

**THUNDER BAY
HYDRO**



Distribution System Plan 2016

CHAPTER 5 CONSOLIDATED FILING REQUIREMENTS
FILED WITH THUNDER BAY HYDRO'S 2016 COS APPLICATION
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GLOSSARY

ACA: Asset Condition Assessment
AMP: Asset Management Plan
CBM: Condition Based Maintenance
CDM: Conservation and Demand Management
CIA: Connection Impact Assessment
DGA: Dissolved Gas Analysis
DR3: Demand Response 3
DSC: Distribution System Code
DSP: Distribution System Plan
ESA: Electrical Safety Authority
GIS: Geographic Information System
HONI: Hydro One Networks Inc.
IEEE: Institute of Electrical and Electronic Engineers
Kinectrics: Kinectrics Inc.
LDC: Local Distribution Company
LOS: Loss of Service
LTR: Limited Time Rating
O&M: Operating and Maintenance
OEB: Ontario Energy Board
PCB: Polychlorinated biphenyls
PM: Preventive Maintenance
PUCC: Public Utilities Coordinating Committee
RM: Reactive Maintenance
RRFE: Renewed Regulatory Framework for Electricity
SCADA: Supervisory Control And Data Acquisition
SME: Subject Matter Expert
TBHEDI: Thunder Bay Hydro Electricity Distribution Inc.

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APPENDICES

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Appendix B: HONI Regional Planning Status Letter for Thunder Bay Sub-Region

Appendix C: Kinectrics Asset Condition Assessment

Appendix D: Grid Modernization Plan

Appendix E: Fleet Plan

Appendix F: Smart Meter Sampling Plan

Appendix G: Tbaytel Fibre Media Release

Appendix H: PCB Management Plan

Appendix I: IS and IT Strategy

Appendix J: Material Capital Project Summaries

Appendix K: Thunder Bay Hydro Inspection and Maintenance Program

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5.0 Introduction

The history of Thunder Bay Hydro Electricity Distribution Inc. (Thunder Bay Hydro) dates back to the 1890's when at the time customers were served from two separate utilities; Port Arthur Public Utilities Commission and Fort William Hydro. In 1970 the two utilities were amalgamated (along with the cities of the same names) to form Thunder Bay Hydro. Thunder Bay Hydro serves 50,617 customers as of December 31, 2015 within a service territory spanning 387 square kilometers bounded by the City of Thunder Bay. Thunder Bay Hydro's service territory is neighbored by Hydro One Networks Inc. (HONI). Figure 5.1.1-1 depicts Thunder Bay Hydro's service territory boundary.

Bulk power is supplied to Thunder Bay Hydro from three HONI owned transformer stations at 25kV. Thunder Bay Hydro owns, operates and maintains approximately 923km of overhead primary distribution circuits, 258km of underground primary distribution circuits, four (4) 12kV distribution stations and ten (10) 4kV distribution stations. This includes; 23, 25kV feeders; 6, 12kV feeders; and 38, 4kV feeders.

Thunder Bay's economy has been ebbed by changes in the world economy. A decline in the size of the forestry industry throughout Northwestern Ontario has greatly impacted the local workforce, suppliers and service providers alike. As a result of the previously mentioned changes the City of Thunder Bay has embarked on a strategic plan to provide diverse opportunities to promote local economic growth. As part of this DSP, Thunder Bay Hydro has made investment plans to upgrade and maintain its distribution system to continue to provide cost effective, reliable and quality power to all existing and future customers.

As of 2015, residential customers comprise approximately 90% of customer accounts while only constituting 35% of total electricity consumption. It is also evident from Figure 5.1.1-2 and Figure 5.1.1-3 Thunder Bay Hydro's customer base and electricity consumption have remained relatively unchanged. The state of the local economy has likely contributed to this lack of growth in customer base.

Several years ago, Thunder Bay Hydro recognized that a significant portion of its assets were nearing the end of their Typical Useful Life (TUL). This realization came with the understanding that further delay in renewal investments would result in an unmanageable quantity of assets requiring replacement in the near future. This fact in conjunction with the static customer base has led Thunder Bay Hydro to focus a significant portion of their investment on system renewal.

Thunder Bay Hydro's vision is people working together, providing services of the best value and quality to our customers. To this end we strive to construct and maintain a safe, environmentally responsible, sustainable and economical distribution system that reliably delivers high quality electricity to our customers. These values of reliability and sustainability are the drivers behind our system renewal investments as well as our proposed grid modernization infrastructure investments.

Thunder Bay Hydro's vision is further reinforced through its CDM results. Thunder Bay Hydro's latest CDM program spanned a three year period from 2011-2014 whereupon completion Thunder Bay Hydro

had achieved 99.2% of its energy savings target of 47.38 GWh, and had achieved 69.9% of its demand target of 8.48 MW. The shortfall of Thunder Bay Hydro's demand target was due in part to the DR3 program being discontinued in early 2014. This program was designed to reduce the demand from large volume customers during certain periods of the year.

It can be noted from Figure 5.1.1-1 that Large Industrial users account for a small portion of THBEDI's customer base, approximately 1%. Conversely, Figure 5.1.1-2 indicates that Large Industrial users account for a large portion of Thunder Bay Hydro's consumption, approximately 50%. The revision to the CDM program portfolio directly impacted these customers, resulting in the deficit previously stated.

Moving forward, Thunder Bay Hydro is targeting similar reductions in the current Conservation First Framework from 2015-2020 tranche of 48 GWh with expectations of improving performance where achievable.

Thunder Bay Hydro has implemented an integrated approach to planning and investing in its distribution system. All material investments are planned and optimized together. These investments typically include the following:

- Customer driven connections;
- Regulatory requirements;
- System renewal and expansion;
- Renewable generation connections;
- General plant investments;
- Grid modernization assets; and
- Regionally planned infrastructure.

