Exhibit K 1.__

# EB-2016-0105

# Thunder Bay Hydro Electricity Distribution Inc.

# OEB Staff Compendium

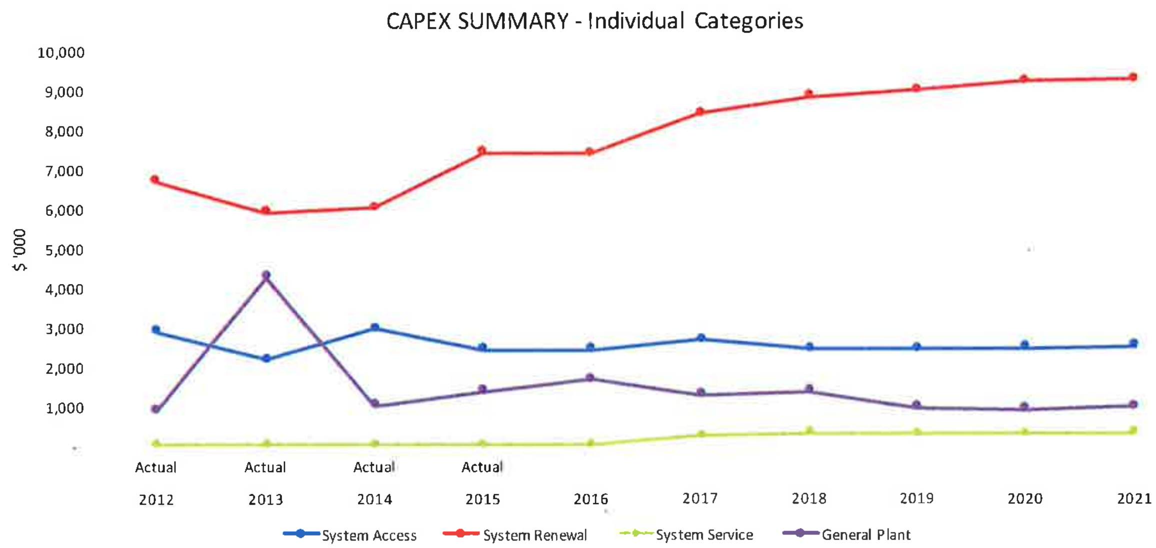
# June 29, 2017

| OEB Category | Thunder Bay Hydro Project | Project Description | Total Expenditure | Driver | Priority Level | Overall Priority |
|---|---|---|---|---|---|---|
| System Access | A 01 | PCB Transformer Replacements | $118,655 | Mandated Obligations | P3 | 8 |
| | A 02 | Customer Recoverable System Modifications | $281,092 | Customer Requests | P3 | 10 |
| | A 11 | Customer Driven System Expansions | $209,034 | Customer Requests | P3 | 5 |
| | A 12 | Residential Service Connections | $445,213 | Customer Requests | P3 | 6 |
| | A 13 | General Service Connections | $926,898 | Customer Requests | P3 | 7 |
| | A 14 | Expansions for Residential Subdivisions | $230,530 | Customer Requests | P3 | 4 |
| | A 15 | System Relocations | $164,881 | Third Party Requests | P3 | 9 |
| | A 21 | Meter Installations | $286,129 | Mandated Obligations | P3 | 11 |
| System Renewal | A 16 | Small Pole Replacements | $342,512 | OH Renewal | P2 | 3 |
| | A 17 | Lines Safety Reports | $761,834 | Safety | P2 | 1 |
| | A 18 | Transformer and Switch Replacements | $756,484 | Asset Failure Renewal | P2 | 2 |
| | B11140 | 25kV Pole Replacements | $584,384 | OH Renewal | P4 | 12 |
| | B12111 | Black Bay-Dewe Voltage Conversion | $1,174,112 | OH Renewal | P4 | 14 |
| | B12112 | Dewe-Rita Voltage Conversion | $1,489,302 | OH Renewal | P4 | 15 |
| | B1270 | Cumming-Brodie Voltage Conversion | $580,677 | OH Renewal | P4 | 16 |
| | B1277 | Donald-Mountdale Voltage Conversion | $310,256 | OH Renewal | P4 | 13 |
| | B1298 | McDougall-Court Voltage Conversion | $789,716 | OH Renewal | P4 | 19 |
| | B12135 | Finlayson - Brodie Voltage Conversion | $893,725 | OH Renewal | P4 | 17 |
| | B14129 | Underground Replacements | $376,868 | UG Renewal | P4 | 18 |
| System Service | A | Grid Modernization | $230,375 | Reliability | P5 | 21 |
| General Plant | C | Fleet - Double Bucket Replacement | $450,000 | System Maintenance Support | P5 | 20 |

**Table 5.4.5-5 2017 Material Capital Projects and Programs**

## Ontario Energy Board Staff – Distribution System Plan Cross Examination

| Category | Historic Actual Expenditures | | | | Bridge Year | Forecast Expenditures | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| | Actual | Actual | Actual | Actual | | | | | | |
| | $ '000 | $ '000 | $ '000 | $ '000 | $ '000 | | | | | |
| System Access | 2,864 | 2,154 | 2,937 | 2,412 | 2,398 | 2,662 | 2,422 | 2,432 | 2,445 | 2,505 |
| System Renewal | 6,664 | 5,888 | 5,994 | 7,413 | 7,388 | 8,380 | 8,818 | 8,976 | 9,217 | 9,261 |
| System Service | - | - | - | - | 1 | 230 | 300 | 280 | 280 | 300 |
| General Plant | 877 | 4,246 | 989 | 1,345 | 1,664 | 1,253 | 1,360 | 946 | 901 | 969 |
| Total Capital Expenditure | 10,405 | 12,287 | 9,920 | 11,171 | 11,451 | 12,526 | 12,900 | 12,634 | 12,842 | 13,036 |




Source: Capital Expenditure Amounts from EB-2016-0105 application, Appendix 2-B, Distribution System Plan, p. 121, Appendix 2-AB (with updated estimates from 2-VECC-8 as filed March 19, 2017)

**System Renewal**

Thunder Bay Hydro expects an increase in System Renewal capital expenditures from 2016 to 2017 of $1,215,055. The increase in expenditures is a direct result of the Asset Condition Assessment which was performed in 2016 by Kinectrics and provided a Health Index (HI) for several major assets. The Health Index distribution contained in Appendix C provided Thunder Bay Hydro a comprehensive view into the condition of assets, and resulted in a suggested level of annual asset renewal in the form of a "Flagged for Action Plan".

The development of the Asset Condition Assessment (ACA) provided Thunder Bay Hydro staff the opportunity to work with an external firm with considerable experience in the field of asset management. This experience has informed Thunder Bay Hydro's staff on the methodologies of assessing condition of equipment, evaluating the associated risk of failure and developing replacement /refurbishment plans. The results have also provided Thunder Bay Hydro better knowledge of the condition of assets within the distribution territory and better informed the Asset Management Process as detailed in 5.3.1.3.

This approach of condition based rather than age based asset management has informed the DSP and resulted in a shift in infrastructure investment. With previous Asset Management Plans, the focus of Thunder Bay Hydro's investment was the decommissioning of 4kV substations and the renewal of associated distribution assets. The analysis by Kinectrics resulted in an extension of power transformer TUL based on winter peaking, low loading levels, and technical analysis of oil results. Due to this, Thunder Bay Hydro has determined that a shift away towards a holistic System Renewal plan is necessary. Thunder Bay Hydro defines a holistic system renewal plan, as one which accounts for renewal of assets on 4kV as well as 12kV and 25kV voltage levels, as well as a mix of overhead and underground projects. In order to meet the asset renewal quantities suggested by Kinectrics an increase from historical levels of investment will occur in underground infrastructure and 25kV pole replacements.

| Account # | Description | 2016 Projection | 2017 Forecast |
|---|---|---|---|
| A 16 | Small Pole Replacements | $ 379,573 | $ 342,512 |
| A 17 | Lines Safety Reports | $ 732,775 | $ 761,834 |
| A 18 | Transformer and Switch Replacements | $ 816,936 | $ 756,484 |
| B | 25kV Pole Replacements | $ - | $ 584,384 |
| B | 4kV Voltage Conversions | $ 5,092,976 | $ 5,367,788 |
| B | Underground Renewal | $ - | $ 376,868 |
| B | Design | $ 142,443 | $ 189,888 |
| | Subtotal | $ 7,164,703 | $ 8,379,758 |

**Table 5.4.4-14 System Renewal Expenditure Variances 2016 Projection to 2017 Forecast**

The shift in expenditures from historical levels of replacement will begin in 2017 and Thunder Bay Hydro anticipates becoming aligned with the "Flagged for Action" plan suggested from Kinectrics by 2019. Thunder Bay Hydro has purposely taken a conservative approach and paced the shift in expenditures over a 3 year period to minimize cost impact to the customer and to complete work in progress.

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Specifically work in progress on 4kV conversion projects, where there are only one or two project areas prior to be completed, prior to decommissioning of a station. In addition, this change is a fundamental shift in philosophies, and requires changes in construction practices, scheduling and labor allocations. Allowing 3 years to become aligned will allow Thunder Bay Hydro the chance to implement these changes in the most cost effective manner.

**System Service**

For the 2017 Forecast period, Thunder Bay Hydro expects expenditures in System Service to increase by $230,375. This increase is to implement automation improvements on selected feeders as an initiative of the 'Grid Modernization Plan' attached as Appendix D.

**General Plant**

For the 2017 Forecast period, Thunder Bay Hydro expects expenditures in General Plant to reduce by $738,305. This decrease in spending is primarily due to the SCADA system expenditure being completed in 2016.

### 5.4.4.6 2017 Forecast vs. 2018 Forecast Capital Expenditure Variances

| Category | 2017 Plan | 2018 Plan | Variance 2017 to 2018 |
|---|---|---|---|
| System Access | $2,662,432 | $2,422,273 | $(240,159) |
| System Renewal | $8,379,756 | $8,818,369 | $438,613 |
| System Service | $230,375 | $300,000 | $69,625 |
| General Plant | $1,167,500 | $1,359,760 | $192,260 |
| Total Expenditure | $12,440,063 | $12,900,402 | $460,339 |

**Table 5.4.4-15 Capital Expenditure Variances 2017 Forecast to 2018 Forecast**

**System Access**

The primary variance within this category is a result of the decrease in capital expenditures due to the completion of the removal of all transformers >50 ppm from the distribution system in the PCB Transformer Replacements project. The Smart Meter Sampling program will also see a decrease in expenditures due to meters sampling schedules decreasing in 2018.

| Account # | Description | 2017 Plan | 2018 Plan | Variance |
|---|---|---|---|---|
| A 01 | PCB Transformer Replacements | $ 118,655 | $ 50,000 | $ (68,655) |
| A 02 | Customer Recoverable System Modifications | $ 281,092 | $ 300,000 | $ 18,908 |
| A 11 | Customer Driven System Expansions | $ 209,034 | $ 180,000 | $ (29,034) |
| A 12 | Residential Service Connections | $ 445,213 | $ 323,500 | $ (121,713) |
| A 13 | General Service Connections | $ 926,898 | $ 900,000 | $ (26,898) |

- Redundancy – preventing any one station from becoming islanded or disconnected from other stations thereby increasing the impact of failure;
- Reliability – maintaining the network mesh allows for load to be more readily transferred to other feeders during an outage event; and
- Operability – capability to isolate and transfer load during maintenance operation with minimal customer interruption.

The above considerations regarding interconnectivity along with age of the infrastructure previously defined how Thunder Bay Hydro prioritized its overhead renewal projects.

Additionally within in the previously identified timeframe, all 12kV power transformers would be replaced as Thunder Bay Hydro's strategy has been to maintain this subnetwork.

Thunder Bay Hydro continues to employ this strategy to the extent that it will continue to convert the 4kV network to 25kV and decommission its substations as a result. However the rate at which this occurs will be reduced due to the results of the ACA as noted in the flagged for action plan.

| ID | Location | MVA | Primary Voltage (kV) | Secondary Voltage (kV) | Age | HI Category | Flagged for Action Year |
|---|---|---|---|---|---|---|---|
| 3T1 | STN #3 HARDISTY | 3 | 22 | 4 | 67 | Poor | 3 |
| 3T2 | STN #3 HARDISTY | 4 | 22 | 4 | 63 | Fair | 7 |
| 16T1 | STN#16 MACDONNEL | 4 | 23 | 4 | 62 | Fair | 7 |
| 21T1 | STN 21 WINDEMERE | 4 | 23 | 4 | 60 | Good | 9 |
| 5T1 | STN 5 DONALD | 4 | 22 | 4 | 58 | Very Good | 12 |
| 16T2 | STN#16 MACDONNEL | 4 | 23 | 4 | 57 | Very Good | 12 |
| 4T1 | STN #4 VICKER | 4 | 22 | 4 | 57 | Very Good | 13 |
| 21T2 | STN 21 WINDEMERE | 4 | 23 | 4 | 57 | Very Good | 12 |
| 14T1 | STN#14 ALGOMA | 4 | 23 | 4 | 57 | Very Good | 14 |
| 18T1 | BALSALM | 6.667 | 23 | 12 | 56 | Very Good | 13 |
| 11T1 | STN 11 HIGH ST | 5 | 23 | 4 | 56 | Very Good | 14 |
| 5T2 | STN 5 DONALD | 4 | 22 | 4 | 53 | Very Good | 17 |
| 9T1 | STN 9 MOUNTDALE | 4 | 22 | 4 | 50 | Very Good | 20 |
| 15T1 | STN #15 GRENVILLE | 6.667 | 24 | 4 | 47 | Very Good | 20+ years |
| 12T1 | STN#12 CAMELOT | 6.667 | 24 | 4 | 47 | Very Good | 20+ years |
| 12T2 | STN#12 CAMELOT | 6.667 | 24 | 4 | 47 | Very Good | 20+ years |
| 23T1 | STN#23 | 6.667 | 24.94 | 12 | 44 | Very Good | 20+ years |
| 36T1B | STN 36 MAPLEWARD | 2 | 22 | 12 | 48 | Very Good | 20+ years |
| 36T1R | STN #36 MAPLEWARD | 2 | 22 | 12 | 48 | Very Good | 20+ years |
| 36T1W | STN #36 MAPLEWARD | 2 | 22 | 12 | 48 | Very Good | 20+ years |

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| | | | | | | | |
|---|---|---|---|---|---|---|---|
| North wood | NORTHWOOD PLAZA | 1.69 | 24.94 | 4 | 44 | Very Good | 20+ years |
| 19T1 | STN 19 BROADWAY | 6.667 | 24.94 | 12 | 36 | Very Good | 20+ years |

**Table 5.3.2-4 Kinectrics ACA Summary of Power Transformers**

Further review of Table 5.3.2-4 indicates that Thunder Bay Hydro's power transformers are in general, very good health for their age. The Kinectrics study has extended their serviceable life due to several factors. Heat is one the main elements that contribute to insulation degradation in transformers. Overloading of transformers and high utilization during peak ambient temperatures contribute to increased heating within transformers, which in turn leads to insulation and dielectric breakdown. Oil tests provide insight into whether these events have occurred in the past and are a consideration in the health of transformers. Thunder Bay Hydro's oil test results indicate that over time, the 4kV power transformers are not showing signs of degradation as a result of this or any other factors.

