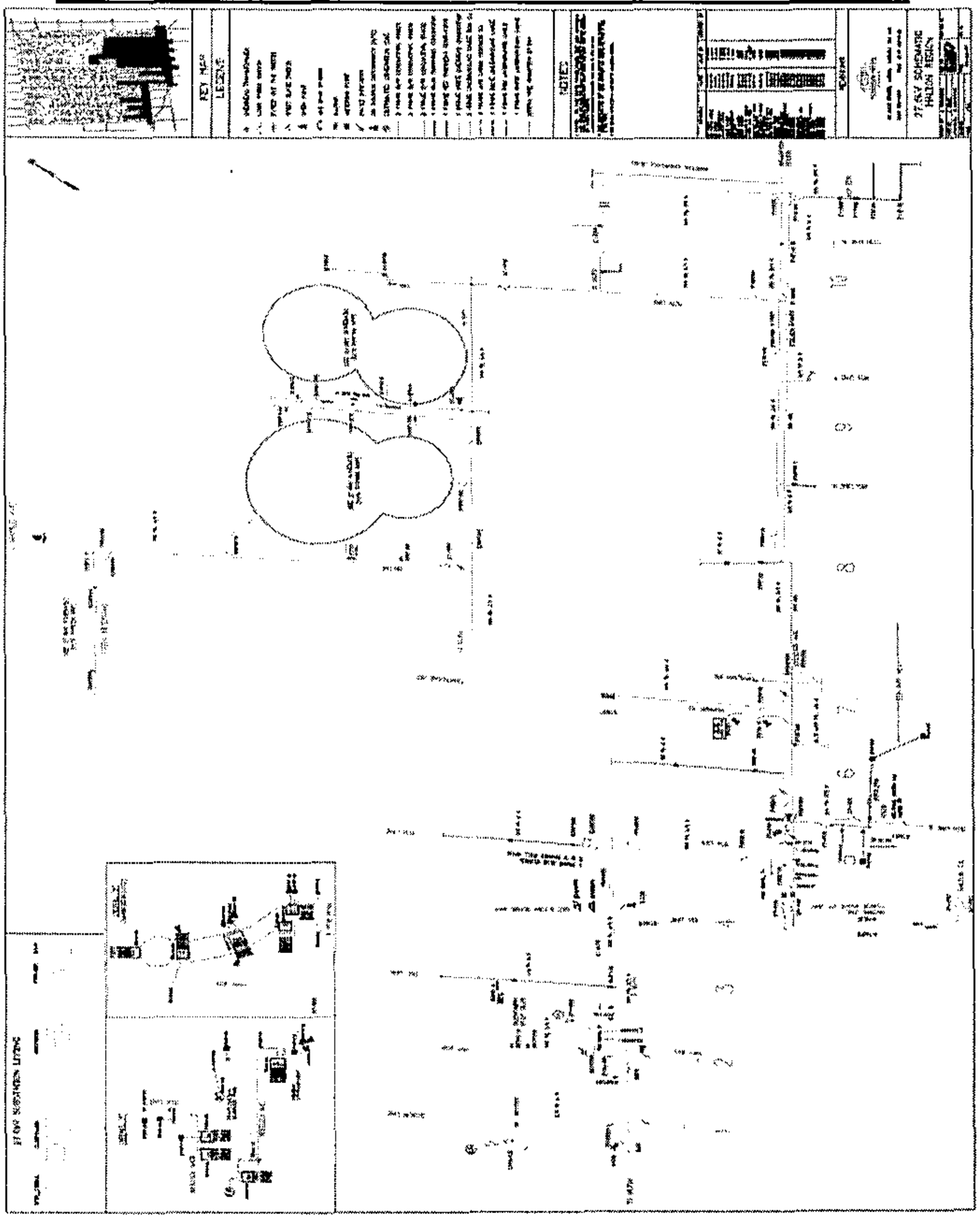
APPENDIX 1-C

MAP OF DISTRIBUTION SYSTEM

Schematic Diagram of HHHI's 44 kV Sub-transmission System



Schematic Diagram of HHHI's 16/27.6Y kV Distribution System



APPENDIX 1-D

COPY OF AUDITED FINANCIAL STATEMENTS FOR 2012, 2013 AND 2014

Financial Statements of

HALTON HILLS HYDRO INC.

Year ended December 31, 2012

KPMG LLP
Chartered Accountants
Box 976
21 King Street West Suite 700
Hamilton ON L8N 3R1

Telephone (905) 523-8200
Telefax (905) 523-2222
www.kpmg.ca

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Halton Hills Hydro Inc.

We have audited the accompanying financial statements of Halton Hills Hydro Inc. (the "Entity") which comprise the balance sheet as at December 31, 2012, and the statements of operations and retained earnings and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, 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.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Entity's preparation and fair presentation of the financial statements 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 Entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Halton Hills Hydro Inc. as at December 31, 2012, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

April 25, 2013
Hamilton, Canada

HALTON HILLS HYDRO INC.
Financial Statements

Year ended December 31, 2012

Financial Statements

HALTON HILLS HYDRO INC.

Balance Sheet

December 31, 2012, with comparative figures for 2011

		2012		2011
Assets				
Current assets:				
Cash and cash equivalents	$	-	$	1,257,808
Accounts receivable (note 4)		6,402,413		4,503,337
Unbilled revenue		5,189,927		6,585,900
PILs receivable		425,567		211,593
Inventory (note 5)		1,004,034		703,545
Due from related companies (note 6)		76,734		85,188
Prepaid expenses and deposits		441,868		284,340
		13,540,543		13,631,711
Regulatory assets (note 7)		2,607,768		6,729,050
Capital assets (note 8)		40,192,619		31,530,819
Future income taxes		-		308,210
	$	56,340,930	$	52,199,790
Liabilities and Shareholder's Equity				
Current liabilities:				
Bank indebtedness	$	2,274,374	$	-
Smart Meter bank loan (note 16 (d))		234,776		230,204
Accounts payable and accrued liabilities (note 9)		8,104,130		7,923,795
Current portion of consumer deposits		230,000		230,000
		10,843,280		8,383,999
Smart Meter bank loan (note 16 (d))		3,459,601		3,694,148
Note payable (note 10)		16,141,970		16,141,970
Consumer deposits		490,918		307,065
Employee future benefits (note 11)		479,747		497,303
Future income taxes		336,741		-
Shareholder's equity:				
Capital stock (note 12)		16,161,663		16,161,663
Retained earnings		8,427,010		7,013,642
		24,588,673		23,175,305
	$	56,340,930	$	52,199,790

See accompanying notes to financial statements.

On behalf of the Board:

Chair

Director

HALTON HILLS HYDRO INC.

Statement of Operations and Retained Earnings

Year ended December 31, 2012, with comparative figures for 2011

	2012	2011
Revenue:		
Service revenue (note 13)	$ 56,181,635	$ 55,012,355
Other income	1,186,589	1,285,159
	57,368,224	56,297,514
Expenditure:		
Cost of power (note 13)	45,746,998	45,727,509
Salaries and benefits	4,759,645	4,342,896
Material costs	2,747,932	1,291,320
Contract services	3,137,463	1,677,082
Property costs	1,473,618	452,403
Other costs (note 14)	894,224	1,087,181
Communication costs	313,648	316,379
Capital taxes	-	(23,491)
Allocated to capital	(7,400,948)	(4,345,429)
	51,672,580	50,525,850
Earnings before the undernoted	5,695,644	5,771,664
Other expenses:		
Amortization	1,684,937	2,186,947
Interest expense	1,111,528	1,164,327
	2,796,465	3,351,274
Earnings before income taxes	2,899,179	2,420,390
Income taxes:		
Current	371,644	459,954
Future (recovery)	36,575	(16,350)
	408,219	443,604
Net earnings	2,490,960	1,976,786
Retained earnings, beginning of year	7,013,642	5,980,561
Dividends on common shares	(1,077,592)	(943,705)
Retained earnings, end of year	$ 8,427,010	$ 7,013,642

See accompanying notes to financial statements.

HALTON HILLS HYDRO INC.

Statement of Cash Flows

Year ended December 31, 2012, with comparative figures for 2011

		2012		2011
Cash provided by (used in):				
Operations:				
Net earnings	$	2,490,960	$	1,976,786
Items not involving cash:				
Amortization		1,862,125		2,186,947
Gain on disposal of capital assets		-		(24,477)
Future income taxes (recovery)		36,575		(16,350)
(Decrease) increase in employee future benefits		(17,556)		8,748
Changes in non-cash operating working capital (note 15)		(994,759)		(1,537,236)
Change in regulatory assets		678,950		503,449
		4,056,295		3,097,867
Financing:				
Advancement (repayment) of Smart Meter loan		(229,975)		424,352
Due from related companies		8,454		52,688
Consumer deposits		183,853		(177,040)
Dividends on common shares		(1,077,592)		(943,705)
Capital contributions		1,085,377		472,705
		(29,883)		(171,000)
Investments:				
Purchase of capital assets (note 8)		(7,558,594)		(4,085,865)
Proceeds on sale of capital assets		-		24,477
		(7,558,594)		(4,061,388)
Decrease in cash and cash equivalents		(3,532,182)		(1,134,521)
Cash and cash equivalents, beginning of year		1,257,808		2,392,329
Cash and cash equivalents (bank indebtedness), end of year	$	(2,274,374)	$	1,257,808

See accompanying notes to financial statements.

Halton Hills Hydro Inc., the "Company", is a wholly-owned subsidiary of Halton Hills Community Energy Corporation incorporated under the laws of the Province of Ontario.

The principal activity of the Company is to provide electric power distribution throughout the municipality of Halton Hills.

1. Regulation:

Regulator:

The Ontario Energy Board (OEB) has regulatory oversight of the electricity industry in the Province of Ontario. The Ontario Energy Board Act, 1998, the Electricity Act, 1998, the Electricity Restructuring Act, 2004 and a number of other provincial statutes set out the OEB's mandate and authority. The OEB prescribes and enforces license requirements and conditions towards the following objectives as set out in the Electricity Restructuring Act, 2004:

- To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; and
- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

The OEB's authority and responsibilities include the ability to approve and set rates for the transmission and distribution of electricity, to provide rate protection for various electricity consumers, and to ensure electricity distribution companies fulfill their customer service obligations.

Rate approval process:

In 2006, the OEB developed a three-year staggered plan to set electricity distribution rates using two methodologies. In year one under the plan, utilities would have their rates set by way of a cost of service review, where the utility applies for rates based on the costs incurred to deliver electricity. In the other two years, utilities would have their rates set by way of Incentive Regulation Mechanism (IRM). These reviews provide a standard rate adjustment that accounts

1. Regulation (continued):

Rate approval process (continued):

for inflation and productivity improvements. Incentive regulation is intended to provide distributors with the opportunity to increase returns to shareholders through the implementation of efficiency initiatives. These efficiencies are also intended to benefit ratepayers by reducing costs.

Type of regulation:

The 2012 Cost of Service Rate application for 2012 rates was filed with the OEB on August 26, 2011. The 2012 Cost of Service application included a move from CGAAP to MIFRS basis of accounting, an increase to capital expenditures and OM&A. A partial settlement was submitted and accepted by the OEB. The first OEB interim rate decision in regards to 2012 rates was received on June 14, 2012 with rate adjustments in effect for May 1, 2012. The second OEB interim rate decision was issued July 4, 2012, pending the outcome of a PP&E review by the OEB Regulatory Audit and Accounting Department. The PP&E review has been completed satisfactorily. The effective date of the rates was May 1, 2012 with an implementation date of July 1, 2012.

A 2013 IRM Rate Application was submitted on October 11, 2012. The OEB rate decision was received on April 4, 2013.

Smart Meter initiatives:

The installation of Smart Meters for the Company began in April 2009 and was completed during 2010 as required by the Energy Conservation Responsibility Act, 2006. These meters will have the capacity to measure and report usage over certain periods, be read remotely and provide customers with access to information about their consumption.

Included in distribution rates effective May 1, 2012 are two Smart Meter Rate Rider charges. The Smart Meter capital and OM&A costs were moved into the appropriate regulatory accounts in 2012. The cost recovery was separated into two different rate riders, Residual Historic and Stranded Meters with class specific recovery. The monthly Smart Meter Residual Historic Rate Rider is in the amounts of $1.31 and $1.38 per customer per month for Residential and General Service less than 50kW classes respectively. The Smart Meter Stranded Meters Rate Rider is in the amounts of $1.13 and $1.46 per customer per month for Residential and General Service less than 50kW classes respectively. Both Rate Riders continue until date of April 30, 2016.

Green Energy and Green Economy Act

In early 2009, the government tabled the *Green Energy and Green Economy Act ("GEGEA")*. This new legislation makes fundamental changes to the roles and responsibilities of LDCs in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

1. Regulation (continued):

Green Energy and Green Economy Act (continued):

The GEGEA provides LDCs with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. LDCs will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDCs will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

New LDC License Requirements - Conservation and Demand Management Targets

On November 12, 2010, the OEB amended LDC licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Company's CDM targets include a demand reduction target of 6.15MW and a consumption reduction target of 22.48GWh. LDCs must also comply with a new CDM Code of the OEB, which provides LDC requirements for the development and delivery of CDM Strategy to the OEB for the achievement of LDC-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Company has filed its CDM Strategy with the OEB.

Regulatory Accounting

In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The Company's regulatory liabilities represent costs with respect to non-distribution market related charges and variances in recoveries that are expected to be settled in future periods.

The OEB Decision and Order EB-2011-0271 dated June 14, 2012 provided for the disposition of $612,426 of the Company's Deferral and Variance account balances, as of December 31, 2010, over a 24 month period ending April 30, 2014.

2. Significant accounting policies:

(a) Basis of accounting:

The financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), as set out in Part V of the CICA Handbook, and reflect the following significant accounting policies as set forth in the Accounting Procedures Handbook issued by the Ontario Energy Board (OEB) under the authority of the Ontario Energy Board Act, 1998.

The following accounting policies under the regulated environment differ from GAAP for companies operating in an unregulated environment:

(i) Capital contributions:

Capital contributions in aid of construction consist of third party contributions toward the cost of constructing Company assets. Amortization of contributed capital is on a straight-line basis over the life of the related asset. Capital contributions for the year of $1,085,377 (2011 - $472,705) have been charged as an offset to capital assets.

(ii) Regulatory assets:

Regulatory assets represent future revenues associated with costs incurred in the current or prior periods, which are expected to be recovered from customers in future periods through the rate setting process.

Regulatory assets result from the provincially approved rate set by the OEB and represent differences between costs incurred and amounts collected through rates. Regulatory assets on the balance sheet at year end relate primarily to retail settlement variance accounts and stranded meters. Regulatory assets will be recognized for rate-setting and financial statement purposes only to the extent allowed by the regulator.

The regulatory assets are recovered through incremental amounts charged to consumers as approved by the OEB.

The Ontario Energy Board Amendments Act (Electricity Pricing), 2003, in conjunction with Bill 4, allows for recovery of regulatory assets. The Company's Group 1 Deferral and Variance accounts, as of December 31, 2008, were recovered through the period ending April 30, 2012.

2. Significant accounting policies (continued):

(a) Basis of accounting (continued):

(iii) *Payments-in-lieu of income taxes:*

Under the Electricity Act, 1998, the Company is required to make payments-in-lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are recorded in accordance with the rules for computing income taxes, taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) and modified by the Electricity Act, 1998, and related regulations.

The Company provides for PILs using the asset and liability method. Under this method, future tax assets and liabilities are recognized, to the extent such are determined likely to be realized, for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment.

As required by CICA Handbook Section 3465, a regulatory liability is recorded for those future tax assets which are expected to be repaid to customers through future rates.

(b) Cash and cash equivalents:

Cash and cash equivalents consist of cash on hand, balances with banks, and investments in money market instruments, with maturities of 90 days or less at acquisition. Investing and financing activities that do not require the use of cash or cash equivalents are excluded from the Statement of Cash Flows and disclosed separately.

(c) Inventory:

Inventory is stated at the lower of cost or net realizable value. Inventory cost includes all costs of purchase, conversion and other costs incurred in bringing the inventory to its present location and condition. When circumstances which previously caused inventory to be written down below cost are no longer in existence, the amount of the write-down shall be reversed.

2. Significant accounting policies (continued):

(d) Capital assets:

On January 1, 2012, the Company revised its accounting policies for property, plant and equipment (PP&E) to comply with requirements of the regulator. As a result, the useful service life of the assets has been revised and is based upon the actual life of the assets experienced by the Company. The accounting policy change has been accounted for prospectively in accordance with the direction of the regulator.

In accordance with the requirements of the regulator, the Company has recorded a cumulative adjustment to capital assets with an offsetting amount recorded to regulatory assets. This adjustment to capital assets and regulatory assets is being amortized over four years. Capital assets are recorded at cost with the exception of this adjustment to capital assets. 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, direct labour, directly attributable overhead costs, and any other costs directly attributable to bringing the asset to a working condition for its intended use. In circumstances where parts of an item of PP&E have different useful lives, such are accounted for as separate items (major components) of PP&E.

Amortization is provided on a straight-line basis over the useful service life as follows:

Asset	Rate
Distribution systems	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

Construction in progress assets are not amortized until the project is complete and in service.

Capital assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

2. Significant accounting policies (continued):

(e) Employee future benefits:

The Corporation 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. These post-retirement costs are recognized in the period in which the employees rendered their services to the Corporation. The excess of the net accumulated actuarial losses over 10% of the accrued benefit obligation is amortized over the average remaining service period of active employees. The expected average remaining service life of the active employees is 12 years.

(f) Revenue recognition:

Service revenue is recorded on the basis of regular meter readings and estimated power usage since the last meter reading date to the year end. The related cost of power is recorded on the basis of power used.

Other income, which includes pole attachment rentals, customer requested services and miscellaneous revenues, are recognized as the service activity is performed.

(g) Use of estimates:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenditures during the reporting period. Significant estimates include unbilled revenue, useful service life of capital assets and employee future benefits. Actual results could differ from those estimates.

2. Significant accounting policies (continued):

(h) Financial instruments:

Financial assets and liabilities:

The financial instrument accounting standards require that all financial instruments are classified into one of the following categories: held-for-trading, available-for-sale, held-to-maturity, other liabilities or loans and receivables. All financial instruments are carried on the balance sheet at fair value, except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The Company has classified its financial instruments as follows:

Cash and cash equivalents	Held-for-trading
Accounts receivable and unbilled revenue	Loans and receivables
Due from related companies	Loans and receivables
Bank indebtedness	Other liabilities
Smart Meter bank loan	Other liabilities
Accounts payable and accrued liabilities	Other liabilities
Consumer deposits	Other liabilities
Note payable	Other liabilities

Held-for-trading financial instruments are measured at fair value, with all gains and losses and transaction costs included in net earnings. Loans and receivables and other liabilities are measured at amortized cost using the effective interest rate method.

Derivatives and hedge accounting:

The Company does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the presentation of these financial statements.

3. Future accounting policies

Transition to International Financial Reporting Standards ("IFRS")

The Canadian Accounting Standards Board ("AcSB") has adopted a strategic plan that will have Canadian GAAP converge with IFRS, effective January 1, 2011 which will require entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved the incorporation of a one year deferral of adoption of Part 1 of the CICA Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook now specifies that first-time adoption, for companies that meet this requirement, is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2012. This deferral has subsequently been deferred further to annual periods beginning on or after January 1, 2015.

The amendment also requires entities that do not prepare its interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

The Company has decided to implement IFRS commencing January 1, 2015.

4. Accounts receivable:

	2012	2011
Electric service revenue	$ 4,373,304	$ 3,282,836
Miscellaneous	2,148,723	1,300,648
Town of Halton Hills	110,711	182,741
	6,632,738	4,766,225
Less: allowance for doubtful accounts	(230,325)	(262,888)
	$ 6,402,413	$ 4,503,337

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

5. Inventory:

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 $626,896 (2011 - $627,794) in asset components and equipment previously classified as materials and supplies inventory.

The amount of inventory consumed by the Company and recognized as an expense during 2012 was $40,481 (2011 - $3,139).

6. Due from related companies:

The Company performs billing and collecting services, capital asset maintenance, finance functions, as well as certain engineering and information system services for related companies.

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

		2012		2011
SouthWestern Energy Inc.	$	(32,738)	$	(50,316)
Halton Hills Community Energy Corporation		(38,718)		2,050
1820259 Ontario Inc.		-		14,247
Harvester Energy Canada Inc.		148,190		119,207
	$	76,734	$	85,188

Administrative services provided by the Company to related companies during the year and measured at the exchange amount are as follows:

		2012		2011
SouthWestern Energy Inc.	$	306,450	$	282,888
Halton Hills Community Energy Corporation		-		61,620
1820259 Ontario Energy Inc.		-		6,860
Harvester Energy Canada Inc		6,000		30,000
	$	312,450	$	381,368

6. Due from related companies (continued):

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:

	2012	2011
Transactions:		
Revenue		
Electrical billings	$ 1,776,858	$ 1,671,328
Expenses		
Property taxes	89,628	87,753
Balances:		
Amounts due from:		
Accounts receivable	110,711	182,741

7. Regulatory assets:

Regulatory assets (liabilities) are as follows:

	2012	2011
Retail settlement variance	$ 79,265	$ 1,692,835
Low voltage	36,254	(649,980)
Other	(629,485)	(528,588)
Smart Meter	1,098,101	5,075,850
Regulatory asset recovery account, net of receipts	842,793	664,348
IFRS	685,444	587,565
Customer liability of future taxes	495,396	(112,980)
	$ 2,607,768	$ 6,729,050

Management expects that regulatory assets arising during 2011 through 2012, other than those approved through the 2012 rate setting process, will be recovered through future rate changes. If in a future decision, the regulator determines that the existing regulatory treatment is no longer applicable, the regulatory assets would be charged to operations.

In the absence of rate regulation, GAAP would require that the actual purchased power costs (including any variances arising from electricity commodity, retail transmission and wholesale market costs) be recognized as an expense when incurred.

In the absence of rate regulation, net earnings for the year would have been lower by $609,396 (2011 - $413,957), future tax asset would be higher by $159,525 (2011 - $55,128), retained earnings would be lower by $394,081 (2011 - $nil) and capital assets would be higher by $nil (2011 - $4,600,847).

8. Capital assets:

	Cost	Accumulated amortization	2012 Net book value	2011 Net book value
Distribution systems	$ 35,023,448	$ 1,095,625	$ 33,927,823	$ 24,986,962
Plant	8,892,749	326,461	8,566,288	8,035,083
Fleet	1,228,502	184,231	1,044,271	1,004,693
Other equipment	1,158,748	103,450	1,055,298	1,239,187
Computer equipment and software	607,892	480,016	127,876	188,424
General office	123,000	10,290	112,710	110,291
Stores equipment	5,161	214	4,947	5,019
Contributed capital	(6,346,445)	(128,903)	(6,217,542)	(5,117,596)
Construction in progress	1,570,948	-	1,570,948	1,078,756
	$ 42,264,003	$ 2,071,384	$ 40,192,619	$ 31,530,819

During the year, the Company recorded capital asset additions of $7,558,594 (2011 - $4,085,865).

As described in note 2(d), the Company recorded a cumulative adjustment of $836,717 to capital assets with an offsetting amount recorded in regulatory assets.

9. Accounts payable and accrued liabilities:

Accounts payable and accrued liabilities also includes $254,583 (2011 - $25,265) due to related companies under common control. These payables arose in the normal course of operations and are due under normal terms of trade.

10. 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, 2015. The prescribed rate of interest is 6.25% from January – April and 5.01% from May – Dec. (2011 – 6.25%).

The Company incurred interest expense in respect of the note payable of $875,433 (2011 - $1,008,873).

11. Employee future benefits:

The Company pays certain medical and life insurance benefits on behalf of its retired employees. The Company recognizes these post-retirement costs in the period in which employees' services were rendered. The accrued benefit liability and expenses for the year ended December 31, 2012 were based on results and assumptions determined by actuarial valuation as at December 31, 2012.

Information regarding the defined benefit plan of the Company is as follows:

		2012		2011
Accrued benefit obligation, beginning of year	$	610,192	$	391,745
Estimated expense for the year		29,006		13,584
Interest expense		28,499		21,941
Benefits paid during year		(11,795)		(12,805)
Actuarial loss		-		195,727
Accrued benefit obligation, end of year		655,902		610,192
Unamortized actuarial (loss) gain		(176,155)		(112,889)
Accrued benefit liability	$	479,747	$	497,303

Amortization of the actuarial gain (loss) was ($19,753) (2011.– $13,972).

The main actuarial assumptions utilized for the valuation are as follows:

General Inflation – future general inflation levels, as measured by the changes in the Consumer Price Index (CPI), were assumed at 2.0% in 2012 and thereafter.

Discount (Interest) Rate – the obligation as at December 31, 2012 of the present value of future liabilities and the expense for the year then ended were determined using a discount rate of 4.5% (2011 – 4.5%). This rate reflects the assumed mid term yield on high quality bonds.

Salary levels – future general salary and wage levels were assumed to increase at the CPI rate adjusted for merit and promotion gains of 2.55% per annum for the first five years and 3.00% per annum thereafter.

Medical costs – medical costs were assumed to increase at the CPI rate plus 8% in 2012. Thereafter, medical costs are assumed to decline by 0.37% per annum.

Dental costs – dental costs were assumed to increase at the CPI rate plus 5.0%.

12. Capital stock:

	2012	2011
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
	$ 16,161,663	$ 16,161,663

13. Service revenue:

	2012	2011
Service revenue consists of:		
Cost of power	$ 45,746,998	$ 45,727,509
Distribution	10,434,637	9,284,846
	$ 56,181,635	$ 55,012,355

14. Other costs:

On November 28, 2008 the OEB commenced a combined proceeding on its own motion to determine the final account balances with respect to Deferred PILs for the period October 1, 2001 to April 30, 2006 for certain electricity distributors. The OEB subsequently determined the Company, one of three electricity distributors, should provide their specific evidence on the disposition of the PILs balance and a series of procedural steps extended over many months.

A proposed settlement was filed with the OEB on September 30, 2010. In its Decision and Procedural Order No.9 dated December 23, 2010, the OEB accepted the Settlement Agreement.

On June 24, 2011, the OEB directed the Company to submit the final balance in the PILs account as at April 30, 2006, reflecting the OEB's findings and the approved Settlement Agreement dated September 30, 2010.

As a result of the proceeding and the filing of the 2012 Cost of Service Application, the Company has recorded a 'one-time' PILs adjustment in the amount of $Nil (2011 – $504,845). This PILs adjustment is reflected in other costs.

15. Changes in non-cash working capital:

(a) The net change is non-cash working capital consists of the following:

	2012	2011
Accounts receivable	$ (1,899,076)	$ (126,932)
Unbilled revenue	1,395,973	(858,027)
PILs receivable	(213,974)	(160,360)
Inventory	(300,489)	(209,638)
Prepaid expenses and deposits	(157,528)	(32,615)
Accounts payable and accrued liabilities	180,335	(149,664)
	$ (994,759)	$ (1,537,236)

(b) Supplemental cash flow information:

	2012	2011
Cash paid during the year for interest	$ 969,613	$ 1,069,234
Cash paid during the year for PILs	827,592	630,000
Non-cash financing activities:		
Decrease in regulatory assets for smart meters transferred to property, plant and equipment	3,423,249	-
Decrease in regulatory assets relating to revised accounting policy for property, plant and equipment	627,459	-
Increase in regulatory assets related to decrease in future tax assets	608,376	220,514

16. Credit facilities:

a) Credit limit

The Company has available an operating credit facility from a financial institution in the amount of $5,500,000 (2011 - $5,500,000). Credit is available to the Company in the form of prime based loans, bankers' acceptances, letters of credit or stand-by letters of guarantee. Interest on prime based loans is at prime. At year end, the letter of credit described in b) below is outstanding and the operating line utilized is $2,100,000. Security is in the form of a first charge over the Company's assets and undertakings and an assignment of liability, fire insurance has been provided.