In the case of this DSP, Thunder Bay Hydro has planned these investments over a five year term. This allows Thunder Bay Hydro to allocate both labour and material resources in a cost-effective and efficient manner to achieve its corporate goals and the evolving needs of its customers; ultimately managing the impacts of these investments on customer rates.

Thunder Bay Hydro has been an active participant in the regional planning process ("RPP"). As members of the working group for the Thunder Bay IRRP as well as members of the Local Advisory Committee, Thunder Bay Hydro developed a load forecast for the City of Thunder Bay, as well as the narratives and methodologies to support this forecast. As an active participant Thunder Bay Hydro has been able to:

- Assist the IESO and HONI in addressing issues at the regional level; and
- Where applicable, integrate and align regional plans into its own DSP

Further information on Thunder Bay Hydro's consultations with stakeholders during the IRRP process is provided in Section 5.1.4.1 Integrated Regional Resource Planning.

Thunder Bay Hydro has taken steps to incorporate grid modernization or smart grid developments in this DSP. Thunder Bay Hydro considers these investments to be those that include:

- Revising features of its distribution to optimize the system, improving operational performance and reliability; and
- Modifying the system, where applicable, to accommodate renewable and distributed generation.

With these strategies in mind, Thunder Bay Hydro plans to implement innovative technologies to improve system operability and provide up-to-date information to better inform customers and Thunder Bay Hydro personnel of changes that have impacted the system.

These investments are made considering the outcomes as related to the four performance measures established by the OEB through the Renewed Regulatory Framework for Electricity (RRFE).

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

The following figures illustrate Thunder Bay Hydro's service territory and customer base.