The results of the oil tests are likely a consequence of the fact that the transformers are lightly loaded and peak loading occurs in the winter months. These factors have ultimately led to the findings in the ACA for this asset category.

Prior to the results of this ACA it was believed that the 4kV power transformers were well beyond their end of life. This was due to the previously mentioned fact that the TUL for this asset was defined as 45 years by the Asset Depreciation Study for the Ontario Energy Board. The realization that these assets are in overall good health represents a significant change in the previous philosophy of accelerated renewal of the 4kV network to allow the stations to be decommissioned. In response to this Thunder Bay Hydro has begun to revise its 4kV renewal program to allow for the stations to remain in service, allowing for better alignment between station decommissioning with the flagged for action year identified in Table 5.3.2-4 for each transformer.

Circuit Breakers

Thunder Bay Hydro currently only employs circuit breakers within its 4kV substations. In general the age and condition of these units are similar to that of the stations in which they are deployed. This is evident from Table 5.3.2-5 below. These assets are maintained to ensure that they remain in service while the corresponding station is in service; otherwise they are removed from service at the time of station decommissioning.

| ID | Station | Location | Type | Manufacturer | Age | HI Category | Flagged for Action Year |
|---|---|---|---|---|---|---|---|
| 36557 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 36558 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 36559 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 36560 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 37979 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 37980 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |

THUNDER BAY HYDRO

# 2017 Capital Project Summary

## A. General Information

| | |
|---|---|
| **Project Name** | Black-Bay Dewe Voltage Conversion |
| **Project Number** | B12111 |
| **Investment Category** | System Renewal |
| **Capital Investment(s)** | |

| Black Bay-Dewe B12111 | **2017** |
|---|---|
| **Capital Cost (5.4.5.2 A.1)** | $1,174,110 |
| **Capital contribution** | $0 |
| **Net Cost** | $1,174,110 |
| **O&M Cost (5.4.5.2 A.2)** | $0 |

There are no expected O&M costs associated with this project, as all assets and the work associated with it will be capitalized.

**Customer Attachments and Load (5.4.5.2 A.2)**

Customer Attachments and Load are not expected to change with the execution of this project, however improvements to system components will positively affect the following;
Customer attachments: approximately 342 customers as broken down by customer class below.

| Project | Residential/ Other | General Users | Large Users | Total |
|---|---|---|---|---|
| Black Bay- Dewe | 334 | 8 | 0 | 342 |

Load: 278 kWh

| | | | |
|---|---|---|---|
| **Start Date (5.4.5.2 A.3)** | 01-01-17 | **In-Service Date (5.4.5.2 A.3)** | 31-12-17 |

**Expenditure Timing for the Test Year**

| **2017 Q1** | **2017 Q2** | **2017 Q3** | **2017 Q4** |
|---|---|---|---|
| $ 293,528 | $ 352,233 | $ 352,233 | $ 176,117 |

The project is a continuation of the pole setting that was completed in 2016. Framing, stringing and services and transformers are to be completed throughout 2017.

**Project Summary**

This project is the completion of a voltage conversion project where pole setting occurred in 2016 and 2017 includes the replacement of end of life 4kV distribution assets and substations that are targeted for replacement with modern 25kV distribution, which will allow for increased system reliability and the installation of modern equipment. The project has been prioritized due to the removal of Grenville Substation which is 47 years of age and has been identified as having a low interconnectivity and no back up transformation should the substation transformer fail. The project includes the replacement of 144 poles; reframe of 4 poles, replacement of 30 pole mount transformers and replacement of 1 pad mount transformer. The project also targets to replace 9400 m of overhead conductor and 500 m of underground cable as a part of this project.

**Risk Identification & Mitigation (5.4.5.2 A.4)**

Scheduling Risk: The projects in this program are subject to scheduling risks with respect to other major projects. All planned capital projects are scheduled for completion in 2017. The mitigation plan for these risks are weekly internal project updates from the Project Manager to review progress and identify action plans to keep construction on schedule. The schedule is built upon the most cost-effective activities occurring in specified seasons. (Pole setting when ground is thawed, pad mount transformers for schools in the summer months, etc.) If the projects go off schedule, the probability of cost increases will likely result. This risk is minimized by ensuring that the schedules are realistic and accurate, maintaining communication with crews and supervisors and utilizing contractors to complete concurrent activities, or assist in completing work to meet schedules.

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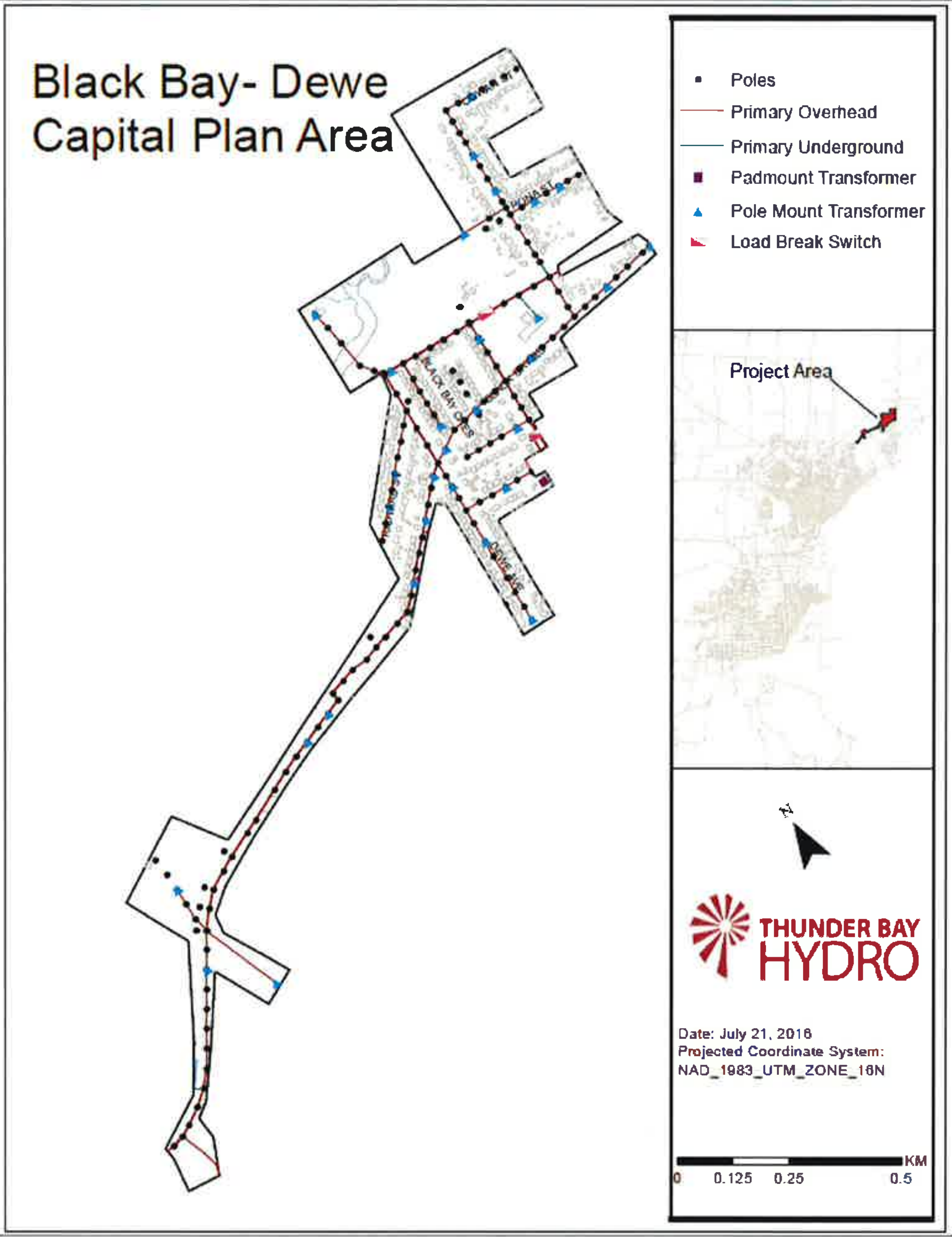
| Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5) |
| --- |
| Thunder Bay Hydro has completed a number of similar projects over the past five years. Most recently, projects have been completed in the Balsam-Minot project area. This project was also a voltage conversion involving the replacement of poles, overhead conductors, underground cable, pole mount transformers, pad mount transformers. The reason for the comparison is that it also had primarily street front poles and minimal easement poles which are substantially more costly to replace. The approximate average cost of construction of these projects on a per pole basis is $7,400. Based on this information, the Black Bay Dewe project's proposed construction cost is in-line with the historic per-unit costs considering this project includes the replacement of 144 poles, the reframe of 4 poles and the replacement of one pad mount transformer. |
| **REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)** |
| Not Applicable |
| **Attach Other project reference material i.e. Images, Drawings and or reference material** |




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

**Efficiency, Customer Value & Reliability - Investment Main Driver (Trigger) (5.4.5.2 B.1a)**

The main drivers are Operational Efficiency and Modernization of Systems. Thunder Bay Hydro seeks to maximize factors that positively affect operational efficiency through consideration of equipment types and the analysis of constraints on the system. The modernization of assets from the 4kV to the 25kV voltage system results in the retirement of distribution transformer stations in need of otherwise expensive upgrades. Over time, uprating the operating voltage during renewal projects to 25kV eliminates the need to operate, maintain, and upgrade stations required for providing electrical connectivity between the 25kV and the 4kV systems. The Black-Bay Dewe and Dewe-Rita are the projects numbers contribute directly to Thunder Bay Hydro's ability to retire Grenville by the end of 2017. While capacity is not a driving factor for any projects under this DSP, uprating of 4kV distribution system to higher more efficient operating voltage will also improve line losses as well as ability to accept more

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| |
|---|
| load and/or generation customers. |
| **Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)** |
| The secondary driver for this project is Effective Asset Management. Thunder Bay Hydro seeks to prioritize project selection based on the long term performance of the utility. Section 5.3.2.3 discusses the replacement strategy for power transformer decommissioning and how it relates to the long term performance of the utility. |
| **Efficiency, Customer Value & Reliability – Investment objectives and/or performance targets (5.4.5.2 B.1a)** |
| The objective of this program is Operational Efficiency. Thunder Bay Hydro acknowledges the benefit to uprating to 4kV (See Net benefits accruing to customers) and seeks to prioritize removal of substations based on power transformer age as well as interconnectivity in the distribution system. The performance objectives of this project it to complete the entire scope within 10% of budget. |
| **Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1a)** |
| Kinectrics provided Thunder Bay Hydro with an Asset Condition Assessment, which indicated the pacing for 4kV station transformers, breakers, transformers and wood pole replacements. (See Appendix C) The voltage conversion projects account for the majority of 4kV replacements. The transformer and switches category accounts for the remainder of 4kV asset replacements. |
| **Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1b)** |
| These projects are ranked P4 – Medium Priority as this work is such that it can be scheduled routinely within the capability of the Utility and support the long term health of the system. Priority is generally subject to the availability of resources and may be consolidated by facility type, work zone or as directed to obtain operational efficiency. This project has been ranked 14 of 21 projects in the test year. |
| **Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1c)** |
| The proactive replacement of end of life 4kV assets such as transformers, poles, cross arms and station transformers as planned in this project area will greatly decrease the probability of unplanned failure. The installation of assets that meet current standards for framing and separation will allow for the installation and operation of equipment in a more efficient manner due to safer working conditions. The project areas have been chosen based on their ability to be constructed in a cost effective manner. |
| **Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1cii)** |
| With the conversion from 4kV to 25kV construction Thunder Bay Hydro expects the following benefits to customers;<br>a) Eliminate older, end of life 4kV distribution assets<br>b) Allow for the deployment of Modernized Grid technologies and all its related benefits to customers which allow the ability to manage and troubleshoot the system<br>c) Standardize construction practices across the different systems, which helps to control construction and operating costs<br>d) Reduce system losses through the elimination of substations<br>e) Allow for the connection of larger loads and generators without major system rebuilds.<br>f) Conform to the standard voltage across the Province making it easier to source material and expertise.<br>g) Eliminate the use of outdated, hard to replace and maintain equipment.<br>h) Eliminate the need for 4kV substations and simplify the operation of the distribution system. |
| **Effect of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)** |
| The conversion projects will improve reliability performance as these projects are typically in older areas of the city where old construction practices were used. These will be replaced with modern standards and equipment, which will improve system operation efficiency through the use of new technologies to protect and control the system. These modern systems will provide more cost effective options to limit outage areas and restore outage areas, providing improved reliability. |
| **Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)** |

| |
|---|
| The projects listed in this category have been identified based on a voltage conversion plan which takes into account the condition of the substation transformers, as well as the geographic location of the substation, the loads it feeds, and the age of infrastructure on the associated feeder.<br>Alternatives for voltage conversion are considered, and are captured below;<br>a) Do nothing approach – this option is not considered appropriate as it results in the potential for long duration outages for those customers affected, and if the outage occurs after business hours it results in a higher cost for replacement.<br>b) Replace like for like at 4kV– this option requires maintenance or and replacement rather than removal of 4kV substations. This option has been reviewed in detail and preliminary estimates to replace or refurbish a substation range from $500,000 to $5,000,000 per substation depending on the components. Annual maintenance on these substations requires labour and associated O&M expenditures, which also result in a higher total cost of ownership to Thunder Bay Hydro rather than removing 4kV substations and converting assets to 25kV as they reach end of life.<br>c) Defer replacement until a later date – this project has been prioritized against other proposed projects, and to defer it would delay the removal of the Grenville substation thus increasing maintenance costs on the substations for a greater number of years.<br>d) Install several step-down transformer banks to supply the area at 4kV and remove the substation, rather than converting to 25kV. This alternative was not chosen as it is not aligned with Thunder Bay Hydro's long term strategic approach to asset management and does not allow Thunder Bay Hydro to take advantage of the benefits of fully converting the area to 25kV as discussed in Net benefits accruing to customers above. The benefits of voltage conversion are further discussed in Section 5.2.3.2. |
| **Safety (5.4.5.2 B.2)** |
| This investment will improve safety to the public, as well as worker safety by replacing existing poles and their associated framing with newer standards which will allow for improved safe work practices. |
| **Cyber-Security, privacy (where applicable) (5.4.5.2 B.3)** |
| Not Applicable |
| **Co-Ordination, Interoperability Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable) (5.4.5.2 B.4i)** |
| Thunder Bay Hydro is a member of the Utilities Standards Forum ("USF") and uses USF standards, supplemented by standards developed internally. The use of USF standards ensures that the design and construction of this project will be done according to a set of standards utilized by a large number of other utilities in Ontario. |
| **Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)** |
| This project is executed in accordance with Thunder Bay Hydro's Asset Management planning processes and policies (Additional details in Section 5.3), to proactively address the suggested station transformers by Kinectrics. (Appendix C)<br>New poles, framing and distribution transformers are designed and installed according to the latest standards and technologies to meet future operational requirements. |
| **Economic Development (where applicable) (5.4.5.2 B.5)** |
| Not Applicable |
| **Environmental Benefits (where applicable) (5.4.5.2 B.6)** |
| Not Applicable |
| **C. Category-Specific Requirements - System Renewal** |
| **Asset performance related operational targets and asset lifecycle optimization policies and practices (5.4.5.2 SR – C1.1)** |
| This project fulfills Operational Effectiveness and Customer Service Quality objectives through a continuous improvement in delivering on system reliability targets of SAIDI and SAIFI results and removing the risk of lengthy unplanned outages from failed poles. This project also supports safety targets with the elimination of porcelain insulators which in failure pose a potential risk to public safety. Additionally, the selected course of proactive replacement rather than reactive replacement has a lower cost per customer and cost per kilometer of line than other alternatives. |
| **Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR – C1.2)** |

Numerous assets involved with these projects are not being replaced due to their performance but rather as part of the process of uprating to 25kV, which results in the need for a higher standard of pole, framing and transformer. Asset condition of various assets relative to typical life varies based on several factors, for example soil conditions or location of transformer in a back lane verses street front that may cause premature deterioration. (Section 5.3.3.1)

**The number of customers in each class potentially affected by the failure of the assets (5.4.5.2 SR – C1.3)**

The number of customers impacted by this project is approximately 342.

| Project | Residential/ Other | General Users | Large Users | Total |
|---|---|---|---|---|
| Black Bay- Dewe | 334 | 8 | 0 | 342 |

Additionally all customers on the same feeder would be affected for a short duration until the appropriate load break, or in-line could be opened to isolate the work area.