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 (2011 - $1,754,315) from a financial institution.

c) Covenants

The above credit facilities require an interest coverage ratio of not less than 1.2 to 1.0, and a total interest bearing debt to capitalization ratio not greater than 0.60 to 1. As at December 31, 2012, the Company is in compliance with these covenants.

d) Term Loan

In 2010, the Company had an available interim demand loan facility up to $4,000,000 by way of Bankers Acceptance to facilitate the implementation of Smart Meters. Security is in the form of a first charge over the Company's assets and undertakings, business insurance and an assignment of fire insurance. The Company drew $3,500,000 at the end of 2010. In August 2011 the loan was paid in full and replaced by a Fixed Term Loan of $4,000,000 due August 30, 2026. The loan has an interest rate of 2.17%, with a rate term renewable annually. Interest of $27,147 was paid and expensed during the year. The loan is payable in the amount of $26,050 monthly principal and interest. Principal payments on the loan are as follows:

	2012
2013	$ 234,776
2014	235,387
2015	240,450
2016	245,622
2017 - 2026	2,738,142
	3,694,377
Less: current portion	(234,776)
Long-term portion of loan	$ 3,459,601

17. Pension agreement:

The Company and its employees contribute to the Ontario Municipal Employee's 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, public utilities and school boards. 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. Contributions by the Company were at a rate of 8.3% for employee earnings below the year's maximum pensionable earnings and 12.8% thereafter. The Company's contribution for employees' current service for the year ended December 31, 2012 was $356,601 (2011 - $312,096).

18. Financial instruments:

Level 1

The carrying value of the cash and cash equivalents, accounts receivable and unbilled revenue, due from related companies bank indebtedness, accounts payable and accrued liabilities, and consumer deposits all approximate fair value because of the short maturity of these instruments. The Smart Meter Bank Loan has a carrying value that approximates fair value as the rate term is renewable annually.

Level 3

The note payable has a fair value of $15,551,000 based on the company's internal borrowing rate of 1.25%.

The Company's activities provide for a variety of financial risks. Exposure to credit risk, market risk and liquidity risk occur in the normal course of the Company's operations as follows:

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 municipality of Halton Hills. No single customer accounts for revenue in excess of 2% of the respective reported balances.

18. Financial instruments (continued):

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 operations. The balance of the allowance for doubtful accounts is disclosed in note 4. No single customer accounts for more than 3% of accounts receivable at year end.

The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2012, approximately $188,760 is considered 90 days past due. The Company has approximately 21,000 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, 2012, the Company holds security deposits in the amount of $720,918 (2011 - $537,065).

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Consumer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Consumer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risks, as determined by the Company. Interest expense of $4,303 (2011 - $3,220) was incurred on consumer deposits.

Market risks

Market risks primarily refer to the risk of loss that may result from changes in commodity prices, foreign exchange rates, and interest rates. The Company currently does not have 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 at the time of filing. This rate of return is approved by the OEB as part of the approval of distribution rates.

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.

19. 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 electrical utilities 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. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2012, no assessments have been made.

20. 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 and long-term debt. As at December 31, 2012, shareholder's equity amounts to $24,588,673 (2011 - $23,175,305) and long-term debt amounts to $19,601,571 (2011 - $19,836,118).

21. Comparative figures:

Certain 2011 comparative figures have been reclassified to conform with the financial statement presentation adopted for the current year.

Financial Statements of

HALTON HILLS HYDRO INC.

Year ended December 31, 2013

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Halton Hills Hydro Inc.

We have audited the accompanying financial statements of Halton Hills Hydro Inc. (the "Entity") which comprise the balance sheet as at December 31, 2013, and the statements of operations and retained earnings and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, 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.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Entity's preparation and fair presentation of the financial statements 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 Entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Halton Hills Hydro Inc. as at December 31, 2013, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 24, 2014
Hamilton, Canada

HALTON HILLS HYDRO INC.

Financial Statements

Year ended December 31, 2013

Financial Statements

HALTON HILLS HYDRO INC.

Balance Sheet

December 31, 2013, with comparative figures for 2012

		2013		2012
Assets				
Current assets:				
Accounts receivable (note 4)	$	6,569,272	$	6,402,413
Unbilled revenue		7,177,715		5,189,927
PILs receivable		504,933		425,567
Inventory (note 5)		821,824		1,004,034
Due from related companies (note 6)		88,154		76,734
Prepaid expenses and deposits		461,576		441,868
		15,623,474		13,540,543
Regulatory assets (note 7)		7,711,900		2,607,768
Capital assets (note 8)		45,694,680		40,192,619
	$	69,030,054	$	56,340,930
Liabilities and Shareholder's Equity				
Current liabilities:				
Bank indebtedness	$	3,937,318	$	2,274,374
Accounts payable and accrued liabilities (note 9)		10,508,352		8,104,130
Current portion of bank term loans (note 15 (d))		424,895		234,776
Current portion of consumer deposits		230,000		230,000
		15,100,565		10,843,280
Bank term loans (note 15 (d))		7,432,423		3,459,601
Note payable (note 10)		16, 141,970		16, 141,970
Consumer deposits		505,282		490,918
Employee future benefits (note 11)		547,447		479,747
Future income taxes		2,385,431		336,741
Shareholder's equity:				
Capital stock (note 12)		16,161,663		16,161,663
Retained earnings		10,755,273		8,427,010
		26,916,936		24,588,673
	$	69,030,054	$	56,340,930

See accompanying notes to financial statements.

On behalf of the Board:

Wayne Whitelaw _______ Chair

[illegible] _______ Director

HALTON HILLS HYDRO INC.

Statement of Operations and Retained Earnings

Year ended December 31, 2013, with comparative figures for 2012

	2013	2012
Revenue:		
Service revenue (note 13)	$ 59,624,436	$ 56,181,635
Other income	1,071,089	1,186,589
	60,695,525	57,368,224
Expenditure:		
Cost of power (note 13)	50,494,619	45,746,998
Salaries and benefits	5,307,544	4,759,645
Material costs	2,663,788	2,747,932
Contract services	3,107,635	3,137,463
Property costs	701,458	1,473,618
Other costs	744,461	894,224
Communication costs	450,064	313,648
Allocated to capital	(7,797,337)	(7,400,948)
	55,672,232	51,672,580
Earnings before the undernoted	5,023,293	5,695,644
Other expenses:		
Amortization	1,360,873	1,684,937
Interest expense	789,250	1,111,528
	2,150,123	2,796,465
Earnings before income taxes	2,873,170	2,899,179
Income taxes:		
Current (recovery)	(733,827)	371,644
Future (recovery)	(16,610)	36,575
	(750,437)	408,219
Net earnings	3,623,607	2,490,960
Retained earnings, beginning of year	8,427,010	7,013,642
Dividends on common shares	(1,295,344)	(1,077,592)
Retained earnings, end of year	$ 10,755,273	$ 8,427,010

See accompanying notes to financial statements.

HALTON HILLS HYDRO INC.

Statement of Cash Flows

Year ended December 31, 2013, with comparative figures for 2012

	2013	2012
Cash provided by (used in):		
Operations:		
Net earnings	$ 3,623,607	$ 2,490,960
Items not involving cash:		
Amortization	1,722,514	1,862,125
Future income taxes (recovery)	(16,610)	36,575
(Decrease) increase in employee future benefits	67,700	(17,556)
Changes in non-cash operating working capital (note 14)	332,711	(994,759)
Change in regulatory assets	(3,038,832)	678,950
	2,691,090	4,056,295
Financing:		
Advancement (repayment) of term loans	4,162,941	(229,975)
Due from related companies	(11,420)	8,454
Consumer deposits	14,364	183,853
Dividends on common shares	(1,295,344)	(1,077,592)
Capital contributions received	907,621	1,085,377
	3,778,162	(29,883)
Investments:		
Purchase of capital assets (note 8)	(8,132,196)	(7,558,594)
	(8,132,196)	(7,558,594)
Decrease in cash and cash equivalents	(1,662,944)	(3,532,182)
Cash and cash equivalents (bank indebtedness), beginning of year	(2,274,374)	1,257,808
Bank indebtedness, end of year	$ (3,937,318)	$ (2,274,374)

See accompanying notes to financial statements.

Halton Hills Hydro Inc., the "Company", is a wholly-owned subsidiary of Halton Hills Community Energy Corporation incorporated under the laws of the Province of Ontario.

The principal activity of the Company is to provide electric power distribution throughout the municipality of Halton Hills.

1. Regulation:

Regulator:

The Ontario Energy Board (OEB) has regulatory oversight of the electricity industry in the Province of Ontario. The Ontario Energy Board Act, 1998, the Electricity Act, 1998, the Electricity Restructuring Act, 2004 and a number of other provincial statutes set out the OEB's mandate and authority. The OEB prescribes and enforces license requirements and conditions towards the following objectives as set out in the Electricity Restructuring Act, 2004:

- To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; and
- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

The OEB's authority and responsibilities include the ability to approve and set rates for the transmission and distribution of electricity, to provide rate protection for various electricity consumers, and to ensure electricity distribution companies fulfill their customer service obligations. The OEB may also prescribe license requirements and conditions of service to electricity distributors 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. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment.

Rate approval process:

The OEB regulates the electricity distribution rates charged by the Company using a combination of annual incentive regulation mechanism ("IRM") adjustments and periodic cost of service reviews. Both such adjustments and reviews are based on applications made by the Company to the OEB.

In 2008, the OEB developed a three-year plan for 3rd generation incentive regulation mechanism ("IRM") to set electricity distribution rates. The IRM process provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications (rebasing plus three years). The IRM process allows a standard rate adjustment that accounts

1. Regulation (continued):

Rate approval process (continued):

for inflation and productivity improvements. Incentive regulation is intended to provide distributors with the opportunity to increase returns to shareholders through the implementation of efficiency initiatives. These efficiencies are also intended to benefit ratepayers by reducing costs.

Type of regulation:

The Company's last Cost of Service Rate application was filed with the OEB on August 26, 2011. The 2012 Cost of Service application included a move from CGAAP to MIFRS basis of accounting, having an impact on capital expenditures and OM&A. A partial settlement was submitted and accepted by the OEB. The first OEB interim rate decision in regards to 2012 rates was received on June 14, 2012 with rate adjustments in effect for May 1, 2012. The second OEB interim rate decision was issued July 4, 2012, effective date of the rates was May 1, 2012 with an implementation date of July 1, 2012. The interim rate decisions issued by the OEB, were dependent upon the outcome of a PP&E review by the OEB Regulatory Audit and Accounting Department. The PP&E review was satisfactorily completed on January 14, 2013. In the OEB's Decision and Order, dated April 4, 2013, the 2012 Tariff of Rates and Charges were declared as final, effective May 1, 2012.

On October 12, 2012 the Company filed an IRM application to adjust its distribution rates effective May 1, 2013. The OEB's Decision and Order approving the application was received on April 4, 2013.

On September 27, 2013 the Company filed an IRM application to adjust its distribution rates effective May 1, 2014. The OEB's Decision and Order approving the application was received on March 13, 2014.

Smart Meter initiatives:

The installation of Smart Meters for the Company began in April 2009 and was completed during 2010 as required by the Energy Conservation Responsibility Act, 2006. These meters will have the capacity to measure and report usage over certain periods, be read remotely and provide customers with access to information about their consumption.

Included in distribution rates effective May 1, 2012 are two Smart Meter Rate Rider charges. The Smart Meter capital and OM&A costs were moved into the appropriate regulatory accounts in 2012. The cost recovery was separated into two different rate riders, Residual Historic and Stranded Meters with class specific recovery. The monthly Smart Meter Residual Historic Rate Rider is in the amounts of $1.31 and $1.38 per customer per month for Residential and General Service less than 50kW classes respectively. The Smart Meter Stranded Meters Rate Rider is in the amounts of $1.13 and $1.46 per customer per month for Residential and General Service less than 50kW classes respectively. Both Rate Riders continue until date of April 30, 2016.

1. Regulation (continued):

Green Energy and Green Economy Act:

In early 2009, the government tabled the *Green Energy and Green Economy Act ("GEGEA")*. This new legislation makes fundamental changes to the roles and responsibilities of LDCs in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The GEGEA provides LDCs with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. LDCs will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDCs will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

New LDC License Requirements - Conservation and Demand Management Targets:

On November 12, 2010, the OEB amended LDC licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Company's CDM targets include a demand reduction target of 6.15MW and a consumption reduction target of 22.48GWh. LDCs must also comply with a new CDM Code of the OEB, which provides LDC requirements for the development and delivery of CDM Strategy to the OEB for the achievement of LDC-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Company has filed its CDM Strategy with the OEB.

Regulatory Accounting:

In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The Company's regulatory liabilities represent costs with respect to non-distribution market related charges and variances in recoveries that are expected to be settled in future periods.

The OEB Decision and Order EB-2011-0271 dated June 14, 2012 provided for the disposition of $612,426 of the Company's Deferral and Variance account balances, as of December 31, 2010, over a 24 month period ending April 30, 2014.

1. Regulation (continued):

Regulatory Accounting (continued):

The OEB Decision and Order EB-2013-0136 dated March 13, 2014 provided for the disposition of the Company's Group 1 Deferral and Variance account balances in the amount of $976,553 as of December 31, 2012, including interest projected to April 30, 2014. These balances are to be disposed of over a one-year period from May 1, 2014 to April 30, 2015.

2. Significant accounting policies:

(a) Basis of accounting:

The financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), as set out in Part V of the CPA Canada Handbook, and reflect the following significant accounting policies as set forth in the Accounting Procedures Handbook issued by the Ontario Energy Board (OEB) under the authority of the Ontario Energy Board Act, 1998.

The following accounting policies under the regulated environment differ from GAAP for companies operating in an unregulated environment:

(i) Capital contributions:

Capital contributions in aid of construction consist of third party contributions toward the cost of constructing Company assets. Amortization of contributed capital is on a straight-line basis over the life of the related asset. Capital contributions for the year of $907,621 (2012 – $1,085,377) have been charged as an offset to capital assets.

(ii) Regulatory assets:

Regulatory assets represent future revenues associated with costs incurred in the current or prior periods, which are expected to be recovered from customers in future periods through the rate setting process.

Regulatory assets result from the provincially approved rate set by the OEB and represent differences between costs incurred and amounts collected through rates. Regulatory assets on the balance sheet at year end relate primarily to retail settlement variance accounts, global adjustment and cost of power. Regulatory assets will be recognized for rate-setting and financial statement purposes only to the extent allowed by the regulator.

The regulatory assets are recovered through incremental amounts charged to consumers as approved by the OEB.

2. Significant accounting policies (continued):

(a) Basis of accounting (continued):

(ii) Regulatory assets (continued):

The Ontario Energy Board Amendments Act (Electricity Pricing), 2003, in conjunction with Bill 4, allows for recovery of regulatory assets. The Company's Group 1 Deferral and Variance accounts, as of December 31, 2010, are recovered through to the period ending April 30, 2014 (EB-2011-0271). The Company's Group 1 Deferral and Variance accounts, as of December 31, 2012, will be recovered over a one-year period from May 1, 2014 to April 30, 2015 (EB-2013-0136).

(iii) Payments-in-lieu of income taxes:

Under the Electricity Act, 1998, the Company is required to make payments-in-lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are recorded in accordance with the rules for computing income taxes, taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) and modified by the Electricity Act, 1998, and related regulations.

The Company provides for PILs using the asset and liability method. Under this method, future tax assets and liabilities are recognized, to the extent such are determined likely to be realized, for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment.

As required by CPA Canada Handbook Section 3465, a regulatory liability is recorded for those future tax assets which are expected to be repaid to customers through future rates.

(b) Cash and cash equivalents:

Cash and cash equivalents consist of cash on hand, balances with banks, and investments in money market instruments, with maturities of 90 days or less at acquisition. Investing and financing activities that do not require the use of cash or cash equivalents are excluded from the Statement of Cash Flows and disclosed separately.

2. Significant accounting policies (continued):

(c) Inventory:

Inventory is stated at the lower of cost or net realizable value. Inventory cost includes all costs of purchase, conversion and other costs incurred in bringing the inventory to its present location and condition. When circumstances which previously caused inventory to be written down below cost are no longer in existence, the amount of the write-down shall be reversed.

(d) Capital assets:

On January 1, 2012, the Company revised its accounting policies for property, plant and equipment (PP&E) to comply with requirements of the regulator. As a result, the useful service life of the assets was revised and is based upon the actual life of the assets experienced by the Company. The accounting policy change was accounted for prospectively in accordance with the direction of the regulator.

In accordance with the requirements of the regulator, the Company has recorded a cumulative adjustment to capital assets with an offsetting amount recorded to regulatory assets. This adjustment to capital assets and regulatory assets is being amortized over four years. Capital assets are recorded at cost with the exception of this adjustment to capital assets. 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, direct labour, directly attributable overhead costs, and any other costs directly attributable to bringing the asset to a working condition for its intended use. In circumstances where parts of an item of PP&E have different useful lives, such are accounted for as separate items (major components) of PP&E.

Amortization is provided on a straight-line basis over the useful service life as follows:

Asset	Rate
Distribution systems	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

Construction in progress assets are not amortized until the project is complete and in service.

2. Significant accounting policies (continued):

(d) Capital assets (continued):

The Company capitalizes borrowing costs relating to the construction of a capital asset that takes a substantial period of time to bring to its intended use.

Capital assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

(e) Employee future benefits:

The Corporation 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. These post-retirement costs are recognized in the period in which the employees rendered their services to the Corporation. The excess of the net accumulated actuarial losses over 10% of the accrued benefit obligation is amortized over the average remaining service period of active employees. The expected average remaining service life of the active employees is 12 years.

(f) Revenue recognition:

Service revenue is recorded on the basis of regular meter readings and estimated power usage since the last meter reading date to the year end. The related cost of power is recorded on the basis of power used.

Other income, which includes pole attachment rentals, customer requested services and miscellaneous revenues, are recognized as the service activity is performed.

(g) Use of estimates:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenditures during the reporting period. Significant estimates include unbilled revenue, useful service life of capital assets and employee future benefits. Actual results could differ from those estimates.

2. Significant accounting policies (continued):

(h) Financial instruments:

Financial assets and liabilities:

The financial instrument accounting standards require that all financial instruments are classified into one of the following categories: held-for-trading, available-for-sale, held-to-maturity, other liabilities or loans and receivables. All financial instruments are carried on the balance sheet at fair value, except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The Company has classified its financial instruments as follows:

Cash and cash equivalents	Held-for-trading
Accounts receivable and unbilled revenue	Loans and receivables
Due from related companies	Loans and receivables
Bank indebtedness	Other liabilities
Bank term loans	Other liabilities
Accounts payable and accrued liabilities	Other liabilities
Consumer deposits	Other liabilities
Note payable	Other liabilities

Held-for-trading financial instruments are measured at fair value, with all gains and losses and transaction costs included in net earnings. Loans and receivables and other liabilities are measured at amortized cost using the effective interest rate method.

Derivatives and hedge accounting:

The Company does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the presentation of these financial statements.

3. Future accounting policies:

a) Transition to International Financial Reporting Standards ("IFRS"):

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that would have Canadian GAAP converge with IFRS, effective January 1, 2011 which would have required entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved the incorporation of a one year deferral of adoption of IFRS into Part 1 of the CPA Canada Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CPA Canada Handbook specified that first-time adoption, for companies that met this requirement, was mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2015.

The amendment also requires entities that do not prepare interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

The Company has decided to implement IFRS commencing January 1, 2015.

b) Accounting for rate regulated activities under IFRS:

The International Accounting Standards Board ("IASB") has issued IFRS 14 *Regulatory Deferral Accounts* in January 2014. This standard provides specific guidance on accounting for the effects of rate regulation and permits first-time adopters of IFRS to continue using previous GAAP to account for regulatory deferral account balances while the IASB completes its comprehensive project in this area. Adoption of this standard is optional for entities eligible to use it. Deferral account balances and movements in the balances will be required to be presented as separate line items on the face of the financial statements distinguished from assets, liabilities, income and expenses that are recognized in accordance with other IFRSs. Extensive disclosures will be required to enable users of the financial statements to understand the features and nature of and risks associated with rate regulation and the effect of rate regulation on the entity's financial position, performance and cash flows.

4. Accounts receivable:

	2013	2012
Electric service revenue	$ 5,155,554	$ 4,373,304
Miscellaneous	1,533,338	2,148,723
Town of Halton Hills	79,821	110,711
	6,768,713	6,632,738
Less: allowance for doubtful accounts	(199,441)	(230,325)
	$ 6,569,272	$ 6,402,413

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

5. Inventory:

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 $625,336 (2012 – $626,896) to capital assets during the year.

The amount of inventory consumed by the Company and recognized as an expense during 2013 was $101,544 (2012 – $40,481).

6. Due from related companies:

The Company performs billing and collecting services, capital asset maintenance, finance functions, as well as certain engineering and information system services for related companies.

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

	2013	2012
SouthWestern Energy Inc.	$ 80,000	$ (32,738)
Halton Hills Community Energy Corporation	5,078	(38,718)
Harvester Energy Canada Inc.	3,076	148,190
	$ 88,154	$ 76,734

6. Due from related companies (continued):

Administrative services provided by the Company to related companies during the year and measured at the exchange amount are as follows:

	2013	2012
SouthWestern Energy Inc.	$ 299,687	$ 306,450
Harvester Energy Canada Inc.	-	6,000
	$ 299,687	$ 312,450

Included in contract services is $205,410 (2012 – $75,804) paid to SouthWestern Energy Inc. for electrical contracting services and smart meter repairs.

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:

	2013	2012
Transactions:		
Revenue		
Electrical billings	$ 1,765,921	$ 1,776,858
Expenses		
Property taxes	$ 90,204	$ 89,628
Balances:		
Amounts due from:		
Accounts receivable	$ 79,821	$ 110,711

7. Regulatory assets:

Regulatory assets (liabilities) are as follows:

	2013	2012
Retail settlement variance	$ 1,518,672	$ 79,265
Low voltage	170,062	36,254
Other	1,312,731	(629,485)
Stranded meters	792,096	1,098,101
Regulatory asset recovery account, net of receipts	662,849	842,793
IFRS	694,794	685,444
Customer liability for future taxes	2,560,696	495,396
	$ 7,711,900	$ 2,607,768

7. Regulatory assets (continued):

Management expects that regulatory assets arising during 2012 through 2013, other than those approved through the 2012 rate setting process, will be recovered through future rate changes. If in a future decision, the regulator determines that the existing regulatory treatment is no longer applicable, the regulatory assets would be charged to operations in the year of determination.

In the absence of rate regulation, GAAP would require that the actual purchased power costs (including any variances arising from electricity commodity, retail transmission and wholesale market costs) be recognized as an expense when incurred.

In the absence of rate regulation, net earnings for the year would have been lower by $4,556,828 (2012 – $609,396), future tax asset would be higher by $547,304 (2012 – $159,525), and retained earnings would be lower by $nil (2012 – $394,081).

8. Capital assets:

			2013	2012
	Cost	Accumulated amortization	Net book value	Net book value
Distribution systems	$ 41,020,073	$ 2,075,961	$ 38,944,112	$ 33,927,823
Plant	9,016,598	660,893	8,355,705	8,566,288
Fleet	1,296,248	343,740	952,508	1,044,271
Other equipment	1,226,530	210,206	1,016,324	1,055,298
Computer equipment and software	908,949	774,587	134,362	127,876
General office	125,050	22,696	102,354	112,710
Stores equipment	5,161	429	4,732	4,947
Contributed capital	(7,254,067)	(294,583)	(6,959,484)	(6,217,542)
Construction in progress	3,144,067	-	3,144,067	1,570,948
	$ 49,488,609	$ 3,793,929	$ 45,694,680	$ 40,192,619

During the year, the Company recorded capital asset additions of $8,132,196 (2012 – $7,558,594).

Borrowing costs capitalized during the year were $55,024 (2012 – $nil).

As described in note 2(d), the Company recorded a cumulative adjustment of $836,717 in 2012 to capital assets with an offsetting amount recorded in regulatory assets.

9. Accounts payable and accrued liabilities:

Accounts payable and accrued liabilities also includes $nil (2012 - $254,583) due to companies under common control. These payables arose in the normal course of operations and are due under normal terms of trade.

10. 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, 2015. The prescribed rate of interest is 4.12% (6.25% – January 01, 2012 to April 30, 2012 and 5.01% – May 01, 2012 – December 31, 2012).

The Company incurred interest expense in respect of the note payable of $665,049 (2012 - $875,433).

11. Employee future benefits:

The Company pays certain medical and life insurance benefits on behalf of its retired employees. The Company recognizes these post-retirement costs in the period in which employees' services were rendered. The accrued benefit liability and expenses for the year ended December 31, 2013 were based on results and assumptions determined by actuarial valuation as at December 31, 2011.

Information regarding the defined benefit plan of the Company is as follows:

	2013	2012
Accrued benefit obligation at January 1	$ 655,902	$ 610,192
Expense for the year	30,311	29,006
Interest for the year	30,592	28,499
Benefits paid during the year	(12,776)	(11,795)
Accrued benefit obligation	704,029	655,902
Unamortized actuarial loss	(156,582)	(176,155)
Net liability as at December 31	$ 547,447	$ 479,747

Amortization of the actuarial loss was ($19,573) (2012 – ($19,573)).

11. Employee future benefits (continued):

The main actuarial assumptions utilized for the valuation are as follows:

General Inflation – future general inflation levels, as measured by the changes in the Consumer Price Index (CPI), were assumed at 2.0% in 2012 and thereafter.

Discount (Interest) Rate – the obligation as at December 31, 2013 of the present value of future liabilities and the expense for the year then ended were determined using a discount rate of 4.5% (2012 – 4.5%). This rate reflects the assumed mid term yield on high quality bonds.

Salary levels – future general salary and wage levels were assumed to increase at the CPI rate adjusted for merit and promotion gains of 2.55% per annum for the first five years and 3.00% per annum thereafter.

Medical costs – medical costs were assumed to increase at the CPI rate plus 8% in 2012. Thereafter, medical costs are assumed to decline by 0.37% per annum.

Dental costs – dental costs were assumed to increase at the CPI rate plus 5.0%.

12. Capital stock:

	2013	2012
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
	$ 16,161,663	$ 16,161,663

13. Service revenue:

	2013	2012
Service revenue consists of:		
Cost of power	$ 50,494,619	$ 45,746,998
Distribution	9,129,817	10,434,637
	$ 59,624,436	$ 56,181,635

14. Changes in non-cash working capital:

(a) The net change is non-cash working capital consists of the following:

		2013		2012
Accounts receivable	$	(166,859)	$	(1,899,076)
Unbilled revenue		(1,987,788)		1,395,973
PILs receivable		(79,366)		(213,974)
Inventory		182,210		(300,489)
Prepaid expenses and deposits		(19,708)		(157,528)
Accounts payable and accrued liabilities		2,404,222		180,335
	$	332,711	$	(994,759)

(b) Supplemental cash flow information:

		2013		2012
Cash paid during the year for interest	$	805,311	$	969,613
Cash paid during the year for PILs		323,335		827,592
Cash received during the year for PILs		977,797		-
Non-cash financing activities:				
Decrease in regulatory assets for smart meters transferred to property, plant and equipment		-		3,423,249
Decrease in regulatory assets relating to revised accounting policy for property, plant and equipment		-		627,459
Increase in regulatory assets related to decrease in future tax assets		2,065,300		608,376

15. Credit facilities:

a) Credit limit:

The Company has available an operating credit facility from a financial institution in the amount of $5,500,000 (2012 - $5,500,000). 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 $2,980,000 (2012 – $2,100,000). 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.

15. Credit facilities (continued):

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 (2012 - $1,754,315) from a financial institution.

c) Covenants:

The above credit facilities require an interest coverage ratio of not less than 1.2 to 1.0, and a total interest bearing debt to capitalization ratio not greater than 0.60 to 1. As at December 31, 2013, the Company is in compliance with these covenants.

d) Term Loans:

(i) Smart Meter Term Loan: Reducing Term Facility, contractual term of 5 years to August 30, 2017 with an amortization period of 15 years to August 30, 2026. The loan interest rate of 2.16%, with a rate term renewable annually. Interest of $76,876 (2012 – $27,147) was paid and expensed during the year. The loan is payable in the amount of $26,030 monthly principal and interest. 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.

(ii) Capital Term Loan 1: Reducing Term Facility, contractual term of 10 years to February 22, 2023 with an amortization period of 20 years to February 22, 2033. The loan interest rate of 2.07%, with a rate term renewable annually. Interest of $33,836 (2012 – $nil) was paid and capitalized during the year. The loan is payable in the amount of $10,183 monthly principal and interest. 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.

(iii) Capital Term Loan 2: Reducing Term Facility, contractual term of 10 years to August 15, 2023 with an amortization period of 20 years to August 15, 2033. The loan interest rate of 2.15%, with a rate term renewable annually. Interest of $17,877 (2012 – $nil) was paid and capitalized during the year. The loan is payable in the amount of $12,826 monthly principal and interest. 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.