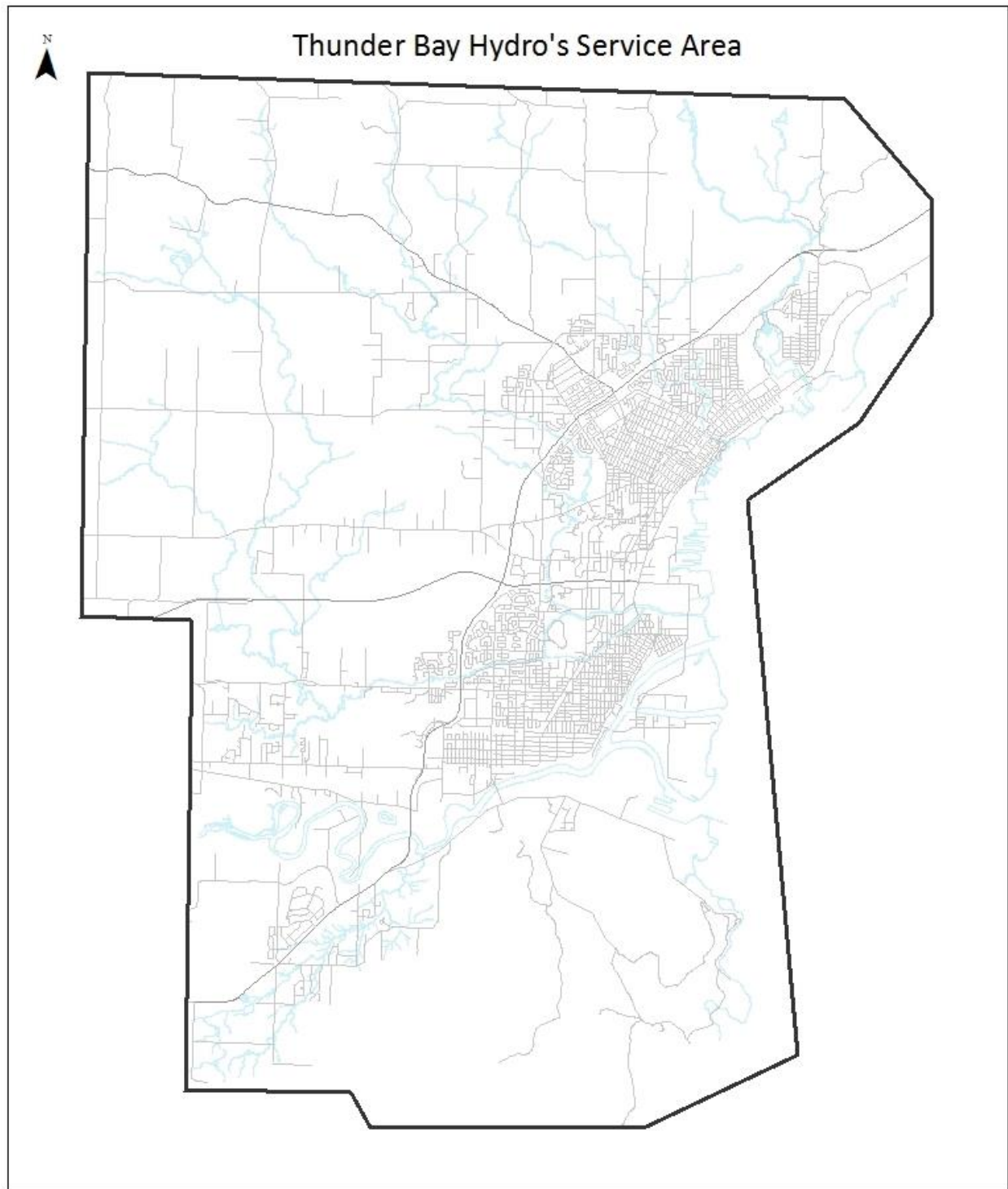


Figure 5.1.1-1 Thunder Bay Hydro Service Territory

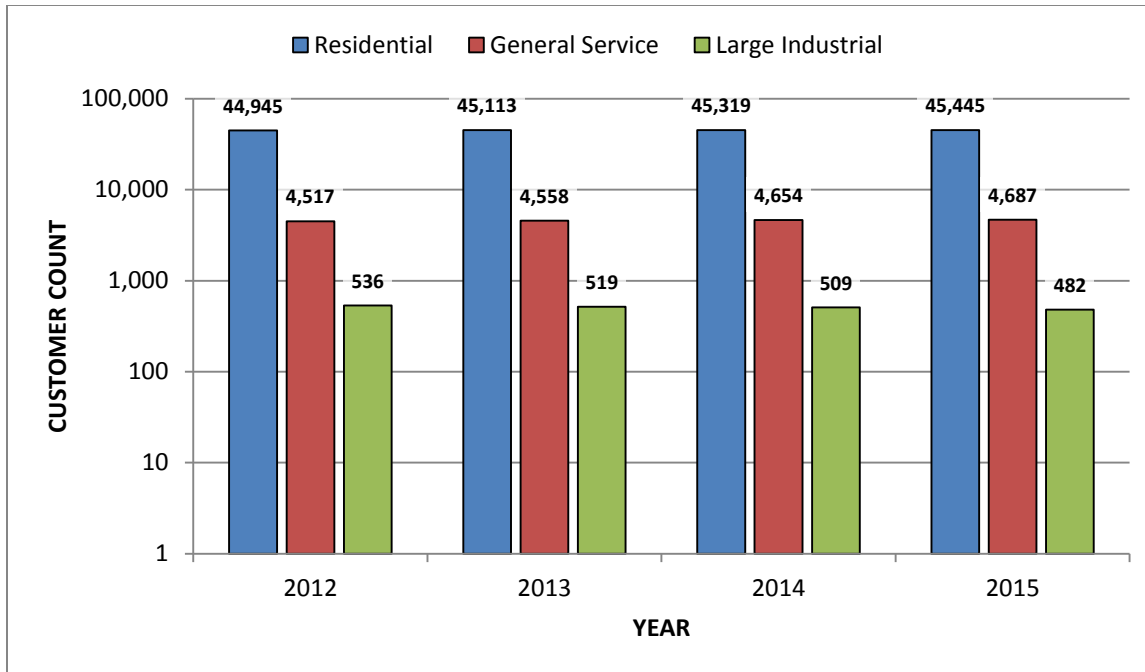


Figure 5.1.1-2 Customer Mix by Class

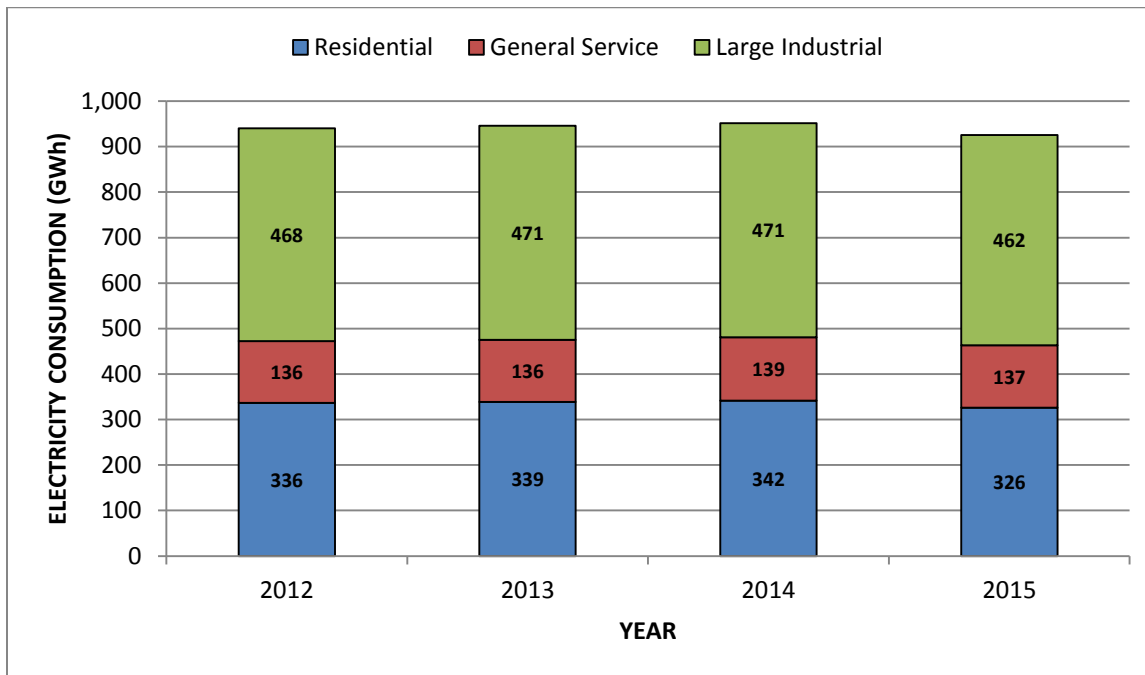


Figure 5.1.1-3 - Electricity Consumption by Customer Class

5.1 General Administrative Matters (OEB Filing Req. 5.1)

The form and the content of these filing requirements reflect the Board's conclusions in relation to distribution infrastructure planning. These filing requirements introduce a standard approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application. As detailed in section 5.2, distributors filing a corporate 'Asset Management Plan' are expected to include and clearly identify in their filings the information set out in these filing requirements and to use the terminology and formats set out in these filing requirements.

Thunder Bay Hydro has prepared this DSP in support of its rate application utilizing the headings and terminology set forth in the Chapter 5 Filing Requirements.

5.1.1 Investment Categories (OEB Filing Req. 5.1.1)

A distributor's investment projects and activities should be grouped for filing purposes into one of the four investment categories listed below, based on the 'trigger' driver of the expenditure, examples of which are provided on Table 1.