**Quantitative customer impacts (5.4.5.2 SR – C1.4)**

Outage events related to customers in this area are indicated below; voltage conversion of the assets in this project will contribute to improving Thunder Bay Hydro's outage statistics in this area.

| Feeder | Total Customers in Project area on specified feeder | Hours of Interruptions | Number of Interruptions |
|---|---|---|---|
| 02M4 | 338 | 11194 | 21744 |
| 02M5 | 4 | 801 | 1382 |

**Qualitative customer impacts (5.4.5.2 SR – C1.5)**

The conversion of these areas will ensure that the number and duration of outages are reduced on these feeders, existing levels of reliability are maintained, and safety issues are eliminated. These projects also make efficient use of existing infrastructure; all of this will maintain or improve customer satisfaction.

**Value of customer impact in terms of characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of the failure (5.4.5.2 SR – C1.6)**

Customer impact in terms of potential failure is high for the affected customers and low on a system level. Depending on the location of a failure, an outage impact and duration will vary depending on the location of the downstream disconnect / isolating device. An outage resulting from a failed asset could result in a loss of economic productivity, and a risk to public safety as street lighting and traffic signals could be affected.

**Timing & Priority of Project (5.4.5.2 SR – C2)**

This project is part of the overall system renewal program for 2017. The assets being replaced fall within the planned levelized replacement quantities. This project does not rely on any other System Renewal, System Access or General plant projects being completed first. This project has been prioritized within the System Renewal category and takes seasonal and resource availability into account. The project has been ranked 14 of 21 projects in the test year.

**Consequences for system O&M costs (5.4.5.2 SR – C3)**

The removal of the ageing 4kV substations is expected to eliminate Thunder Bay Hydro's operating and maintenance costs associated with these stations. Substations require regular maintenance annually. There is also an increase to the operating cost for maintenance of the property and buildings for the substations. 4kV substations pose a security risk, from theft of copper, to trespassing hazards and an environmental risk from spilled oil. The recent asset management assessment performed for Thunder Bay Hydro substations identified the end of life of each substation transformer with no 4kV substations as needing immediate replacement; however, the cost to replace a substation is considerable and offers no new features or advantages beyond supplying existing load with the same capabilities. Converting the load to 25kV and eliminating the substation altogether allows for all the advantages that a 25kV system offers, and removes the disadvantages from having a 4kV system. Preliminary estimates to replace or refurbish a substation ranges from $500,000 to $5,000,000 per substation, depending on what devices are replaced (e.g. transformer, feeder breakers) or all of the station (i.e. transformers, busses, protection and control, etc.).

**Impact on Reliability performance and or Safety (5.4.5.2 SR – C4)**

Replacement of these assets will have a positive impact on reliability performance and safety in the following ways;

a) Tree trimming due to replacement will improve reliability by reducing the amount of storm damage
b) Installation of new standards will enhance clearance providing for safer working conditions for both Thunder Bay Hydro and Third party employees
c) Installation of new standards includes animal protection which will reduce the number of animal contact related outage, improving reliability
d) Improved reliability by reducing potential failures prior to failure and greatly decreasing restoration times

**Analysis of Project Benefits and Timing (5.4.5.2 SR – C5)**

| |
|---|
| Thunder Bay Hydro has implemented a project prioritization system for all system renewal projects, starting in 2017. The system optimizes capital expenditure planning by establishing quantity levels for replacement in each asset category based on the asset condition assessment completed by Kinectrics. In addition to this Thunder Bay Hydro also considers additional the risk levels by evaluating how asset failures or system constraints will affect public safety, Employee Safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction. The timing of the project considers the benefits and costs described in this project summary. Costs of the project may be affected by increases in a requirement for contractors and material prices. While there is some uncertainty in the cost and timing of the project, delaying this project beyond 2017 may cause the risk of failure to increase dramatically and will reduce some of the project benefits.<br>Additionally the modernization of the project area to 25kV will have the added benefit of installing reclosing devices to replace vintage breakers which do not have this functionality, thus improving the reliability and outage durations to customers. |
| **Like for Like Renewal Analysis, Alternative Comparison (5.4.5.2 SR – C6)** |
| The projects included in this category will be analyzed for completion in a like for like manner, but where a benefit to customers and the utility will improve reliability and operability, an alternative design shall be considered. |

- Redundancy – preventing any one station from becoming islanded or disconnected from other stations thereby increasing the impact of failure;
- Reliability – maintaining the network mesh allows for load to be more readily transferred to other feeders during an outage event; and
- Operability – capability to isolate and transfer load during maintenance operation with minimal customer interruption.

The above considerations regarding interconnectivity along with age of the infrastructure previously defined how Thunder Bay Hydro prioritized its overhead renewal projects.

Additionally within in the previously identified timeframe, all 12kV power transformers would be replaced as Thunder Bay Hydro's strategy has been to maintain this subnetwork.

Thunder Bay Hydro continues to employ this strategy to the extent that it will continue to convert the 4kV network to 25kV and decommission its substations as a result. However the rate at which this occurs will be reduced due to the results of the ACA as noted in the flagged for action plan.

| ID | Location | MVA | Primary Voltage (kV) | Secondary Voltage (kV) | Age | HI Category | Flagged for Action Year |
|---|---|---|---|---|---|---|---|
| 3T1 | STN #3 HARDISTY | 3 | 22 | 4 | 67 | Poor | 3 |
| 3T2 | STN #3 HARDISTY | 4 | 22 | 4 | 63 | Fair | 7 |
| 16T1 | STN#16 MACDONNEL | 4 | 23 | 4 | 62 | Fair | 7 |
| 21T1 | STN 21 WINDEMERE | 4 | 23 | 4 | 60 | Good | 9 |
| 5T1 | STN 5 DONALD | 4 | 22 | 4 | 58 | Very Good | 12 |
| 16T2 | STN#16 MACDONNEL | 4 | 23 | 4 | 57 | Very Good | 12 |
| 4T1 | STN #4 VICKER | 4 | 22 | 4 | 57 | Very Good | 13 |
| 21T2 | STN 21 WINDEMERE | 4 | 23 | 4 | 57 | Very Good | 12 |
| 14T1 | STN#14 ALGOMA | 4 | 23 | 4 | 57 | Very Good | 14 |
| 18T1 | BALSALM | 6.667 | 23 | 12 | 56 | Very Good | 13 |
| 11T1 | STN 11 HIGH ST | 5 | 23 | 4 | 56 | Very Good | 14 |
| 5T2 | STN 5 DONALD | 4 | 22 | 4 | 53 | Very Good | 17 |
| 9T1 | STN 9 MOUNTDALE | 4 | 22 | 4 | 50 | Very Good | 20 |
| 15T1 | STN #15 GRENVILLE | 6.667 | 24 | 4 | 47 | Very Good | 20+ years |
| 12T1 | STN#12 CAMELOT | 6.667 | 24 | 4 | 47 | Very Good | 20+ years |
| 12T2 | STN#12 CAMELOT | 6.667 | 24 | 4 | 47 | Very Good | 20+ years |
| 23T1 | STN#23 | 6.667 | 24.94 | 12 | 44 | Very Good | 20+ years |
| 36T1B | STN 36 MAPLEWARD | 2 | 22 | 12 | 48 | Very Good | 20+ years |
| 36T1R | STN #36 MAPLEWARD | 2 | 22 | 12 | 48 | Very Good | 20+ years |
| 36T1W | STN #36 MAPLEWARD | 2 | 22 | 12 | 48 | Very Good | 20+ years |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| North wood | NORTHWOOD PLAZA | 1.69 | 24.94 | 4 | 44 | Very Good | 20+ years |
| 19T1 | STN 19 BROADWAY | 6.667 | 24.94 | 12 | 36 | Very Good | 20+ years |

**Table 5.3.2-4 Kinectrics ACA Summary of Power Transformers**

Further review of Table 5.3.2-4 indicates that Thunder Bay Hydro's power transformers are in general, very good health for their age. The Kinectrics study has extended their serviceable life due to several factors. Heat is one the main elements that contribute to insulation degradation in transformers. Overloading of transformers and high utilization during peak ambient temperatures contribute to increased heating within transformers, which in turn leads to insulation and dielectric breakdown. Oil tests provide insight into whether these events have occurred in the past and are a consideration in the health of transformers. Thunder Bay Hydro's oil test results indicate that over time, the 4kV power transformers are not showing signs of degradation as a result of this or any other factors.

The results of the oil tests are likely a consequence of the fact that the transformers are lightly loaded and peak loading occurs in the winter months. These factors have ultimately led to the findings in the ACA for this asset category.

Prior to the results of this ACA it was believed that the 4kV power transformers were well beyond their end of life. This was due to the previously mentioned fact that the TUL for this asset was defined as 45 years by the Asset Depreciation Study for the Ontario Energy Board. The realization that these assets are in overall good health represents a significant change in the previous philosophy of accelerated renewal of the 4kV network to allow the stations to be decommissioned. In response to this Thunder Bay Hydro has begun to revise its 4kV renewal program to allow for the stations to remain in service, allowing for better alignment between station decommissioning with the flagged for action year identified in Table 5.3.2-4 for each transformer.

<u>Circuit Breakers</u>

Thunder Bay Hydro currently only employs circuit breakers within its 4kV substations. In general the age and condition of these units are similar to that of the stations in which they are deployed. This is evident from Table 5.3.2-5 below. These assets are maintained to ensure that they remain in service while the corresponding station is in service; otherwise they are removed from service at the time of station decommissioning.

| ID | Station | Location | Type | Manufacturer | Age | HI Category | Flagged for Action Year |
|---|---|---|---|---|---|---|---|
| 36557 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 36558 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 36559 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 36560 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 37979 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 37980 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |

| ID | Station | Location | Type | Manufacturer | Age | HI Category | Flagged for Action Year |
|---|---|---|---|---|---|---|---|
| 37981 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 37982 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 38306 | 3 | Hardisty | OCB | General Electric | 67 | Poor | 8 |
| 34912 | 14 | Algoma St. | OCB | General Electric | 67 | Poor | 8 |
| 34913 | 14 | Algoma St. | OCB | General Electric | 67 | Poor | 8 |
| 34914 | 14 | Algoma St. | OCB | General Electric | 67 | Poor | 8 |
| 34915 | 14 | Algoma St. | OCB | General Electric | 67 | Poor | 8 |
| 34916 | 14 | Algoma St. | OCB | General Electric | 67 | Poor | 8 |
| 85782 | 15 | Grenville St. | ACB | Pioneer Electric | 64 | Fair | 20+ years |
| 85783 | 15 | Grenville St. | ACB | Pioneer Electric | 64 | Fair | 20+ years |
| 85784 | 15 | Grenville St. | ACB | Pioneer Electric | 64 | Fair | 20+ years |
| 85785 | 15 | Grenville St. | ACB | Pioneer Electric | 64 | Fair | 20+ years |
| 85786 | 15 | Grenville St. | ACB | Pioneer Electric | 64 | Fair | 20+ years |
| 2-0444-1 | 4 | Vickers | ACB | Allis Chalmers | 62 | Good | 20+ years |
| 2-0444-2 | 4 | Vickers | ACB | Allis Chalmers | 62 | Good | 20+ years |
| 2-0444-3 | 4 | Vickers | ACB | Allis Chalmers | 62 | Good | 20+ years |
| 2-0444-4 | 4 | Vickers | ACB | Allis Chalmers | 62 | Good | 20+ years |
| 38923 | 16 | MacDonnell St. | OCB | General Electric | 62 | Good | 20+ years |
| 38924 | 16 | MacDonnell St. | OCB | General Electric | 62 | Good | 20+ years |
| 38925 | 16 | MacDonnell St. | OCB | General Electric | 62 | Good | 20+ years |
| 38926 | 16 | MacDonnell St. | OCB | General Electric | 62 | Good | 20+ years |
| 38927 | 16 | MacDonnell St. | OCB | General Electric | 62 | Good | 20+ years |
| 52775 | 16 | MacDonnell St. | OCB | General Electric | 62 | Good | 20+ years |
| 52776 | 16 | MacDonnell St. | OCB | General Electric | 62 | Good | 20+ years |
| 52777 | 16 | MacDonnell St. | OCB | General Electric | 62 | Good | 20+ years |
| 52781 | 16 | MacDonnell St. | OCB | General Electric | 62 | Good | 20+ years |
| 201097 | 21 | Windemere | OCB | English Electric | 60 | Good | 20+ years |
| 201131 | 21 | Windemere | OCB | English Electric | 60 | Good | 20+ years |
| 201133 | 21 | Windemere | OCB | English Electric | 60 | Good | 20+ years |
| 231986 | 21 | Windemere | OCB | English Electric | 60 | Good | 20+ years |
| 231987 | 21 | Windemere | OCB | English Electric | 60 | Good | 20+ years |
| 52778 | 21 | Windemere | OCB | General Electric | 60 | Good | 20+ years |
| 52782 | 21 | Windemere | OCB | General Electric | 60 | Good | 20+ years |
| 52784 | 21 | Windemere | OCB | General Electric | 60 | Good | 20+ years |
| 52785 | 21 | Windemere | OCB | General Electric | 60 | Good | 20+ years |
| 51854 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |
| 51853 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |
| 51855 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |

20

| ID | Station | Location | Type | Manufacturer | Age | HI Category | Flagged for Action Year |
|---|---|---|---|---|---|---|---|
| 51856 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |
| 51857 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |
| 55979 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |
| 55980 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |
| 55981 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |
| 55982 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |
| 55983 | 5 | Donald | OCB | General Electric | 58 | Very Good | 20+ years |
| 52774 | 18 | Balsam St. | OCB | General Electric | 57 | Very Good | 20+ years |
| 52779 | 18 | Balsam St. | OCB | General Electric | 57 | Very Good | 20+ years |
| 52780 | 18 | Balsam St. | OCB | General Electric | 57 | Very Good | 20+ years |
| 52783 | 18 | Balsam St. | OCB | General Electric | 57 | Very Good | 20+ years |
| 52786 | 18 | Balsam St. | OCB | General Electric | 57 | Very Good | 20+ years |
| 55560 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| 55565 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| W2090-5 | 9 | Mountdale Ave. | ACB | Pioneer Electric | 45 | Very Good | 20+ years |
| 55561 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| 55563 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| 55570 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| 55559 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| 55562 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| W2090-4 | 9 | Mountdale Ave. | ACB | Pioneer Electric | 45 | Very Good | 20+ years |
| 55564 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| 55566 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| 55567 (SPARE) | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| 55569 | 12 | Camelot St. | ACB | General Electric | 54 | Very Good | 20+ years |
| W2090-1 | 9 | Mountdale Ave. | ACB | Pioneer Electric | 45 | Very Good | 20+ years |
| W2090-2 | 9 | Mountdale Ave. | ACB | Pioneer Electric | 45 | Very Good | 20+ years |
| W2090-3 | 9 | Mountdale Ave. | ACB | Pioneer Electric | 45 | Very Good | 20+ years |
| 1742876 | 11 | High St. | VAC | Square D | 12 | Very Good | 20+ years |
| 1742877 | 11 | High St. | VAC | Square D | 12 | Very Good | 20+ years |
| 1742875 | 11 | High St. | VAC | Square D | 12 | Very Good | 20+ years |
| 1742878 | 11 | High St. | VAC | Square D | 12 | Very Good | 20+ years |
| 1742879 | 11 | High St. | VAC | Square D | 12 | Very Good | 20+ years |

**Table 5.3.2-5 - Kinectrics ACA Summary of Circuit Breakers**

Both circuit breakers and station transformers are highly critical assets and as such, are assessed on an individual basis and a corresponding condition is assigned to each unit. This methodology is typically

THUNDER BAY HYDRO

# 2017 Capital Project Summary

## A. General Information

| | |
|---|---|
| **Project Name** | Cumming-Brodie Voltage Conversion |
| **Project Number** | B1270 |
| **Investment Category** | System Renewal |
| **Capital Investment(s)** | |

| Cumming-Brodie B1270 | **2017** |
|---|---|
| **Capital Cost (5.4.5.2 A.1)** | $580,677 |
| **Capital contribution** | $0 |
| **Net Cost** | $580,677 |
| **O&M Cost (5.4.5.2 A.2)** | $0 |

There are no expected O&M costs associated with this project, as all assets and the work associated with it will be capitalized.

**Customer Attachments and Load (5.4.5.2 A.2)**

Customer Attachments and Load are not expected to change with the execution of this project, however improvements to system components will positively affect the following;
Customer attachments: approximately 421 customers as broken down by customer class below.

| Project | Residential/ Other | General Users | Large Users | Total |
|---|---|---|---|---|
| Cumming- Brodie | 399 | 22 | 0 | 421 |

Load: 351 kWh

| | | | |
|---|---|---|---|
| **Start Date (5.4.5.2 A.3)** | 01-01-17 | **In-Service Date (5.4.5.2 A.3)** | 31-12-17 |

**Expenditure Timing for the Test Year**

| 2017 Q1 | 2017 Q2 | 2017 Q3 | 2017 Q4 |
|---|---|---|---|
| $0 | $ 174,203 | $ 406,474 | $0 |

The Cumming-Brodie project consists of setting poles in 2017. Framing, stringing and services and transformers are to be completed in 2018.

**Project Summary**

This project is a voltage conversion project which will be completed over a 2 year period. Expenditures on pole setting will occur in 2017, and 2018 will include the replacement of 4kV distribution assets with 25kV distribution assets. This project has been prioritized due to the area being fed by Hardisty Substation which has one transformer that is 67 years of age and another that is 63 years of age, which have both been identified as poor condition. Expenditures in 2017 include the installation of 123 poles.

**Risk Identification & Mitigation (5.4.5.2 A.4)**

Scheduling Risk: The projects in this program are subject to scheduling risks with respect to other major projects. All planned capital projects are scheduled for completion in 2017. The mitigation plan for these risks are weekly internal project updates from the Project Manager to review progress and identify action plans to keep construction on schedule. The schedule is built upon the most cost-effective activities occurring in specified seasons. (Pole setting when ground is thawed ) If the projects go off schedule, the probability of cost increases will likely result. This risk is minimized by ensuring that the schedules are realistic and accurate, maintaining communication with crews and supervisors and utilizing contractors to complete concurrent activities, or assist in completing work to meet schedules.

**Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)**

THUNDER BAY HYDRO

# 2017 Capital Project Summary

## A. General Information

| | |
|---|---|
| **Project Name** | Finlayson-Brodie Voltage Conversion |
| **Project Number** | B12135 |
| **Investment Category** | System Renewal |

**Capital Investment(s)**

| Finlayson – Brodie B12135 | **2017** |
|---|---|
| **Capital Cost (5.4.5.2 A.1)** | $893,725 |
| **Capital contribution** | $0 |
| **Net Cost** | $893,725 |
| **O&M Cost (5.4.5.2 A.2)** | $0 |

There are no expected O&M costs associated with this project, as all assets and the work associated with it will be capitalized.

**Customer Attachments and Load (5.4.5.2 A.2)**

Customer Attachments and Load are not expected to change with the execution of this project, however improvements to system components will positively affect the following;

Customer attachments: approximately 234 customers as broken down by customer class below.

| Project | Residential/ Other | General Users | Large Users | Total |
|---|---|---|---|---|
| Finlayson- Brodie | 225 | 9 | 0 | 234 |

Load: 193 kWh

| | | | |
|---|---|---|---|
| **Start Date (5.4.5.2 A.3)** | 01-01-17 | **In-Service Date (5.4.5.2 A.3)** | 31-12-17 |

**Expenditure Timing for the Test Year**

| 2017 Q1 | 2017 Q2 | 2017 Q3 | 2017 Q4 |
|---|---|---|---|
| $0 | $178,745 | $357,490 | $357,490 |

The Finlayson-Brodie project consists of a complete voltage conversion of the project area in 2017.

**Project Summary**

This project is a complete voltage conversion project. Expenditures include the replacement of all 4kV distribution assets with 25kV. The project has been prioritized due to the removal of Hardisty Substation which has one transformer that is 67 years of age and another that is 63 years of age have both been identified as poor condition. The project includes the replacement of 65 poles; reframe of 10 poles, replacement of 16 pole mount transformers and 1 pad mount transformer. The project also targets to replace 4973 m of overhead conductor as part of this project.

**Risk Identification & Mitigation (5.4.5.2 A.4)**

Scheduling Risk: The projects in this program are subject to scheduling risks with respect to other major projects. All planned capital projects are scheduled for completion in 2017. The mitigation plan for these risks are weekly internal project updates from the Project Manager to review progress and identify action plans to keep construction on schedule. The schedule is built upon the most cost-effective activities occurring in specified seasons. (Pole setting when ground is thawed, pad mount transformers for schools in the summer months, ect) If the projects go off schedule, the probability of cost increases will likely result. This risk is minimized by ensuring that the schedules are realistic and accurate, maintaining communication with crews and supervisors and utilizing contractors to complete concurrent activities, or assist in completing work to meet schedules.

**Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)**

# Scorecard - Thunder Bay Hydro Electricity Distribution Inc.

9/29/2016

| Performance Outcomes | Performance Categories | Measures | | 2011 | 2012 | 2013 | 2014 | 2015 | 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 | | 99.80% | 99.10% | 99.80% | 100.00% | 99.90% | up | 90.00% | |
| | | Scheduled Appointments Met On Time | | 91.90% | 99.60% | 97.80% | 100.00% | 99.90% | up | 90.00% | |
| | | Telephone Calls Answered On Time | | 91.80% | 90.10% | 91.80% | 87.10% | 92.40% | down | 65.00% | |
| | **Customer Satisfaction** | First Contact Resolution | | | | | A+ | A+ | | | |
| | | Billing Accuracy | | | | | 99.97% | 99.93% | down | 98.00% | |
| | | Customer Satisfaction Survey Results | | | | | A | A | | | |
| **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 | | | | | | 82.00% | | | |
| | | Level of Compliance with Ontario Regulation 22/04 [1] | | C | C | C | C | C | flat | | C |
| | | Serious Electrical Incident Index | Number of General Public Incidents | 0 | 0 | 0 | 0 | 0 | flat | | 0 |
| | | | Rate per 10, 100, 1000 km of line | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | flat | | 0.000 |
| | **System Reliability** | Average Number of Hours that Power to a Customer is Interrupted [2] | | 2.77 | 1.28 | 1.03 | 1.92 | 2.02 | up (target not met) | | 1.92 |
| | | Average Number of Times that Power to a Customer is Interrupted [2] | | 3.65 | 3.12 | 2.02 | 2.69 | 2.39 | down | | 3.03 |
| | **Asset Management** | Distribution System Plan Implementation Progress | | | | | On track | On-track | | | |
| | **Cost Control** | Efficiency Assessment | | | 3 | 3 | 3 | 3 | | | |
| | | Total Cost per Customer [3] | | $577 | $568 | $585 | $606 | $635 | | | |
| | | Total Cost per Km of Line [3] | | $24,196 | $24,533 | $25,631 | $26,864 | $27,195 | | | |
| **Public Policy Responsiveness** Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board). | **Conservation & Demand Management** | Net Cumulative Energy Savings [4] | | | | | | 10.92% | | | 48.42 GWh |
| | **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% | 100.00% | flat | 90.00% | |
| **Financial Performance** Financial viability is maintained; and savings from operational effectiveness are sustainable. | **Financial Ratios** | Liquidity: Current Ratio (Current Assets/Current Liabilities) | | 1.85 | 1.72 | 1.62 | 1.85 | 1.61 | | | |
| | | Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio | | 0.86 | 0.81 | 0.66 | 0.72 | 0.75 | | | |
| | | Profitability: Regulatory Return on Equity | Deemed (included in rates) | 3.75% | 3.75% | 7.00% | 7.00% | 7.00% | | | |
| | | | Achieved | 7.24% | 7.74% | 6.34% | 5.99% | 5.69% | | | |

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

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

detailed these benefits and attributed costs in their report published in 2006. The list as it pertains to Thunder Bay Hydro grid modernization initiatives is as follows:

- Reduction in forced outages/interruptions,
- Reduction in restoration time and reduced operations and maintenance due to predictive analytics and self-healing attribute of the grid,
- Other benefits due to self-diagnosing and self-healing,
- Increased integration of distributed generation resources and higher capacity utilization,
- Power quality, reliability, and system availability and capacity improvement due to improved power flow,
- Environmental benefits gained by increased asset utilization.

## 3.2 Benefits to Customers

Thunder Bay Hydro's reliability trend indicates that the average number of hours and average number of times that a customer is interrupted has declined from 2010 to 2015 (See Figure 1 and Figure 2).

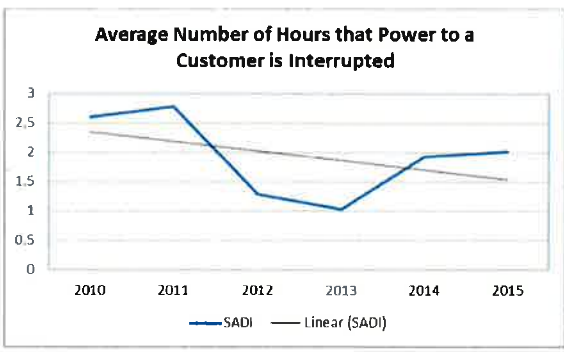



Figure 1- 2010-2015 Average Hours of Interruptions[2]

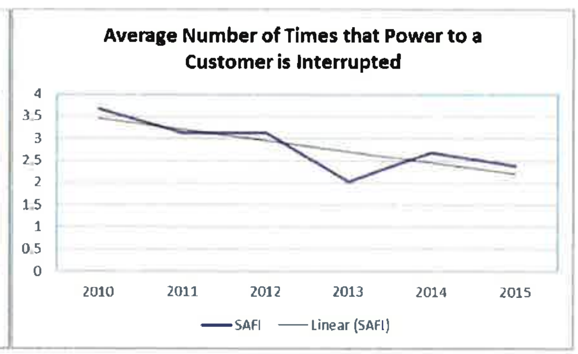



Figure 2- 2010-2015 Average Number of Interruptions

While this trend indicates improvement, Thunder Bay Hydro continues to strive for enhanced quality of service and is listening to its customers input on outage issues and intends to provide its customers with better visibility and more timely information related to outages. Apart from the benefits to the LDC, there are specific advantages to customers that a grid modernization initiative will deliver. Installing devices with sensing technologies will provide

[2] Ontario Energy Board, Thunder Bay Hydro Scorecard 2014, retrieved on May 17, 2016 from http://www.ontarioenergyboard.ca

- **Component C – Serious Electrical Incident Index – Distributor Target Met**

The Serious Electrical Incident Index component of the public safety measure is intended to address the consequential impact of improving public electrical safety on the distribution networks over time. It measures the number and rate of serious electrical incidents occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line. Both the number of general public incidents and the rate per km of line are shown on the scorecard.

Thunder Bay Hydro's Serious Electrical Incident Index in 2015 is "0.0". Historical data related to this measure has been tracked by Thunder Bay Hydro and the Electrical Safety Authority, and Thunder Bay Hydro is proud that there are no such incidents to report for the years 2011-2015.

## System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted 'SAIDI' – Distributor Target Not Met**

System Average Interruption Duration Index 'SAIDI' is an indicator of system reliability that expresses the length of interruptions that customers experience in a year on average. All planned and unplanned sustained interruptions should be used to calculate this index. SAIDI is defined as the total customer hours of sustained interruption normalized per customer served. Thunder Bay Hydro's reliability statistic for the average number of hours that power to a customer is interrupted increased from 1.92 in 2014 to 2.02 in 2015, a change of 0.10.

This average duration of outages is often due to severity of weather events. However, In 2015 Thunder Bay Hydro's customer hours of interruption (excluding loss of supply to distributor) increased from 96,651 to 102,090, a total increase of 5,439. Overall Thunder Bay Hydro customers experienced a decrease of 30 total outage events during the 2015 year. Specific decreases in events can be traced to less scheduled outages for maintenance and capital work, as well as less unscheduled outages related to tree contact with distribution equipment that causes power outages. Thunder Bay Hydro has been focused on a preventative outage program that plans a more aggressive vegetation management to combat extreme weather.