15. Credit facilities (continued):

d) Term Loans (continued):

Principal payments on the term loans are as follows:

		2013
2014	$	424,895
2015		434,078
2016		443,046
2017		453,034
2018		462,825
2019 – 2033		5,639,440
		7,857,318
Less: current portion		(424,895)
Long-term portion of loan	$	7,432,423

16. Pension agreement:

The Company and its employees contribute to the Ontario Municipal Employee's 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, public utilities and school boards. 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. Contributions by the Company were at a rate of 9.0% for employee earnings below the year's maximum pensionable earnings and 14.6% thereafter. The Company's contribution for employees' current service for the year ended December 31, 2013 was $382,894 (2012 - $356,601).

17. Financial instruments:

Level 1

The carrying value of the cash and cash equivalents, accounts receivable and unbilled revenue, due from related companies, bank indebtedness, 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 rate term is renewable annually.

17. Financial instruments (continued):

Level 3

The note payable has a fair value of $15,470,000 based on the company's internal borrowing rate of 2.15%.

The Company's activities provide for a variety of financial risks. Exposure to credit risk, market risk and liquidity risk occur in the normal course of the Company's operations as follows:

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 operations. The balance of the allowance for doubtful accounts is disclosed in note 4. No single customer accounts for more than 3% of accounts receivable at year end.

The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2013, approximately $172,458 (2012 – $188,760) is considered 90 days past due. The Company has approximately 21,832 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, 2013, the Company holds security deposits in the amount of $735,282 (2012 – $720,918).

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Consumer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Consumer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Company. Interest expense of $4,757 (2012 – $4,303) was incurred on consumer deposits.

Market risks

Market risks primarily refer to the risk of loss that may result from changes in commodity prices, foreign exchange rates, and interest rates. The Company currently does not have 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 at the time of filing. This rate of return is approved by the OEB as part of the approval of distribution rates.

17. Financial instruments (continued):

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.

18. 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 electrical utilities 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. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2013, no assessments have been made.

19. 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, 2013, shareholder's equity amounts to $26,916,936 (2012 – $24,588,673), bank term loans amounts to $7,857,318 (2012 – $3,694,377) and note payable amounts to $16,141,970 (2012 – $16,141,970).

20. Comparative figures:

Certain 2012 comparative figures have been reclassified to conform with the financial statement presentation adopted for the current year.

Financial Statements of

HALTON HILLS HYDRO INC.

Year ended December 31, 2014

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Halton Hills Hydro Inc.

We have audited the accompanying financial statements of Halton Hills Hydro Inc. (the "Entity") which comprise the balance sheet as at December 31, 2014, and the statements of operations and retained earnings and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, 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.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Entity's preparation and fair presentation of the financial statements 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 Entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Halton Hills Hydro Inc. as at December 31, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 16, 2015
Hamilton, Canada

HALTON HILLS HYDRO INC.

Financial Statements

Year ended December 31, 2014

Financial Statements

HALTON HILLS HYDRO INC.

Balance Sheet

December 31, 2014, with comparative information for 2013

	2014	2013
Assets		
Current assets:		
Accounts receivable (note 4)	$ 6,007,479	$ 6,569,272
Unbilled revenue	8,043,091	7,177,715
PILs receivable	969,525	504,933
Inventory (note 5)	1,226,655	821,824
Due from related companies (note 6)	-	88,154
Prepaid expenses and deposits	400,640	461,576
	16,647,390	15,623,474
Regulatory assets (note 7)	8,198,840	7,711,900
Capital assets (note 8)	52,217,048	45,694,680
	$ 77,063,278	$ 69,030,054
Liabilities and Shareholder's Equity		
Current liabilities:		
Bank indebtedness	$ 3,708,651	$ 3,937,318
Accounts payable and accrued liabilities (note 9)	12,615,574	10,508,352
Due to related companies (note 6)	80,072	-
Current portion of bank term loans (note 15 (d))	552,754	424,895
Current portion of consumer deposits	228,837	230,000
	17,185,888	15,100,565
Bank term loans (note 15 (d))	9,841,457	7,432,423
Note payable (note 10)	16,141,970	16,141,970
Consumer deposits	227,293	505,282
Employee future benefits (note 11)	604,005	547,447
Future income taxes	4,022,972	2,385,431
Shareholder's equity:		
Capital stock (note 12)	16,161,663	16,161,663
Retained earnings	12,878,030	10,755,273
	29,039,693	26,916,936
	$ 77,063,278	$ 69,030,054

See accompanying notes to financial statements.

On behalf of the Board:

Eleanor Young Chair

Roger A. Albert Director

HALTON HILLS HYDRO INC.

Statement of Operations and Retained Earnings

Year ended December 31, 2014, with comparative information for 2013

	2014	2013
Revenue:		
Service revenue (note 13)	$ 64,934,884	$ 59,624,436
Other income	1,206,824	1,071,089
	66,141,708	60,695,525
Expenditure:		
Cost of power (note 13)	55,410,232	50,494,619
Salaries and benefits	2,796,402	2,676,884
Material costs	41,233	79,858
Contract services	871,069	624,888
Property costs	706,837	701,458
Other costs	438,482	644,461
Communication costs	434,260	450,064
	60,698,515	55,672,232
Earnings before the undernoted	5,443,193	5,023,293
Other expenses:		
Amortization	1,419,473	1,360,873
Interest expense	824,898	789,250
	2,244,371	2,150,123
Earnings before income taxes	3,198,822	2,873,170
Income taxes:		
Current (recovery)	(452,226)	(733,827)
Future (recovery)	231,731	(16,610)
	(220,495)	(750,437)
Net earnings	3,419,317	3,623,607
Retained earnings, beginning of year	10,755,273	8,427,010
Dividends on common shares	(1,296,560)	(1,295,344)
Retained earnings, end of year	$ 12,878,030	$ 10,755,273

See accompanying notes to financial statements.

HALTON HILLS HYDRO INC.

Statement of Cash Flows

Year ended December 31, 2014, with comparative information for 2013

	2014	2013
Cash provided by (used in):		
Operations:		
Net earnings	$ 3,419,317	$ 3,623,607
Items not involving cash:		
Amortization	1,757,647	1,722,514
Future income taxes (recovery)	231,731	(16,610)
Increase in employee future benefits	56,558	67,700
Changes in non-cash operating working capital (note 14)	995,151	332,711
Change in regulatory assets	918,870	(3,038,832)
	7,379,274	2,691,090
Financing:		
Advancement of term loans	2,536,893	4,162,941
Due from (to) related companies	168,226	(11,420)
(Decrease) increase in consumer deposits	(279,152)	14,364
Dividends on common shares	(1,296,560)	(1,295,344)
Capital contributions received	1,195,066	907,621
	2,324,473	3,778,162
Investments:		
Purchase of capital assets (note 8)	(9,475,080)	(8,132,196)
	(9,475,080)	(8,132,196)
Increase (decrease) in cash and cash equivalents	228,667	(1,662,944)
Bank indebtedness, beginning of year	(3,937,318)	(2,274,374)
Bank indebtedness, end of year	$ (3,708,651)	$ (3,937,318)

See accompanying notes to financial statements.

Halton Hills Hydro Inc., the "Company", is a wholly-owned subsidiary of Halton Hills Community Energy Corporation incorporated under the laws of the Province of Ontario.

The principal activity of the Company is to provide electric power distribution throughout the municipality of Halton Hills.

1. Regulation:

Regulator:

The Ontario Energy Board (OEB) has regulatory oversight of the electricity industry in the Province of Ontario. The Ontario Energy Board Act, 1998, the Electricity Act, 1998, the Electricity Restructuring Act, 2004 and a number of other provincial statutes set out the OEB's mandate and authority. The OEB prescribes and enforces license requirements and conditions towards the following objectives as set out in the Electricity Restructuring Act, 2004:

- To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; and
- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

The OEB's authority and responsibilities include the ability to approve and set rates for the transmission and distribution of electricity, to provide rate protection for various electricity consumers, and to ensure electricity distribution companies fulfill their customer service obligations. The OEB may also prescribe license requirements and conditions of service to electricity distributors 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. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment.

Rate approval process:

The OEB regulates the electricity distribution rates charged by the Company using a combination of annual incentive regulation mechanism ("IRM") adjustments and periodic cost of service reviews. Both such adjustments and reviews are based on applications made by the Company to the OEB.

1. Regulation (continued):

Rate approval process (continued):

In 2012, the OEB developed a three-year plan for 4th generation IRM to set electricity distribution rates. The IRM process provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications (rebasing plus three years). The IRM process allows a standard rate adjustment that accounts for inflation and productivity improvements. Incentive regulation is intended to provide distributors with the opportunity to increase returns to shareholders through the implementation of efficiency initiatives. These efficiencies are also intended to benefit ratepayers by reducing costs.

Type of regulation:

The Company's last Cost of Service Rate application was filed with the OEB on August 26, 2011. The 2012 Cost of Service application included a move from Canadian GAAP ("CGAAP") to Modified IFRS ("MIFRS") basis of accounting, having an impact on capital expenditures and operating, maintenance and administrative ("OM&A") expenses. A partial settlement was submitted and accepted by the OEB. The first OEB interim rate decision in regards to 2012 rates was received on June 14, 2012 with rate adjustments in effect for May 1, 2012. The second OEB interim rate decision was issued July 4, 2012, effective date of the rates was May 1, 2012 with an implementation date of July 1, 2012. The interim rate decisions issued by the OEB, were dependent upon the outcome of a property, plant and equipment ("PP&E") review by the OEB Regulatory Audit and Accounting Department. The PP&E review was satisfactorily completed on January 14, 2013. In the OEB's Decision and Order, dated April 4, 2013, the 2012 Tariff of Rates and Charges were declared as final, effective May 1, 2012.

On October 12, 2012 the Company filed an IRM application to adjust its distribution rates effective May 1, 2013. The OEB's Decision and Order approving the application was received on April 4, 2013.

On September 27, 2013 the Company filed an IRM application to adjust its distribution rates effective May 1, 2014. The OEB's Decision and Order approving the application was received on March 13, 2014.

On October 20, 2014 the Company filed an IRM application to adjust its distribution rates effective May 1, 2015. The OEB's Decision and Order approving the application was received on March 19, 2015.

1. Regulation (continued):

Smart Meter initiatives:

The installation of Smart Meters for the Company began in April 2009 and was completed during 2010 as required by the Energy Conservation Responsibility Act, 2006. These meters will have the capacity to measure and report usage over certain periods, be read remotely and provide customers with access to information about their consumption.

Included in distribution rates effective May 1, 2012 are two Smart Meter Rate Rider charges. The Smart Meter capital and OM&A costs were moved into the appropriate regulatory accounts in 2012. The cost recovery was separated into two different rate riders, Residual Historic and Stranded Meters with class specific recovery. The monthly Smart Meter Residual Historic Rate Rider is in the amounts of $1.31 and $1.38 per customer per month for Residential and General Service less than 50kW classes respectively. The Smart Meter Stranded Meters Rate Rider is in the amounts of $1.13 and $1.46 per customer per month for Residential and General Service less than 50kW classes respectively. Both Rate Riders continue until date of April 30, 2016.

Green Energy and Green Economy Act:

In early 2009, the government tabled the *Green Energy and Green Economy Act ("GEGEA")*. This new legislation makes fundamental changes to the roles and responsibilities of Local Distribution Companies ("LDCs") in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The GEGEA provides LDCs with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. LDCs will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDCs will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

New LDC License Requirements - Conservation and Demand Management Targets ("CDM"):

On November 12, 2010, the OEB amended LDC licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Company's CDM targets include a demand reduction target of 6.15MW and a consumption reduction target of 22.48GWh. LDCs must also comply with a new CDM Code of the OEB, which provides LDC requirements for the development and delivery of CDM Strategy to the OEB for the achievement of LDC-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Company has filed its CDM Strategy with the OEB.

1. Regulation (continued):

Regulatory Accounting:

In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The Company's regulatory liabilities represent costs with respect to non-distribution market related charges and variances in recoveries that are expected to be settled in future periods.

The OEB Decision and Order EB-2011-0271 dated June 14, 2012 provided for the disposition of $612,426 of the Company's Deferral and Variance account balances, as of December 31, 2010, over a 24 month period ending April 30, 2014.

The OEB Decision and Order EB-2013-0136 dated March 13, 2014 provided for the disposition of the Company's Group 1 Deferral and Variance account balances in the amount of $976,553 as of December 31, 2012, including interest projected to April 30, 2014. These balances are to be disposed of over a one-year period from May 1, 2014 to April 30, 2015.

The OEB Decision and Order EB-2014-0079 dated March 19, 2015 provided for the disposition of the Company's Group 1 Deferral and Variance account balances in the amount of $1,607,685 as of December 31, 2013, including interest projected to April 30, 2015. These balances are to be disposed of over a one-year period from May 1, 2015 to April 30, 2016.

2. Significant accounting policies:

(a) Basis of accounting:

The financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), as set out in Part V of the CPA Canada Handbook, and reflect the following significant accounting policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the Ontario Energy Board Act, 1998.

2. Significant accounting policies (continued):

(a) Basis of accounting (continued):

The following accounting policies under the regulated environment differ from GAAP for companies operating in an unregulated environment:

(i) Capital contributions:

Capital contributions in aid of construction consist of third party contributions toward the cost of constructing Company assets. Amortization of contributed capital is on a straight-line basis over the life of the related asset. Capital contributions for the year of $1,195,066 (2013 – $907,621) have been charged as an offset to capital assets.

(ii) Regulatory assets:

Regulatory assets represent future revenues associated with costs incurred in the current or prior periods, which are expected to be recovered from customers in future periods through the rate setting process.

Regulatory assets result from the provincially approved rate set by the OEB and represent differences between costs incurred and amounts collected through rates. Regulatory assets on the balance sheet at year end relate primarily to retail settlement variance accounts, global adjustment and cost of power. Regulatory assets will be recognized for rate-setting and financial statement purposes only to the extent allowed by the regulator.

The regulatory assets are recovered through incremental amounts charged to consumers as approved by the OEB.

The Ontario Energy Board Amendments Act (Electricity Pricing), 2003, in conjunction with Bill 4, allows for recovery of regulatory assets. The Company's Group 1 Deferral and Variance accounts, as of December 31, 2010, are recovered through to the period ending April 30, 2014 (EB-2011-0271). The Company's Group 1 Deferral and Variance accounts, as of December 31, 2012, will be recovered over a one-year period from May 1, 2014 to April 30, 2015 (EB-2013-0136). The Company's Group 1 Deferral and Variance accounts, as of December 31, 2013, will be recovered over a one-year period from May 1, 2015 to April 30, 2016 (EB-2014-0079).

(iii) Payments-in-lieu of income taxes:

Under the Electricity Act, 1998, the Company is required to make payments-in-lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are recorded in accordance with the rules for computing income taxes, taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) and modified by the Electricity Act, 1998, and related regulations.

2. Significant accounting policies (continued):

(a) Basis of accounting (continued):

(iii) Payments-in-lieu of income taxes (continued):

The Company provides for PILs using the asset and liability method. Under this method, future tax assets and liabilities are recognized, to the extent such are determined likely to be realized, for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment.

As required by CPA Canada Handbook Section 3465, a regulatory liability is recorded for those future tax assets which are expected to be repaid to customers through future rates.

(b) Cash and cash equivalents:

Cash and cash equivalents consist of cash on hand, balances with banks, and investments in money market instruments, with maturities of 90 days or less at acquisition. Investing and financing activities that do not require the use of cash or cash equivalents are excluded from the Statement of Cash Flows and disclosed separately.

(c) Inventory:

Inventory is stated at the lower of cost or net realizable value. Inventory cost includes all costs of purchase, conversion and other costs incurred in bringing the inventory to its present location and condition. When circumstances which previously caused inventory to be written down below cost are no longer in existence, the amount of the write-down shall be reversed.

(d) Capital assets:

On January 1, 2012, the Company revised its accounting policies for property, plant and equipment (PP&E) to comply with requirements of the regulator. As a result, the useful service life of the assets was revised and is based upon the actual life of the assets experienced by the Company. The accounting policy change was accounted for prospectively in accordance with the direction of the regulator.

2. Significant accounting policies (continued):

(d) Capital assets (continued):

In accordance with the requirements of the regulator, the Company has recorded a cumulative adjustment to capital assets with an offsetting amount recorded to regulatory assets. This adjustment to capital assets and regulatory assets is being amortized over four years. Capital assets are recorded at cost with the exception of this adjustment to capital assets. 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, direct labour, directly attributable overhead costs, and any other costs directly attributable to bringing the asset to a working condition for its intended use. In circumstances where parts of an item of PP&E have different useful lives, such are accounted for as separate items (major components) of PP&E.

Amortization is provided on a straight-line basis over the useful service life as follows:

Asset	Rate
Distribution systems	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

Construction in progress assets are not amortized until the project is complete and in service.

The Company capitalizes borrowing costs relating to the construction of a capital asset that takes a substantial period of time to bring to its intended use.

Capital assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when the carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

2. 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. These post-retirement costs are recognized in the period in which the employees rendered their services to the Company. The excess of the net accumulated actuarial losses over 10% of the accrued benefit obligation is amortized over the average remaining service period of active employees. The expected average remaining service life of the active employees is 12 years.

(f) Revenue recognition:

Service revenue is recorded on the basis of regular meter readings and estimated power usage since the last meter reading date to the year end. The related cost of power is recorded on the basis of power used.

Other income, which includes pole attachment rentals, customer requested services and miscellaneous revenues, are recognized as the service activity is performed.

(g) Use of estimates:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenditures during the reporting period. Significant estimates include unbilled revenue, useful service life of capital assets and employee future benefits. Actual results could differ from those estimates.

2. Significant accounting policies (continued):

(h) Financial instruments:

Financial assets and liabilities:

The financial instrument accounting standards require that all financial instruments are classified into one of the following categories: held-for-trading, available-for-sale, held-to-maturity, other liabilities or loans and receivables. All financial instruments are carried on the balance sheet at fair value, except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The Company has classified its financial instruments as follows:

Cash and cash equivalents	Held-for-trading
Accounts receivable and unbilled revenue	Loans and receivables
Due from related companies	Loans and receivables
Bank indebtedness	Other liabilities
Bank term loans	Other liabilities
Accounts payable and accrued liabilities	Other liabilities
Consumer deposits	Other liabilities
Note payable	Other liabilities
Due to related companies	Other liabilities

Held-for-trading financial instruments are measured at fair value, with all gains and losses and transaction costs included in net earnings. Loans and receivables and other liabilities are measured at amortized cost using the effective interest rate method.

Derivatives and hedge accounting:

The Company does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the presentation of these financial statements.

3. Future accounting policies:

a) Transition to International Financial Reporting Standards ("IFRS"):

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that would have Canadian GAAP converge with IFRS, effective January 1, 2011 which would have required entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved the incorporation of a one year deferral of adoption of IFRS into Part 1 of the CPA Canada Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CPA Canada Handbook specified that first-time adoption, for companies that met this requirement, was mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2015.

The amendment also requires entities that do not prepare interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

The Company has decided to implement IFRS commencing January 1, 2015.

b) Accounting for rate regulated activities under IFRS:

The International Accounting Standards Board ("IASB") has issued IFRS 14 *Regulatory Deferral Accounts* in January 2014. This standard provides specific guidance on accounting for the effects of rate regulation and permits first-time adopters of IFRS to continue using previous GAAP to account for regulatory deferral account balances while the IASB completes its comprehensive project in this area. Adoption of this standard is optional for entities eligible to use it. Deferral account balances and movements in the balances will be required to be presented as separate line items on the face of the financial statements distinguished from assets, liabilities, income and expenses that are recognized in accordance with other IFRSs. Extensive disclosures will be required to enable users of the financial statements to understand the features and nature of and risks associated with rate regulation and the effect of rate regulation on the entity's financial position, performance and cash flows.

4. Accounts receivable:

	2014	2013
Electric service revenue	$ 5,531,491	$ 5,155,554
Miscellaneous	509,750	1,533,338
Town of Halton Hills	158,239	79,821
	6,199,480	6,768,713
Less: allowance for doubtful accounts	(192,001)	(199,441)
	$ 6,007,479	$ 6,569,272

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

5. Inventory:

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 $775,330 (2013 – $625,336) to capital assets during the year.

The amount of inventory consumed by the Company and recognized as an expense during 2014 was $41,233 (2013 – $101,544).

6. Due from (to) related companies:

The Company performs billing and collecting services, capital asset maintenance, finance functions, as well as certain engineering and information system services for related companies.

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

	2014	2013
SouthWestern Energy Inc.	$ 68,043	$ 80,000
Halton Hills Community Energy Corporation	(148,115)	5,078
Harvester Energy Canada Inc.	-	3,076
	$ (80,072)	$ 88,154

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

Administrative services provided by the Company to related companies during the year and measured at the exchange amount are as follows:

	2014	2013
SouthWestern Energy Inc.	$ 323,026	$ 299,687
	$ 323,026	$ 299,687

Included in contract services is $132,228 (2013 – $205,410) paid to SouthWestern Energy Inc. for electrical contracting services and smart meter repairs.

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:

	2014	2013
Transactions:		
Revenue		
Electrical billings	$ 2,071,897	$ 1,765,921
Expenses		
Property taxes	99,417	90,204
Balances:		
Amounts due from:		
Accounts receivable	158,239	79,821

7. Regulatory assets:

Regulatory assets are as follows:

	2014	2013
Retail settlement variance	$ 1,524,244	$ 1,518,672
Low voltage	160,712	170,062
Other	1,276,064	1,312,731
Stranded meters	496,364	792,096
Regulatory asset recovery account, net of receipts	67,798	662,849
IFRS	707,152	694,794
Regulatory future taxes	3,966,506	2,560,696
	$ 8,198,840	$ 7,711,900

7. Regulatory assets (continued):

Management expects that regulatory assets arising during 2012 through 2014, other than those approved through the 2012 rate setting process, will be recovered through future rate changes. If in a future decision, the regulator determines that the existing regulatory treatment is no longer applicable, the regulatory assets would be charged to operations in the year of determination.

In the absence of rate regulation, GAAP would require that the actual purchased power costs (including any variances arising from electricity commodity, retail transmission and wholesale market costs) be recognized as an expense when incurred.

In the absence of rate regulation, net earnings for the year would have been lower by $114,401 (2013 – $4,556,828), future tax asset would be higher by $372,539 (2013 – $547,304), and retained earnings would be lower by $nil (2013 – $nil).

8. Capital assets:

			2014	2013
	Cost	Accumulated amortization	Net book value	Net book value
Distribution systems	$ 48,637,406	$ 3,187,992	$ 45,449,414	$ 38,944,112
Plant	9,653,533	976,064	8,677,469	8,355,705
Fleet	1,681,459	475,079	1,206,380	952,508
Other equipment	1,255,343	293,663	961,680	1,016,324
Computer equipment and software	1,727,856	1,043,144	684,712	134,362
General office	126,090	63,077	63,013	102,354
Stores equipment	5,161	2,323	2,838	4,732
Contributed capital	(8,449,121)	(485,070)	(7,964,051)	(6,959,484)
Construction in progress	3,135,593	-	3,135,593	3,144,067
	$ 57,773,320	$ 5,556,272	$ 52,217,048	$ 45,694,680

During the year, the Company recorded capital asset additions of $9,475,080 (2013 – $8,132,196).

Borrowing costs capitalized during the year were $114,206 (2013 – $55,024).

As described in note 2(d), the Company recorded a cumulative adjustment of $836,717 in 2012 to capital assets with an offsetting amount recorded in regulatory assets.

9. Accounts payable and accrued liabilities:

Accounts payable and accrued liabilities also includes $nil (2013 – $nil) due to companies under common control. These payables arose in the normal course of operations and are due under normal terms of trade.

10. 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. The prescribed rate of interest is 4.12% (6.25% – January 1, 2012 to April 30, 2012 and 5.01% – May 1, 2012 – December 31, 2012).

The Company incurred interest expense in respect of the note payable of $665,049 (2013 – $665,049).

11. Employee future benefits:

The Company pays certain medical and life insurance benefits on behalf of its retired employees. The Company recognizes these post-retirement costs in the period in which employees' services were rendered. The accrued benefit liability and expenses for the year ended December 31, 2014 were based on results and assumptions determined by actuarial valuation as at December 31, 2014.

Information regarding the defined benefit plan of the Company is as follows:

	2014	2013
Accrued benefit obligation at January 1	$ 704,029	$ 655,902
Expense for the year	31,675	30,311
Interest for the year	32,780	30,592
Benefits paid during the year	(14,526)	(12,776)
Accrued benefit obligation	753,958	704,029
Unamortized actuarial loss	(149,953)	(156,582)
Net liability as at December 31	$ 604,005	$ 547,447

Amortization of the actuarial loss was $6,629 (2013 – $19,573).

11. Employee future benefits (continued):

The main actuarial assumptions utilized for the valuation are as follows:

General Inflation – future general inflation levels, as measured by the changes in the Consumer Price Index (CPI), were assumed at 2.0% in 2014 and thereafter.

Discount (Interest) Rate – the obligation as at December 31, 2014 of the present value of future liabilities and the expense for the year then ended were determined using a discount rate of 4.05% (2013 – 4.5%). This rate reflects the market interest rates at the measurement date on high quality debt instruments with consideration given to the timing and amount of projected benefit payments.

Salary levels – future general salary and wage levels were assumed to increase at the CPI rate adjusted for merit and promotion gains of 2.25% (2013 – 2.55%) per annum for the first two years and 2.70% (2013 – 3.00%) per annum thereafter. This rate reflects the expected Consumer Price Index adjusted for productivity, merit and promotion.

Medical costs – medical costs were assumed to increase at the CPI rate plus 5% in 2012. Thereafter, medical costs are assumed to decline by 0.30% per annum.

Dental costs – dental costs were assumed to increase at the CPI rate plus 2.6%.

12. Capital stock:

	2014	2013
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
	$ 16,161,663	$ 16,161,663

13. Service revenue:

	2014	2013
Service revenue consists of:		
Cost of power	$ 55,410,232	$ 50,494,619
Distribution	9,524,652	9,129,817
	$ 64,934,884	$ 59,624,436

14. Changes in non-cash working capital:

(a) The net change is non-cash working capital consists of the following:

	2014	2013
Accounts receivable	$ 561,793	$ (166,859)
Unbilled revenue	(865,377)	(1,987,788)
PILs receivable	(464,592)	(79,366)
Inventory	(404,831)	182,210
Prepaid expenses and deposits	60,936	(19,708)
Accounts payable and accrued liabilities	2,107,222	2,404,222
	$ 995,151	$ 332,711

(b) Supplemental cash flow information:

	2014	2013
Cash paid during the year for interest	$ 824,898	$ 805,311
Cash paid during the year for PILs	-	323,335
Cash received during the year for PILs	460,818	977,797
Non-cash financing activities:		
Increase in regulatory assets related to decrease in future tax assets	$ 1,405,810	$ 2,065,300

15. Credit facilities:

a) Credit limit:

The Company has available an operating credit facility from a financial institution in the amount of $9,000,000 (2013 – $5,500,000). 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 $3,540,000 (2013 – $2,980,000). 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.

15. Credit facilities (continued):

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 (2013 – $1,754,315) from a financial institution.

c) Covenants:

The above credit facilities require an interest coverage ratio of not less than 1.2 to 1.0, and a total interest bearing debt to capitalization ratio not greater than 0.60 to 1. As at December 31, 2014, the Company is in compliance with these covenants.

d) Term Loans:

(i) Smart Meter Term Loan: Reducing Term Facility, contractual term of 5 years to August 30, 2017 with an amortization period of 15 years to August 30, 2026. The loan interest rate of 2.16%, with a rate term renewable annually. Interest of $71,952 (2013 – $76,876) was paid and expensed during the year. The loan is payable in the amount of $26,030 monthly principal and interest. 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.

(ii) Capital Term Loan 1: Reducing Term Facility, contractual term of 10 years to February 22, 2023 with an amortization period of 20 years to February 22, 2033. The loan interest rate of 2.16%, with a rate term renewable annually. Interest of $40,625 (2013 – $33,836) was paid and capitalized during the year. The loan is payable in the amount of $10,264 monthly principal and interest. 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.

(iii) Capital Term Loan 2: Reducing Term Facility, contractual term of 10 years to August 15, 2023 with an amortization period of 20 years to August 15, 2033. The loan interest rate of 2.15%, with a rate term renewable annually. Interest of $52,029 (2013 – $17,877) was paid and capitalized during the year. The loan is payable in the amount of $12,826 monthly principal and interest. 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.