- System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide customer (including generator customer) or group of customers with access to electricity services via the distribution system.*
- System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintaining the ability of the distributor's distribution system to provide customers with electricity services.*
- System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.*
- General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tool and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities.*

A project or activity involving two or more 'drivers' associated with different categories should be placed in the category corresponding to the 'trigger' driver. For example a project triggered by the need to replace end of service life components in a distribution station should be considered a 'system renewal' investment, even if in anticipation of future system

requirements (a 'system service' driver) the project includes assets rated for a higher voltage and/or capable of handling reverse flows. Note, however (as detailed in section 5.4.5) , information on all drivers of a given project or activity should be used to justify proposed capital investments.

Thunder Bay Hydro has summarized the key drivers that are associated with each investment category in the following table. Representative projects and activities that are applicable to Thunder Bay Hydro are listed based on the trigger driver for that particular investment.

	OEB Example Drivers	OEB Example Projects	Thunder Bay Hydro Drivers	Thunder Bay Hydro Projects/Activities
System Access	Customer Service Requests	~ New Customer Connections ~ Modifications to existing customer connections ~ Expansions for customer connections or property development	Customer Service Requests	~ A11 Customer Driven System Expansions ~ A12 Residential Service Connections ~ A13 General Service Connections ~ A14 Expansions for Residential Subdivisions
	Other 3 rd party infrastructure development requirements	~ System Modifications for property or infrastructure development (e.g. relocating pole lines for road widening)	Other 3 rd party infrastructure development requirements	~ A15 System Relocations
	Mandated Service Obligations (Distribution System Code, Conditions of Service, etc.)	~ Metering ~ Long Term Load Transfer	Mandated Service Obligations	~ A01 PCB Transformer Replacements ~ A02 Customer Recoverable System Modifications ~ A21 Meter Installations
System Renewal	Assets/asset systems at end of service life due to: • Failure • Failure risk • Substandard performance • High performance risk • Functional Obsolescence	Programs to refurbish/replace assets or asset systems; e.g. batteries, cable (by type) cable splices, civil works, conductor, elbows & inserts, insulators, poles (by type), physical plant, relays, switchgear, transformers (by type).	Assets/asset systems at end of service life due to: • Failure • Failure risk • Functional Obsolescence	~ A16 Small Pole Replacements ~ A17 Lines Safety Reports ~ A18 Transformer and Switch Replacements ~ A22 Operations Safety Reports ~ Part B Projects – Voltage Conversions, 25kV Pole Replacements, Underground Replacements

	OEB Example Drivers	OEB Example Projects	Thunder Bay Hydro Drivers	Thunder Bay Hydro Projects/Activities
System Service	Expected changes in load that will constrain the ability of the system to provide consistent service delivery.	~ Property acquisition ~ Capacity upgrade (by type), e.g. phases, circuits, conductor, voltage, transformation, line extensions	Expected changes in load that will constrain the ability of the system to provide consistent service delivery.	~None expected
	System operational objectives: • Safety • Reliability • Power Quality • Other performance/functionality	~ Protection & control upgrade, e.g. reclosers, tap changer control/relays, transfer trip ~ Automation (new/upgrades) by device/type function ~ SCADA ~ Distribution loss reduction	System operational objectives: • Safety • Reliability • Power Quality • Other performance /functionality	~A35 Grid Modernization
General Plant	System capital investment support System maintenance support Business operations efficiency Non-system physical support	~ Land acquisition ~ Structures & depreciable improvements ~ Equipment and tools ~ Supplies ~ Finance/admin/billing software & systems ~ Rolling stock ~ Intangibles (e.g. land rights, capital contributions to other utilities)	System capital investment support System maintenance support Business operations efficiency Non-system physical support	~ Part C Capital Expenditures ~ Building/Fixtures ~ Office Equipment/Graphics ~ IT Capital ~ Fleet/Rolling Stock ~ Major Tools

Table 5.1.1-1 Summary of Investment Drivers

5.1.2 Investments Related to Renewable Energy Generation (OEB Filing Req. 5.1.2)

Under the renewed regulatory framework, a distributor's investments to accommodate and connect renewable energy generation (i.e. REG investments) are integral to its DS Plan, which includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the OEB Act.

Thunder Bay Hydro acknowledges its responsibility to ensure that its distribution system has, and will continue to have, the ability to connect renewable energy generation ("REG") facilities. Where system modifications are required to accommodate and connect REG investments, explanations will be provided on: the nature and magnitude of the system impacts of the project; the costs of these system modifications; and the means by which these costs are to be recovered.

5.1.3 Timing of Filing (OEB Filing Req. 5.1.3)

All distributors are required to file a DS Plan as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. Distributors proposing to use the 'Annual IR index' method for 2014 rates are not required to use Chapter 5 when filing an application. However, any distributor using the 'Annual IR Index' method must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and is required to do so at five year intervals thereafter while using the Annual IR Index method. The Board may also require a DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications.

This DSP is being filed as part of Thunder Bay Hydro's rate application.

5.1.4 Planning in Consultation with Third Parties (OEB Filing Req. 5.1.4)

5.1.4.1 Regional Planning and Consultations (OEB Filing Req. 5.1.4.1)

Prior to filing a DS Plan and at a time and in a manner to be determined in consultation with the participants in a Regional Planning Process, a distributor must:

- 1) Provide regionally interconnected distributors (including host and/or embedded where applicable), the transmitter to which the distributor is connected and the OPA (where applicable) with information on:*
 - forecast load at existing (and proposed, if any) points of interconnection;*

- *forecast renewable generation connectional and any planned network investments to accommodate the connection;*
- *investments involving smart grid equipment and/or systems that could have an impact on the operation of assets serving the regionally interconnected utilities; and*
- *the results of projects or activities involving the study or demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned by the distributor of the forecast period.*

Thunder Bay Hydro has been an active participant in the regional planning process (“RPP”). As members of the working group for the Thunder Bay IRRP as well as members of the Local Advisory Committee, Thunder Bay Hydro developed a load forecast for the City of Thunder Bay, as well as the narratives and methodologies to support this forecast. In addition Thunder Bay Hydro developed distribution system options to address capacity needs. Thunder Bay Hydro has consulted with stakeholders in its region in preparing this DSP, a letter regarding the status of the Regional planning process for the Thunder Bay Sub-Region can be found in Section 5.2.2 and Appendix B.