In 2014 Thunder Bay Hydro experienced a total of 12 significant influencing statistic outage events, whereas in 2015 there are 24 significant outage events. These events were primarily in the month of December, and were the highest contributor to an increase of customer hours of interruption affecting the most customers.

## 2-Staff-34

Ref: App. 2 – DSP – S 5.2.3.2: Summary of Performance over the Historical Period. Summary of Operational Effectiveness Measures – IV. System Reliability Indicators, p. 42

At the above reference, the following table is shown:

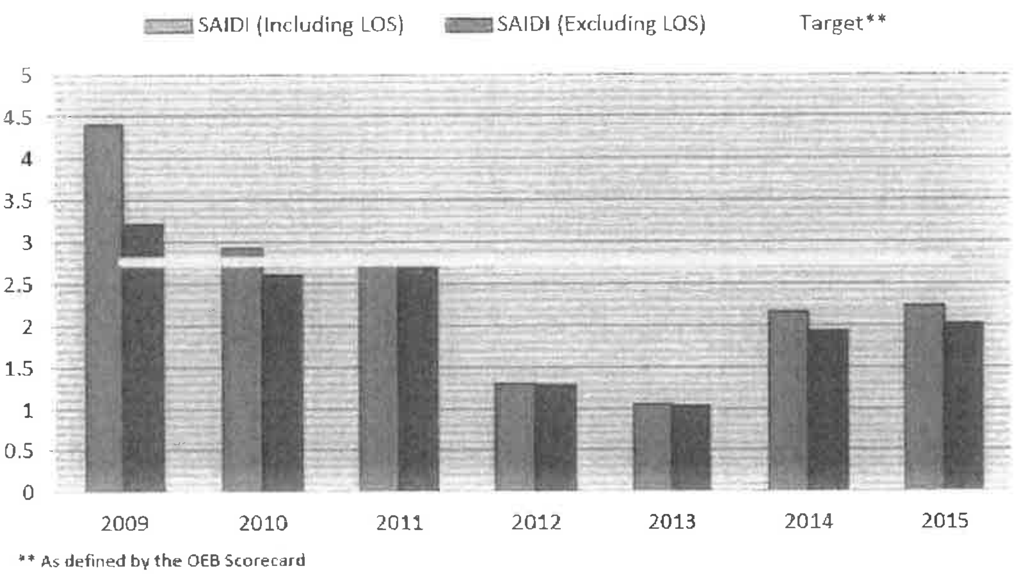



**Figure 5.2.3-2 Historical SAIDI Performance**

a) Please explain the reasons for the comparatively high SAIDI in 2009.
b) Please explain the reasons for the step improvement in SAIDI from 2011 to 2012.
c) Please explain the reasons for the increase in SAIDI from 2012 & 2013 to 2014 & 2015.

### Thunder Bay Hydro Response:

a) High SAIDI in 2009 was attributable to a windstorm we had on September 28 and a significant Loss of Supply event at Hydro One's FWTS in October.

b) 2011 to 2012 had less significantly sized outages due to fewer weather related outage events.

c) 2012 and 2013 had less significantly sized outages due to fewer weather related outage events.

2014 and 2015 could be considered a more "normal" year with regard to the number of significant weather related outage events.

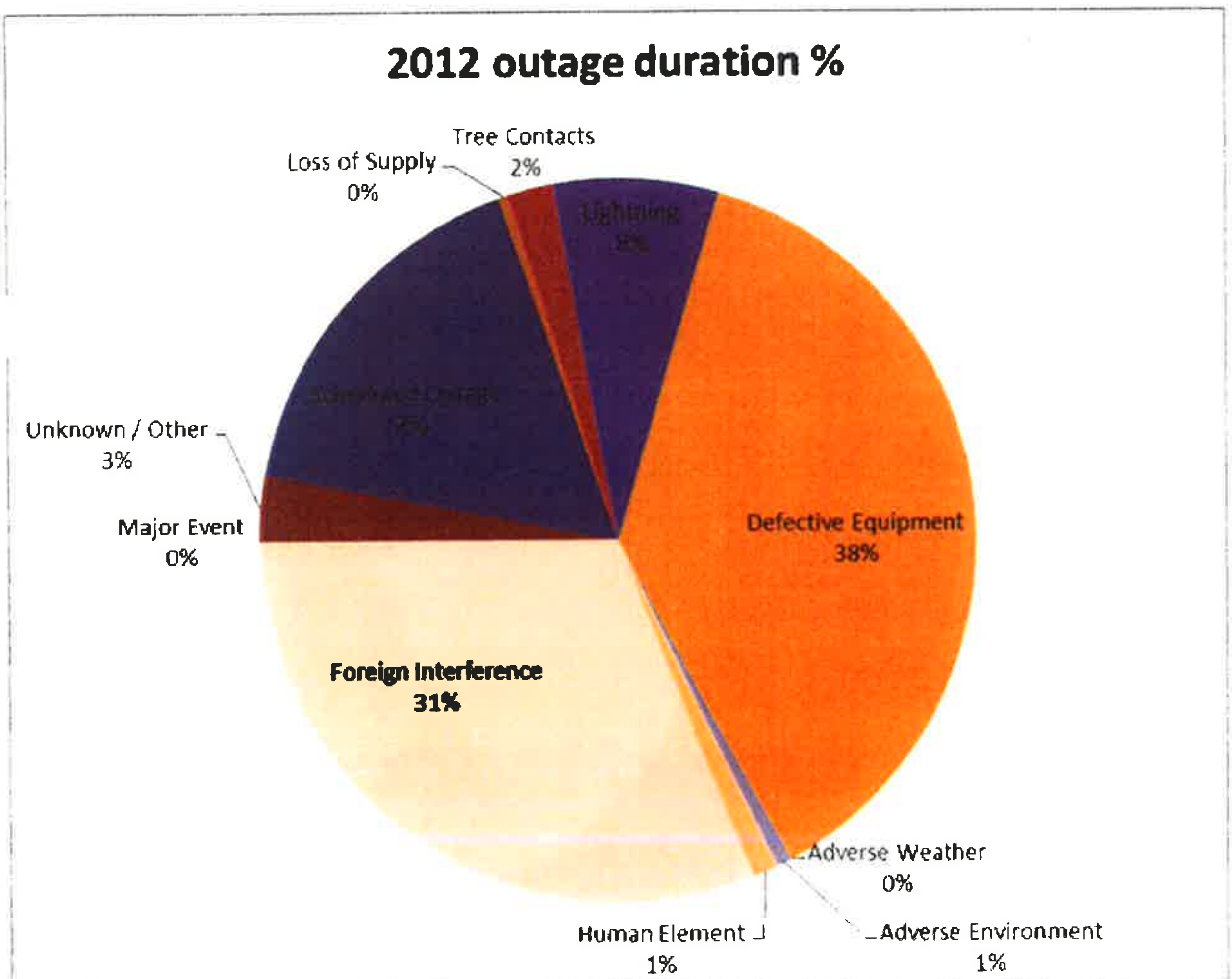
## AMPCO-6

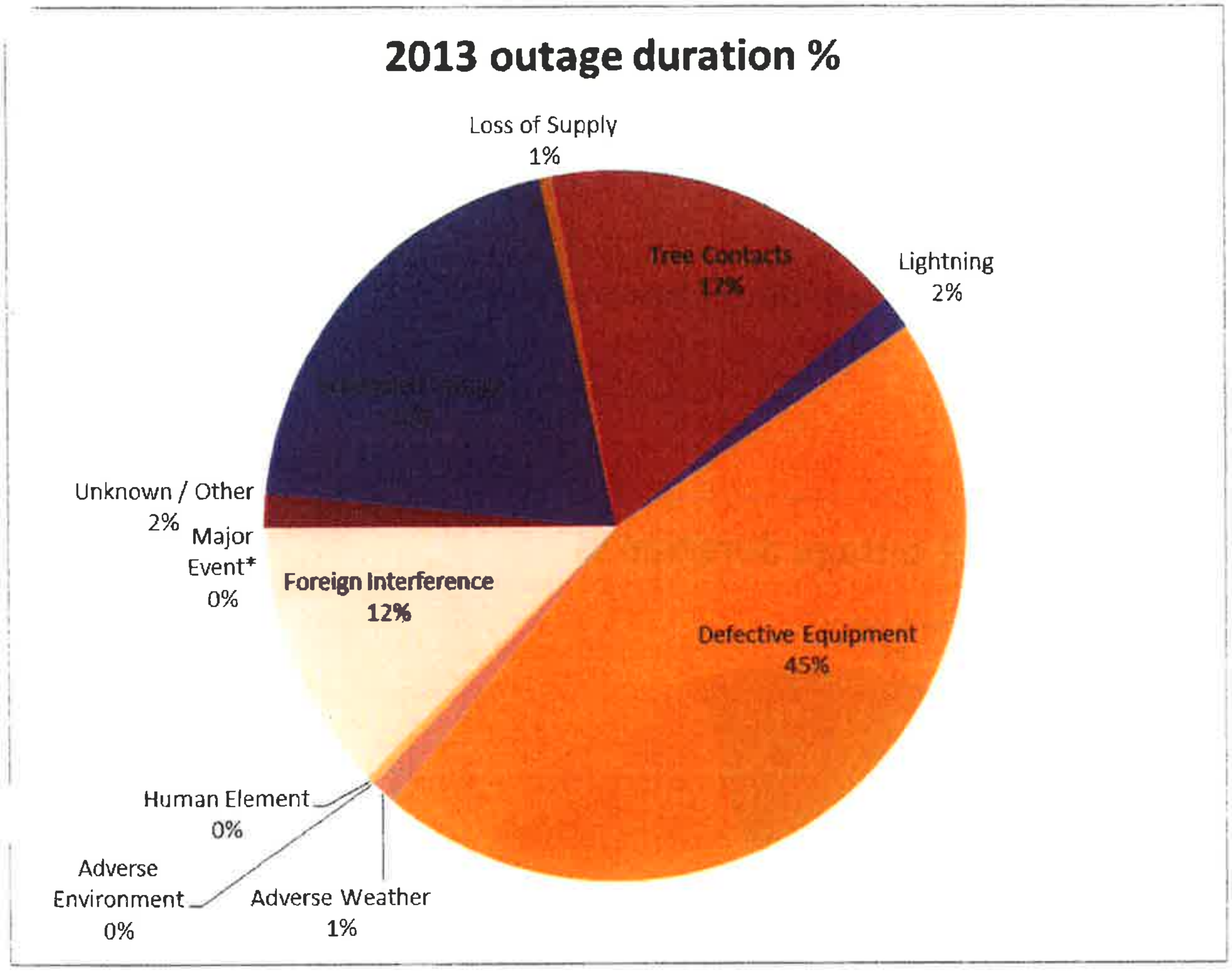
Ref: Appendix 2-B DSP Page 44

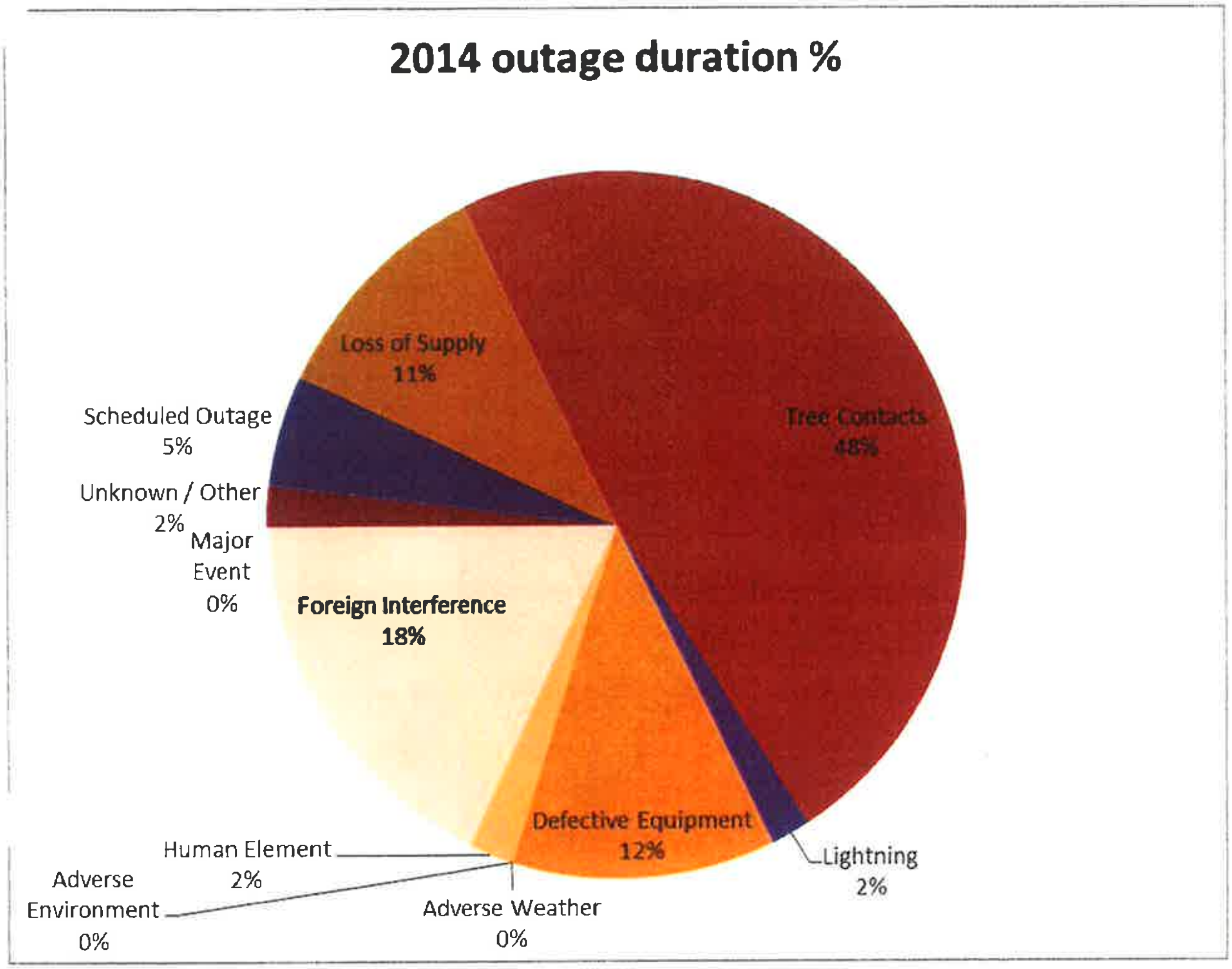
a) Figure 5.2.3-5 Outage Causes by Duration: Please provide Figure 5.2.3-5 separately for each of the following years: 2012, 2013, 2014, and 2015.