(iv) Capital Term Loan 3: Reducing Term Facility, contractual term of 10 years to August 18, 2024 with an amortization period of 20 years to August 18, 2034. The loan interest rate of 2.16%, with a rate term renewable annually. Interest of $21,552 was paid and capitalized during the year. The loan is payable in the amount of $15,405 monthly principal and interest. 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.

15. Credit facilities (continued):

d) Term Loans (continued):

Principal payments on the term loans are as follows:

	2014
2015	$ 552,754
2016	561,969
2017	574,449
2018	587,147
2019	599,945
2020 – 2034	7,517,947
	10,394,211
Less: current portion	(552,754)
Long-term portion of loan	$ 9,841,457

16. Pension agreement:

The Company and its employees contribute to the Ontario Municipal Employee's 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, public utilities and school boards. 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. Contributions by the Company were at a rate of 9.0% for employee earnings below the year's maximum pensionable earnings and 14.6% thereafter. The Company's contribution for employees' current service for the year ended December 31, 2014 was $388,886 (2013 - $382,894).

17. Financial instruments:

Level 1

The carrying value of the cash and cash equivalents, accounts receivable and unbilled revenue, due from (to) related companies, bank indebtedness, 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 rate term is renewable annually.

17. Financial instruments (continued):

Level 3

The note payable has a fair value of $15,470,000 based on the company's internal borrowing rate of 2.15%.

The Company's activities provide for a variety of financial risks. Exposure to credit risk, market risk and liquidity risk occur in the normal course of the Company's operations as follows:

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 operations. The balance of the allowance for doubtful accounts is disclosed in note 4. No single customer accounts for more than 3% of accounts receivable at year end.

The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2014, approximately $109,415 (2013 – $172,458) is considered 90 days past due. The Company has approximately 21,853 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, 2014, the Company holds security deposits in the amount of $456,130 (2013 – $735,282).

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Consumer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Consumer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Company. Interest expense of $4,779 (2013 – $4,757) was incurred on consumer deposits.

Market risks

Market risks primarily refer to the risk of loss that may result from changes in commodity prices, foreign exchange rates, and interest rates. The Company currently does not have 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 at the time of filing. This rate of return is approved by the OEB as part of the approval of distribution rates.

17. Financial instruments (continued):

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.

18. 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 electrical utilities 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. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2014, no assessments have been made.

19. 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, 2014, shareholder's equity amounts to $28,810,606 (2013 – $26,916,936), bank term loans amounts to $10,394,211 (2013 – $7,857,318) and note payable amounts to $16,141,970 (2013 – $16,141,970).

20. Comparative figures:

Certain 2013 comparative figures have been reclassified to conform with the financial statement presentation adopted for the current year.

APPENDIX 1-E

RECONCILIATION OF AFS to RRR TRIAL BALANCE 2.1.7 FILING

		ASSETS	2012	Audited Financial Statement Line Item
		[redacted]		
	Account No	Account Description	Amount	
Current Assets	1005	Cash	-	Cash and cash equivalents
Current Assets	1010	Cash Advances and Working Funds	-	
Current Assets	1020	Interest Special Deposits	-	
Current Assets	1030	Dividend Special Deposits	-	
Current Assets	1040	Other Special Deposits	-	
Current Assets	1060	Term Deposits	-	
Current Assets	1070	Current Investments	-	
Current Assets	1100	Customer Accounts Receivable	4,126,660	Accounts Receivable
Current Assets	1100	Customer Accounts Receivable	211,593	Accounts Receivable
Current Assets	1102	Accounts Receivable - Services	-	
Current Assets	1104	Accounts Receivable - Recoverable Work	548,060	Accounts Receivable
Current Assets	1105	Accounts Receivable - Merchandise, Jobbing, etc.	-	
Current Assets	1110	Other Accounts Receivable	1,746,425	Accounts Receivable
Current Assets	1110	Other Accounts Receivable	425,567	Pils Receivable
Current Assets	1120	Accrued Utility Revenues	5,189,927	Unbilled Revenue
Current Assets	1130	Accumulated Provision for Uncollectible Accounts--Credit	(230,325)	Accounts Receivable
Current Assets	1140	Interest and Dividends Receivable	0	
Current Assets	1150	Rents Receivable	-	
Current Assets	1170	Notes Receivable	-	
Current Assets	1180	Prepayments	441,868	Prepaid Expenses and Deposits
Current Assets	1190	Miscellaneous Current and Accrued Assets	-	
Current Assets	1200	Accounts Receivable from Associated Companies	76,734	Due from related companies
Current Assets	1210	Notes Receivable from Associated Companies	-	
			-	
		[redacted]	-	
	Account No	Account Description	-	
Inventory	1305	Fuel Stock	-	
Inventory	1330	Plant Materials and Operating Supplies	1,004,034	Inventory
Inventory	1340	Merchandise	-	
Inventory	1350	Other Materials and Supplies	-	
			-	
		[redacted]	-	
	Account No	Account Description	-	
Non-Current Assets	1405	Long Term Investments in Non-Associated Companies	-	
Non-Current Assets	1408	Long Term Receivable - Street Lighting Transfer	-	
Non-Current Assets	1410	Other Special or Collateral Funds	-	
Non-Current Assets	1415	Sinking Funds	-	
Non-Current Assets	1425	Unamortized Debt Expense	-	
Non-Current Assets	1445	Unamortized Discount on Long-Term Debt--Debit	-	
Non-Current Assets	1455	Unamortized Deferred Foreign Currency Translation Gains and Losses	-	
Non-Current Assets	1460	Other Non-Current Assets	-	
Non-Current Assets	1465	O.M.E.R.S. Past Service Costs	-	
Non-Current Assets	1470	Past Service Costs - Employee Future Benefits	-	

Non-Current Assets	1475	Past Service Costs - Other Pension Plans	-	
Non-Current Assets	1480	Portfolio Investments - Associated Companies	-	
Non-Current Assets	1485	Investment in Associated Companies - Significant Influence	-	
Non-Current Assets	1490	Investment in Subsidiary Companies	-	
	Account No	**Account Description**		
Other Assets and Deferred	1505	Unrecovered Plant and Regulatory Study Costs	-	Regulatory Assets
Other Assets and Deferred	1508	Other Regulatory Assets	685,444	Regulatory Assets
Other Assets and Deferred	1510	Preliminary Survey and Investigation Charges	-	Regulatory Assets
Other Assets and Deferred	1515	Emission Allowance Inventory	-	Regulatory Assets
Other Assets and Deferred	1516	Emission Allowances Withheld	-	Regulatory Assets
Other Assets and Deferred	1518	RCVARetail	(245)	Regulatory Assets
Other Assets and Deferred	1520	Power Purchase Variance Account	-	Regulatory Assets
Other Assets and Deferred	1521	MEI - Special Purpose Charge	724	Regulatory Assets
Other Assets and Deferred	1525	Miscellaneous Deferred Debits	-	Regulatory Assets
Other Assets and Deferred	1530	Deferred Losses from Disposition of Utility Plant	-	Regulatory Assets
Other Assets and Deferred	1531	Renewable Connection Capital Deferral Account	-	Regulatory Assets
Other Assets and Deferred	1532	Renewable Connection OM&A Deferral Account	-	Regulatory Assets
Other Assets and Deferred	1534	Smart Grid Capital Deferral Account	-	Regulatory Assets
Other Assets and Deferred	1535	Smart Grid Capital OM&A Account	-	Regulatory Assets
Other Assets and Deferred	1540	Unamortized Loss on Reacquired Debt	-	Regulatory Assets
Other Assets and Deferred	1545	Development Charge Deposits/ Receivables	-	Regulatory Assets
Other Assets and Deferred	1548	RCVASTR	348	Regulatory Assets
Other Assets and Deferred	1550	LV Variance Account	36,254	Regulatory Assets
Other Assets and Deferred	1555	Smart Meter Capital and Recovery Offset Variance	1,098,101	Regulatory Assets
Other Assets and Deferred	1556	Smart Meter OM&A Variance	(0)	Regulatory Assets
Other Assets and Deferred	1560	Deferred Development Costs	-	Regulatory Assets
Other Assets and Deferred	1562	Deferred Payments in Lieu of Taxes	(2,672)	Regulatory Assets
Other Assets and Deferred	1563	Deferred PILs Contra Account	-	Regulatory Assets
Other Assets and Deferred	1565	Conservation and Demand Management Expenditures and Recoveries	-	Regulatory Assets
Other Assets and Deferred	1566	CDM Contra	-	Regulatory Assets
Other Assets and Deferred	1570	Qualifying Transition Costs	-	Regulatory Assets
Other Assets and Deferred	1571	Pre-market Opening Energy Variance	(627,538)	Regulatory Assets
Other Assets and Deferred	1572	Extraordinary Event Costs	-	Regulatory Assets
Other Assets and Deferred	1574	Deferred Rate Impact Amounts	-	Regulatory Assets
Other Assets and Deferred	1575	IFRS-CGAAP Transitional PP&E Amounts	-	Regulatory Assets
Other Assets and Deferred	1580	RSVAWMS	(1,071,460)	Regulatory Assets
Other Assets and Deferred	1582	RSVAONE-TIME	-	Regulatory Assets
Other Assets and Deferred	1584	RSVANW	480,628	Regulatory Assets
Other Assets and Deferred	1586	RSVACN	422,837	Regulatory Assets
Other Assets and Deferred	1588	RSVAPOWER	247,157	Regulatory Assets
Other Assets and Deferred	1590	Recovery of regulatory asset balances	-	Regulatory Assets
Other Assets and Deferred	1592	2006 PILs & Taxes Variance	-	Regulatory Assets
Other Assets and Deferred	1595	Sub-Account Disposition of Account Balances Approved in 2009	842,794	Regulatory Assets
Other Assets and Deferred	1595	Disposition and Recovery of Regulatory Balances Control Account		Regulatory Assets
Other Assets and Deferred	1595	Sub-Account Disposition of Account Balances Approved in 2008		Regulatory Assets

	Account No	Account Description		
Electric Plant and Service - I	1605	Electric Plant in Service - Control Account		
	Account No	Account Description -		
Intangible Plant	1606	Organization	374,370	Capital Assets
Intangible Plant	1608	Franchises and Consents	-	Capital Assets
Intangible Plant	1610	Miscellaneous Intangible Plant	-	Capital Assets
			-	Capital Assets
	Account No	Account Description		
Distribution Plant	1805	Land	591,341	Capital Assets
Distribution Plant	1612	Land Rights	4,738	Capital Assets
Distribution Plant	1808	Buildings and Fixtures	3,590,614	Capital Assets
Distribution Plant	1810	Leasehold Improvements	-	Capital Assets
Distribution Plant	1815	Transformer Station Equipment - Normally Primary above 50 kV	-	Capital Assets
Distribution Plant	1820	Distribution Station Equipment - Normally Primary below 50 kV	5,713,606	Capital Assets
Distribution Plant	1825	Storage Battery Equipment	-	Capital Assets
Distribution Plant	1830	Poles, Towers and Fixtures	19,075,259	Capital Assets
Distribution Plant	1835	Overhead Conductors and Devices	6,929,755	Capital Assets
Distribution Plant	1840	Underground Conduit	1,077,676	Capital Assets
Distribution Plant	1845	Underground Conductors and Devices	6,524,393	Capital Assets
Distribution Plant	1850	Line Transformers	8,037,729	Capital Assets
Distribution Plant	1855	Services	3,032,052	Capital Assets
Distribution Plant	1860	Meters	4,969,692	Capital Assets
Distribution Plant	1865	Other Installations on Customer's Premises	-	Capital Assets
Distribution Plant	1870	Leased Property on Customer Premises	-	Capital Assets
Distribution Plant	1875	Street Lighting and Signal Systems	-	Capital Assets
			-	
	Account No	Account Description		
General Plant	1905	Land	-	Capital Assets
General Plant	1906	Land Rights	-	Capital Assets
General Plant	1908	Buildings and Fixtures	-	Capital Assets
General Plant	1910	Leasehold Improvements	-	Capital Assets
General Plant	1915	Office Furniture and Equipment	426,778	Capital Assets
General Plant	1920	Computer Equipment - Hardware	1,352,790	Capital Assets
General Plant	1611	Computer Software	1,426,105	Capital Assets
General Plant	1930	Transportation Equipment	2,760,304	Capital Assets
General Plant	1935	Stores Equipment	59,018	Capital Assets
General Plant	1940	Tools, Shop and Garage Equipment	649,237	Capital Assets
General Plant	1945	Measurement and Testing Equipment	-	Capital Assets
General Plant	1950	Power Operated Equipment	-	Capital Assets
General Plant	1955	Communication Equipment	-	Capital Assets
General Plant	1960	Miscellaneous Equipment	-	Capital Assets
General Plant	1965	Water Heater Rental Units	-	Capital Assets
General Plant	1970	Load Management Controls - Customer Premises	633,035	Capital Assets
General Plant	1975	Load Management Controls - Utility Premises	-	Capital Assets
General Plant	1980	System Supervisory Equipment	1,120,704	Capital Assets

General Plant	1985	Sentinel Lighting Rental Units	-	Capital Assets
General Plant	1990	Other Tangible Property	-	Capital Assets
General Plant	1995	Contributions and Grants - Credit	(6,346,445)	Capital Assets
			-	Capital Assets
		[redacted]	-	Capital Assets
	Account No	Account Description	-	Capital Assets
Other capital Assets	2005	Property Under Capital Leases	-	Capital Assets
Other capital Assets	2010	Electric Plant Purchased or Sold	-	Capital Assets
Other capital Assets	2020	Experimental Electric Plant Unclassified	-	Capital Assets
Other capital Assets	2030	Electric Plant and Equipment Leased to Others	-	Capital Assets
Other capital Assets	2040	Electric Plant Held for Future Use	-	Capital Assets
Other capital Assets	2050	Completed Construction Not Classified--Electric	-	Capital Assets
Other capital Assets	2055	Construction Work in Progress--Electric	1,570,979	Capital Assets
Other capital Assets	2060	Electric Plant Acquisition Adjustment	-	Capital Assets
Other capital Assets	2065	Other Electric Plant Adjustment	-	Capital Assets
Other capital Assets	2070	Other Utility Plant	-	Capital Assets
Other capital Assets	2075	Non-Utility Property Owned or Under Capital Leases	-	Capital Assets
		[redacted]		
	Account No	Account Description		
Accumulated Amortization	2105	Accumulated Amortization of Electric Utility Plan - PP	(23,231,005)	Capital Assets
Accumulated Amortization	2120	Accumulated Amortization of Electric Utility Plant - Intangibles	(150,107)	Capital Assets
Accumulated Amortization	2140	Accumulated Amortization of Electric Plant Acquisition Adjustment	-	Capital Assets
Accumulated Amortization	2160	Accumulated Amortization of Other Utility Plant	-	Capital Assets
Accumulated Amortization	2180	Accumulated Amortization of Non-Utility Property	-	Capital Assets
			-	
		LIABILITIES AND EQUITY		
		[redacted]		
	Account No	Account Description		
Current Liabilities	2205	Accounts Payable	(6,705,170)	Accounts Payable and Accrued Liabilities
Current Liabilities	2208	Customer Credit Balances	(985,548)	Accounts Payable and Accrued Liabilities
Current Liabilities	2210	Current Portion of Customer Deposits	(230,000)	Current Portion of Customer Deposit
Current Liabilities	2215	Dividends Declared	-	
Current Liabilities	2220	Miscellaneous Current and Accrued Liabilities	-	
Current Liabilities	2225	Notes and Loans Payable	(2,274,374)	Bank indebtedness
Current Liabilities	2240	Accounts Payable to Associated Companies	-	
Current Liabilities	2242	Notes Payable to Associated Companies	-	
Current Liabilities	2250	Debt Retirement Charges(DRC) Payable	(259,002)	Accounts Payable and Accrued Liabilities
Current Liabilities	2252	Transmission Charges Payable	-	
Current Liabilities	2254	Electrical Safety Authority Fees Payable	-	
Current Liabilities	2256	Independent Market Operator Fees and Penalties Payable	-	
Current Liabilities	2260	Current Portion of Long Term Debt	(234,776)	Smart Meter Bank Loan
Current Liabilities	2262	Ontario Hydro Debt - Current Portion	-	
Current Liabilities	2264	Pensions and Employee Benefits - Current Portion	-	
Current Liabilities	2268	Accrued Interest on Long Term Debt	-	
Current Liabilities	2270	Matured Long Term Debt	-	
Current Liabilities	2272	Matured Interest on Long Term Debt	-	

Current Liabilities	2285	Obligations Under Capital Leases--Current	-	
Current Liabilities	2290	Commodity Taxes	-	
Current Liabilities	2292	Payroll Deductions / Expenses Payable	(154,411)	Accounts Payable and Accrued Liabilities
Current Liabilities	2294	Accrual for Taxes Payments in Lieu of Taxes, Etc.	-	
Current Liabilities	2296	Future Income Taxes - Current	-	
			-	
		[illegible]		
	Account No	Account Description		
Non-Current Liability	2305	Accumulated Provision for Injuries and Damages	-	
Non-Current Liability	2306	Employee Future Benefits	(479,747)	Employee Future Benefits
Non-Current Liability	2308	Other Pensions - Past Service Liability	-	
Non-Current Liability	2310	Vested Sick Leave Liability	-	
Non-Current Liability	2315	Accumulated Provision for Rate Refunds	-	
Non-Current Liability	2320	Other Miscellaneous Non-Current Liabilities	-	
Non-Current Liability	2325	Obligations Under Capital Lease--Non-Current	-	
Non-Current Liability	2330	Development Charge Fund	-	
Non-Current Liability	2335	Long Term Customer Deposits	(490,918)	Customer Deposit
Non-Current Liability	2340	Collateral Funds Liability	-	
Non-Current Liability	2345	Unamortized Premium on Long Term Debt	-	
Non-Current Liability	2348	O.M.E.R.S. - Past Service Liability - Long Term Portion	-	
Non-Current Liability	2350	Deferred Tax - Non-Current	157,524	Future Income Tax
Non-Current Liability	2350	Deferred Tax - Non-Current	(494,265)	Future Income Tax
Non-Current Liability	2350	Deferred Tax - Non-Current	495,396	Regulatory Assets
		[illegible]		
	Account No	Account Description		
Other Liabilities and Deferr	2405	Other Regulatory Liabilities	-	
Other Liabilities and Deferr	2410	Deferred Gains from Disposition of Utility Plant	-	
Other Liabilities and Deferr	2415	Unamortized Gain on Reacquired Debt	-	
Other Liabilities and Deferr	2425	Other Deferred Credits	-	
Other Liabilities and Deferr	2435	Accrued Rate-Payer Benefit	-	
		[illegible]		
	Account No	Account Description		
Long Terms Debt	2505	Debentures Outstanding - Long Term Portion	-	
Long Terms Debt	2510	Debenture Advances	-	
Long Terms Debt	2515	Reacquired Bonds	-	
Long Terms Debt	2520	Other Long Term Debt	-	
Long Terms Debt	2525	Term Bank Loans - Long Term Portion	(3,459,601)	Smart Meter Bank Loan
Long Terms Debt	2530	Ontario Hydro Debt Outstanding - Long Term Portion	-	
Long Terms Debt	2550	Advances from Associated Companies	(16,141,969)	Note Payable
		[illegible]		
	Account No	Account Description		
Shareholder's Equity	3005	Common Shares Issued	(16,161,663)	Capital Stock
Shareholder's Equity	3008	Preference Shares Issued	-	
Shareholder's Equity	3010	Contributed Surplus	-	
Shareholder's Equity	3020	Donations Received	-	
Shareholder's Equity	3022	Development Charges Transferred to Equity	-	

Shareholder's Equity	3026	Capital Stock Held in Treasury	-	
Shareholder's Equity	3030	Miscellaneous Paid-In Capital	-	
Shareholder's Equity	3035	Installments Received on Capital Stock	-	
Shareholder's Equity	3040	Appropriated Retained Earnings	-	
Shareholder's Equity	3045	Unappropriated Retained Earnings	(7,013,642)	Retained Earnings
Shareholder's Equity	3047	Appropriations of Retained Earnings - Current Period	-	
Shareholder's Equity	3048	Dividends Payable-Preference Shares	-	
Shareholder's Equity	3049	Dividends Payable-Common Shares	1,077,592	Retained Earnings
Shareholder's Equity	3055	Adjustment to Retained Earnings	-	
Shareholder's Equity	3065	Unappropriated Undistributed Subsidiary Earnings	-	
		Shareholder's Equity Acct 3046		
	Account No	**Account Description**		
	3046	Balance Transferred From Income	(2,490,960)	Net Earnings
		INCOME STATEMENT		
		[redacted]	-	
	Account No	**Account Description**		
Sales of Electricity	4006	Residential Energy Sales	(16,108,314)	Service Revenue
Sales of Electricity	4010	Commercial Energy Sales	(4,325,328)	Service Revenue
Sales of Electricity	4015	Industrial Energy Sales	(16,612,637)	Service Revenue
Sales of Electricity	4020	Energy Sales to Large Users	-	Service Revenue
Sales of Electricity	4025	Street Lighting Energy Sales	(206,706)	Service Revenue
Sales of Electricity	4030	Sentinel Lighting Energy Sales	(37,909)	Service Revenue
Sales of Electricity	4035	General Energy Sales	(67,190)	Service Revenue
Sales of Electricity	4040	Other Energy Sales to Public Authorities	-	Service Revenue
Sales of Electricity	4045	Energy Sales to Railroads and Railways	-	Service Revenue
Sales of Electricity	4050	Revenue Adjustment	-	Service Revenue
Sales of Electricity	4055	Energy Sales for Resale	-	Service Revenue
Sales of Electricity	4060	Interdepartmental Energy Sales	-	Service Revenue
Sales of Electricity	4062	Billed WMS	(2,646,854)	Service Revenue
Sales of Electricity	4064	Billed One-Time	-	Service Revenue
Sales of Electricity	4066	Billed NW	(2,885,393)	Service Revenue
Sales of Electricity	4068	Billed CN	(2,250,997)	Service Revenue
Sales of Electricity	4075	Billed - LV	(605,671)	Service Revenue
		[redacted]		
	Account No	**Account Description**		
Revenue from Services-Dist	4080	Distribution Services Revenue	(10,434,637)	Service Revenue
Revenue from Services-Dist	4082	Retail Services Revenues	-	
Revenue from Services-Dist	4084	Service Transaction Requests (STR) Revenues	-	
Revenue from Services-Dist	4090	Electric Services Incidental to Energy Sales	-	
		[redacted]		
	Account No	**Account Description**		
Revenue from Services-Trai	4105	Transmission Charges Revenue	-	
Revenue from Services-Trai	4110	Transmission Services Revenue	-	

		[redacted]		
	Account No	Account Description		
Other Operating Revenues	4205	Interdepartmental Rents	-	Other income
Other Operating Revenues	4210	Rent from Electric Property	(170,039)	Other income
Other Operating Revenues	4215	Other Utility Operating Income	-	Other income
Other Operating Revenues	4220	Other Electric Revenues	-	Other income
Other Operating Revenues	4225	Late Payment Charges	(98,211)	Other income
Other Operating Revenues	4230	Sales of Water and Water Power	-	Other income
Other Operating Revenues	4235	Miscellaneous Service Revenues	(362,112)	Other income
Other Operating Revenues	4240	Provision for Rate Refunds	-	Other income
Other Operating Revenues	4245	Government Assistance Directly Credited to Income	-	Other income
		[redacted]		
	Account No	Account Description		
Other Income / Deductions	4305	Regulatory Debits	-	Other income
Other Income / Deductions	4310	Regulatory Credits	-	Other income
Other Income / Deductions	4315	Revenues from Electric Plant Leased to Others	-	Other income
Other Income / Deductions	4320	Expenses of Electric Plant Leased to Others	-	Other income
Other Income / Deductions	4325	Revenues from Merchandise, Jobbing, Etc.	(31,444)	Other income
Other Income / Deductions	4330	Costs and Expenses of Merchandising, Jobbing, Etc.	-	Other income
Other Income / Deductions	4335	Profits and Losses from Financial Instrument Hedges	-	Other income
Other Income / Deductions	4340	Profits and Losses from Financial Instrument Investments	-	Other income
Other Income / Deductions	4345	Gains from Disposition of Future Use Utility Plant	-	Other income
Other Income / Deductions	4350	Losses from Disposition of Future Use Utility Plant	-	Other income
Other Income / Deductions	4355	Gain on Disposition of Utility and Other Property	(46,318)	Other income
Other Income / Deductions	4360	Loss on Disposition of Utility and Other Property	-	Other income
Other Income / Deductions	4365	Gains from Disposition of Allowances for Emission	-	Other income
Other Income / Deductions	4370	Losses from Disposition of Allowances for Emission	-	Other income
Other Income / Deductions	4375	Revenues from Non-Utility Operations	(940,788)	Other income
Other Income / Deductions	4380	Expenses of Non-Utility Operations	634,338	Other income
Other Income / Deductions	4385	Non-Utility Rental Income	(38,865)	Other income
Other Income / Deductions	4390	Miscellaneous Non-Operating Income	-	Other income
Other Income / Deductions	4395	Rate-Payer Benefit Including Interest	-	Other income
Other Income / Deductions	4398	Foreign Exchange Gains and Losses, Including Amortization	-	Other income
			-	Other income
		[redacted]		
	Account No	Account Description		
Investment Income	4405	Interest and Dividend Income	(133,150)	Other income
Investment Income	4415	Equity in Earnings of Subsidiary Companies	-	Other income
		[redacted]		
	Account No	Account Description		
Generation Expenses - Ope	4505	Operation Supervision and Engineering	-	
Generation Expenses - Ope	4510	Fuel	-	
Generation Expenses - Ope	4515	Steam Expense	-	
Generation Expenses - Ope	4520	Steam From Other Sources	-	
Generation Expenses - Ope	4525	Steam Transferred--Credit	-	
Generation Expenses - Ope	4530	Electric Expense	-	
Generation Expenses - Ope	4535	Water For Power	-	

Generation Expenses - Ope	4540	Water Power Taxes	-	
Generation Expenses - Ope	4545	Hydraulic Expenses	-	
Generation Expenses - Ope	4550	Generation Expense	-	
Generation Expenses - Ope	4555	Miscellaneous Power Generation Expenses	-	
Generation Expenses - Ope	4560	Rents	-	
Generation Expenses - Ope	4565	Allowances for Emissions	-	
			-	
	Account No	Account Description		
Other Power Supply Expens	4705	Power Purchased	37,358,084	Power Costs
Other Power Supply Expens	4708	Charges-WMS	2,646,854	Power Costs
Other Power Supply Expens	4710	Cost of Power Adjustments	-	Power Costs
Other Power Supply Expens	4712	Charges-One-Time	-	Power Costs
Other Power Supply Expens	4714	Charges-NW	2,885,393	Power Costs
Other Power Supply Expens	4715	System Control and Load Dispatching	-	Power Costs
Other Power Supply Expens	4716	Charges-CN	2,250,997	Power Costs
Other Power Supply Expens	4720	Other Expenses	-	Power Costs
Other Power Supply Expens	4725	Competition Transition Expense	-	Power Costs
Other Power Supply Expens	4730	Rural Rate Assistance Expense	-	Power Costs
Other Power Supply Expens	4750	Charges - LV	605,671	Power Costs
	Account No	Account Description		
Distribution Expenses - Ope	5005	Operation Supervision and Engineering	164,258	Salaries and Benefits
Distribution Expenses - Ope	5010	Load Dispatching	-	
Distribution Expenses - Ope	5012	Station Buildings and Fixtures Expense	52	Property Costs
Distribution Expenses - Ope	5014	Transformer Station Equipment - Operation Labour	-	
Distribution Expenses - Ope	5015	Transformer Station Equipment - Operation Supplies and Expenses	-	
Distribution Expenses - Ope	5016	Distribution Station Equipment - Operation Labour	50,055	Salaries and Benefits
Distribution Expenses - Ope	5017	Distribution Station Equipment - Operation Supplies and Expenses	5,245	Material Costs
Distribution Expenses - Ope	5020	Overhead Distribution Lines and Feeders - Operation Labour	114,329	Salaries and Benefits
Distribution Expenses - Ope	5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-	
Distribution Expenses - Ope	5030	Overhead Subtransmission Feeders - Operation	-	
Distribution Expenses - Ope	5035	Overhead Distribution Transformers- Operation	-	
Distribution Expenses - Ope	5040	Underground Distribution Lines and Feeders - Operation Labour	-	
Distribution Expenses - Ope	5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	2,582	Material Costs
Distribution Expenses - Ope	5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	4,073	Salaries and Benefits
Distribution Expenses - Ope	5050	Underground Subtransmission Feeders - Operation	179,114	Salaries and Benefits
Distribution Expenses - Ope	5055	Underground Distribution Transformers - Operation	87,651	Salaries and Benefits
Distribution Expenses - Ope	5060	Street Lighting and Signal System Expense	-	
Distribution Expenses - Ope	5065	Meter Expense	121,252	Salaries and Benefits
Distribution Expenses - Ope	5070	Customer Premises - Operation Labour	4,608	Salaries and Benefits
Distribution Expenses - Ope	5075	Customer Premises - Materials and Expenses	-	
Distribution Expenses - Ope	5085	Miscellaneous Distribution Expense	6,281	Other Costs
Distribution Expenses - Ope	5085	Miscellaneous Distribution Expense	42,671	Salaries and Benefits
Distribution Expenses - Ope	5085	Miscellaneous Distribution Expense	15,448	Property Costs
Distribution Expenses - Ope	5090	Underground Distribution Lines and Feeders - Rental Paid	-	
Distribution Expenses - Ope	5095	Overhead Distribution Lines and Feeders - Rental Paid	-	
Distribution Expenses - Ope	5096	Other Rent	-	