2) Consult with regionally interconnected distributors (including host and embedded where applicable) the transmitter(s) to which the distributor is connected in preparing their DS Plan.

Thunder Bay Hydro is surrounded on all borders of its service territory by HONI and as such collaborates and shares information on a regular basis via the IRRP meetings established by the IESO, as well as annual HONI stakeholder meetings. While awaiting the IESO’s final report, Thunder Bay Hydro remains committed to the process and continues to collaborate with HONI where possible. Thunder Bay Hydro will also continue to participate and attend presentations at IESO municipal engagement events.

5.1.4.2 Renewable Energy Generation Investments (OEB Filing Req. 5.1.4.2)

Prior to filing a DS Plan, a distributor must:

- 1) Not less than 60 days (where REG investments are contemplated; 30 days otherwise) in advance of the date the distributor needs to receive the OPA letter for inclusion in an application, a distributor must submit information to the OPA in relation to the REG investments identified in their DS Plan and requires in writing that the OPA provide a letter commenting on the information by a date that conforms to the distributor’s filing timetable.***

It is mandated by the OEB that all distributors submit information to the IESO in relation to the REG investments identified in their DSP and request in writing that the IESO provide a letter commenting on

the REG Plan, no less than 30 days in advance of filing the DSP where the distributor is not requesting investments related to REG projects. Thunder Bay Hydro has followed these instructions from the OEB by preparing and submitting to the IESO a REG Investment Plan identified in Appendix A that details the following:

- Present levels of Distributed Generation Connections;
- Present Capacity and Factors limiting full utilization of capacity;
- Forecasted Distributed Generation Connections; and
- Investments to facilitate Renewable Energy Generation.

2) *The Board expects that the OPA comment letter will include:*

- *The applications it has received from renewable generators through the FIT program for connection in the distributor's service area;*
- *Whether the distributor has consulted with the OPA, or participated in planning meeting with the OPA;*
- *The potential need for co-ordination with other distributors and/or transmitters or other on implementing elements of the REG investments; and*
- *Whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.*

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

The IESO has reviewed the REG investment plan and comments are set out in Appendix A of this DSP.

5.1.5 Performance Reporting (OEB Filing Req. 5.1.5)

A distributor is to provide information on its performance in relation to its DS Plan as set out in section 5.2.3, including information on the achievement of the operation or other objectives targeted by investments the costs for which were approved in a previous applications(s). Through its RRR filing, a distributor is also required to report annually on its performance, including in relation to reliability and any Performance Scorecard metrics established by the Board, including metrics related to asset management and capital expenditure planning as applicable.

Thunder Bay Hydro utilizes the balanced performance scorecard established by the OEB to continuously monitor and report on its performance as it relates to the four performance outcomes of the Renewed Regulatory Framework for Electricity (RRFE). Thunder Bay Hydro has been continuously monitoring its performance in regards to implementing its asset management and capital expenditure plan.

Scorecard - Thunder Bay Hydro Electricity Distribution Inc.

6/28/2016

Performance Outcomes	Performance Categories	Measures	2011	2012	2013	2014	2015	Trend	Target	
									Industry	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%	⬆️	90.00%	
		Scheduled Appointments Met On Time	91.90%	99.60%	97.80%	100.00%	99.90%	⬆️	90.00%	
		Telephone Calls Answered On Time	91.80%	90.10%	91.80%	87.10%	92.40%	⬆️	65.00%	
	Customer Satisfaction	First Contact Resolution				A+	A+			
		Billing Accuracy				99.97%	99.93%	➡️	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	C	C	C	C	C	⬆️		C
		Serious Electrical Incident Index	0	0	0	0	0	⬆️		0
		Number of General Public Incidents Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	⬆️		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted ¹	2.77	1.28	1.03	1.82	2.02	⬆️		1.92
		Average Number of Times that Power to a Customer is Interrupted ¹	3.65	3.12	2.02	2.69	2.39	⬆️		3.03
	Asset Management	Distribution System Plan Implementation Progress				On track	On-track			
	Cost Control	Efficiency Assessment		3	3	3				
		Total Cost per Customer ²	\$577	\$568	\$585	\$606				
		Total Cost per Km of Line ²	\$24,196	\$24,533	\$25,631	\$26,864				
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	2015-2020 CDM Target (GWh)								
		Targeted Annual CDM Savings (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%		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	3.75%	3.75%	7.00%	7.00%	7.00%			
		Deemed (included in rates) Achieved	7.24%	7.74%	6.34%	5.99%	5.69%			

Notes:

1. Regarding the System Reliability measures, an upward arrow indicates decreasing reliability and a downward arrow indicates improving reliability

2. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.

Legend: ⬆️ up ⬇️ down ➡️ flat

🟢 target met 🟡 target not met

Figure 5.1.5-1 2015 Preliminary Scorecard

5.2 Distribution System Plans (OEB Filing Req. 5.2)

Distributors are encouraged to organize the required information using the section heading indicated. If a distributor's application uses alternative section heading and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the heading/subheading used in the application filed to the section headings/subheadings indicated below.

5.2.1 Distribution System Plan Overview (OEB Filing Req. 5.2.1)

This section provides the Board and stakeholders with a high level overview of the information filed in the DS Plan, including but not limited to:

- a) key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives;*

5.2.1.1 Key Elements of the DSP (OEB Filing Req. 5.2.1a)

Thunder Bay Hydro focuses on several initiatives that drive the size and mix of our capital investment. Through internal and external stakeholder engagement we are able to form our core business objectives; we then continuously monitor our performance to ensure these objectives are satisfied. These planning objectives, listed in order of priority are further defined in Section 5.4.2.1, but are summarized as follows:

- 1) Ensuring the health and safety of the public and Thunder Bay Hydro's employees.
- 2) Mitigating existing or future impacts to the environment
- 3) Compliance with regulatory and legal obligations.
- 4) Fulfillment of customer demand work.
- 5) Retirement of assets which have reached the end of their useful life.
- 6) Improvement of operational efficiency.