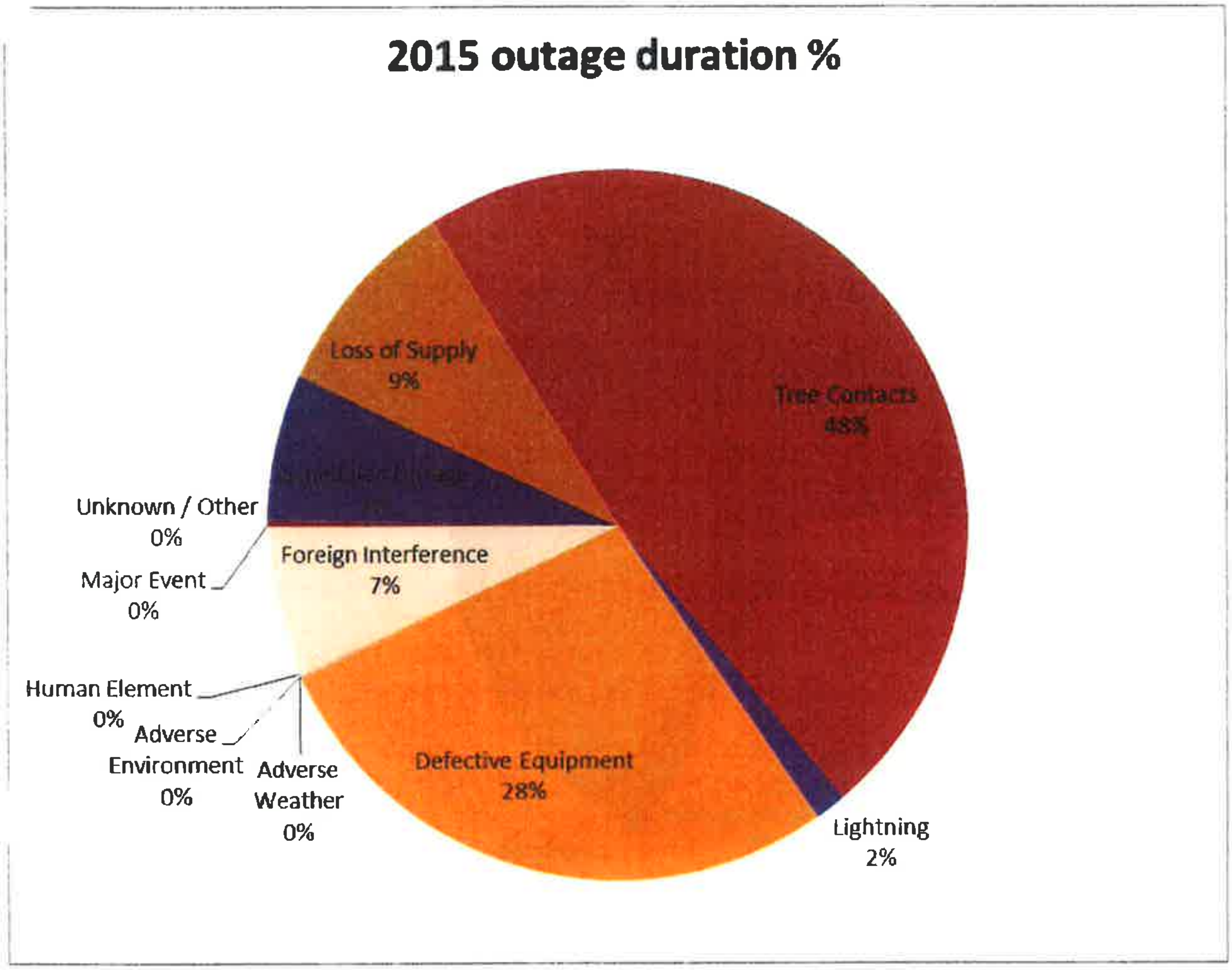
b) Please provide a Figure that shows the Outage Causes by Duration for 2016.

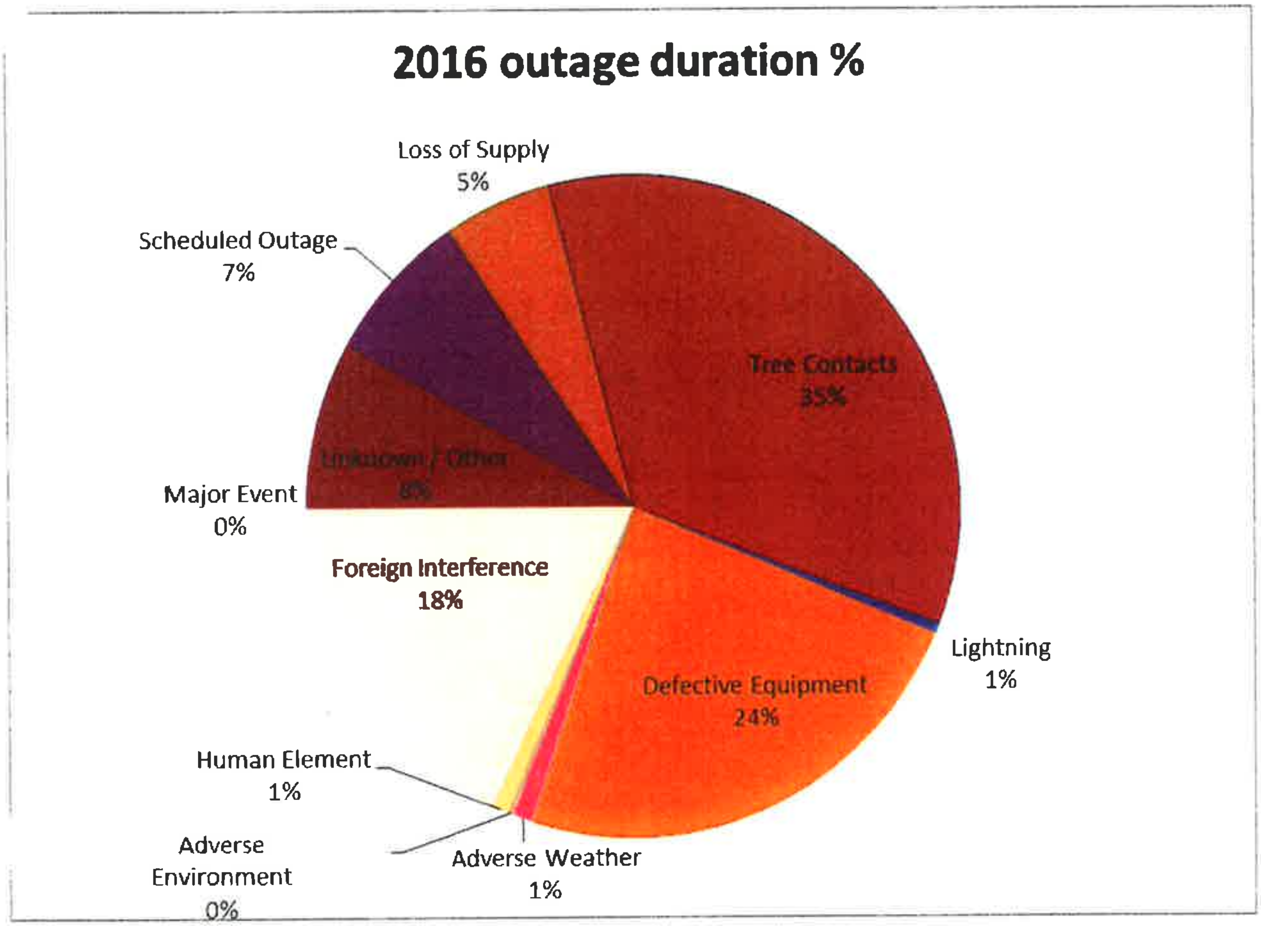
### Thunder Bay Hydro Response:




2013 outage duration %
Loss of Supply
1%
Tree Contacts
17%
Lightning
2%
Unknown / Other
2%
Major
Event*
0%
Foreign Interference
12%
Defective Equipment
45%
Human Element
0%
Adverse
Environment
0%
Adverse Weather
1%


2014 outage duration %
Loss of Supply
11%
Tree Contacts
48%
Scheduled Outage
5%
Unknown / Other
2%
Major
Event
0%
Foreign Interference
18%
Defective Equipment
12%
Lightning
2%
Human Element
2%
Adverse
Environment
0%
Adverse Weather
0%


2015 outage duration %
Loss of Supply
9%
Tree Contacts
48%
Unknown / Other
0%
Foreign Interference
7%
Major Event
0%
Human Element
0%
Adverse
Environment
0%
Adverse
Weather
0%
Defective Equipment
28%
Lightning
2%


2016 outage duration %
Loss of Supply 5%
Scheduled Outage 7%
Tree Contacts 35%
Unknown / Other
Major Event 0%
Foreign Interference 18%
Lightning 1%
Defective Equipment 24%
Human Element 1%
Adverse Environment 0%
Adverse Weather 1%

**2-VECC-13**

Reference: E2/Appendix 2-B/ DSP/pg.74

a) Please provide a table which shows the number of 25kv poles that have been or are planned for replacement in each year 2012 through 2021.
b) Please add a row for each year showing the cost for 25kv pole replacement in each year.
c) At page 74 of the DSP it states that 10% or 2084 poles are in Very Poor (238) or Poor (1846) condition. Please add another row which shows for each year the number of poles at year end (i.e. after of that year's capital plan) that are forecast to be in either very poor or poor condition.
d) Please provide the same a) through c) for 4kV poles.

## THUNDER BAY HYDRO UPDATED RESPONSE

**Number of 25kV poles planned for replacement**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Quantity** | 69 | 88 | 92 | 162 | 133 | 193 | 330 | 380 | 380 | 395 |
| **Cost** | $870,981 | $882,720 | $844,977 | $1,515,734 | $1,112,348 | $1,688,730 | $3,181,429 | $3,798,667 | $3,885,973 | $3,923,693 |
| **Very Poor** | n/a | n/a | n/a | n/a | 101 | 13 | 0 | 0 | 0 | 0 |
| **Poor** | n/a | n/a | n/a | n/a | 1014 | 910 | 604 | 227 | 254 | 572 |

**Number of 4kV poles planned for replacement**

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Quantity** | 391 | 375 | 444 | 381 | 461 | 385 | 197 | 183 | 195 | 222 |
| **Cost** | $5,628,491 | $4,562,253 | $4,400,255 | $4,330,290 | $5,235,419 | $5,367,788 | $3,924,167 | $2,948,334 | $2,991,666 | $3,000,000 |
| **Very Poor** | n/a | n/a | n/a | n/a | 136 | 0 | 0 | 0 | 0 | 0 |
| **Poor** | n/a | n/a | n/a | n/a | 832 | 583 | 396 | 215 | 83 | 37 |

## 2-Staff-39

Ref: App. 2 – DSP – S 5.3.1.3: Asset Management Strategy, C. Process– ii. Asset Condition Assessment, pp. 60-61

At the above reference, it is stated that:

> Traditionally, Thunder Bay Hydro has utilized the average age of its assets as an indicator of health of its assets; and more broadly, average age of its wood poles as a proxy for overall system health. Utilizing a TUL of 50 years for its wood poles, Thunder Bay Hydro targeted an average age of 25 years for this asset population. Through detailed analysis, Thunder Bay Hydro determined that 700 poles are required to be replaced annually to obtain a half-year reduction in age over the same period. This 700 pole replacement target accounts for approximately 70% of Thunder Bay Hydro's system renewal budget annually.

a) Please provide the justification for Thunder Bay Hydro to pursue the proposed accelerated pole replacement program in terms of expected improvement in system performance indices (SAIDI, SAIFI, CAIDI).
b) Please provide detailed calculations showing the need for 700 poles to be replaced annually to obtain a half-year reduction in age over the same period.

**Thunder Bay Hydro Response:**

(a) Thunder Bay Hydro cannot justify the accelerated pole replacement program in terms of SAIDI, SAIFI, and CAIDI as these are not the primary drivers for the accelerated replacement program.

(b) The example that follows details how 700 poles yields a half year reduction in age annually.

ıble III-1 Health Index Results Summary

| Asset Category | | Population | Sample Size | Average Health Index | Average Age | Health Index Distribution: Very Poor (< 25%) | Poor (25 - <50%) | Fair (50 - <70%) | Good (70 - <85%) | Very Good (>= 85%) | Average Age |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Station Transformers | All | 23 | 23 | 88% | 52 | 0 | 1 | 2 | 1 | 19 | 52 |
| | 4 kV | 17 | 17 | 86% | 54 | 0 | 1 | 1 | 2 | 13 | 54 |
| | 12 kV | 6 | 6 | 94% | 47 | 0 | 0 | 0 | 0 | 6 | 47 |
| Breakers | Breakers | 77 | 77 | 72% | 56 | 0 | 14 | 18 | 9 | 36 | 56 |
| * Wood Poles | All | 19813 | 19813 | 75% | 28 | 238 | 1846 | 6816 | 4121 | 6792 | 28 |
| | 4 kV | 3862 | 3862 | 63% | 36 | 136 | 832 | 1499 | 802 | 593 | 36 |
| | 25 kV | 15951 | 15951 | 77% | 27 | 83 | 925 | 5207 | 3392 | 6345 | 27 |
| Distribution Transformers | Pad Mounted Transformers | 2206 | 2206 | 87% | 25 | 13 | 29 | 73 | 380 | 1711 | 25 |
| | Pole Mounted Transformers | 4143 | 4141 | 81% | 29 | 202 | 137 | 144 | 155 | 3505 | 29 |
| | Vault Transformers | 285 | 285 | 78% | 33 | 17 | 8 | 42 | 79 | 139 | 33 |
| OH Switches | All | 729 | 305 | 76% | 32 | 100 | 38 | 69 | 86 | 435 | 32 |
| | 4kV In-Line | 101 | 46 | 71% | 32 | 26 | 0 | 9 | 11 | 55 | 32 |
| | 4kV Manual Air Break | 7 | 2 | 70% | 32 | 0 | 4 | 0 | 0 | 4 | 32 |
| | 12 and 25kV In-Line | 399 | 148 | 80% | 31 | 43 | 27 | 19 | 32 | 278 | 31 |
| | 12 and 25kV Manual Air Break | 183 | 74 | 78% | 33 | 25 | 7 | 12 | 17 | 121 | 33 |
| | 25kV Motorized Load Break | 39 | 10 | 67% | 39 | 4 | 8 | 8 | 4 | 16 | 39 |
| Underground Switches | 25kV Underground Load Break Switches | 80 | 30 | 81% | 31 | 0 | 10 | 14 | 2 | 54 | 31 |
| Underground Cables* | All | 432 | 374 | 80% | 29 | 13 | 12 | 133 | 16 | 259 | 29 |
| | 4kV | 44 | 29 | 44% | 43 | 15 | 6 | 9 | 0 | 14 | 43 |
| | 12 and 25kV | 387 | 344 | 84% | 28 | -4 | 8 | 124 | 15 | 244 | 28 |

b) and c) Asset quantities planned for replacement and completed by asset category in each of the years 2012 through to 2021 under all programs are listed below.

| | Station Transformers | | Breakers | Wood Poles | | Distribution Transformers | | | OH Switches | Underground Switches | Underground Cables | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 4 kV | 12 kV | Breakers | 4 kV | 25 kV | Pad Mounted Transformers | Pole Mounted Transformers | Vault Transformers | All | 25kV Underground Load Break Switches | 4kV | 12 and 25kV |
| 2012 | 0 | 0 | 0 | 391 | 69 | 29 | 49 | 3 | n/a | 0 | 0 | 0 |
| 2013 | 0 | 0 | 0 | 375 | 88 | 18 | 78 | 11 | n/a | 0 | 0 | 0.34 |
| 2014 | 0 | 0 | 0 | 444 | 92 | 15 | 86 | 12 | n/a | 0 | 0 | 2.2 |
| 2015 | 0 | 0 | 0 | 381 | 162 | 49 | 106 | 7 | n/a | 0 | 0 | 2.2 |
| 2016 | 0 | 0 | 0 | 461 | 133 | 52 | 109 | 9 | 30 | 0 | 0 | 0.96 |
| 2017 | 0 | 0 | 0 | 385 | 193 | 75 | 171 | 3 | 40 | 0 | 1 | 1.4 |
| 2018 | 0 | 0 | 0 | 185 | 362 | 53 | 171 | 9 | 25 | 1 | 1 | 3.2 |
| 2019 | 0 | 0 | 0 | 137 | 426 | 44 | 170 | 3 | 25 | 1 | 1 | 5.2 |
| 2020 | 0 | 0 | 0 | 142 | 433 | 44 | 170 | 9 | 25 | 1 | 1 | 5.6 |
| 2021 | 0 | 0 | 0 | 122 | 435 | 44 | 171 | 3 | 25 | 1 | 1 | 5.2 |

n/a = quantities of these assets were not tracked in these years

The ACA is the process by which the condition of an asset is determined based on known characteristics of the asset as well as the condition data that has been collected during inspection. Thunder Bay Hydro engages a third party contractor (Kinectrics) to perform the detailed analysis of its assets. The methodology consists of creating a health index for each asset whereby condition scores are assigned to weighted categories unique to each asset class. Failure rates are then applied to each asset based on expert knowledge and industry averages. The result of this is a quantitative distribution for each asset category based on the 'health' of the individual assets in the category. The graphical representation of this, a stacked horizontal bar chart, allows for the easy identification of assets that are in poor health as a percentage of the population.