		Distr		
	Account No	Account Description		
Distribution Expenses - Mai	5105	Maintenance Supervision and Engineering	-	
Distribution Expenses - Mai	5110	Maintenance of Buildings and Fixtures - Distribution Stations	-	
Distribution Expenses - Mai	5112	Maintenance of Transformer Station Equipment	-	
Distribution Expenses - Mai	5114	Maintenance of Distribution Station Equipment	275	Property Costs
Distribution Expenses - Mai	5114	Maintenance of Distribution Station Equipment	3,325	Contract Services
Distribution Expenses - Mai	5114	Maintenance of Distribution Station Equipment	135,078	Salaries and Benefits
Distribution Expenses - Mai	5120	Maintenance of Poles, Towers and Fixtures	19,759	Material Costs
Distribution Expenses - Mai	5120	Maintenance of Poles, Towers and Fixtures	12,202	Contract Services
Distribution Expenses - Mai	5120	Maintenance of Poles, Towers and Fixtures	45,970	Salaries and Benefits
Distribution Expenses - Mai	5125	Maintenance of Overhead Conductors and Devices	109,200	Salaries and Benefits
Distribution Expenses - Mai	5130	Maintenance of Overhead Services	107,781	Salaries and Benefits
Distribution Expenses - Mai	5135	Overhead Distribution Lines and Feeders - Right of Way	255,104	Contract Services
Distribution Expenses - Mai	5135	Overhead Distribution Lines and Feeders - Right of Way	136,735	Salaries and Benefits
Distribution Expenses - Mai	5145	Maintenance of Underground Conduit	6,328	Contract Services
Distribution Expenses - Mai	5145	Maintenance of Underground Conduit	19,859	Salaries and Benefits
Distribution Expenses - Mai	5150	Maintenance of Underground Conductors and Devices	18,858	Salaries and Benefits
Distribution Expenses - Mai	5155	Maintenance of Underground Services	23,048	Salaries and Benefits
Distribution Expenses - Mai	5155	Maintenance of Underground Services	4,255	Other Costs
Distribution Expenses - Mai	5160	Maintenance of Line Transformers	46,794	Salaries and Benefits
Distribution Expenses - Mai	5160	Maintenance of Line Transformers	4,294	Material Costs
Distribution Expenses - Mai	5160	Maintenance of Line Transformers	5,188	Contract Services
Distribution Expenses - Mai	5160	Maintenance of Line Transformers	-	Property Costs
Distribution Expenses - Mai	5165	Maintenance of Street Lighting and Signal Systems	-	Salaries and Benefits
Distribution Expenses - Mai	5165	Maintenance of Street Lighting and Signal Systems	-	Material Costs
Distribution Expenses - Mai	5170	Sentinel Lights - Labour	-	
Distribution Expenses - Mai	5172	Sentinel Lights - Materials and Expenses	-	
Distribution Expenses - Mai	5175	Maintenance of Meters	951,608	Property Costs
Distribution Expenses - Mai	5178	Customer Installations Expenses- Leased Property	-	
Distribution Expenses - Mai	5185	Water Heater Rentals - Labour	-	
Distribution Expenses - Mai	5186	Water Heater Rentals - Materials and Expenses	-	
Distribution Expenses - Mai	5190	Water Heater Controls - Labour	-	
Distribution Expenses - Mai	5192	Water Heater Controls - Materials and Expenses	-	
Distribution Expenses - Mai	5195	Maintenance of Other Installations on Customer Premises	-	
			-	
			-	
	Account No	Account Description	-	
Other Expenses	5205	Purchase of Transmission and System Services	-	
Other Expenses	5210	Transmission Charges	-	
Other Expenses	5215	Transmission Charges Recovered	-	
			-	
			-	
	Account No	Account Description	-	
Billing And Collecting	5305	Supervision	97,977	Salaries and Benefits
Billing And Collecting	5310	Meter Reading Expense	32,940	Contract Services
Billing And Collecting	5315	Customer Billing	270,569	Salaries and Benefits

Billing And Collecting	5315	Customer Billing	68,054	Contract Services
Billing And Collecting	5315	Customer Billing	7,382	Property Costs
Billing And Collecting	5315	Customer Billing	84,733	Communication Costs
Billing And Collecting	5315	Customer Billing	85,262	Other Costs
Billing And Collecting	5320	Collecting	333,961	Salaries and Benefits
Billing And Collecting	5325	Collecting- Cash Over and Short	1,863	Other Costs
Billing And Collecting	5330	Collection Charges	3,417	Other Costs
Billing And Collecting	5335	Bad Debt Expense	86,102	Other Costs
Billing And Collecting	5340	Miscellaneous Customer Accounts Expenses	-	
		[redacted]		
	Account No	**Account Description**		
Community Relations	5405	Supervision	-	
Community Relations	5410	Community Relations - Sundry	-	
Community Relations	5415	Energy Conservation	-	
Community Relations	5420	Community Safety Program	-	
Community Relations	5425	Miscellaneous Customer Service and Informational Expenses	-	
			-	
		[redacted]	-	
	Account No	**Account Description**	-	
Sales Expenses	5505	Supervision	-	
Sales Expenses	5510	Demonstrating and Selling Expense	-	
Sales Expenses	5515	Advertising Expense	-	
Sales Expenses	5520	Miscellaneous Sales Expense	-	
		[redacted]		
	Account No	**Account Description**		
Administr and Gen Expense	5605	Executive Salaries and Expenses	372,758	Salaries and Benefits
Administr and Gen Expense	5605	Executive Salaries and Expenses	12,309	Other Costs
Administr and Gen Expense	5605	Executive Salaries and Expenses	-	Property Costs
Administr and Gen Expense	5605	Executive Salaries and Expenses	1,704	Communication Costs
Administr and Gen Expense	5605	Executive Salaries and Expenses	-	Contract Services
Administr and Gen Expense	5610	Management Salaries and Expenses	351,762	Salaries and Benefits
Administr and Gen Expense	5615	General Administrative Salaries and Expenses	192,764	Salaries and Benefits
Administr and Gen Expense	5615	General Administrative Salaries and Expenses	319,139	Communication Costs
Administr and Gen Expense	5615	General Administrative Salaries and Expenses	88,735	Other Costs
Administr and Gen Expense	5615	General Administrative Salaries and Expenses	11,445	Contract Services
Administr and Gen Expense	5620	Office Supplies and Expenses	42,835	Material Costs
Administr and Gen Expense	5625	Administrative Expense Transferred/Credit	-	
Administr and Gen Expense	5630	Outside Services Employed	78,974	Contract Services
Administr and Gen Expense	5635	Property Insurance	44,016	Property Costs
Administr and Gen Expense	5640	Injuries and Damages	54,288	Property Costs
Administr and Gen Expense	5645	Employee Pensions and Benefits	-	
Administr and Gen Expense	5650	Franchise Requirements	-	
Administr and Gen Expense	5655	Regulatory Expenses	122,753	Other Costs
Administr and Gen Expense	5660	General Advertising Expenses	14,555	Other Costs
Administr and Gen Expense	5665	Miscellaneous General Expenses	104,035	Other Costs
Administr and Gen Expense	5670	Rent	-	
Administr and Gen Expense	5675	Maintenance of General Plant	224,866	Contract Services

Administr and Gen Expense	5675	Maintenance of General Plant	-	Property Costs
Administr and Gen Expense	5680	Electrical Safety Authority Fees	-	
Administr and Gen Expense	5685	Independent Market Operator Fees and Penalties	-	
Administr and Gen Expense	5695	OM&A Contra	-	
	Account No	**Account Description**		
Amortization Expenses	5705	Amortization Expense - Property, Plant, and Equipment	1,684,937	Amortization
Amortization Expenses	5710	Amortization of Limited Term Electric Plant	-	
Amortization Expenses	5715	Amortization of Intangibles and Other Electric Plant	-	Amortization
Amortization Expenses	5720	Amortization of Electric Plant Acquisition Adjustments	-	
Amortization Expenses	5725	Miscellaneous Amortization	-	
Amortization Expenses	5730	Amortization of Unrecovered Plant and Regulatory Study Costs	-	
Amortization Expenses	5735	Amortization of Deferred Development Costs	-	
Amortization Expenses	5740	Amortization of Deferred Charges	-	
			-	
	Account No	**Account Description**		
Interest Expenses	6005	Interest on Long Term Debt		
Interest Expenses	6010	Amortization of Debt Discount and Expense	-	
Interest Expenses	6015	Amortization of Premium on Debt/Credit	-	
Interest Expenses	6020	Amortization of Loss on Reacquired Debt	-	
Interest Expenses	6025	Amortization of Gain on Reacquired Debt--Credit	-	
Interest Expenses	6030	Interest on Debt to Associated Companies	-	Interest Expense
Interest Expenses	6035	Other Interest Expense	1,111,528	Interest Expense
Interest Expenses	6040	Allowance for Borrowed Funds Used During Construction--Credit	-	
Interest Expenses	6042	Allowance For Other Funds Used During Construction	-	
Interest Expenses	6045	Interest Expense on Capital Lease Obligations	-	
	Account No	**Account Description**		
	6105	Taxes Other Than Income Taxes	99,638	Other Costs
Taxes	6110	Income Taxes	416,811	Income Taxes
Taxes	6115	Provision for Future Income Taxes	-	
	Account No	**Account Description**		
Other Deductions	6205	Donations	4,875	Other Costs
Other Deductions	6210	Life Insurance	-	
Other Deductions	6215	Penalties	-	
Other Deductions	6225	Other Deductions	-	
	Account No	**Account Description**		
Extraordinary Items	6305	Extraordinary Income	-	
Extraordinary Items	6310	Extraordinary Deductions	-	
Extraordinary Items	6315	Income Taxes: Extraordinary Item	-	
			-	

	Account No	Account Description		
Disconected Operations	6405	Discontinues Operations - Income/ Gains	-	
Disconected Operations	6410	Discontinued Operations - Deductions/ Losses	-	
Disconected Operations	6415	Income Taxes, Discontinued Operations	-	
	Total		(2,490,959)	

Service Revenue			(56,181,636)	
Other income			(1,186,589)	
			(57,368,225)	
Power Costs			45,746,999	
Salaries and Benefits			3,031,124	
Material Costs			74,716	
Property costs			1,073,068	
Other Costs			634,080	
Contract Services			698,426	
Communication Costs			405,577	
Capital Tax			-	
Amortization			1,684,937	
Interest Expense			1,111,528	
Income Taxes			416,811	
Allocated to capital				
			54,877,265	
Net Income per USoA			(2,490,960)	
Net Income per Financial Statements			2,490,960	
			(0)	

		ASSETS	2013	Audited Financial Statement Line Item
		[redacted]		
	Account No	Account Description	Amount	
Current Assets	1005	Cash	-	Cash and cash equivalents
Current Assets	1010	Cash Advances and Working Funds	-	
Current Assets	1020	Interest Special Deposits	-	
Current Assets	1030	Dividend Special Deposits	-	
Current Assets	1040	Other Special Deposits	-	
Current Assets	1060	Term Deposits	-	
Current Assets	1070	Current Investments	-	
Current Assets	1100	Customer Accounts Receivable	4,943,937	Accounts Receivable
Current Assets	1100	Customer Accounts Receivable	211,593	Accounts Receivable
Current Assets	1102	Accounts Receivable - Services	-	
Current Assets	1104	Accounts Receivable - Recoverable Work	361,802	Accounts Receivable
Current Assets	1105	Accounts Receivable - Merchandise, Jobbing, etc.	-	
Current Assets	1110	Other Accounts Receivable	1,251,383	Accounts Receivable
Current Assets	1110	Other Accounts Receivable	504,933	Pils Receivable
Current Assets	1120	Accrued Utility Revenues	7,177,715	Unbilled Revenue
Current Assets	1130	Accumulated Provision for Uncollectible Accounts--Credit	(199,441)	Accounts Receivable
Current Assets	1140	Interest and Dividends Receivable	-	
Current Assets	1150	Rents Receivable	-	
Current Assets	1170	Notes Receivable	-	
Current Assets	1180	Prepayments	461,576	Prepaid Expenses
Current Assets	1190	Miscellaneous Current and Accrued Assets	-	
Current Assets	1200	Accounts Receivable from Associated Companies	88,153	Due from related companies
Current Assets	1210	Notes Receivable from Associated Companies	-	
			-	
		[redacted]	-	
	Account No	Account Description	-	
Inventory	1305	Fuel Stock	-	
Inventory	1330	Plant Materials and Operating Supplies	821,824	Inventory
Inventory	1340	Merchandise	-	
Inventory	1350	Other Materials and Supplies	-	
			-	
		[redacted]	-	
	Account No	Account Description	-	
Non-Current Assets	1405	Long Term Investments in Non-Associated Companies	-	
Non-Current Assets	1408	Long Term Receivable - Street Lighting Transfer	-	
Non-Current Assets	1410	Other Special or Collateral Funds	-	
Non-Current Assets	1415	Sinking Funds	-	
Non-Current Assets	1425	Unamortized Debt Expense	-	
Non-Current Assets	1445	Unamortized Discount on Long-Term Debt--Debit	-	
Non-Current Assets	1455	Unamortized Deferred Foreign Currency Translation Gains and Losses	-	
Non-Current Assets	1460	Other Non-Current Assets	-	
Non-Current Assets	1465	O.M.E.R.S. Past Service Costs	-	
Non-Current Assets	1470	Past Service Costs - Employee Future Benefits	-	
Non-Current Assets	1475	Past Service Costs - Other Pension Plans	-	

Non-Current Assets	1480	Portfolio Investments - Associated Companies	-	
Non-Current Assets	1485	Investment in Associated Companies - Significant Influence	-	
Non-Current Assets	1490	Investment in Subsidiary Companies	-	
Non-Current Assets	1495	Deferred Taxes- Non Current	2,560,696	Regulatory Assets
		[illegible]		
	Account No	**Account Description**		
Other Assets and Deferred Charges	1505	Unrecovered Plant and Regulatory Study Costs	-	Regulatory Assets
Other Assets and Deferred Charges	1508	Other Regulatory Assets	694,794	Regulatory Assets
Other Assets and Deferred Charges	1510	Preliminary Survey and Investigation Charges	-	Regulatory Assets
Other Assets and Deferred Charges	1515	Emission Allowance Inventory	-	Regulatory Assets
Other Assets and Deferred Charges	1516	Emission Allowances Withheld	-	Regulatory Assets
Other Assets and Deferred Charges	1518	RCVARetail	772	Regulatory Assets
Other Assets and Deferred Charges	1520	Power Purchase Variance Account	-	Regulatory Assets
Other Assets and Deferred Charges	1521	MEI - Special Purpose Charge	-	Regulatory Assets
Other Assets and Deferred Charges	1525	Miscellaneous Deferred Debits	-	Regulatory Assets
Other Assets and Deferred Charges	1530	Deferred Losses from Disposition of Utility Plant	-	Regulatory Assets
Other Assets and Deferred Charges	1531	Renewable Connection Capital Deferral Account	-	Regulatory Assets
Other Assets and Deferred Charges	1532	Renewable Connection OM&A Deferral Account	-	Regulatory Assets
Other Assets and Deferred Charges	1534	Smart Grid Capital Deferral Account	-	Regulatory Assets
Other Assets and Deferred Charges	1535	Smart Grid Capital OM&A Account	-	Regulatory Assets
Other Assets and Deferred Charges	1540	Unamortized Loss on Reacquired Debt	-	Regulatory Assets
Other Assets and Deferred Charges	1545	Development Charge Deposits/ Receivables	-	Regulatory Assets
Other Assets and Deferred Charges	1548	RCVASTR	368	Regulatory Assets
Other Assets and Deferred Charges	1550	LV Variance Account	170,062	Regulatory Assets
Other Assets and Deferred Charges	1551		17,560	Regulatory Assets
Other Assets and Deferred Charges	1555	Smart Meter Capital and Recovery Offset Variance	792,097	Regulatory Assets
Other Assets and Deferred Charges	1556	Smart Meter OM&A Variance	-	Regulatory Assets
Other Assets and Deferred Charges	1560	Deferred Development Costs	-	Regulatory Assets
Other Assets and Deferred Charges	1562	Deferred Payments in Lieu of Taxes	-	Regulatory Assets
Other Assets and Deferred Charges	1563	Deferred PILs Contra Account	-	Regulatory Assets
Other Assets and Deferred Charges	1565	Conservation and Demand Management Expenditures and Recoveries	-	Regulatory Assets
Other Assets and Deferred Charges	1566	CDM Contra	-	Regulatory Assets
Other Assets and Deferred Charges	1570	Qualifying Transition Costs	-	Regulatory Assets
Other Assets and Deferred Charges	1571	Pre-market Opening Energy Variance	(418,365)	Regulatory Assets
Other Assets and Deferred Charges	1572	Extraordinary Event Costs	-	Regulatory Assets
Other Assets and Deferred Charges	1574	Deferred Rate Impact Amounts	1,712,395	Regulatory Assets
Other Assets and Deferred Charges	1575	IFRS-CGAAP Transitional PP&E Amounts	-	Regulatory Assets
Other Assets and Deferred Charges	1580	RSVAWMS	(1,409,973)	Regulatory Assets
Other Assets and Deferred Charges	1582	RSVAONE-TIME	-	Regulatory Assets
Other Assets and Deferred Charges	1584	RSVANW	1,225,754	Regulatory Assets
Other Assets and Deferred Charges	1586	RSVACN	866,637	Regulatory Assets
Other Assets and Deferred Charges	1588	RSVAPOWER	(219,965)	Regulatory Assets
Other Assets and Deferred Charges	1589	RSVA GA	1,056,219	Regulatory Assets
Other Assets and Deferred Charges	1590	Recovery of regulatory asset balances	-	Regulatory Assets
Other Assets and Deferred Charges	1592	2006 PILs & Taxes Variance	-	Regulatory Assets
Other Assets and Deferred Charges	1595	Sub-Account Disposition of Account Balances Approved in 2010	281,723	Regulatory Assets
Other Assets and Deferred Charges	1595	Sub-Account Disposition of Account Balances Approved in 2012	341,805	Regulatory Assets
Other Assets and Deferred Charges	1595	Sub-Account Disposition of Account Balances Approved in 2008	39,321	Regulatory Assets

		[redacted]		
	Account No	Account Description		
Electric Plant and Service - Detailed	1605	Electric Plant in Service - Control Account		
		[redacted]		
	Account No	Account Description		
Intangible Plant	1606	Organization	374,370	Capital Assets
Intangible Plant	1608	Franchises and Consents	-	Capital Assets
Intangible Plant	1610	Miscellaneous Intangible Plant	-	Capital Assets
			-	Capital Assets
		[redacted]		
	Account No	Account Description		
Distribution Plant	1805	Land	591,591	Capital Assets
Distribution Plant	1612	Land Rights	4,738	Capital Assets
Distribution Plant	1808	Buildings and Fixtures	3,590,614	Capital Assets
Distribution Plant	1810	Leasehold Improvements	-	Capital Assets
Distribution Plant	1815	Transformer Station Equipment - Normally Primary above 50 kV	-	Capital Assets
Distribution Plant	1820	Distribution Station Equipment - Normally Primary below 50 kV	5,713,606	Capital Assets
Distribution Plant	1825	Storage Battery Equipment	-	Capital Assets
Distribution Plant	1830	Poles, Towers and Fixtures	22,266,952	Capital Assets
Distribution Plant	1835	Overhead Conductors and Devices	8,009,640	Capital Assets
Distribution Plant	1840	Underground Conduit	1,150,788	Capital Assets
Distribution Plant	1845	Underground Conductors and Devices	7,143,546	Capital Assets
Distribution Plant	1850	Line Transformers	8,731,981	Capital Assets
Distribution Plant	1855	Services	3,054,541	Capital Assets
Distribution Plant	1860	Meters	5,308,957	Capital Assets
Distribution Plant	1865	Other Installations on Customer's Premises	-	Capital Assets
Distribution Plant	1870	Leased Property on Customer Premises	-	Capital Assets
Distribution Plant	1875	Street Lighting and Signal Systems	-	Capital Assets
			-	
		[redacted]		
	Account No	Account Description		
General Plant	1905	Land	-	Capital Assets
General Plant	1906	Land Rights	-	Capital Assets
General Plant	1908	Buildings and Fixtures	-	Capital Assets
General Plant	1910	Leasehold Improvements	-	Capital Assets
General Plant	1915	Office Furniture and Equipment	429,916	Capital Assets
General Plant	1920	Computer Equipment - Hardware	1,497,027	Capital Assets
General Plant	1611	Computer Software	1,582,924	Capital Assets
General Plant	1930	Transportation Equipment	2,828,050	Capital Assets
General Plant	1935	Stores Equipment	59,018	Capital Assets
General Plant	1940	Tools, Shop and Garage Equipment	697,339	Capital Assets
General Plant	1945	Measurement and Testing Equipment	-	Capital Assets
General Plant	1950	Power Operated Equipment	-	Capital Assets
General Plant	1955	Communication Equipment	-	Capital Assets
General Plant	1960	Miscellaneous Equipment	-	Capital Assets
General Plant	1965	Water Heater Rental Units	-	Capital Assets
General Plant	1970	Load Management Controls - Customer Premises	734,195	Capital Assets

General Plant	1975	Load Management Controls - Utility Premises	-	Capital Assets
General Plant	1980	System Supervisory Equipment	1,137,242	Capital Assets
General Plant	1985	Sentinel Lighting Rental Units	-	Capital Assets
General Plant	1990	Other Tangible Property	-	Capital Assets
General Plant	1995	Contributions and Grants - Credit	(7,254,067)	Capital Assets
			-	Capital Assets
		[redacted]	-	Capital Assets
	Account No	**Account Description**	-	Capital Assets
Other capital Assets	2005	Property Under Capital Leases	-	Capital Assets
Other capital Assets	2010	Electric Plant Purchased or Sold	-	Capital Assets
Other capital Assets	2020	Experimental Electric Plant Unclassified	-	Capital Assets
Other capital Assets	2030	Electric Plant and Equipment Leased to Others	-	Capital Assets
Other capital Assets	2040	Electric Plant Held for Future Use	-	Capital Assets
Other capital Assets	2050	Completed Construction Not Classified--Electric	-	Capital Assets
Other capital Assets	2055	Construction Work in Progress--Electric	3,144,067	Capital Assets
Other capital Assets	2060	Electric Plant Acquisition Adjustment	-	Capital Assets
Other capital Assets	2065	Other Electric Plant Adjustment	-	Capital Assets
Other capital Assets	2070	Other Utility Plant	-	Capital Assets
Other capital Assets	2075	Non-Utility Property Owned or Under Capital Leases	-	Capital Assets
		[redacted]		
	Account No	**Account Description**		
Accumulated Amortization	2105	Accumulated Amortization of Electric Utility Plan - PP	(24,952,249)	Capital Assets
Accumulated Amortization	2120	Accumulated Amortization of Electric Utility Plant - Intangibles	(150,107)	Capital Assets
Accumulated Amortization	2140	Accumulated Amortization of Electric Plant Acquisition Adjustment	-	Capital Assets
Accumulated Amortization	2160	Accumulated Amortization of Other Utility Plant	-	Capital Assets
Accumulated Amortization	2180	Accumulated Amortization of Non-Utility Property	-	Capital Assets
			-	
		LIABILITIES AND EQUITY		
		[redacted]		
	Account No	**Account Description**		
Current Liabilities	2205	Accounts Payable	(8,923,363)	Accounts Payable and Accrued Liabilities
Current Liabilities	2208	Customer Credit Balances	(1,141,338)	Accounts Payable and Accrued Liabilities
Current Liabilities	2210	Current Portion of Customer Deposits	(230,000)	Current Portion of Customer Deposit
Current Liabilities	2215	Dividends Declared	-	
Current Liabilities	2220	Miscellaneous Current and Accrued Liabilities	-	
Current Liabilities	2225	Notes and Loans Payable	(3,937,094)	Bank indebtedness
Current Liabilities	2240	Accounts Payable to Associated Companies	-	
Current Liabilities	2242	Notes Payable to Associated Companies	-	
Current Liabilities	2250	Debt Retirement Charges(DRC) Payable	(295,122)	Accounts Payable and Accrued Liabilities
Current Liabilities	2252	Transmission Charges Payable	-	
Current Liabilities	2254	Electrical Safety Authority Fees Payable	-	
Current Liabilities	2256	Independent Market Operator Fees and Penalties Payable	-	
Current Liabilities	2260	Current Portion of Long Term Debt	-	
Current Liabilities	2262	Ontario Hydro Debt - Current Portion	-	
Current Liabilities	2264	Pensions and Employee Benefits - Current Portion	-	
Current Liabilities	2268	Accrued Interest on Long Term Debt	-	

Current Liabilities	2270	Matured Long Term Debt	-	
Current Liabilities	2272	Matured Interest on Long Term Debt	-	
Current Liabilities	2285	Obligations Under Capital Leases--Current	-	
Current Liabilities	2290	Commodity Taxes	-	
Current Liabilities	2292	Payroll Deductions / Expenses Payable	(148,762)	Accounts Payable and Accrued Liabilities
Current Liabilities	2294	Accrual for Taxes Payments in Lieu of Taxes, Etc.	-	
Current Liabilities	2296	Future Income Taxes - Current	-	
			-	
	Account No	Account Description		
Non-Current Liability	2305	Accumulated Provision for Injuries and Damages	-	
Non-Current Liability	2306	Employee Future Benefits	(547,447)	Employee Future Benefits
Non-Current Liability	2308	Other Pensions - Past Service Liability	-	
Non-Current Liability	2310	Vested Sick Leave Liability	-	
Non-Current Liability	2315	Accumulated Provision for Rate Refunds	-	
Non-Current Liability	2320	Other Miscellaneous Non-Current Liabilities	-	
Non-Current Liability	2325	Obligations Under Capital Lease--Non-Current	-	
Non-Current Liability	2330	Development Charge Fund	-	
Non-Current Liability	2335	Long Term Customer Deposits	(505,282)	Customer Deposit
Non-Current Liability	2340	Collateral Funds Liability	-	
Non-Current Liability	2345	Unamortized Premium on Long Term Debt	-	
Non-Current Liability	2348	O.M.E.R.S. - Past Service Liability - Long Term Portion	-	
Non-Current Liability	2350	Deferred Tax - Non-Current	(2,385,431)	Future Income Tax
	Account No	Account Description		
Other Liabilities and Deferred Credits	2405	Other Regulatory Liabilities	-	
Other Liabilities and Deferred Credits	2410	Deferred Gains from Disposition of Utility Plant	-	
Other Liabilities and Deferred Credits	2415	Unamortized Gain on Reacquired Debt	-	
Other Liabilities and Deferred Credits	2425	Other Deferred Credits	-	
Other Liabilities and Deferred Credits	2435	Accrued Rate-Payer Benefit	-	
	Account No	Account Description		
Long Terms Debt	2505	Debentures Outstanding - Long Term Portion	-	
Long Terms Debt	2510	Debenture Advances	-	
Long Terms Debt	2515	Reacquired Bonds	-	
Long Terms Debt	2520	Other Long Term Debt	-	
Long Terms Debt	2525	Term Bank Loans - Long Term Portion	(7,857,309)	Smart Meter Bank Loan
Long Terms Debt	2530	Ontario Hydro Debt Outstanding - Long Term Portion	-	
Long Terms Debt	2550	Advances from Associated Companies	(16,141,969)	Note Payable
	Account No	Account Description		
Shareholder's Equity	3005	Common Shares Issued	(16,161,663)	Capital Stock
Shareholder's Equity	3008	Preference Shares Issued	-	
Shareholder's Equity	3010	Contributed Surplus	-	
Shareholder's Equity	3020	Donations Received	-	
Shareholder's Equity	3022	Development Charges Transferred to Equity	-	