The output of this integrated planning process is a levelized plan which addresses the short-term and mid-term concerns of the utility. This process is also critical in assessing future demands on the system and is crucial in establishing a long-term strategy for continued success in achieving our objectives. A summary of the proposed capital investments by OEB categories is provided in Table 5.2.1-1.

Category	2016	2017	2018	2019	2020	2021
System Access	\$2,722,077	\$2,662,432	\$2,422,273	\$2,432,053	\$2,444,765	\$2,505,497
System Renewal	\$7,164,703	\$8,379,756	\$8,818,369	\$8,975,721	\$9,216,828	\$9,261,478
System Service	\$0	\$230,375	\$300,000	\$280,000	\$280,000	\$300,000
General Plant	\$1,905,805	\$1,167,500	\$1,359,760	\$946,131	\$900,514	\$969,308
Total Expenditure	\$11,792,585	\$12,440,063	\$12,900,402	\$12,633,905	\$12,842,107	\$13,036,284

Table 5.2.1-1 Capital Expenditure Plan Forecast

System Access

System Access investments involve modifications to existing systems that will allow Thunder Bay Hydro to provide future and existing customers access to its electricity services. These investments are most often initiated by customer and third party requests and the projects are completed to fulfill Thunder Bay Hydro's service obligations. These investments typically include the following:

- New customer connections;
- Line relocations;
- Subdivision development;
- Metering projects.

System Access forecasts are based on previous year's results along with consultation with third parties to determine what projects will proceed in the current planning cycle.

Thunder Bay Hydro is also establishing a smart meter pre-sampling and final compliance sampling program which aligns with the requirements detailed within Measurement Canada's (MC) Statistical Method Specification (S-S-06) so that the utility can extend their smart meter's in-service life and ultimately maximize the return on investment. These investments are detailed in Appendix F.

System Renewal

System Renewal investments involve replacing and/or refurbishing assets to extend the original service life of the assets and thereby maintain the ability of the distribution system to provide customers with electricity. These investments are necessary to prevent large populations of assets from reaching the end of their useful life, leading to a decline in reliability performance and increase in risks to Thunder Bay Hydro employees and the public.

Thunder Bay Hydro engaged Kinectrics Inc., a category leader in providing life cycle management solutions for the electricity industry to perform an Asset Condition Assessment (ACA) on its key distribution system assets. The process included an in-depth review and analysis of the data available for these major assets, as well as a detailed report outlining the health of Thunder Bay Hydro's system (via a health index). The output of this process yielded levelized renewal targets for each asset category.

- Pole mounted transformers;

- Pad mounted transformers;
- Vault transformers;
- Wood Poles;
- Switches;
- Underground Cables;
- Substation Transformers; and
- Substation Breakers.

The ACA is an essential driver for Thunder Bay Hydro decisions on maintenance levels, maintenance requirements, and decisions regarding the selection and scope of capital investments. Ultimately, the objective of this assessment is to monitor physical indicators of asset degradation or malfunction, correlate these observations to the distribution system reliability statistics and maintain or replace these assets in a timely and economical fashion.

The outcome of these assessments has indicated that Thunder Bay Hydro needs to continue increasing investment in System Renewal, to ensure that we continue to serve our customers with reliable power. Thunder Bay Hydro has sensibly and gradually increased its expenditures in System Renewal projects, to minimize the impact of these increases on the customer.

System Service

System Service investments include expansions or upgrades to existing systems to support growth of existing customers or improve operational efficiencies and flexibilities. It also includes improvements to the existing system with regards to reliability, power quality and performance/ functionality. Thunder Bay Hydro understands that improvements must benefit both the Customer and the LDC and has included a detailed Grid Modernization Plan located in Appendix D, with the goal of providing better visibility and operational flexibility to achieve grid performance. The areas that Thunder Bay Hydro is focusing its investment are the following:

- Automated Switch Installation;
- Distributed Automation Implementation; and
- Outage Management System Improvements.

General Plant

General plant investments include those that are made to maintain assets that are part of the day-to-day operational and business activities but are not directly part of the distribution system. This typically includes the following asset categories:

- Tools and equipment;
- Fleet of vehicles;
- Land and buildings; and
- Information systems hardware and software.

Thunder Bay Hydro has been and will continue to invest in fleet and major tool renewal as required. The current Vehicle and Equipment Resource Justification Plan is included in Appendix E.

Thunder Bay Hydro has been and will continue to invest in Information Systems hardware and renewal for its staff, and completes end of life replacement for all computer hardware, SAN/Firewall, and network station/servers, a detailed listing of expenditures for the forecast period is included in Appendix I: IS and IT Assessment.

b) the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution;

5.2.1.2 Sources of Cost Savings Expected (OEB Filing Req. 5.2.1b)

- Continued asset condition assessment is expected to provide information allowing Thunder Bay Hydro to determine the most appropriate pace and level of investment for renewal of its assets. This will lead to an optimized level of reactive versus proactive levels of replacements of infrastructure. Cost efficiencies are expected to be realized with the reduction in unexpected replacement of equipment on premium time.
- Life Extension Programs can reduce costs when compared to replacement programs. An example of life-extension programs at Thunder Bay Hydro is the pole transformer painting program, where spare transformers located in the yard that are identified as having rusting, are sanded and painted, extending the life of the asset
- Distribution Automation has the potential to positively impact reliability statistics and increase labour efficiencies. The implementation of the Grid Modernization Plan (found in Appendix D) is expected to automate operations in selected areas and allow for improvements to outage area identification; thusly increasing the effectiveness associated with system patrolling and restoration of outages in those areas.
- Any voltage conversion work that occurs in conjunction with the line rebuilds will have a positive impact on the reduction of line losses (I^2R)
- Through the system renewal and voltage uprating process, Thunder Bay Hydro will be reducing inventory requirements of 4kV materials and equipment. These savings will not be fully realized until the end of the conversion process whereby all 4kV stock items can be removed.
- The retirement of Grenville, Mountdale and Hardisty 4kV substations over the forecast period will eliminate the O&M costs associated with maintaining and operating these stations. As detailed in section 5.3, these assets are at the end of their useful lives and as a result further capital investments will be avoided for the buildings and equipment associated with these stations.