Health Index (HI) is a composite quantitative measure of an asset's condition based on available condition data (testing, inspections, utilization, expert opinion, age, etc.). The purpose of HI is to identify a subset of assets within the total population which require action. There are fundamentally 2 groups of assets:

1. Reactively replaced, i.e. run to failure with only replacement available as an action. For these assets the objective of the condition assessment was to predict what percentage of the population Thunder Bay Hydro needs to worry about over the next several years. For reactively replaced assets it is assumed that the consequence of failure is the same for each unit and specific units are not identified for action, rather percentage of the total population. The probability of failure is related to the HI and used in conjunction with the demographics to estimated number of units that are expected to fail each year. The probability curve was generated using typical and extreme lives of assets in each category to estimate number of units (rather than specific units) that are expected to fail. Even "young" assets with low probability of failure contribute to the overall estimate since even some of the recently installed assets may fail while not all of the "old" assets will.

2. Proactively replaced assets are usually replaced/refurbished/repaired before they fail based on the on their overall risk, which is a combination of probability of failure and consequence of failure, estimated using criticality. This is done for specific units and they are marked for action once a threshold risk score or probability of failure levels is exceeded.

An overview of the strategy that Thunder Bay Hydro employs within each category is listed below.

| ASSET CATEGORY | OPERATING STRATEGY |
|---|---|
| Power Transformers | Proactive Maintenance |
| Circuit Breakers | Proactive Maintenance |
| Wood Poles | Reactive Maintenance |
| Padmount Transformers | Reactive Maintenance |
| Pole Mounted Transformers | Reactive Maintenance |
| Vault Transformers | Reactive Maintenance |
| Overhead Switches | Reactive Maintenance |
| Underground Switches | Reactive Maintenance |

| | |
|---|---|
| Underground Primary | Reactive Maintenance |
| Reclosers | Reactive Maintenance |
| Metering | Reactive Maintenance |
| Overhead Primary Conductor | Reactive Maintenance |
| Underground Secondary Cable | Reactive Maintenance |
| Underground Secondary Cable | Reactive Maintenance |

**Table 5.3.1-3 Thunder Bay Hydro Asset Operating Strategy**

Engaging Kinectrics has produced a shift in thinking at Thunder Bay Hydro from an age based to a condition based asset condition assessment, which has resulted in a more optimized asset management plan, replacing only those assets which are at end of life.

The output of this process is a quantitative listing of assets that are targeted for action annually. This information becomes an input into the risk analysis phase.

Outputs:

- Asset Condition Report – the report provides information regarding; the expected levelized renewal targets by asset class, asset condition by category and identifies gaps in data to assist in the continual improvement of the asset management process.

iii. Reliability Risk/Consequence Assessment

Inputs:

- GIS System – GIS provides the means to divide Thunder Bay Hydro's service territory into project areas for assessment. The GIS system also provides the geospatial information for our assets as well as information regarding the physical conditions surrounding our assets which aids in the analysis of potential safety, environmental or accessibility concerns. Utilizing this system Thunder Bay Hydro is able to quantify and summarize all of the assets located in a project area.
- Asset Condition Data – Thunder Bay Hydro utilizes the above asset condition data and input from subject matter experts to determine the likelihood of failure of various asset types. This, in conjunction with the consequences of failure determines the risk posed by an asset or group of assets.
- Asset Capacity Utilization / Constraint Assessment – Thunder Bay Hydro considers utilization and constraints of its assets during risk analysis phase as well during the design phase of projects. Considerations include load forecasts for service territory, feeder loading levels as well as asset loading levels. For example, the utilization of existing transformers in a project area will be analyzed to determine if current sizing corresponds to current and proposed future utilization as a means to appropriately size the units.

Process:

## ER -VECC -6

Ref: ACA/pg. 16 Table III-2

a) For each asset category please provide a comparison of Table III-2 10 year levelized Flagged for Action Plan in the ACA with TBH's capital expenditure proposals for 2017 through 2021.

b) Given the ACA is based on 2015 data please explain how 2016 actual capital expenditures are being considered in the response to a).

c) For each asset category please provide both the quantity of assets TBH has or proposes to replace in 2016 and 2017 and provide a comparison to the first year amount flagged in the ACA action plan. Please comment on any differences.

d) Please provide the change in reliability risk if TBH were to replace the number of assets recommended but equally over 10 years.

e) Table III-2 generally shows a larger quantity of asset replacements in year 1 then would be the case if assets were replaced on as an equal amount over the ten years. Please explain why and what difference would occur if TBH replaced a greater number of assets in 2 or 3, rather than year one of its capital plan. That is how does altering the pace of asset replacement affect reliability?

### THUNDER BAY HYDRO RESPONSE

The Ontario Energy Board stated in Procedural Order No. 5 that (**emphasis added**):

> "Intervenors shall request any relevant information and documentation from Thunder Bay Hydro on **the new expert report only**, by written interrogatories filed with the OEB and served on all parties by June 2, 2017."

VECC does not cite the new expert report in this interrogatory. Rather VECC's questions relate solely to the ACA. The ACA has been on the evidentiary record, and all parties including VECC have had ample opportunity to ask questions about it. It is

Thunder Bay Hydro submits that this interrogatory is in breach of the procedural directions of the Board in Procedural Order No. 5.

Despite this, to the extent additional information may be of assistance to the Ontario Energy Board in its decision making on this case, and to avoid further procedural delays, Thunder Bay Hydro has asked that Kinectrics provide a response to this interrogatory.

a) While preparing the response to this interrogatory TBH discovered an error in Table III-2. Specifically, the spreadsheet used to calculate the 10 year FFAP included an incorrect cell reference. Attached below are the corrections provided by Kinectrics to fix for that error.

TBH believes that its DSP is not affected based on the results of this table as the error only affected the last two years of the 10 year levelized quantities and the DSP only encompasses the first 5 years of levelized planning. Therefore there are no further revisions to be made as a result of the error in this table.

The below amended Table III-2 from the Kinectrics ACA contains both Kinectrics proposed levelized plan and Thunder Bay Hydro's proposed plans in response to this IR.

| Asset Category | | 10 Year LEVELIZED Flagged for Action Total | | | | TBH Proposed First Year (2017) Quantity | TBH Proposed 10 Year (2017-2027) Quantity |
|---|---|---|---|---|---|---|---|
| | | First Year | | 10 Year | | | |
| | | Quantity | Percentage | Quantity | Percentage | | |
| Substation Transformers | 4 kV Secondary Transformers | 0 | 0% | 4 | 24% | 0 | 0 |

| Asset Category | | 10 Year LEVELIZED Flagged for Action Total | | | | TBH Proposed First Year (2017) Quantity | TBH Proposed 10 Year (2017-2027) Quantity |
|---|---|---|---|---|---|---|---|
| | | First Year | | 10 Year | | | |
| | | Quantity | Percentage | Quantity | Percentage | | |
| | 12 kV Secondary Transformers | 0 | 0% | 0 | 0% | 0 | 0 |
| **Circuit Breakers** | Circuit Breakers | 0 | 0% | 14 | 18% | 0 | 0 |
| **Wood Poles** | 4 kV Wood Poles | 232 | 6% | 1815 | 48% | 385 | 1849 |
| | 25 kV Wood Poles | 460 | 3% | 4390 | 30% | 193 | 4242 |
| **Distribution Transformers** | Pad Mounted Transformers | 44 | 2% | 262 | 12% | 75 | 302 |
| | Pole Mounted Transformers | 171 | 4% | 1048 | 25% | 171 | 1046 |
| | Vault Transformers | 10 | 4% | 110 | 39% | 3 | 91 |
| **Overhead Switches** | 4kV In-Line OH Switches | 3 | 3% | 37 | 37% | 20 | 72 |
| | 4kV Manual Air Break OH Switches | 0 | 0% | 7 | 100% | 10 | 17 |
| | 12 and 25kV In-Line OH Switches | 15 | 4% | 99 | 25% | 5 | 59 |
| | 12 and 25kV Manual Air Break OH Switches | 5 | 3% | 39 | 21% | 5 | 37 |
| | 12 and 25kV Motorized Load Break OH Switches | 2 | 5% | 22 | 56% | 0 | 19 |
| **Underground Switches** | 25kV Underground Load Break Switches | 1 | 1% | 17 | 21% | 0 | 16 |
| **Underground Cables*** | 4kV UG Cables | 1 | 2% | 11 | 25% | 1 | 11 |
| | 12 and 25kV UG Cables | 6 | 2% | 71 | 18% | 1.4 | 62.6 |

c) The below table provides a 2016 Thunder Bay Hydro actual replacements and 2017 proposed replacements as well as a comparison of the Kinectrics Levelized Replacement Target for year 0. There are differences in the split between 4kV and 25kV wood poles due to the completion of several 4kV conversion projects work-in-progress prior to alignment in 2019. In addition there are differences in the number of pad mounted distribution transformers and overhead switches planned for replacement or removal due to their functional obsolescence in 4kV projects.

| | 4 kV | 12 kV | Breakers | 4 kV | 25 kV | Pad Mounted Transformers | Pole Mounted Transformers | Vault Transformers | 4kV In-Line | 4kV Manual Air Break | 12 and 25kV In-Line | 12 and 25kV Manual Air Break | 25kV Motorized Load Break | 25kV Underground Load Break Switches | 4kV | 12 and 25kV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2016 TBH Actual Replacements | 0 | 0 | 0 | 461 | 133 | 52 | 109 | 9 | 12 | 0 | 12 | 6 | 0 | 0 | 0 | 0.96 |
| 2017 Kinectrics Levelized Replacement Target (Yr0) | 0 | 0 | 0 | 232 | 460 | 44 | 171 | 10 | 3 | 0 | 15 | 5 | 2 | 1 | 1 | 6 |
| 2017 TBH Replacement Target | 0 | 0 | 0 | 385 | 193 | 75 | 171 | 3 | 7 | 2 | 5 | 5 | 0 | 0 | 1 | 1.4 |

## KINECTRICS RESPONSE

a) Below is the corrected Table III-2 Total Year 1 and 10-Year Total Flagged for Action Plan.

| Asset Category | | 10 Year Flagged for Action Total | | | | 10 Year LEVELIZED Flagged for Action Total | | | | Replacement Strategy |
|---|---|---|---|---|---|---|---|---|---|---|
| | | First Year | | 10 Year | | First Year | | 10 Year | | |
| | | Quantity | Percentage | Quantity | Percentage | Quantity | Percentage | Quantity | Percentage | |
| Substation Transformers | 4 kV Secondary Transformers | 0 | 0% | 4 | 24% | 0 | 0% | 4 | 24% | proactive |
| | 12 kV Secondary Transformers | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | proactive |
| Circuit Breakers | Circuit Breakers | 0 | 0% | 14 | 18% | 0 | 0% | 14 | 18% | proactive |
| Wood Poles | 4 kV Wood | 364 | 9% | 1865 | 48% | 232 | 6% | 1815 | 47% | proactive |

| Asset Category | | 10 Year Flagged for Action Total | | | | 10 Year LEVELIZED Flagged for Action Total | | | | Replacement Strategy |
|---|---|---|---|---|---|---|---|---|---|---|
| | | First Year | | 10 Year | | First Year | | 10 Year | | |
| | | Quantity | Percentage | Quantity | Percentage | Quantity | Percentage | Quantity | Percentage | |
| | Poles | | | | | | | | | |
| | 25 kV Wood Poles | 544 | 3% | 4807 | 30% | 460 | 3% | 4390 | 28% | proactive |
| Distribution Transformers | Pad Mounted Transformers | 204 | 9% | 254 | 12% | 44 | 2% | 262 | 12% | proactive |
| | Pole Mounted Transformers | 625 | 15% | 1049 | 25% | 171 | 4% | 1048 | 25% | reactive |
| | Vault Transformers | 14 | 5% | 116 | 41% | 10 | 4% | 110 | 39% | reactive |
| Overhead Switches | 4kV In-Line OH Switches | 3 | 3% | 41 | 41% | 3 | 3% | 37 | 37% | reactive |
| | 4kV Manual Air Break OH Switches | 0 | 0% | 4 | 57% | 0 | 0% | 7 | 100% | reactive |
| | 12 and 25kV In-Line OH Switches | 30 | 8% | 95 | 24% | 15 | 4% | 99 | 25% | reactive |
| | 12 and 25kV Manual Air Break OH Switches | 20 | 11% | 41 | 22% | 5 | 3% | 39 | 21% | reactive |
| | 12 and 25kV Motorized Load Break OH Switches | 0 | 0% | 16 | 41% | 2 | 5% | 22 | 56% | reactive |
| Underground Switches | 25kV Underground Load Break Switches | 0 | 0% | 15 | 19% | 1 | 1% | 17 | 21% | reactive |
| Underground Cables | 4kV UG Cables | 2 | 5% | 5 | 11% | 1 | 2% | 11 | 25% | reactive |
| | 12 and 25kV UG Cables | 4 | 1% | 75 | 19% | 6 | 2% | 71 | 18% | reactive |

b) ACA was based on the input data/information as of the end of 2015 and is a snap shot in time aimed at assisting with the annual budgeting process. 2016 replacement were not considered in the ACA study.

c) This strikes a balance between dealing with a backlog of assets in the FFAP while mitigating impact on rates.