Shareholder's Equity	3026	Capital Stock Held in Treasury	-	
Shareholder's Equity	3030	Miscellaneous Paid-In Capital	-	
Shareholder's Equity	3035	Installments Received on Capital Stock	-	
Shareholder's Equity	3040	Appropriated Retained Earnings	-	
Shareholder's Equity	3045	Unappropriated Retained Earnings	(8,427,010)	Retained Earnings
Shareholder's Equity	3047	Appropriations of Retained Earnings - Current Period	-	
Shareholder's Equity	3048	Dividends Payable-Preference Shares	-	
Shareholder's Equity	3049	Dividends Payable-Common Shares	1,295,344	Retained Earnings
Shareholder's Equity	3055	Adjustment to Retained Earnings	-	
Shareholder's Equity	3065	Unappropriated Undistributed Subsidiary Earnings	-	
		Shareholder's Equity Acct 3046		
	Account No	**Account Description**		
	3046	Balance Transferred From Income	(3,623,607)	Net Earnings
		INCOME STATEMENT		
		[redacted]	-	
	Account No	**Account Description**		
Sales of Electricity	4006	Residential Energy Sales	(17,336,894)	Service Revenue
Sales of Electricity	4010	Commercial Energy Sales	(4,756,024)	Service Revenue
Sales of Electricity	4015	Industrial Energy Sales	(18,949,865)	Service Revenue
Sales of Electricity	4020	Energy Sales to Large Users	-	Service Revenue
Sales of Electricity	4025	Street Lighting Energy Sales	(231,471)	Service Revenue
Sales of Electricity	4030	Sentinel Lighting Energy Sales	(82,347)	Service Revenue
Sales of Electricity	4035	General Energy Sales	(75,251)	Service Revenue
Sales of Electricity	4040	Other Energy Sales to Public Authorities	-	Service Revenue
Sales of Electricity	4045	Energy Sales to Railroads and Railways	-	Service Revenue
Sales of Electricity	4050	Revenue Adjustment	-	Service Revenue
Sales of Electricity	4055	Energy Sales for Resale	-	Service Revenue
Sales of Electricity	4060	Interdepartmental Energy Sales	-	Service Revenue
Sales of Electricity	4062	Billed WMS	(2,729,242)	Service Revenue
Sales of Electricity	4064	Billed One-Time	-	Service Revenue
Sales of Electricity	4066	Billed NW	(3,196,989)	Service Revenue
Sales of Electricity	4068	Billed CN	(2,522,891)	Service Revenue
Sales of Electricity	4075	Billed - LV	(613,646)	Service Revenue
		[redacted]		
	Account No	**Account Description**		
Revenue from Services-Distribution	4080	Distribution Services Revenue	(9,129,818)	Service Revenue
Revenue from Services-Distribution	4082	Retail Services Revenues	-	
Revenue from Services-Distribution	4084	Service Transaction Requests (STR) Revenues	-	
Revenue from Services-Distribution	4090	Electric Services Incidental to Energy Sales	-	
		[redacted]		
	Account No	**Account Description**		
Revenue from Services-Transmission	4105	Transmission Charges Revenue	-	
Revenue from Services-Transmission	4110	Transmission Services Revenue	-	

		[redacted]		
	Account No	Account Description		
Other Operating Revenues	4205	Interdepartmental Rents	-	Other income
Other Operating Revenues	4210	Rent from Electric Property	(164,833)	Other income
Other Operating Revenues	4215	Other Utility Operating Income	-	Other income
Other Operating Revenues	4220	Other Electric Revenues	-	Other income
Other Operating Revenues	4225	Late Payment Charges	(107,188)	Other income
Other Operating Revenues	4230	Sales of Water and Water Power	-	Other income
Other Operating Revenues	4235	Miscellaneous Service Revenues	(331,859)	Other income
Other Operating Revenues	4240	Provision for Rate Refunds	-	Other income
Other Operating Revenues	4245	Government Assistance Directly Credited to Income	-	Other income
		[redacted]		
	Account No	Account Description		
Other Income / Deductions	4305	Regulatory Debits	-	Other income
Other Income / Deductions	4310	Regulatory Credits	-	Other income
Other Income / Deductions	4315	Revenues from Electric Plant Leased to Others	-	Other income
Other Income / Deductions	4320	Expenses of Electric Plant Leased to Others	-	Other income
Other Income / Deductions	4325	Revenues from Merchandise, Jobbing, Etc.	(47,108)	Other income
Other Income / Deductions	4330	Costs and Expenses of Merchandising, Jobbing, Etc.	-	Other income
Other Income / Deductions	4335	Profits and Losses from Financial Instrument Hedges	-	Other income
Other Income / Deductions	4340	Profits and Losses from Financial Instrument Investments	-	Other income
Other Income / Deductions	4345	Gains from Disposition of Future Use Utility Plant	-	Other income
Other Income / Deductions	4350	Losses from Disposition of Future Use Utility Plant	-	Other income
Other Income / Deductions	4355	Gain on Disposition of Utility and Other Property	(12,118)	Other income
Other Income / Deductions	4360	Loss on Disposition of Utility and Other Property	-	Other income
Other Income / Deductions	4365	Gains from Disposition of Allowances for Emission	-	Other income
Other Income / Deductions	4370	Losses from Disposition of Allowances for Emission	-	Other income
Other Income / Deductions	4375	Revenues from Non-Utility Operations	(804,580)	Other income
Other Income / Deductions	4380	Expenses of Non-Utility Operations	504,893	Other income
Other Income / Deductions	4385	Non-Utility Rental Income	(33,685)	Other income
Other Income / Deductions	4390	Miscellaneous Non-Operating Income	-	Other income
Other Income / Deductions	4395	Rate-Payer Benefit Including Interest	-	Other income
Other Income / Deductions	4398	Foreign Exchange Gains and Losses, Including Amortization	-	Other income
			-	Other income
		[redacted]		
	Account No	Account Description		
Investment Income	4405	Interest and Dividend Income	(74,610)	Other income
Investment Income	4415	Equity in Earnings of Subsidiary Companies	-	Other income
		[redacted]		
	Account No	Account Description		
Generation Expenses - Operation	4505	Operation Supervision and Engineering	-	
Generation Expenses - Operation	4510	Fuel	-	
Generation Expenses - Operation	4515	Steam Expense	-	
Generation Expenses - Operation	4520	Steam From Other Sources	-	
Generation Expenses - Operation	4525	Steam Transferred--Credit	-	
Generation Expenses - Operation	4530	Electric Expense	-	
Generation Expenses - Operation	4535	Water For Power	-	

Generation Expenses - Operation	4540	Water Power Taxes	-	
Generation Expenses - Operation	4545	Hydraulic Expenses	-	
Generation Expenses - Operation	4550	Generation Expense	-	
Generation Expenses - Operation	4555	Miscellaneous Power Generation Expenses	-	
Generation Expenses - Operation	4560	Rents	-	
Generation Expenses - Operation	4565	Allowances for Emissions	-	
			-	
	Account No	Account Description		
Other Power Supply Expenses	4705	Power Purchased	41,431,851	Power Costs
Other Power Supply Expenses	4707		-	Power Costs
Other Power Supply Expenses	4708	Charges-WMS	2,729,242	Power Costs
Other Power Supply Expenses	4710	Cost of Power Adjustments	-	Power Costs
Other Power Supply Expenses	4712	Charges-One-Time	-	Power Costs
Other Power Supply Expenses	4714	Charges-NW	3,196,989	Power Costs
Other Power Supply Expenses	4715	System Control and Load Dispatching	-	Power Costs
Other Power Supply Expenses	4716	Charges-CN	2,522,891	Power Costs
Other Power Supply Expenses	4720	Other Expenses	-	Power Costs
Other Power Supply Expenses	4725	Competition Transition Expense	-	Power Costs
Other Power Supply Expenses	4730	Rural Rate Assistance Expense	-	Power Costs
Other Power Supply Expenses	4750	Charges - LV	613,646	Power Costs
	Account No	Account Description		
Distribution Expenses - Operation	5005	Operation Supervision and Engineering	209,266	Salaries and Benefits
Distribution Expenses - Operation	5010	Load Dispatching	-	
Distribution Expenses - Operation	5012	Station Buildings and Fixtures Expense	112	Property Costs
Distribution Expenses - Operation	5014	Transformer Station Equipment - Operation Labour	-	
Distribution Expenses - Operation	5015	Transformer Station Equipment - Operation Supplies and Expenses	-	
Distribution Expenses - Operation	5016	Distribution Station Equipment - Operation Labour	54,800	Salaries and Benefits
Distribution Expenses - Operation	5017	Distribution Station Equipment - Operation Supplies and Expenses	5,477	Material Costs
Distribution Expenses - Operation	5020	Overhead Distribution Lines and Feeders - Operation Labour	(78,621)	Salaries and Benefits
Distribution Expenses - Operation	5020	Overhead Distribution Lines and Feeders - Operation Labour	23,993	Communication Costs
Distribution Expenses - Operation	5020	Overhead Distribution Lines and Feeders - Operation Labour	142,645	Other Costs
Distribution Expenses - Operation	5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-	
Distribution Expenses - Operation	5030	Overhead Subtransmission Feeders - Operation	-	
Distribution Expenses - Operation	5035	Overhead Distribution Transformers- Operation	-	
Distribution Expenses - Operation	5040	Underground Distribution Lines and Feeders - Operation Labour	-	
Distribution Expenses - Operation	5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	424	Material Costs
Distribution Expenses - Operation	5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	3,151	Salaries and Benefits
Distribution Expenses - Operation	5050	Underground Subtransmission Feeders - Operation	138,577	Salaries and Benefits
Distribution Expenses - Operation	5055	Underground Distribution Transformers - Operation	67,814	Salaries and Benefits
Distribution Expenses - Operation	5060	Street Lighting and Signal System Expense	-	
Distribution Expenses - Operation	5065	Meter Expense	160,475	Salaries and Benefits
Distribution Expenses - Operation	5065	Meter Expense	836	Communication Costs
Distribution Expenses - Operation	5065	Meter Expense	728	Contract Services
Distribution Expenses - Operation	5065	Meter Expense	12,219	Material Costs
Distribution Expenses - Operation	5070	Customer Premises - Operation Labour	3,565	Salaries and Benefits
Distribution Expenses - Operation	5075	Customer Premises - Materials and Expenses	-	

Distribution Expenses - Operation	5085	Miscellaneous Distribution Expense	5,970	Other Costs
Distribution Expenses - Operation	5085	Miscellaneous Distribution Expense	33,014	Salaries and Benefits
Distribution Expenses - Operation	5085	Miscellaneous Distribution Expense	16,000	Property Costs
Distribution Expenses - Operation	5090	Underground Distribution Lines and Feeders - Rental Paid	-	
Distribution Expenses - Operation	5095	Overhead Distribution Lines and Feeders - Rental Paid	-	
Distribution Expenses - Operation	5096	Other Rent	-	
		[redacted]		
	Account No	**Account Description**		
Distribution Expenses - Maintenance	5105	Maintenance Supervision and Engineering	-	
Distribution Expenses - Maintenance	5110	Maintenance of Buildings and Fixtures - Distribution Stations	-	
Distribution Expenses - Maintenance	5112	Maintenance of Transformer Station Equipment	-	
Distribution Expenses - Maintenance	5114	Maintenance of Distribution Station Equipment	-	Property Costs
Distribution Expenses - Maintenance	5114	Maintenance of Distribution Station Equipment	1,639	Contract Services
Distribution Expenses - Maintenance	5114	Maintenance of Distribution Station Equipment	104,507	Salaries and Benefits
Distribution Expenses - Maintenance	5120	Maintenance of Poles, Towers and Fixtures	24,790	Material Costs
Distribution Expenses - Maintenance	5120	Maintenance of Poles, Towers and Fixtures	17,496	Contract Services
Distribution Expenses - Maintenance	5120	Maintenance of Poles, Towers and Fixtures	35,566	Salaries and Benefits
Distribution Expenses - Maintenance	5125	Maintenance of Overhead Conductors and Devices	84,486	Salaries and Benefits
Distribution Expenses - Maintenance	5130	Maintenance of Overhead Services	83,388	Salaries and Benefits
Distribution Expenses - Maintenance	5135	Overhead Distribution Lines and Feeders - Right of Way	177,652	Contract Services
Distribution Expenses - Maintenance	5135	Overhead Distribution Lines and Feeders - Right of Way	105,789	Salaries and Benefits
Distribution Expenses - Maintenance	5145	Maintenance of Underground Conduit	14,364	Contract Services
Distribution Expenses - Maintenance	5145	Maintenance of Underground Conduit	15,364	Salaries and Benefits
Distribution Expenses - Maintenance	5150	Maintenance of Underground Conductors and Devices	14,590	Salaries and Benefits
Distribution Expenses - Maintenance	5155	Maintenance of Underground Services	17,832	Salaries and Benefits
Distribution Expenses - Maintenance	5155	Maintenance of Underground Services	23	Other Costs
Distribution Expenses - Maintenance	5160	Maintenance of Line Transformers	39,501	Salaries and Benefits
Distribution Expenses - Maintenance	5160	Maintenance of Line Transformers	2,700	Material Costs
Distribution Expenses - Maintenance	5160	Maintenance of Line Transformers	617	Contract Services
Distribution Expenses - Maintenance	5160	Maintenance of Line Transformers	2,253	Communication Costs
Distribution Expenses - Maintenance	5165	Maintenance of Street Lighting and Signal Systems	-	Salaries and Benefits
Distribution Expenses - Maintenance	5165	Maintenance of Street Lighting and Signal Systems	-	Material Costs
Distribution Expenses - Maintenance	5170	Sentinel Lights - Labour	-	
Distribution Expenses - Maintenance	5172	Sentinel Lights - Materials and Expenses	-	
Distribution Expenses - Maintenance	5175	Maintenance of Meters	-	Property Costs
Distribution Expenses - Maintenance	5178	Customer Installations Expenses- Leased Property	-	
Distribution Expenses - Maintenance	5185	Water Heater Rentals - Labour	-	
Distribution Expenses - Maintenance	5186	Water Heater Rentals - Materials and Expenses	-	
Distribution Expenses - Maintenance	5190	Water Heater Controls - Labour	-	
Distribution Expenses - Maintenance	5192	Water Heater Controls - Materials and Expenses	-	
Distribution Expenses - Maintenance	5195	Maintenance of Other Installations on Customer Premises	-	
			-	
		[redacted]	-	
	Account No	**Account Description**	-	
Other Expenses	5205	Purchase of Transmission and System Services	-	
Other Expenses	5210	Transmission Charges	-	
Other Expenses	5215	Transmission Charges Recovered	-	

			-	
		[redacted]	-	
	Account No	Account Description	-	
Billing And Collecting	5305	Supervision	96,782	Salaries and Benefits
Billing And Collecting	5310	Meter Reading Expense	32,626	Contract Services
Billing And Collecting	5315	Customer Billing	247,404	Salaries and Benefits
Billing And Collecting	5315	Customer Billing	57,989	Contract Services
Billing And Collecting	5315	Customer Billing	96,697	Property Costs
Billing And Collecting	5315	Customer Billing	94,521	Communication Costs
Billing And Collecting	5315	Customer Billing	83,627	Other Costs
Billing And Collecting	5320	Collecting	406,202	Salaries and Benefits
Billing And Collecting	5325	Collecting- Cash Over and Short	-	Other Costs
Billing And Collecting	5330	Collection Charges	4,241	Other Costs
Billing And Collecting	5335	Bad Debt Expense	90,000	Other Costs
Billing And Collecting	5340	Miscellaneous Customer Accounts Expenses	-	
		[redacted]		
	Account No	Account Description		
Community Relations	5405	Supervision	-	
Community Relations	5410	Community Relations - Sundry	-	
Community Relations	5415	Energy Conservation	-	
Community Relations	5420	Community Safety Program	-	
Community Relations	5425	Miscellaneous Customer Service and Informational Expenses	-	
			-	
		[redacted]	-	
	Account No	Account Description	-	
Sales Expenses	5505	Supervision	-	
Sales Expenses	5510	Demonstrating and Selling Expense	-	
Sales Expenses	5515	Advertising Expense	-	
Sales Expenses	5520	Miscellaneous Sales Expense	-	
		[redacted]		
	Account No	Account Description		
Administr and Gen Expenses	5605	Executive Salaries and Expenses	408,272	Salaries and Benefits
Administr and Gen Expenses	5605	Executive Salaries and Expenses	1,440	Other Costs
Administr and Gen Expenses	5605	Executive Salaries and Expenses		Property Costs
Administr and Gen Expenses	5605	Executive Salaries and Expenses	-	Communication Costs
Administr and Gen Expenses	5605	Executive Salaries and Expenses	-	Contract Services
Administr and Gen Expenses	5610	Management Salaries and Expenses	435,656	Salaries and Benefits
Administr and Gen Expenses	5615	General Administrative Salaries and Expenses	262,441	Salaries and Benefits
Administr and Gen Expenses	5615	General Administrative Salaries and Expenses	316,645	Communication Costs
Administr and Gen Expenses	5615	General Administrative Salaries and Expenses	148,793	Other Costs
Administr and Gen Expenses	5615	General Administrative Salaries and Expenses	6,022	Contract Services
Administr and Gen Expenses	5620	Office Supplies and Expenses	33,720	Material Costs
Administr and Gen Expenses	5625	Administrative Expense Transferred/Credit	-	
Administr and Gen Expenses	5630	Outside Services Employed	72,818	Contract Services
Administr and Gen Expenses	5635	Property Insurance	44,591	Property Costs
Administr and Gen Expenses	5640	Injuries and Damages	63,050	Property Costs
Administr and Gen Expenses	5645	Employee Pensions and Benefits	-	

Administr and Gen Expenses	5650	Franchise Requirements	-	
Administr and Gen Expenses	5655	Regulatory Expenses	131,651	Other Costs
Administr and Gen Expenses	5660	General Advertising Expenses	34,524	Other Costs
Administr and Gen Expenses	5665	Miscellaneous General Expenses	122,598	Other Costs
Administr and Gen Expenses	5670	Rent	-	
Administr and Gen Expenses	5675	Maintenance of General Plant	246,439	Contract Services
Administr and Gen Expenses	5675	Maintenance of General Plant	-	Property Costs
Administr and Gen Expenses	5680	Electrical Safety Authority Fees	2,688	
Administr and Gen Expenses	5685	Independent Market Operator Fees and Penalties	-	
Administr and Gen Expenses	5695	OM&A Contra	-	
		[illegible]		
	Account No	**Account Description**		
Amortization Expenses	5705	Amortization Expense - Property, Plant, and Equipment	1,360,873	Amortization
Amortization Expenses	5710	Amortization of Limited Term Electric Plant	-	
Amortization Expenses	5715	Amortization of Intangibles and Other Electric Plant	-	Amortization
Amortization Expenses	5720	Amortization of Electric Plant Acquisition Adjustments	-	
Amortization Expenses	5725	Miscellaneous Amortization	-	
Amortization Expenses	5730	Amortization of Unrecovered Plant and Regulatory Study Costs	-	
Amortization Expenses	5735	Amortization of Deferred Development Costs	-	
Amortization Expenses	5740	Amortization of Deferred Charges	-	
			-	
		[illegible]		
	Account No	**Account Description**		
Interest Expenses	6005	Interest on Long Term Debt	-	
Interest Expenses	6010	Amortization of Debt Discount and Expense	-	
Interest Expenses	6015	Amortization of Premium on Debt/Credit	-	
Interest Expenses	6020	Amortization of Loss on Reacquired Debt	-	
Interest Expenses	6025	Amortization of Gain on Reacquired Debt--Credit	-	
Interest Expenses	6030	Interest on Debt to Associated Companies	-	Interest Expense
Interest Expenses	6035	Other Interest Expense	789,250	Interest Expense
Interest Expenses	6040	Allowance for Borrowed Funds Used During Construction--Credit	-	
Interest Expenses	6042	Allowance For Other Funds Used During Construction	-	
Interest Expenses	6045	Interest Expense on Capital Lease Obligations	-	
		[illegible]		
	Account No	**Account Description**		
	6105	Taxes Other Than Income Taxes	90,207	Other Costs
Taxes	6110	Income Taxes	(733,828)	Income Taxes
Taxes	6115	Provision for Future Income Taxes	(16,609)	Income Taxes -Future
		[illegible]		
	Account No	**Account Description**		
Other Deductions	6205	Donations	2,975	Other Costs
Other Deductions	6210	Life Insurance	-	
Other Deductions	6215	Penalties	-	
Other Deductions	6225	Other Deductions	-	
		[illegible]		

	Account No	Account Description		
Extraordinary Items	6305	Extraordinary Income	-	
Extraordinary Items	6310	Extraordinary Deductions	-	
Extraordinary Items	6315	Income Taxes: Extraordinary Item	-	
			-	
		[redacted]		
	Account No	**Account Description**		
Disconected Operations	6405	Discontinues Operations - Income/ Gains	-	
Disconected Operations	6410	Discontinued Operations - Deductions/ Losses	-	
Disconected Operations	6415	Income Taxes, Discontinued Operations	-	
	Total		**(3,623,607)**	

Service Revenue			(59,624,437)	
Other income			(1,071,088)	
			(60,695,525)	
Power Costs			50,494,619	
Salaries and Benefits			2,949,818	
Material Costs			79,329	
Property costs			220,449	
Other Costs			858,693	
Contract Services			628,388	
Communication Costs			438,247	
Capital Tax			-	
Amortization			1,360,873	
Interest Expense			789,250	
Income Taxes			(733,828)	
Income Taxes -Future			(16,609)	
Allocated to capital				
			57,069,229	
Net Income per USoA			**(3,623,607)**	
Net Income per Financial Statements			**3,623,607**	
			(0)	

	2014 Balance Sheet																						
	Assets								Liabilities and Shareholder's Equity														
USofA	Accounts receivable 1	Unbilled Revenue 2	PILS receivable 3	Inventory 4	Due from related companies 5	Prepaid exp and dep 6	Regulatory Assets 7	Capital Assets 8	Bank indebtedness 9	AP and Accrued Liabilities 10	Due to Related Companies 11	Current portion of bank term loans 12	Current Portion of Consumer Deposits 13	Bank term loans 14	Note Payable 15	Consumer Deposit 16	Employee Future benefits 17	Future Income taxes 18	Capital Stock 19	Retained Earnings 20	Totals	2.1.7	Re-allocation for AFS presentation
1100	5,504,673	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,504,673	5,504,673	(0)
1104	323,422	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	323,422	323,422	0
1110	371,385	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	371,385	371,385	0
1120	-	8,043,091	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,043,091	8,043,091	-
1130	(192,001)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(192,001)	(192,001)	0
1180	-	-	969,525	-	-	400,640	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,370,165	1,370,165	(0)
1200	-	-	-	-	(80,072)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(80,072)	-	(80,072)
1330	-	-	-	1,226,655	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,226,655	1,226,655	(0)
1495	-	-	-	-	-	-	3,966,506	-	-	-	-	-	-	-	-	-	-	-	-	-	3,966,506	3,966,506	-
1508	-	-	-	-	-	-	707,152	-	-	-	-	-	-	-	-	-	-	-	-	-	707,152	707,152	0
1518	-	-	-	-	-	-	6,154	-	-	-	-	-	-	-	-	-	-	-	-	-	6,154	6,154	0
1521	-	-	-	-	-	-	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	(1)
1525	-	-	-	-	-	-	-	-	-	8,184	-	-	-	-	-	-	-	-	-	-	8,184	(0)	8,184
1548	-	-	-	-	-	-	485	-	-	-	-	-	-	-	-	-	-	-	-	-	485	485	0
1550	-	-	-	-	-	-	160,712	-	-	-	-	-	-	-	-	-	-	-	-	-	160,712	160,712	0
1551	-	-	-	-	-	-	6,447	-	-	-	-	-	-	-	-	-	-	-	-	-	6,447	6,447	0
1555	-	-	-	-	-	-	496,362	-	-	-	-	-	-	-	-	-	-	-	-	-	496,362	496,362	(0)
1556	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	2
1562	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1568	-	-	-	-	-	-	(108,200)	-	-	-	-	-	-	-	-	-	-	-	-	-	(108,200)	(108,200)	(0)
1572	-	-	-	-	-	-	1,579,798	-	-	-	-	-	-	-	-	-	-	-	-	-	1,579,798	1,579,798	(0)
1575	-	-	-	-	-	-	(208,619)	-	-	-	-	-	-	-	-	-	-	-	-	-	(208,619)	(208,619)	(0)
1580	-	-	-	-	-	-	(430,105)	-	-	-	-	-	-	-	-	-	-	-	-	-	(430,105)	(430,105)	0
1582	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	0
1584	-	-	-	-	-	-	656,984	-	-	-	-	-	-	-	-	-	-	-	-	-	656,984	656,984	(0)
1586	-	-	-	-	-	-	286,376	-	-	-	-	-	-	-	-	-	-	-	-	-	286,376	286,376	(0)
1588	-	-	-	-	-	-	337,808	-	-	-	-	-	-	-	-	-	-	-	-	-	337,808	337,808	0
1589	-	-	-	-	-	-	673,181	-	-	-	-	-	-	-	-	-	-	-	-	-	673,181	673,181	0
1590	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1592	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1595	-	-	-	-	-	-	67,798	-	-	-	-	-	-	-	-	-	-	-	-	-	67,798	67,799	(1)
1606	-	-	-	-	-	-	-	192,292	-	-	-	-	-	-	-	-	-	-	-	-	192,292	192,292	(0)
1611	-	-	-	-	-	-	-	1,254,069	-	-	-	-	-	-	-	-	-	-	-	-	1,254,069	1,254,069	(0)
1612	-	-	-	-	-	-	-	4,738	-	-	-	-	-	-	-	-	-	-	-	-	4,738	4,738	(0)
1820	-	-	-	-	-	-	-	1,090,632	-	-	-	-	-	-	-	-	-	-	-	-	1,090,632	1,090,632	0
1830	-	-	-	-	-	-	-	19,528,781	-	-	-	-	-	-	-	-	-	-	-	-	19,528,781	19,528,781	(0)
1835	-	-	-	-	-	-	-	8,838,661	-	-	-	-	-	-	-	-	-	-	-	-	8,838,661	8,838,661	0
1840	-	-	-	-	-	-	-	1,053,498	-	-	-	-	-	-	-	-	-	-	-	-	1,053,498	1,053,498	(0)
1845	-	-	-	-	-	-	-	10,351,686	-	-	-	-	-	-	-	-	-	-	-	-	10,351,686	10,351,687	(1)
1850	-	-	-	-	-	-	-	9,357,738	-	-	-	-	-	-	-	-	-	-	-	-	9,357,738	9,357,738	(0)
1855	-	-	-	-	-	-	-	2,477	-	-	-	-	-	-	-	-	-	-	-	-	2,477	2,477	(0)
1860	-	-	-	-	-	-	-	4,783,115	-	-	-	-	-	-	-	-	-	-	-	-	4,783,115	4,783,115	0
1905	-	-	-	-	-	-	-	591,341	-	-	-	-	-	-	-	-	-	-	-	-	591,341	591,341	0
1908	-	-	-	-	-	-	-	2,689,156	-	-	-	-	-	-	-	-	-	-	-	-	2,689,156	2,689,156	0
1915	-	-	-	-	-	-	-	124,820	-	-	-	-	-	-	-	-	-	-	-	-	124,820	124,820	0
1920	-	-	-	-	-	-	-	473,717	-	-	-	-	-	-	-	-	-	-	-	-	473,717	473,717	(0)
1930	-	-	-	-	-	-	-	1,681,458	-	-	-	-	-	-	-	-	-	-	-	-	1,681,458	1,681,458	(0)
1940	-	-	-	-	-	-	-	353,023	-	-	-	-	-	-	-	-	-	-	-	-	353,023	353,023	(0)
1955	-	-	-	-	-	-	-	696,864	-	-	-	-	-	-	-	-	-	-	-	-	696,864	696,864	(0)
1990	-	-	-	-	-	-	-	17,387	-	-	-	-	-	-	-	-	-	-	-	-	17,387	17,387	(0)
1995	-	-	-	-	-	-	-	(8,449,121)	-	-	-	-	-	-	-	-	-	-	-	-	(8,449,121)	(8,449,121)	(0)
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	3,133,245	-	-	-	-	-	-	-	-	-	-	-	-	3,133,245	3,133,246	(1)
2105	-	-	-	-	-	-	-	(3,916,205)	-	-	-	-	-	-	-	-	-	-	-	-	(3,916,205)	(3,916,205)	(0)
2120	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2160	-	-	-	-	-	-	-	(1,636,326)	-	-	-	-	-	-	-	-	-	-	-	-	(1,636,326)	(1,636,327)	1
2205	-	-	-	-	-	-	-	-	-	3,800,412	-	-	-	-	-	-	-	-	-	-	3,800,412	(3,800,412)	(0)
2220	-	-	-	-	-	-	-	-	-	6,576,506	-	-	-	-	-	-	-	-	-	-	6,576,506	(6,584,689)	(8,183)
2225	-	-	-	-	-	-	-	-	3,708,651	-	-	-	-	-	-	-	-	-	-	-	3,708,651	(3,708,651)	(0)
2240	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(80,072)	(80,072)
2250	-	-	-	-	-	-	-	-	-	278,317	-	-	-	-	-	-	-	-	-	-	278,317	(278,317)	(0)
2260	-	-	-	-	-	-	-	-	-	-	-	552,754	-	-	-	-	-	-	-	-	552,754	(552,754)	(0)
2290	-	-	-	-	-	-	-	-	-	(162,767)	-	-	-	-	-	-	-	-	-	-	(162,767)	162,768	1
2292	-	-	-	-	-	-	-	-	-	393,546	-	-	-	-	-	-	-	-	-	-	393,546	(393,547)	(1)
2312	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	604,005	-	-	-	604,005	(604,005)	(0)
2335	-	-	-	-	-	-	-	-	-	1,651,926	-	-	228,837	-	-	227,293	-	-	-	-	2,108,056	(2,108,056)	0
2350	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,022,972	-	-	4,022,972	(4,022,972)	-
2440	-	-	-	-	-	-	-	-	-	69,449	-	-	-	-	-	-	-	-	-	-	69,449	(69,449)	0
2525	-	-	-	-	-	-	-	-	-	-	-	-	-	9,841,458	-	-	-	-	-	-	9,841,458	(9,841,457)	1
2550	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,141,969	-	-	-	-	-	16,141,969	(16,141,969)	(0)
3005	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,161,663	-	16,161,663	(16,161,663)	(0)
3045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12,878,030	12,878,030	(12,064,037)	
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	6,007,479	8,043,091	969,525	1,226,655	(80,072)	400,640	8,198,840	52,217,046	3,708,651	12,615,573	-	552,754	228,837	9,841,458	16,141,969	227,293	604,005	4,022,972	16,161,663	12,878,030			
						16,567,318		77,063,275					17,185,887							29,039,693			