- Standardized Designs are expected to minimize engineering and installation requirements of projects by limiting material diversity. Thunder Bay Hydro is part of the Utilities Standard Forum (“USF”) group to standardize installation drawings for use in the projects in this DSP.
- Devices such as portable tablets and the use of web-based applications are expected to replace paper-based data collection and are expected to improve operational efficiency, reduce the possibility of data translation errors, and provide labour savings in data entry.

c) the period covered by the DS Plan (historical and forecast years);

5.2.1.3 Period Covered by the DSP (OEB Filing Req. 5.2.1c)

This DSP covers the historical period, defined as 2012 through 2016 (bridge year) inclusive. As per the update to Chapter 2 Filing Requirements applicable for 2017 cost of service rate applications, Thunder Bay Hydro has included planned capital budgets for each historical year and the bridge year, including the OEB approved amount for the last rebasing year. The forecast period covers 2017 through 2021 inclusive.

d) an indication of the vintage of information on investment ‘drivers’ used to justify investments identified in the application (i.e. the information should be considered ‘current’ as of what date?);

5.2.1.4 Vintage of the Information on Investment Drivers (OEB Filing Req. 5.2.1d)

Thunder Bay Hydro understands the importance of having up-to-date data to inform on decision making processes affecting the asset management portfolio. As a result we closely monitor the status of our current capital spending and use this data to forecast as accurately as possible. The information contained within the DSP should be considered current as of December 31, 2015.

e) where applicable, an indication of important changes to the distributor’s asset management process (i.e. enhanced asset data quality or scope; improved analytic tools, process refinements; etc.) since the last DS Plan filing; and

5.2.1.5 Important Changes to the AM Process (OEB Filing Req. 5.2.1e)

This is Thunder Bay Hydro’s first DSP filing, as a result, included is information regarding changes to asset management process as it relates to the Asset Management Plan (AMP).

Thunder Bay Hydro has a well-established inspection and maintenance program used to assess the condition of various components within the distribution system. Through these various programs,

Thunder Bay Hydro satisfies the requirements of the Distribution System Code (DSC) and any directives provided by the Ontario Energy Board.

Since its last rebasing, Thunder Bay Hydro has undertaken the following initiatives to improve the Asset Management Process:

- Deployment of mobile assessment program for poles, overhead switches, underground switches and pad mounted transformers which are retained in the Geographic Information Systems (GIS);
- Engagement of Kinectrics to complete an Asset Condition Assessment on system components and provide information on data gaps to improve assessment techniques;
- Refinement of analysis techniques leveraging GIS to improve accuracy during the budgeting process.
- Refinement of the project prioritization matrix and scoring for project selection
- Refinement of inspection criteria to provide more consistent and objective results

Thunder Bay Hydro is committed to continuous improvement and will actively seek out cost effective opportunities for enhancing the asset management process.

f) aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (i.e. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known.

5.2.1.6 Aspects Contingent Upon the Outcome of Ongoing Activities (OEB Filing Req. 5.2.1f)

The Thunder Bay Sub-Region IRRP is currently in progress and the final deliverable is expected December 16, 2016, thus the final report will not be included in this DSP.

At the time of writing it was understood that the Thunder Bay Sub-Region has sufficient load meeting capability and a margin approach has been deemed as sufficient in supplying additional growth in peak demand. Future demand growth and changes to the local supply mix may use up this margin but there is no commitment needed from Thunder Bay Hydro for investment in infrastructure for the forecasted period of this DSP. (2017-2021)

5.2.2 Coordinated Planning with Third Parties (OEB Filing Req. 5.2.2)

To demonstrate that a distributor has met the Board's expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate, a distributor must provide:

a) A description of the consultation(s), including

- the purpose of the consultation (i.e. Regional Planning Process);*
- whether the distributor initiated the consultation or was invited to participate;*
- the other participants in the consultation process (i.e. customers, transmitter, OPA);*
- the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (i.e. Regional Infrastructure Plan, Integrated regional Resource Plan); and*
- an indication of whether the consultation(s) have or are expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.*

5.2.2.1 Customer Engagement (OEB Filing Req. 5.2.2a)

Thunder Bay Hydro recognizes the importance of coordinating infrastructure planning with customers, regional and municipal governments, third party attachers and CDM program partners. This coordination generates sound financial investments that balance affordability for the ratepayers and the need to provide safe reliable power to the same. With this goal in mind, Thunder Bay Hydro sought to encourage feedback from customers through several channels.

UtilityPULSE Customer Satisfaction Survey

The purpose of the customer consultations was to solicit feedback from the customer regarding their views of Thunder Bay Hydro's performance with respect to customer service, company image and overall management. Thunder Bay hydro initiated the consultation engaging Simul Corporation to provide information regarding customer care within the utility. This undertaking is typically completed on a 2 year cycle, with the last report being completed in 2015, and the next being scheduled for 2017. The final deliverable is a report (contained in Attachment 1G in Exhibit 1) which contains data specific to the utility, as well comparisons of Thunder Bay Hydro to other utilities provincially and nationally. Where available the report also compares current results to previous years. The feedback received provides insight on customer's state of mind and perceptions of the utility but also some actionable advice. Thunder Bay Hydro expects that this consultation will affect how Thunder Bay Hydro communicates with customers and what customer service initiatives need investment in the future. If for example the survey resulted in customers requesting more timely information regarding outages or

restoration of outages, Thunder Bay Hydro would research and determine appropriate investments related to this outcome.