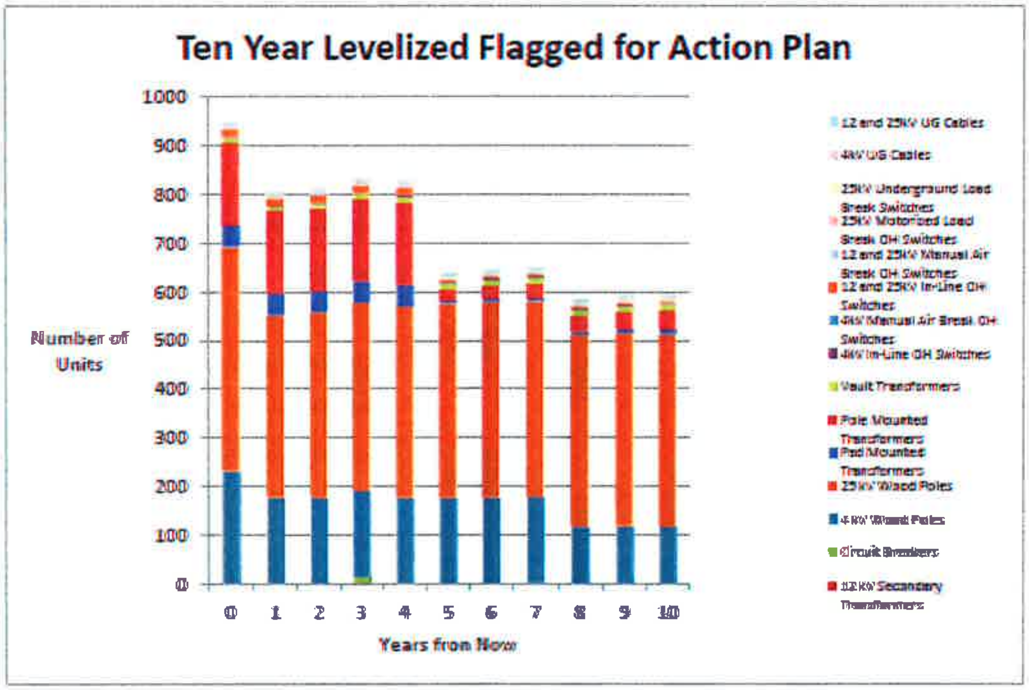
d) and e) Refer to the Kinectrics response in ER-Staff-80 a) and b) regarding reliability. In addition it is not possible to quantify the reliability change if replacements are not done per FFA. The FFA is a probabilistic assessment, which means that for nearly all assets (with the exception of station transformers and breakers) the specific asset flagged for action is not determined, i.e. only estimated quantities are determined. As such, the reliability impact can't be quantified. It can only be said that, from a qualitative standpoint, that risk increases because the likelihood of failure of assets will increase as they continue to remain in service.

# ER-Staff-83

Ref: p.8

At the above reference, the figure below is shown:

**Figure 3 - TBHEDI's 10-Year FFAP**




a) Please explain the reasons for the significantly higher number of units flagged for action during the first five years (year 0 to 4) shown in Figure 3, and particularly the number of units in year 0. Please quantify the explanation, to the extent possible.

b) Does the Flagged-for-Action Plan (FFAP) shown in Figure 3 incorporate the asset replacements forecast in the present filing? If not, please provide an updated version of Figure 3 that does incorporate the forecast replacements.

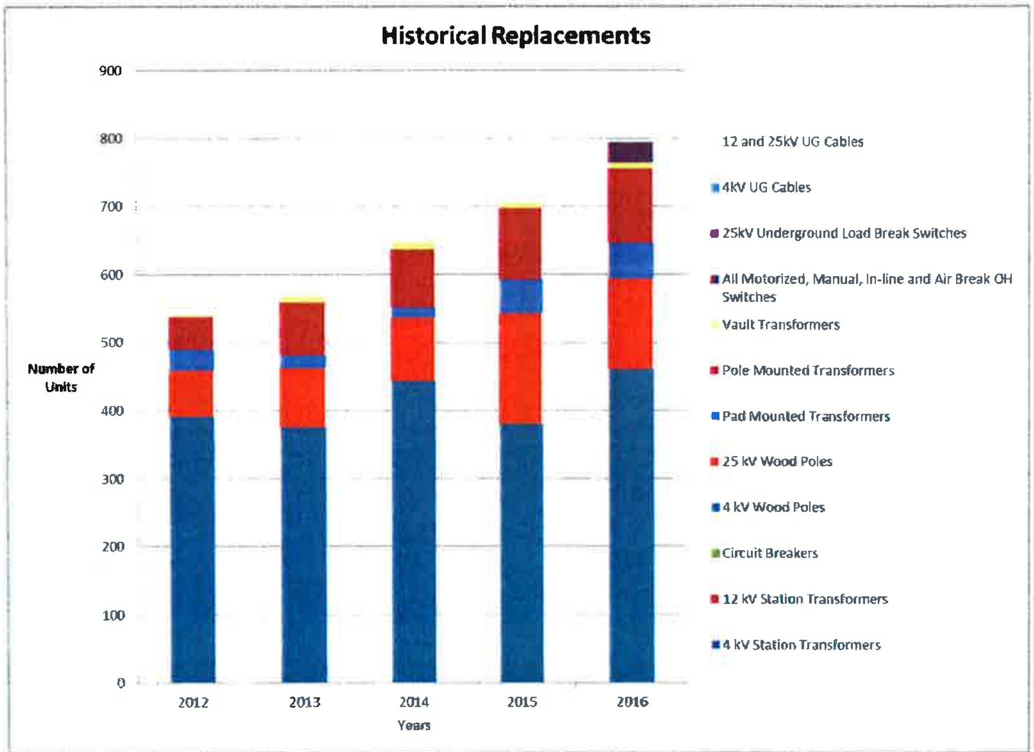
c) What would be the anticipated reliability impacts of implementing a replacement program that was more evenly paced over the planning horizon shown in Figure 3?

d) Please compare the FFAP with historical replacements for the 5 year period immediately prior to year 0 in Figure 3.

e) Please explain the reasons for any significant (>10%) inter-annual unit flagged for action counts over the historical and planned horizons, by asset class.

## THUNDER BAY HYDRO RESPONSE

d) Please see below the historical replacements for the 5 year period immediately prior to year 0.




## KINECTRICS RESPONSE

a) The number of units flagged for action is derived from HI and generated failure curves as described in the Kinectrics ACA report included in Exhibit 2, Attachment 2-I, Appendix C. For those that are proactively addressed, specific units are flagged for action once their POF exceeds 0.8.The units with only age data available have a number of units expected to fail each year estimated without identifying specific units. Once this analysis was done, a five-year averaging was done or criticality considered in levelizing the FFAP.

The reason there are higher quantities flagged in the first 5 years is because it was found that there is a backlog of units that need to be addressed. i.e. larger quantities in very poor/poor condition that will translate to larger quantities to be addressed in the near future.

b) The asset replacement forecast in the present rate filing incorporates FFAP is an input in representing condition driven replacement needs along with other drivers (see response to ER-Staff-79 a)) and not the other way around.

c) Please see our response to ER-Staff-80 b)

e) FFAP was developed for the first time in 2016 and represents condition based only replacement requirements. Historical replacements represent not only condition based replacements but also replacements for other reasons and, thus, should not be compared to the FFAP in the ACA.

## EXECUTIVE SUMMARY

I was retained by Thunder Bay Hydro Electricity Distribution Inc. (TBHEDI) to review its Distribution System Plan (DSP) with a particular focus on System Renewal investments in the test year. The review was primarily aimed at evaluating how and to what extent the results of Asset Condition Assessment (ACA) study performed for TBHEDI by Kinectrics Inc. (Kinectrics) were incorporated in establishing TBHEDI's System Renewal capital needs as presented in the TBHEDI's DSP.

I was also asked to perform a high level brief overview of TBHEDI's DSP compatibility with the OEB's Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 "Consolidated Distribution System Plan Filing Requirements" (Chapter 5).

In addition to reviewing TBHEDI's ACA report and DSP, I benchmarked some of the TBHEDI's OEB prescribed measures against several comparable Ontario's Local Distribution Companies (LDCs). I also compared useful life values used in the Kinectrics ACA study for TBHEDI's assets with that in the OEB publication entitled "Asset Deprecation Study for the Ontario Energy Board" issued on July 8, 2010.

The following report is structured to address the seven (7) specific questions related to the methodology I used in my assessment, as per instructions from the lawyer for TBHEDI Mr. John A.D. Vellone contained in *Appendix A*.

Based on my review of TBHEDI's System Renewal expenditure requirements as presented in the DSP, I have concluded that the ACA study findings were properly incorporated in the development of System Renewal Capital investments portfolio while striking a balance between addressing the backlog of assets identified in the ACA report as being in "poor" and "very poor" condition and avoiding an undesired significant increase in System Renewal investment level.

It is important to note that the final System Renewal budget for 2017 was not directly and exclusively derived from the Health Index distribution in the ACA report (the relationship is described in detail in the body of this report). Furthermore, although condition based needs represent an important input in developing System Investment capital requirements, there are other factors that are taken into account when deciding on appropriate System Renewal level, such as physical obsolescence, functional obsolescence, compliance with standards, municipal initiatives, and corporate considerations, e.g. financial constraints, input from customers, safety and environmental concerns, etc.

Although increase in System Renewal investments is expected to result in improved reliability it is not possible to quantify such an improvement due to many unknown factors that contribute to supply interruptions to customers.

The variances across the System Renewal category are as a result of continued efforts to reach asset renewal levels as recommended in the ACA. Thunder Bay Hydro will be shifting expenditures away from 4kV Voltage Conversions and increasing expenditures in Underground and 25kV Pole Replacement projects, for an overall increase in the renewal category.

iii. Year over year step increases in system renewal for 2020 are discussed in Section 5.4.4.7 page 132 of the DSP, 2018-2021 Forecast Capital Expenditure Variance Trending Analysis

Over the 2018 to 2021 forecast period, Thunder Bay Hydro expects to see only minimal increases of approximately 1.2% in the System Renewal category to reach targeted levels of asset renewal. Thunder Bay Hydro recognizes the importance of renewing all asset categories and anticipates alignment with suggested levels in the Kinectrics report (Appendix C) by 2019.

Thunder Bay Hydro has been investing in System Renewal since 2008 and has continued to increase the replacement of wood poles, distribution transformers and overhead switches through to 2017. Expenditures in these accounts have not increased at the same rate as quantities have increased and this is in large part due to the cost-efficiencies employed by the utility. In order to implement a balanced renewal plan, Thunder Bay Hydro will continue to shift expenditures away from 4kV Conversions and increase expenditures in Underground and 25kV renewal projects.

b) Yes, Thunder Bay Hydro did implement a change in its maintenance and asset replacement strategy in 2015. Thunder Bay Hydro experienced a failure of a padmount transformer that resulted in a significant remediation effort leading to significantly increased cost of replacement. With the implementation of electronic inspections Thunder Bay Hydro was able to increase the efficiency with which it completed these inspections. In reaction to this previously mentioned failure Thunder Bay Hydro began to increase the scrutiny with which it inspected its assets. With this data Thunder Bay Hydro replaced assets that posed an increased risk of failure found during the inspection in an attempt to reduce the reoccurrence of the above failure.

c) Thunder Bay Hydro has quantified the OM&A savings likely as a result of anticipated capital expenditures in over the next 5 years.

| Efficiencies Realized and Redeployed on Internal projects | | | | | |
|---|---|---|---|---|---|
| Sources | 2017 | 2018 | 2019 | 2020 | 2021 |
| a. Continued Asset Condition Assessment | $ - | $ - | $ - | $ - | $ - |
| b. Life Extenstion Programs | $ - | $ - | $ - | $ - | $ - |
| c. Distribution Automation | $ 16,373 | $ 17,192 | $ 18,051 | $ 18,954 | $ 19,902 |
| d. Voltage Conversion work | $ - | $ - | $ - | $ - | $ - |
| e. Inventory Requirement Reduction | $ - | $ - | $ - | $ - | $ - |
| f. Retirement of 4kV Stations | $ - | $ - | $ - | $ - | $ - |
| g. Standardized Designs | | | | | |
| h. Use of Tablets and Technology | $ 8,234 | $ 8,646 | $ 9,078 | $ 9,532 | $ 10,009 |
| Total Efficiencies Realized | $ 24,607 | $ 25,838 | $ 27,130 | $ 28,486 | $ 29,910 |

| Cash Outlay | | | | | |
|---|---|---|---|---|---|
| Sources | 2017 | 2018 | 2019 | 2020 | 2021 |
| a. Continued Asset Condition Assessment | $ - | $ - | $ - | $ - | $ - |
| b. Life Extenstion Programs | $ - | $ - | $ - | $ - | $ - |
| c. Distribution Automation | $ - | $ - | $ - | $ - | $ - |
| d. Voltage Conversion work | $ - | $ - | $ - | $ - | $ - |
| e. Inventory Requirement Reduction | $ 39,539 | $ 32,498 | $ 16,028 | $ 20,970 | $ 18,508 |
| f. Retirement of 4kV Stations | $ - | $ - | $ - | $ - | $ - |
| g. Standardized Designs | $ - | $ - | $ - | $ - | $ - |
| h. Use of Tablets and Technology | $ - | $ - | $ - | $ - | $ - |
| Total Cash Outlay Savings | $ 39,539 | $ 32,498 | $ 16,028 | $ 20,970 | $ 18,508 |

| O&M Savings | | | | | |
|---|---|---|---|---|---|
| Sources | 2017 | 2018 | 2019 | 2020 | 2021 |
| a. Continued Asset Condition Assessment | $ 11,005 | $ 11,555 | $ 12,133 | $ 12,739 | $ 13,376 |
| b. Life Extenstion Programs | $ 19,603 | $ 12,252 | $ 12,252 | $ 7,351 | $ 4,901 |
| c. Distribution Automation | $ - | $ - | $ - | $ - | $ - |
| d. Voltage Conversion work | $ 6,253 | $ 6,253 | $ 6,253 | $ 6,253 | $ 6,253 |
| e. Inventory Requirement Reduction | $ - | $ - | $ - | $ - | $ - |
| f. Retirement of 4kV Stations | $ - | $ 8,657 | $ 16,988 | $ 24,556 | $ 24,556 |
| g. Standardized Designs | $ 2,700 | $ 5,400 | $ 8,100 | $ 10,800 | $ 13,500 |
| h. Use of Tablets and Technology | $ - | $ - | $ - | $ - | $ - |
| Total O&M Savings | $ 39,561 | $ 44,117 | $ 55,726 | $ 61,699 | $ 62,586 |

b) No, trends in spending are not being tracked in relation to these potential cost savings. Thunder Bay Hydro is planning to monitor the status of OM&A spending in the forecasted years and correlate it to the proposed cost savings identified in part (a) above.

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