	2014 Income Statement															
	Revenue		Expenditures							Other Expenses		Income Taxes				
USofA	Service Revenue:	Other Income:	Cost of Power:	Salaries and benefits:	Material costs:	Contract Services:	Property costs:	Other costs:	Communication costs:	Ammortization:	Interest expense:	Current:	Future:	Totals	2.1.7	Re-allocation for AFS presentation
	1	2	3	4	5	6	7	8	9	10	11	12	13			
4006	46,695,715	-	-	-	-	-	-	-	-	-	-	-	-	46,695,715	(46,695,715)	(0)
4010	1,687,281	-	-	-	-	-	-	-	-	-	-	-	-	1,687,281	(1,687,281)	(0)
4015	798,214	-	-	-	-	-	-	-	-	-	-	-	-	798,214	(798,214)	(0)
4025	32,638	-	-	-	-	-	-	-	-	-	-	-	-	32,638	(32,638)	(0)
4030	830	-	-	-	-	-	-	-	-	-	-	-	-	830	(830)	-
4035	4,947,566	-	-	-	-	-	-	-	-	-	-	-	-	4,947,566	(4,947,566)	(0)
4062	334,046	-	-	-	-	-	-	-	-	-	-	-	-	334,046	(334,046)	(0)
4066	463,739	-	-	-	-	-	-	-	-	-	-	-	-	463,739	(463,739)	(0)
4068	353,116	-	-	-	-	-	-	-	-	-	-	-	-	353,116	(353,116)	0
4075	63,980	-	-	-	-	-	-	-	-	-	-	-	-	63,980	(63,980)	(0)
4076	33,107	-	-	-	-	-	-	-	-	-	-	-	-	33,107	(33,107)	(0)
4080	9,524,651	-	-	-	-	-	-	-	-	-	-	-	-	9,524,651	(9,514,402)	10,249
4082	-	1	-	-	-	-	-	-	-	-	-	-	-	1	(15,204)	(15,203)
4084	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(308)	(308)
4086	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10,250)	(10,250)
4210	-	166,859	-	-	-	-	-	-	-	-	-	-	-	166,859	(166,859)	0
4225	-	107,919	-	-	-	-	-	-	-	-	-	-	-	107,919	(107,919)	(0)
4235	-	432,977	-	-	-	-	-	-	-	-	-	-	-	432,977	(432,977)	(0)
4325	-	(7,504)	-	-	-	-	-	-	-	-	-	-	-	(7,504)	7,504	(0)
4375	-	353,355	-	-	-	-	-	-	-	-	-	-	-	353,355	(353,354)	1
4385	-	28,931	-	-	-	-	-	-	-	-	-	-	-	28,931	(28,931)	(0)
4390	-	36,608	-	-	-	-	-	-	-	-	-	-	-	36,608	(36,608)	(0)
4405	-	87,678	-	-	-	-	-	-	-	-	-	-	-	87,678	(87,678)	(0)
4705	-	-	50,887,226	-	-	-	-	-	-	-	-	-	-	50,887,226	50,887,226	(0)
4707	-	-	3,275,018	-	-	-	-	-	-	-	-	-	-	3,275,018	3,275,018	0
4708	-	-	334,046	-	-	-	-	-	-	-	-	-	-	334,046	334,046	0
4714	-	-	463,740	-	-	-	-	-	-	-	-	-	-	463,740	463,740	(0)
4716	-	-	353,116	-	-	-	-	-	-	-	-	-	-	353,116	353,116	(0)
4720	-	-	33,107	-	-	-	-	-	-	-	-	-	-	33,107	0	33,107
4750	-	-	63,979	-	-	-	-	-	-	-	-	-	-	63,979	63,979	(0)
4751	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33,107	(33,107)
5005	-	-	-	203,934	-	-	-	-	-	-	-	-	-	203,934	203,933	1
5012	-	-	-	-	-	-	814	-	-	-	-	-	-	814	814	(0)
5016	-	-	-	58,139	-	-	-	-	-	-	-	-	-	58,139	58,139	(0)
5017	-	-	-	-	1,227	-	-	394	1,600	-	-	-	-	3,221	3,221	0
5020	-	-	-	130,873	-	-	-	-	-	-	-	-	-	130,873	130,873	(0)
5025	-	-	-	-	33,341	217,836	-	-	-	-	-	-	-	251,177	251,177	(0)
5035	-	-	-	10,033	151	750	-	439	-	-	-	-	-	11,373	11,374	(1)
5040	-	-	-	7,192	-	-	-	-	-	-	-	-	-	7,192	7,192	(0)
5045	-	-	-	-	1,894	1,620	-	450	-	-	-	-	-	3,964	3,965	(1)
5065	-	-	-	98,708	1,227	10,799	-	466	10,066	-	-	-	-	121,266	121,267	(1)
5085	-	-	-	-	-	-	(333)	-	-	-	-	-	-	(333)	(333)	(0)
5114	-	-	-	-	-	9,321	-	-	-	-	-	-	-	9,321	9,321	0
5120	-	-	-	198,162	236	1,957	-	-	-	-	-	-	-	200,355	207,556	(7,201)
5125	-	-	-	-	-	-	-	8,351	-	-	-	-	-	8,351	8,351	(0)
5135	-	-	-	17,045	1,160	264,225	-	-	-	-	-	-	-	282,430	282,429	1
5150	-	-	-	-	120	18,392	-	-	-	-	-	-	-	18,512	18,512	(0)
5155	-	-	-	86,989	-	-	-	-	-	-	-	-	-	86,989	86,989	0
5175	-	-	-	-	227	-	-	-	1,835	-	-	-	-	2,062	2,061	1
5305	-	-	-	146,072	-	-	-	-	-	-	-	-	-	146,072	146,073	(1)
5310	-	-	-	-	-	52,060	-	-	-	-	-	-	-	52,060	52,060	0
5315	-	-	-	118,513	-	65,405	52,154	683	157,545	-	-	-	-	394,300	409,812	(15,512)
5320	-	-	-	430,452	-	11,835	3,622	50	67,882	-	-	-	-	513,841	513,841	(0)
5325	-	-	-	-	-	-	-	131	-	-	-	-	-	131	131	0
5330	-	-	-	-	-	-	-	5,012	-	-	-	-	-	5,012	5,012	0
5335	-	-	-	-	-	-	-	76,418	-	-	-	-	-	76,418	76,418	(0)
5605	-	-	-	551,799	-	-	-	-	-	-	-	-	-	551,799	551,799	0
5610	-	-	-	224,091	-	-	-	-	-	-	-	-	-	224,091	224,091	0
5615	-	-	-	476,502	1,650	22,111	47,478	27,164	87,611	-	-	-	-	662,516	662,516	(0)
5620	-	-	-	1,665	-	-	33,193	21,460	16,315	-	-	-	-	72,633	72,633	0
5630	-	-	-	-	-	194,760	-	-	-	-	-	-	-	194,760	194,759	1
5635	-	-	-	-	-	-	45,374	-	-	-	-	-	-	45,374	45,374	(0)
5640	-	-	-	-	-	-	60,280	-	-	-	-	-	-	60,280	60,280	0
5645	-	-	-	16,609	-	-	-	-	54,394	-	-	-	-	71,003	71,005	(2)
5655	-	-	-	-	-	-	-	154,363	-	-	-	-	-	154,363	133,671	20,692
5660	-	-	-	-	-	-	-	1,700	-	-	-	-	-	1,700	1,700	(0)
5665	-	-	-	19,625	-	-	163,552	129,428	37,012	-	-	-	-	349,617	349,616	1
5675	-	-	-	-	-	-	300,700	1,408	-	-	-	-	-	302,108	302,109	(1)

2014 Income Statement																
	Revenue		Expenditures							Other Expenses		Income Taxes				
USofA	Service Revenue:	Other Income:	Cost of Power:	Salaries and benefits:	Material costs:	Contract Services:	Property costs:	Other costs:	Communication costs:	Ammortization:	Interest expense:	Current:	Future:	Totals	2.1.7	Re-allocation for AFS presentation
	1	2	3	4	5	6	7	8	9	10	11	12	13			
5705	-	-	-	-	-	-	-	-	-	1,419,473	-	-	-	1,419,473	1,419,473	0
6005	-	-	-	-	-	-	-	-	-	-	664,347	-	-	664,347	664,347	(0)
6035	-	-	-	-	-	-	-	-	-	-	160,551	-	-	160,551	160,551	0
6110	-	-	-	-	-	-	-	-	-	-	-	(452,226)	-	(452,226)	(452,226)	-
6115	-	-	-	-	-	-	-	-	-	-	-	-	231,731	231,731	231,731	-
6205	-	-	-	-	-	-	-	3,362	-	-	-	-	-	3,362	24,054	(20,692)
9070	-	-	-	-	-	-	-	7,203	-	-	-	-	-	7,203	-	7,203
	64,934,883	1,206,824	55,410,232	2,796,403	41,233	871,071	706,834	438,482	434,260	1,419,473	824,898	(452,226)	231,731			
		66,141,707							60,698,515		2,244,371		(220,495)			

APPENDIX 1-F

2015 and 2016 PRO FORMA STATEMENTS

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2015 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(54,820,906)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	0
4030-Sentinel Energy Sales	0
4035-General Energy Sales	0
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(3,064,223)
4076-Smart Meter Entity Charges	(206,273)
4066-NW	(3,885,570)
4068-CN	(2,748,453)
4075-LV Charges	(1,373,936)
3000-Sales of Electricity Total	**(66,099,360)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(9,847,171)
4080-2-SSS Revenue	0
4082-RS Rev	0
4084-Serv Tx Requests	0
4090-Electric Services Incidental to Energy Sales SMART METER REVENUE	0
3050-Revenues From Services - Distirbution Total	**(9,847,171)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(171,914)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(277,000)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(203,470)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(652,384)**

Account Description	Total
3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	(40,000)
4360-Loss on Disposition of Utility and Other Property	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(331,697)
4380-Expenses of Non-Utility Operations	0
4385-Expenses of Non-Utility Operations	(21,600)
4390-Miscellaneous Non-Operating Income	(65,000)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(458,297)**
3200-Investment Income	
4405-Interest and Dividend Income	(100,000)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(100,000)**
3350-Power Supply Expenses	
4705-Power Purchased	54,820,906
4708-WMS	2,365,365
4710-Cost of Power Adjustments	0
4712-Charges - one time	0
4714-NW	3,885,570
4715-System Control and Load Dispatching	0
4716-CN	2,748,453
4720-Other Expenses	0
4751-Smart Meter Entity Charges	206,273
4730-Rural Rate Assistance Expense	698,858
4750-LV Charges	1,373,936
3350-Power Supply Expenses Total	**66,099,360**

Account Description	Total
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	197,020
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	19,680
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	209,334
5017-Distribution Station Equipment - Operation Supplies and Expenses	38,256
5020-Overhead Distribution Lines and Feeders - Operation Labour	452,461
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	78,932
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	12,000
5040-Underground Distribution Lines and Feeders - Operation Labour	0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	10,100
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	231,580
5070-Customer Premises - Operation Labour	0
5075-Customer Premises - Materials and Expenses	0
5085-Miscellaneous Distribution Expense	16,000
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**1,265,363**

Account Description	Total
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	0
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	10,500
5120-Maintenance of Poles, Towers and Fixtures	16,000
5125-Maintenance of Overhead Conductors and Devices	0
5130-Maintenance of Overhead Services	0
5135-Overhead Distribution Lines and Feeders - Right of Way	297,500
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	16,500
5155-Maintenance of Underground Services	0
5160-Maintenance of Line Transformers	0
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	500
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**341,000**
3650-Billing and Collecting	
5305-Supervision	193,712
5310-Meter Reading Expense	29,800
5315-Customer Billing	724,444
5320-Collecting	544,537
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	2,400
5335-Bad Debt Expense	90,000
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**1,584,893**
3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	0
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**0**

Account Description	Total
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	615,289
5610-Management Salaries and Expenses	446,326
5615-General Administrative Salaries and Expenses	692,718
5620-Office Supplies and Expenses	97,075
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	107,800
5635-Property Insurance	45,980
5640-Injuries and Damages	73,251
5645-Employee Pensions and Benefits	93,566
5650-Franchise Requirements	0
5655-Regulatory Expenses	138,500
5660-General Advertising Expenses	5,800
5665-Miscellaneous Expenses	443,469
5670-Rent	0
5675-Maintenance of General Plant	157,243
5680-Electrical Safety Authority Fees	0
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**2,917,017**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	2,119,419
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**2,119,419**

Account Description	Total
3900-Interest Expense	
6005-Interest on Long Term Debt	1,125,041
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	0
6035-Other Interest Expense	0
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**1,125,041**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	101,896
3950-Taxes Other Than Income Taxes Total	**101,896**
4000-Income Taxes	
6110-Income Taxes	(256,455)
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**(256,455)**
4100-Extraordinary & Other Items	
6205-Donations - LEAP	12,000
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions to balance	0
4100-Extraordinary & Other Items Total	**12,000**
Net Income - (Gain)/Loss	**(1,847,676)**

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, License Number , File Number

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2016 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(54,904,781)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	0
4030-Sentinel Energy Sales	0
4035-General Energy Sales	0
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(3,068,988)
4076-Smart Meter Entity Charges	(204,731)
4066-NW	(3,654,054)
4068-CN	(2,869,148)
4075-LV Charges	(1,373,936)
3000-Sales of Electricity Total	**(66,075,638)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(11,262,055)
4080-2-SSS Revenue	0
4082-RS Rev	0
4084-Serv Tx Requests	0
4090-Electric Services Incidental to Energy Sales SMART METER REVENUE	0
3050-Revenues From Services - Distirbution Total	**(11,262,055)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(171,914)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(277,000)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(203,470)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(652,384)**

Account Description	Total
3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	(40,000)
4360-Loss on Disposition of Utility and Other Property	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(331,697)
4380-Expenses of Non-Utility Operations	0
4385-Expenses of Non-Utility Operations	(21,600)
4390-Miscellaneous Non-Operating Income	(65,000)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(458,297)**
3200-Investment Income	
4405-Interest and Dividend Income	(100,000)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(100,000)**
3350-Power Supply Expenses	
4705-Power Purchased	54,904,781
4708-WMS	2,369,043
4710-Cost of Power Adjustments	0
4712-Charges - one time	0
4714-NW	3,654,054
4715-System Control and Load Dispatching	0
4716-CN	2,869,148
4720-Other Expenses	0
4751-Smart Meter Entity Charges	204,731
4730-Rural Rate Assistance Expense	699,945
4750-LV Charges	1,373,936
3350-Power Supply Expenses Total	**66,075,638**

Account Description	Total
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	240,916
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	19,680
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	195,574
5017-Distribution Station Equipment - Operation Supplies and Expenses	38,256
5020-Overhead Distribution Lines and Feeders - Operation Labour	481,275
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	95,918
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	13,800
5040-Underground Distribution Lines and Feeders - Operation Labour	0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	12,125
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	242,103
5070-Customer Premises - Operation Labour	0
5075-Customer Premises - Materials and Expenses	0
5085-Miscellaneous Distribution Expense	16,000
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**1,355,647**

Account Description	Total
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	0
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	10,500
5120-Maintenance of Poles, Towers and Fixtures	16,800
5125-Maintenance of Overhead Conductors and Devices	0
5130-Maintenance of Overhead Services	0
5135-Overhead Distribution Lines and Feeders - Right of Way	327,500
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	18,825
5155-Maintenance of Underground Services	0
5160-Maintenance of Line Transformers	0
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	500
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**374,125**
3650-Billing and Collecting	
5305-Supervision	197,420
5310-Meter Reading Expense	39,586
5315-Customer Billing	975,639
5320-Collecting	584,093
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	4,200
5335-Bad Debt Expense	90,000
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**1,890,937**
3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	0
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**0**

Account Description	Total
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	628,891
5610-Management Salaries and Expenses	543,015
5615-General Administrative Salaries and Expenses	692,003
5620-Office Supplies and Expenses	106,539
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	156,440
5635-Property Insurance	45,980
5640-Injuries and Damages	73,251
5645-Employee Pensions and Benefits	95,501
5650-Franchise Requirements	0
5655-Regulatory Expenses	141,000
5660-General Advertising Expenses	5,800
5665-Miscellaneous Expenses	468,115
5670-Rent	0
5675-Maintenance of General Plant	165,536
5680-Electrical Safety Authority Fees	0
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**3,122,070**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	2,356,442
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**2,356,442**

Account Description	Total
3900-Interest Expense	
6005-Interest on Long Term Debt	1,165,806
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	0
6035-Other Interest Expense	0
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**1,165,806**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	104,440
3950-Taxes Other Than Income Taxes Total	**104,440**
4000-Income Taxes	
6110-Income Taxes	(220,666)
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**(220,666)**
4100-Extraordinary & Other Items	
6205-Donations - LEAP	12,027
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions to balance	0
4100-Extraordinary & Other Items Total	**12,027**
Net Income - (Gain)/Loss	**(2,311,908)**

APPENDIX 1-G

2014 ANNUAL STATEMENTS – PARENT COMPANY
HALTON HILLS COMMUNITY ENERGY CORPORATION

Non-consolidated Financial Statements of

HALTON HILLS COMMUNITY ENERGY CORPORATION

Year ended December 31, 2014

KPMG

KPMG LLP
Box 976
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Hamilton ON L8N 3R1

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INDEPENDENT AUDITORS' REPORT

To the Directors of Halton Hills Community Energy Corporation

We have audited the accompanying non-consolidated financial statements of Halton Hills Community Energy Corporation, (the "Entity") which comprise the non-consolidated balance sheet as at December 31, 2014, the non-consolidated statements of operations and deficit and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The non-consolidated financial statements have been prepared by management in accordance with the basis of accounting in Note 1 to the non-consolidated financial statements.

Management's Responsibility for the Non-consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these non-consolidated financial statements in accordance with the basis of accounting in Note 1 to the non-consolidated financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of the non-consolidated financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of non-consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these non-consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the non-consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the non-consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the non-consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Entity's preparation and fair presentation of the non-consolidated financial statements 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 Entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the non-consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the non-consolidated financial statements presents fairly, in all material respects, the non-consolidated financial position of Halton Hills Community Energy Corporation as at December 31, 2014, and its non-consolidated results of operations and its non-consolidated cash flows for the year then ended in accordance with the basis of accounting in Note 1 to the non-consolidated financial statements.

Basis of Accounting and Restriction on Use

Without modifying our opinion, we draw attention to Note 1 to the non-consolidated financial statements, which describes the basis of accounting. The non-consolidated financial statements are prepared to assist Halton Hills Community Energy Corporation to prepare its corporate income tax returns. As a result, the non-consolidated financial statements may not be suitable for another purpose. Our report is intended solely for Halton Hills Community Energy Corporation and for the federal and provincial income tax authorities and should not be used by parties other than Halton Hills Community Energy Corporation or the federal and provincial tax authorities.

Other Matters

Halton Hills Community Energy Inc. has prepared consolidated financial statements for the year ended December 31, 2014 in accordance with Canadian generally accepted accounting principles on which we issued a separate auditors' report dated April 24, 2015.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 24, 2015
Hamilton, Canada

HALTON HILLS COMMUNITY ENERGY CORPORATION

Non-consolidated Financial Statements

Year ended December 31, 2014

Financial Statements

HALTON HILLS COMMUNITY ENERGY CORPORATION

Non-consolidated Balance Sheet

December 31, 2014, with comparative information for 2013

	2014	2013
Assets		
Current assets:		
Cash and cash equivalents	$ 58,369	$ 129,982
Accounts receivable	62,446	56,394
Prepaid expense	6,322	4,423
Current portion of loan receivable (note 2)	25,152	24,761
Due from related companies (note 3)	88,131	-
	240,420	215,560
Loan receivable (note 2)	373,234	398,386
Due from related companies (note 3)	91,595	-
Long-term investments (note 4)	16,555,330	16,555,430
Capital assets (note 5)	111,627	41,316
Future income taxes	731,676	5,033
	$ 18,103,882	$ 17,215,725
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 91,516	$ 48,032
Current portion of loan payable (note 6)	144,584	143,985
Due to related companies (note 3)	-	20,177
	236,100	212,194
Long-term loan payable (note 6)	3,173,133	3,317,110
	3,409,233	3,529,304
Shareholder's equity:		
Capital stock (note 7)	16,161,663	16,161,663
Retained earnings (deficit)	(1,467,014)	(2,475,242)
	14,694,649	13,686,421
	$ 18,103,882	$ 17,215,725

See accompanying notes to non-consolidated financial statements.

On behalf of the Board:

_________________ Director

_________________ Director

HALTON HILLS COMMUNITY ENERGY CORPORATION

Non-consolidated Statement of Operations and Deficit

Year ended December 31, 2014, with comparative information for 2013

	2014	2013
Revenue:		
Dividends	$ 1,573,719	$ 1,390,906
Other income	310,836	99,267
	1,884,555	1,490,173
Expenses:		
Salaries and benefits	216,973	3,500
Contract services and other	22,706	187,313
Bad debt expense (note 3)	(206,500)	212,914
	33,179	403,727
Earnings before the undernoted	1,851,376	1,086,446
Amortization	4,090	2,045
Interest expense	73,750	81,380
Earnings before income taxes	1,773,536	1,003,021
Income taxes:		
Current (recovery)	-	-
Future (recovery)	(726,643)	2,873
	(726,643)	2,873
Net earnings	2,500,179	1,000,148
Deficit, beginning of year	(2,475,242)	(1,983,441)
Dividends on common shares	(1,491,951)	(1,491,949)
Retained earnings (deficit), end of year	$ (1,467,014)	$ (2,475,242)

See accompanying notes to non-consolidated financial statements.

HALTON HILLS COMMUNITY ENERGY CORPORATION

Non-consolidated Statement of Cash Flows

Year ended December 31, 2014, with comparative information for 2013

		2014		2013
Cash provided by (used in):				
Operations:				
Net earnings	$	2,500,179	$	1,000,148
Items not involving cash:				
Amortization		4,090		2,045
Future income taxes		(726,643)		2,873
Disposition of investment – Harvester Energy Canada Inc.		100		-
Changes in non-cash operating working capital (note 8)		35,533		19,947
		1,813,259		1,025,013
Financing:				
Bank loan		-		(2,910,000)
Loan payable		(143,378)		3,461,095
Change in related party balances, net		(108,308)		57,848
Dividends on common shares		(1,491,951)		(1,491,949)
		(1,743,637)		(883,006)
Investments:				
Purchase of capital assets		(74,401)		(43,361)
Loan receivable		24,761		24,377
Note receivable		(91,595)		-
		(141,235)		(18,984)
(Decrease) increase in cash and cash equivalents		(71,613)		123,023
Cash and cash equivalents, beginning of year		129,982		6,959
Cash and cash equivalents, end of year	$	58,369	$	129,982

See accompanying notes to non-consolidated financial statements.

Halton Hills Community Energy Corporation (the "Company"), is a wholly-owned corporation of The Town of Halton Hills. Halton Hills Community Energy Corporation is the parent company of Halton Hills Hydro Inc., and SouthWestern Energy Inc. The principal activity of the Company is the marketing of energy.

1. Significant accounting policies:

(a) Basis of accounting:

These financial statements have been prepared in accordance with Part V of the CPA Canada Handbook which is the accounting framework used in the preparation of the financial statements in the prior year. These financial statements are not prepared in accordance with Canadian generally accepted accounting principles ("GAAP") in that the required accounting framework is Part I of the CPA Canada Handbook, being International Financial Reporting Standards ("IFRS").

The financial statements have been prepared on a non-consolidated basis for income tax purposes. These financial statements materially differ from GAAP because they are non-consolidated.

The Company has also prepared consolidated financial statements for the same period in accordance with GAAP and distributed such to its Directors and Shareholder.

(b) Cash and cash equivalents:

Cash and cash equivalents consist of cash on hand, balances with banks, and investments in money market instruments, with maturities of 90 days or less at acquisition. Investing and financing activities that do not require the use of cash or cash equivalents are excluded from the Statement of Cash Flows and disclosed separately.

(c) Long term investments:

Long-term investments in subsidiary Companies are recorded at cost.

(d) Capital assets:

Capital assets are recorded at cost. Amortization is provided on a straight-line basis over the useful service life of 5 years for the electric vehicle charging stations.

Construction in progress assets are not amortized until the project is complete and in service.

1. Significant accounting policies (continued):

(e) Use of estimates:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenditures during the reporting period. Actual results could differ from those estimates.

(f) Financial instruments:

Financial assets and liabilities:

The financial instrument accounting standards require that all financial instruments are classified into one of the following categories: held-for-trading, available-for-sale, held-to-maturity, other liabilities or loans and receivables. All financial instruments are carried on the balance sheet at fair value, except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The Company has classified its financial instruments as follows:

Cash and cash equivalents	Held-for-trading
Accounts receivable	Loans and receivables
Due from related companies	Loans and receivables
Loan receivable	Loans and receivables
Bank loan	Other liabilities
Accounts payable and accrued liabilities	Other liabilities
Long-term loan payable	Other liabilities
Due to related companies	Other liabilities

Held-for-trading financial instruments are measured at fair value, with all gains and losses and transaction costs included in net earnings. Loans and receivables and other liabilities are measured at amortized cost using the effective interest rate method.

Derivatives and hedge accounting:

The Company does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the presentation of these financial statements.

1. Significant accounting policies (continued):

(g) Payment-in-lieu of income taxes:

Under the Electricity Act, 1998, the Company is required to make payments-in-lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation.

These payments are recorded in accordance with the rules for computing income taxes as per the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) and modified by the Electricity Act, 1998, and related regulations.

The Company accounts for PILs using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

(h) Revenue recognition:

Dividend income is recognized when dividends are declared and payable. Other income is comprised of interest income and is recognized as earned.

(i) Emerging accounting issue:

Transition to International Financial Reporting Standards

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that would have Canadian GAAP converge with IFRS, effective January 1, 2011 which would have required entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved the incorporation of a one year deferral of adoption of IFRS into Part 1 of the CPA Canada Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CPA Canada Handbook specified that first-time adoption, for companies that met this requirement, was mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2015.

The amendment also requires entities that do not prepare interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

The Company has decided to implement IFRS commencing January 1, 2015.

2. Loan receivable:

The loan receivable from the Town of Halton Hills bears interest of 3.0% per annum with quarterly interest and principal repayments up to August 30, 2029. Interest received from the Town of Halton Hills was $6,393 (2013 - $6,779).

	2014	2013
Total loan receivable	$ 398,386	$ 423,147
Less: current portion	25,152	24,761
	$ 373,234	$ 398,386

3. Due from (to) related companies:

Amounts due from (to) related companies are unsecured and have no specific interest, except for the amount due from SouthWestern Energy Inc., successor to Harvester Energy Canada Inc. which bears interest at 4.12% (2013 – 4.12%) per annum.

Allowance for Doubtful Accounts previously represented the amount due from Harvester Energy Canada Inc.; SouthWestern Energy Inc. has assumed responsibility of the debt and the statements reflect the bad debt recovery. Bad debt recovery (expense) is $250,000 (2013 – ($212,914)).

The amounts arose during the normal course of operations.

	2014	2013
Halton Hills Hydro Inc.	$ 148,115	$ (5,078)
SouthWestern Energy Inc.	(59,984)	(15,099)
SouthWestern Energy Inc., successor to Harvester Energy Canada Inc.	2,493,323	2,608,227
	2,581,454	2,588,050
Less: allowance for doubtful accounts	(2,401,728)	(2,608,227)
Less: current	88,131	(20,177)
	$ 91,595	$ -

4. Long-term investments:

The Company holds the following long-term investments in subsidiaries, all of which are wholly-owned:

	2014	2013
Harvester Energy Canada Inc.	$ -	$ 100
SouthWestern Energy Inc.	393,667	393,667
Halton Hills Hydro Inc.	16,161,663	16,161,663
	$16,555,330	$16,555,430

5. Capital assets:

The capital assets of the Company consist of the following:

			2014	2013
	Cost	Accumulated amortization	Net book value	Net book value
Electric charging station	$ 20,449	$ 6,135	$ 14,314	$ 18,404
Work-in-progress	97,313	-	97,313	22,912
	$ 117,762	$ 6,135	$ 111,627	$ 41,316

During the year, the company recorded capital asset additions of $74,401 (2013 - $20,449).

6. Long-term loan payable:

Term loan facility renewal in the amount of $3,377,502 on July 2, 2014 at a fixed rate of 2.23% per annum for a Rate Term expiring July 2, Amortization period of 228 months, monthly blended payments of principal and interest on the loan are $18,186. The loan is secured by a General Security Agreement representing a first charge on all personal property.2015.

	2014	2013
Total loan payable	$ 3,317,717	$ 3,461,095
Less current portion	144,584	143,985
	$ 3,173,133	$ 3,317,110

7. Capital stock:

	2014	2013
Authorized:		
Unlimited number of preference shares		
Unlimited number of common shares		
Issued and fully paid:		
1,000 common shares	$ 16,161,663	$ 16,161,663

8. Changes in non-cash working capital:

The net change is non-cash working capital consists of the following:

	2014	2013
Accounts receivable	$ (6,052)	$ (21,156)
Prepaid expense	(1,899)	6,657
Accounts payable and accrued liabilities	43,484	34,446
	$ 35,533	$ 19,947

9. Financial instruments:

The carrying value of the cash and cash equivalents, accounts receivable, loan receivable, bank loan, accounts payable and accrued liabilities and due to/from related companies all approximate fair value because of the short maturity of these instruments.

The Company's activities provide for a variety of financial risks. Exposure to credit risk, market risk and liquidity risk occur in the normal course of the Company's operations as follows:

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, loan receivable, and notes receivable, expose the Company to credit risk.

9. Financial instruments (continued):

Market risks

Market risk primarily refers to the risk of loss that may result from changes in commodity prices, foreign exchange rates, and interest rates. The Company currently does not have commodity or foreign exchange risk. The Company's interest rate risk is limited to the loan receivable with The Town of Halton Hills which bears interest at 3.0% and due from related company, SouthWestern Energy Inc., successor to Harvester Energy Canada Inc., which bears interest at 4.12%.

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 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.

10. Capital disclosures:

The main objectives of the Company when managing capital are to ensure ongoing access to funding to maintain and improve the asset base, compliance with covenants related to any credit facilities, prudent management of its capital structure and to deliver the appropriate financial returns.

The Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2014, shareholder's equity amounts to $16,369,734 (2013 - $13,686,421) and long-term debt amounts to $3,317,717 (2013 – $3,461,095).

APPENDIX 1-H

CODE OF CONDUCT

Halton Hills
Community Energy
CORPORATION

CODE OF CONDUCT

1. INTRODUCTION

Halton Hills Community Energy Corporation and its affiliates, Halton Hills Hydro Inc. and SouthWestern Energy Inc. are committed to conducting all business dealings in compliance with all applicable laws and regulations, based on the highest ethical standards and in full compliance with this Code.

As representatives of Halton Hills Community Energy Corporation (HHCEC) and its affiliates, employees, directors and agents are expected to comply with all provincial, federal and local laws as well as internal policies and to conduct themselves in a manner, which in no way jeopardizes the integrity and the image of HHCEC or its affiliates.

The Code applies to all business activities of HHCEC and its affiliates, inclusive of the activities of all employees, directors, and agents.

2. CORE PRINCIPLES

Integrity

It is the expectation of HHCEC and its affiliates that all employees, directors and agents shall:

- not participate in situations where personal interests interfere with work responsibilities;
- never disclose confidential or sensitive information inappropriately;
- engage in practices that promote the openness and fairness of competition;
- protect business assets and use them responsibly for business purposes;
- ensure that they are never involved in the appointment, promotion or hiring of anyone with whom they have a family or personal friendship; and
- treat fellow employees, customers and all others with respect, honesty, courtesy and dignity. Any form of harassment or violence including behaviours that demean, threaten or humiliate others will not be tolerated;
- be honest, trustworthy, reliable and dependable in fulfilling all of your duties.

Performance Excellence

It is the expectation of HHCEC and its affiliates that all employees, directors and agents will:

- take accountability for their work and for their results. Be committed to giving their full efforts in everything they do and recognize that they must continue to seek new ways to be more effective and efficient;
- provide a work environment in which suggestions for improvement are welcomed and implemented where appropriate;
- recognize the accomplishments of colleagues and of the organization as a whole;
- seize opportunities to improve their own skills while developing, supporting and recognizing the talents and abilities of others; and
- actively grow the profitability of our businesses.

Citizenship

It is the expectation of HHCEC and its affiliates that all employees, directors and agents will:

- act in a way that protects the health and safety of the public, our contractors, fellow employees and themselves;
- act in an environmentally responsible manner; and
- respect and support the social and cultural diversities of the communities where they live, work and serve.

3. CONFLICT OF INTEREST

3.1 Definition: *Any situation where your personal interest conflicts, reasonably appears to conflict, or could potentially conflict, with the interests of HHCEC and/or its affiliates.*

Clarity Note: It is the responsibility of all employees, directors and agents to seek guidance from their direct supervisor or other senior executive in the event there is any concern regarding the application of this policy to a particular circumstance or interest.

In order to avoid a conflict of interest:

- base any business decisions on merit and strictly in the best interest of HHCEC and its affiliates;
- Derive no personal benefit, whether direct or indirect, as a result of making a business decision on behalf of HHCEC and/or or its affiliates;

- Avoid any situation that may create, or reasonably appear to create, a conflict of interest between your personal interests and those of HHCEC and/or its affiliates;
- Do not take any part in, or in any way influence, any decision related to HHCEC and/or its affiliates that might result in a financial or other advantage for yourself, your family members, or friends. Always ensure that these relationships do not impact your ability to make sound, impartial, and objective decisions on behalf of HHCEC and/or its affiliates;

3.2 Gifts and Favours

Employees establish and maintain many interactions with other individuals, companies and organizations to carry out necessary business functions and may be exposed to opportunities for personal financial benefit. Accepting or offering gifts or favours may compromise or appear to compromise the ability to make business decisions that are in the best interest of HHCEC and/or its affiliates.

Employees shall never solicit gifts, favours, hospitality or anything of monetary value.

Acceptance by employees, directors or agents of gifts or favours is acceptable when:

- The gift(s) is merchandise distributed to all participants at a conference/seminar (ie) bags, t-shirts, mugs etc;
- The gift is a result of random draw (ie.) door prize where all attendees are automatically entered at a conference; and/or
- The gift is an educational opportunity of benefit to HHCEC and/or its affiliates and senior management approval is granted.

Acceptance of gifts and/or favour(s) is not permitted when:

- The value of a gift may reasonably be perceived as having the ability to influence decisions of the recipient.

No employee, director or agent shall offer payment, gift or favours to any person in a position of trust or public responsibility with the intent to induce them to violate their duties or to obtain favourable treatment.

Unacceptable gifts should be returned with thanks and clarification of our policy.

3.3 Directorships

Employees shall not be an officer or serve on the Board of any private or public business entity that competes with HHCEC and/or its affiliates.

Management staff will not typically be an officer or serve on the Board of any private or public business entity that contracts directly with HHCEC and/or its affiliates (excluding where the business entity is solely a utility customer of HHCEC). Any exception must be approved in writing by the Board of Directors.

4. LEGAL COMPLIANCE

The business of HHCEC and its affiliates shall be conducted in compliance with all applicable laws and contractual obligations. Employees should be familiar with the laws and regulations that relate to their work and must comply with them. It is the responsibility of managers and supervisors to ensure that members of their team are aware of their responsibilities in this regard and seek advice from the appropriate department where clarification is required.

5. ACCOUNTING, FINANCE & BUSINESS REPORTING

Appropriate entries into the books and records of HHCEC and its affiliates shall be made of all transactions in order to meet our legal, regulatory and financial requirements. No false or artificial entries or entries that obscure the purposes of the underlying transaction shall be made for any reason. No undisclosed or unrecorded funds or assets shall be established or maintained.

The making of payments of any nature or the use of funds or assets of HHCEC and/or its affiliates for any purpose which would be in violation of any applicable law or corporate undertaking is prohibited.

6. INFORMATION TECHNOLOGY AND USE OF THE INTERNET

HHCEC and its affiliates do not tolerate non-work related use of computers or the internet. Every employee who uses corporate technology and equipment will be guided by sound business ethics and professional judgement in addition to being familiar with practices governing the use of technology and the internet (ie)

- No pornography sites;
- No racist materials ;
- No joke sites.

7. CONFIDENTIALITY

HHCEC and its affiliates will make all reasonable efforts to protect confidential information with respect to its customers, its employees, its business partners and Shareholder. No employee, director or agent will take action that knowingly violates any disclosure of information legislation. Information will be provided, as required, to regulatory and government agencies.

The Chair and the President & CEO are the Officers of the Corporation when communicating with the media on corporate matters.

8. PROPRIETARY INFORMATION

As a provider of services to the public, HHCEC and its affiliates have available certain customer related information. This information is and must be strictly controlled, and no employee, director or agent should use such information in any manner which is not authorized by HHCEC or its affiliates or the customer. Proprietary information must be protected from unauthorized access or disclosure during and after employment with HHCEC and/or its affiliates. All documents and records belonging to HHCEC and/or its affiliates must be returned when an employee leaves employment.

9.a) INTELLECTUAL PROPERTY

All intellectual property arising from employment with HHCEC and its affiliates shall be the property of the employer. Employees must make full disclosure of all intellectual property, including inventions, and assign all rights to their employer, without charge, so as to enable HHCEC or an affiliate to apply for intellectual property protection.

9.b) CORPORATE PROPERTY

All corporate property arising from employment with HHCEC and its affiliates is the property of the employer. Property of the employer shall not be used for any personal use without prior permission from your immediate supervisor. Non-work related use of corporate property will not be tolerated.

10. HEALTH AND SAFETY

In order to maintain a safe and healthy workplace, employees, directors and agents are expected to take a proactive approach to health and safety by minimizing or eliminating risks wherever possible. Employees, directors and agents shall comply with all applicable Health & Safety Policies including the laws and regulations regarding safe work practices. Any areas of concern should be reported immediately to the Joint Health & Safety Committee.

11. EMPLOYMENT

HHCEC and its affiliates are equal opportunity employers committed to providing a workplace that is free from harassment and discrimination in all its forms in accordance with the principles set forth in the *Ontario Human Rights Code* and the *Occupational Health and Safety Act*.

12. OUR COMMUNITY AND ENVIRONMENT

HHCEC and its affiliates are committed to being socially and environmentally responsible, recognizing that the competitive pressures for economic growth and cost efficiency must be integrated with environmental stewardship. The implementation of creative ideas for waste management and reduction, recycling and re-use programs is encouraged. The HHCEC and its affiliates are committed to responsibly managing all aspects of its business to meet or exceed recognized environmental, health and safety standards and legal requirements.

13. REPORTING OF ILLEGAL OR UNETHICAL BEHAVIOUR

If any employee, director or agent reasonably believes someone associated with HHCEC or its affiliates has breached this Code in any way, they have a responsibility to address such behaviour. Conduct that may be in breach of the Code shall be reported to the President & CEO or the Chair of the Board.

Discrimination, retaliation, threats or harassment against any person who reports in good faith and/or who participates in good faith in an investigation of reports or complaints of conduct contrary to this Code is strictly prohibited.

14. COMMUNICATION AND TRAINING

All employees, directors and agents are expected to comply with all workplace rules and policies, as well as the Code of Conduct. This means reading the Code and ensuring they understand it.

15. ACCOUNTABILITIES

All employees, directors and agents shall:

- Ensure they comply with the Code;
- Complete any required training on the Code;
- Declare any actual, perceived or potential conflicts of interest to their Supervisor or Senior Management;
- Immediately report any violations or suspected violations of the Code to their Supervisor or Senior Management;

Supervisors/Managers, in addition to their responsibilities as employees, shall:

- Ensure that their employees understand and comply with the Code;
- Review the Code with their employees on an annual basis;
- Create an environment that ensures that employees feel comfortable bringing their concerns forward;
- Maintain the confidentiality of the individual who raises a concern to the extent permitted by law and the Corporation's ability to address the concern;
- Immediately inform the President & CEO of any actual or reasonably suspected violations of the Code;

- Inform consultants, contractors, business partners and suppliers of our expectations so that they comply with our Code and immediately report non-compliance to the President & CEO.

16. COMPLIANCE

Failure to act in accordance with the guidelines outlined in this Code may have consequences for the individual as well as cause harm to HHCEC and its. affiliates. Individual consequences may include disciplinary action, up to and including termination. The need for employees, directors and agents to understand and act in accordance with this Code of Conduct is a serious matter.

This Code represents general standards. It clarifies expectations. It does not replace laws, sound business ethics or good judgement.

The President will notify all employees of any revisions to this Code of Conduct Policy. Modifications may be necessary, among other reasons, to maintain compliance with federal, provincial or local regulations and/or accommodate organizational. change.

Halton Hills
Community Energy
CORPORATION

CODE OF CONDUCT

EMPLOYEE / DIRECTOR ACKNOWLEDGEMENT

I have read, and understand that the employer expects me to abide with the terms therein of the "Code of Conduct".

NAME: ____________________________________

DATE: ____________________________________

SIGNATURE: ____________________________________

APPENDIX 1-I

CUSTOMER ENGAGEMENT ACTIVITIES SUMMARY

File Number: EB-2015-0074
Exhibit:
Tab:
Schedule:
Page:

Date:

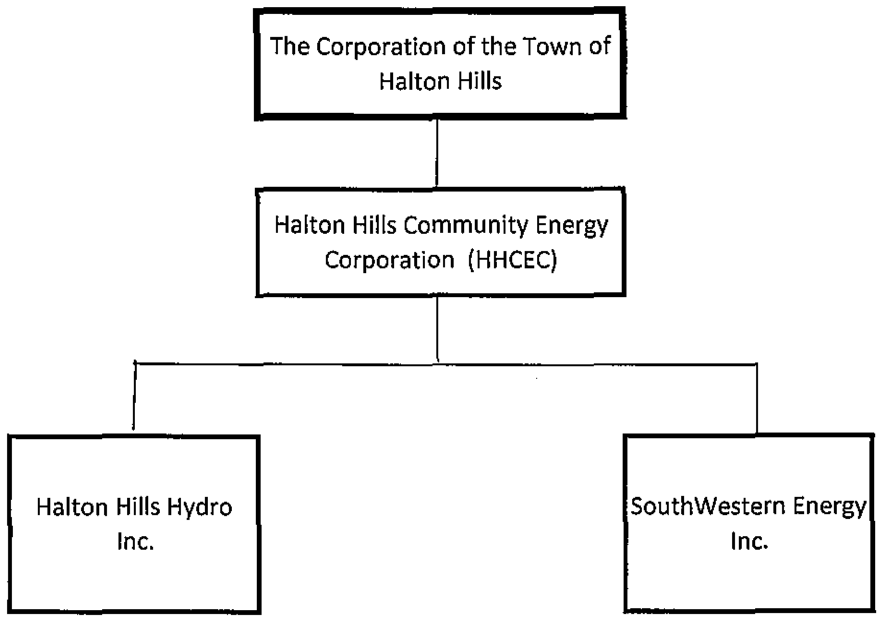
Appendix 2-AC
Customer Engagement Activities Summary

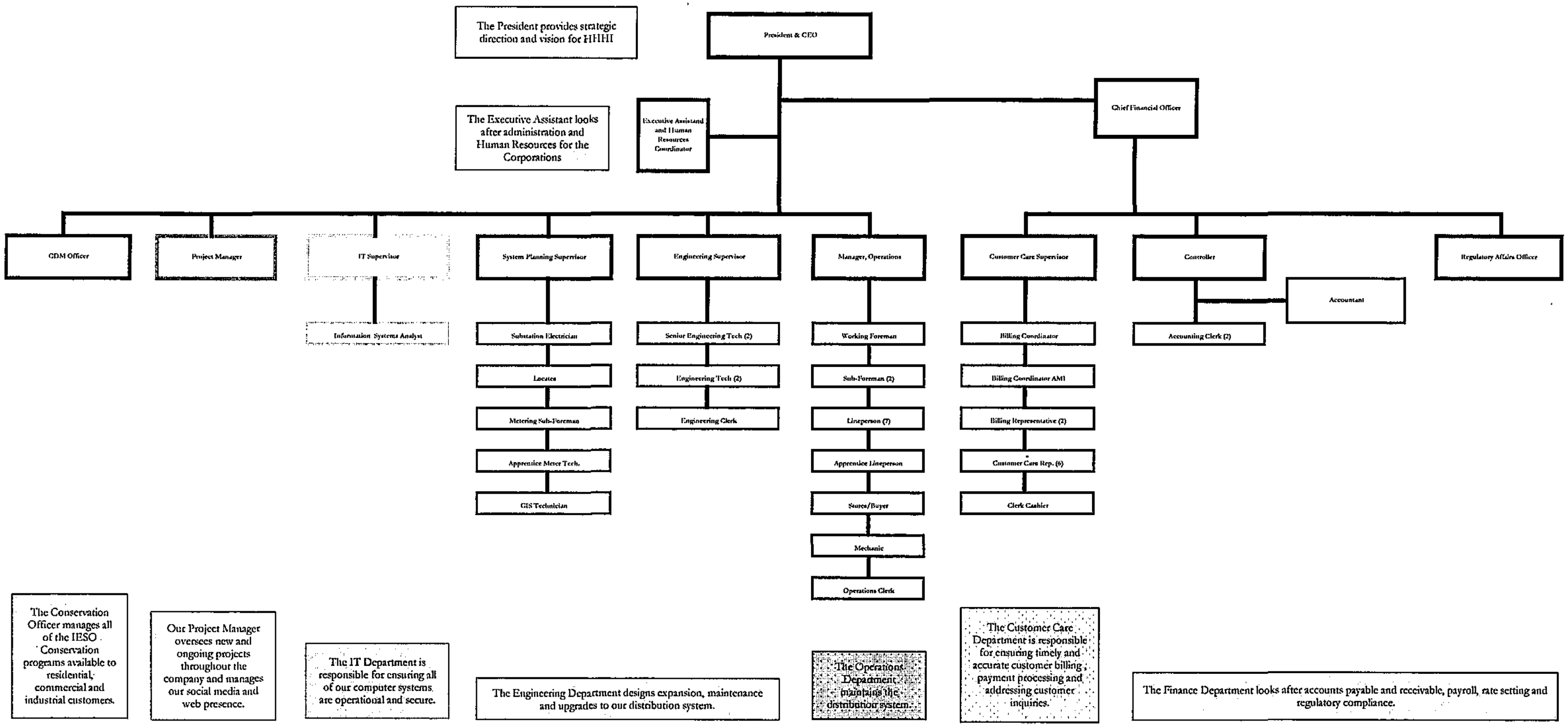
Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
4900 Walk in customers per year	1,Bill Payment, account setup, general inquiries, technical service layout requests and payment	Continue to maintain a front office open to the public to service customers who prefer a face to face interaction and who are paying their bills in person.
24,483 Customer phone calls in 2014	1, Bill Payment, Account Setup, general inquiries, outage information	Implementing an IVR system to provide additional options and information for custoemrs
1517 Written Requests for Information in 2014	1, Account history, requests to set up pre-authorized payment and equal billing 2. Requests received by e-mail, letter or webform	Continue to respond quickly to written inquiries as per our historical SQI's. Continue to offer a variety of ways for customers to contact our office.
Tree Trimming Customer Meeting January 2015	1, Provide customers with an understanding of our tree trimming program, impacts on their trees, why and how we trim and tree trimming schedule 2.Most customers were happy that we would be trimming their trees to reduce outages	Discussed specific trees with customers, provide door knockers in advance of trimming in their area
Social Media Updates	1. Power outage updates 2. Energy Conservation information 3. Updates on programmes and services we offer 4. Safety information 5. Community event information	Currently 20% of our customers follow us on social media. Continue to grow our base of followers through continueing to post timely relevant information. Continuing to enhace outage information provided online.
Website updates	1. Power outage updates 2. Halton Hills Hydro news and events 3. energy conservation information 4. Safety information 5. updated rate information 6. Access to customers billing, payment and energy use information	Continuing to improve power outage information posted online. Continue to update website and maintain AODA compliance.
4205 Locates performed in 2014	1. Performing locates is a safety and legal requirement	Continue to provide locating services for customers
170 Technical Service layouts in 2014	1. Service upgrades, new services, changes or relocations of existing services 2. Residential or commercial customers	New estimating software installed in 2014 speeds up the estimating process and assists engineering in providing excellent responses to Technical Service requests.
Participation in Community Events such as Fall Fairs, Canada Day, Christmas Parade, Farmers markets	1. Participation in approximately 20 community events annually 2. Providing customers with an opportunity to meet utility representatives in person 3. Answer customer inquiries 4. Promote CDM programs and other utility initiatives 5. Maintain a strong community presence	Community events are staffed by Halton Hills Hydro employees, providing a face to the utility. In 2015, HHH held its second Community Open House. Attendance was double the first event, with over 200 people. The utility continues to support community events and maintain a strong position as a community leader.
Customer Satisfaction Survey (2014 & every 2 years)	1. Benchmarking Halton Hills Hydro compared to other Ontario LDCs 2. Understanding customers perceptions and concerns	90% of customers are very or fairly satisfied. Continue to improve customer experience. Overall A rating for performance. Ongoing training for customer care staff and all staff to ensure customer expectations are met. Learn from survey results and focus improving scores with each successive survey. Continue to survey customers every two years to continuously guage performance improvements.
Bill messages and inserts	1. Onbill messaging and bill inserts to update customers on rates, provide OEB updates, CDM information, payment information	Bill inserts are also available on our website for customers who receive electronic bills.
4770 Appointments Scheduled in 2014	1. Meet with customers for site visits or other customer requested meetings	Ensure we continue to meet appointments on time.
2015 Customer engagement survey for COS - 426 telephone respondents	1. Understand customer preferences & priorities with respect to capital & operating spending 2. Understand customers perceptions re power outages	Details of survey attached as Appendix J of the Distribution System Plan
2015 Customer engagement survey for COS - 930 online respondents	1. Understand customer preferences & priorities with respect to capital & operating spending 2. Understand customers perceptions re power outages	Details of survey attached as Appendix J of the Distribution System Plan
2015 Business Customer Focus Group - 7 customers participated	1. Understand customer preferences & priorities with respect to capital & operating spending 2. Understand customers perceptions re power outages	Customers were surprised to learn that only 10-15% of their bill goes to HHH. Details of survey attached as Appendix J of the Distribution System Plan
2015 Residential Customer Focus Group - 20 customers participated	1. Understand customer preferences & priorities with respect to capital & operating spending 2. Understand customers perceptions re power outages	Customers were surprised to learn that only20% of their bill goes to HHH. Details of survey attached as Appendix J of the Distribution System Plan
2015 Community Open House - approximately 200 customers attended - double the attendance of first open house in 2012	1. Information about Halton Hills Hydro services and programs 2. Energy conservation information 3. Community presence - an opportunity for customers to see our facility, meet our staff, understand who we are and our role in the community	Continue to host open house events every few years, continue to maintain a strong community presence
School Safety Programs	1. Visit local schools to teach electricity safety and energy conservation	Continue with this program

APPENDIX 1-J

UTILITY ORGANIZATION CHARTS

Ownership Structure




The President provides strategic direction and vision for HHHI
President & CEO
The Executive Assistant looks after administration and Human Resources for the Corporations
Executive Assistand and Human Resources Coordinator
Chief Financial Officer
CDM Officer
Project Manager
IT Supervisor
Information Systems Analyst
System Planning Supervisor
Substation Electrician
Locates
Metering Sub-Foreman
Apprentice Meter Tech.
GIS Technician
Engineering Supervisor
Senior Engineering Tech (2)
Engineering Tech (2)
Engineering Clerk
Manager, Operations
Working Foreman
Sub-Foreman (2)
Lineperson (7)
Apprentice Lineperson
Stores/Buyer
Mechanic
Operations Clerk
Customer Care Supervisor
Billing Coordinator
Billing Coordinator AMI
Billing Representative (2)
Customer Care Rep. (6)
Clerk Cashier
Controller
Accountant
Accounting Clerk (2)
Regulatory Affairs Officer
The Conservation Officer manages all of the IESO Conservation programs available to residential, commercial and industrial customers.
Our Project Manager oversees new and ongoing projects throughout the company and manages our social media and web presence.
The IT Department is responsible for ensuring all of our computer systems are operational and secure.
The Engineering Department designs expansion, maintenance and upgrades to our distribution system.
The Operations Department maintains the distribution system.
The Customer Care Department is responsible for ensuring timely and accurate customer billing, payment processing and addressing customer inquiries.
The Finance Department looks after accounts payable and receivable, payroll, rate setting and regulatory compliance.

APPENDIX 1-K

OEB ISSUED SCORECARD

Scorecard - Halton Hills Hydro Inc.

8/27/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%	flat	90.00%	
		Scheduled Appointments Met On Time		99.20%	98.00%	100.00%	100.00%	100.00%	up	90.00%	
		Telephone Calls Answered On Time		86.20%	85.50%	87.70%	83.20%	89.70%	up	65.00%	
	Customer Satisfaction	First Contact Resolution						100%			
		Billing Accuracy					99.91%	99.95%	flat	98.00%	
		Customer Satisfaction Survey Results					93%	90%			
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 [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	flat		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		1.78	1.38	1.23	2.08	1.21	down		at least within 1.23 - 2.08
		Average Number of Times that Power to a Customer is Interrupted		2.75	1.49	1.34	1.48	1.47	down		at least within 1.34 - 2.75
	Asset Management	Distribution System Plan Implementation Progress					On-track	On-track			
	Cost Control	Efficiency Assessment				1	1	1			
		Total Cost per Customer [1]		$622	$647	$684	$642	$701			
		Total Cost per Km of Line [1]		$9,208	$9,382	$9,542	$9,034	$9,866			
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 Annual Peak Demand Savings (Percent of target achieved) [2]			16.40%	22.64%	35.12%	37.32%			6.15MW
		Net Cumulative Energy Savings (Percent of target achieved)			33.17%	61.00%	72.22%	86.91%			22.48GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%		90.00%	
	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.15	1.69	1.25	1.06	1.09			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.91	0.87	0.90	1.04	1.04			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.57%	9.12%	9.12%	8.82%			
			Achieved		9.14%	13.30%	14.97%	12.91%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information .
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years .

Legend: up down flat
target met target not met