The general outcome of the report finds that Thunder Bay Hydro consistently performs at or above industry expectations from across Ontario and Canada. A copy of the full report can be found in Attachment 1G in Exhibit 1. Highlights from the report can be found below.

Overall Customer Satisfaction

The UtilityPULSE scorecard has been designed to assess overall customer satisfaction as defined by six categories deemed most important to influencing customer affinity to the utility.

Thunder Bay Hydro's UtilityPULSE Report Card		
Category	Thunder Bay Hydro	Ontario
1 Customer Care	B+	B
Price and Value	B+	B+
Customer Service	A	B+
2 Company Image	A	B+
Company Leadership	A	B+
Corporate Stewardship	A	A
3 Management Operations	A	A
Operational Effectiveness	A	A
Power Quality and Reliability	A+	A
Overall	A	B+

Figure 5.2.2-1 UtilityPULSE Report Card

Meeting or exceeding customer expectations is fundamentally the main responsibility of the LDC. Thunder Bay Hydro has been successful in meeting these expectations in the past and plans to do so in the future.

Operational Effectiveness

Attributes strongly linked to a customer's perception of operations excellence			
Category	Thunder Bay Hydro	Ontario	National
Provides consistent, reliable electricity	91%	88%	90%
Quickly handles outages and restores power	90%	85%	87%
Makes electricity safety a top priority for employees and contractors	90%	87%	89%
Operates a cost effective electricity distribution system	71%	63%	72%
Overall the utility provides excellent quality services	86%	83%	85%

Figure 5.2.2-2 UtilityPULSE Customer Perceptions

Decision Partners Mental Models Research

In partnership with Decision Partners, Thunder Bay Hydro launched its customer engagement survey in 2015. Thunder Bay Hydro initiated the consultation and the primary purpose of this survey is to inform on the DSP. This engagement is particularly different from surveys completed in the past. The research is performed on a random sample of customers (residential, commercial and large industrial) who become participants in an informed discussion. The final deliverable is a report (Attachment 1K in Exhibit 1) which contains data specific to development to the DSP. This gives Thunder Bay Hydro the opportunity to gain insight, from a customers' perspective, after they have been adequately informed and educated. The goal is to seek customer input, assess this meaningful information from an informed audience and best determine how incorporate this input into the DSP.

When customers were initially asked where they thought the top priorities for the electricity industry lie for the next 5 years, most interviewees said to stabilize or reduce costs.

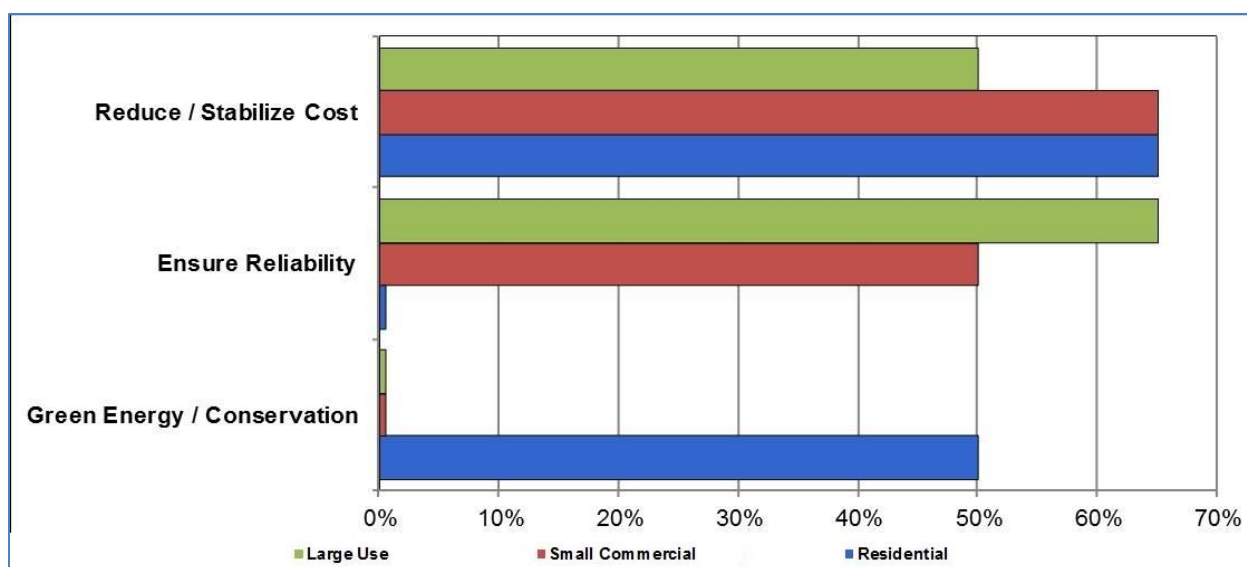


Figure 5.2.2-3 – Decision Partners: Electricity Industry Top Priorities

System Renewal

When asked to discuss their thoughts regarding system renewal investments, nearly all Interviewees (95% Overall) recognized the need for these investments. However, many (55% Overall) argued that they should be made without increasing rates for customers.

System Service and System Access

When asked to discuss their thoughts regarding investments in system service and system access, Interviewees from the Small Commercial and Large User Customers classes recognized the need for these investments, citing the need for reliability. Many again, however mentioned the desire for fewer rate increases. Some noted the lack of growth in Thunder Bay.

Many Interviewees (50% Overall) rated investments in system service and system access as somewhat critical. Generally, the criticality of these investments was rated lower than system renewal, with a few rating them as “not very critical”.

General Investments

Many Interviewees expressed confidence in the process and the right decisions would be made.

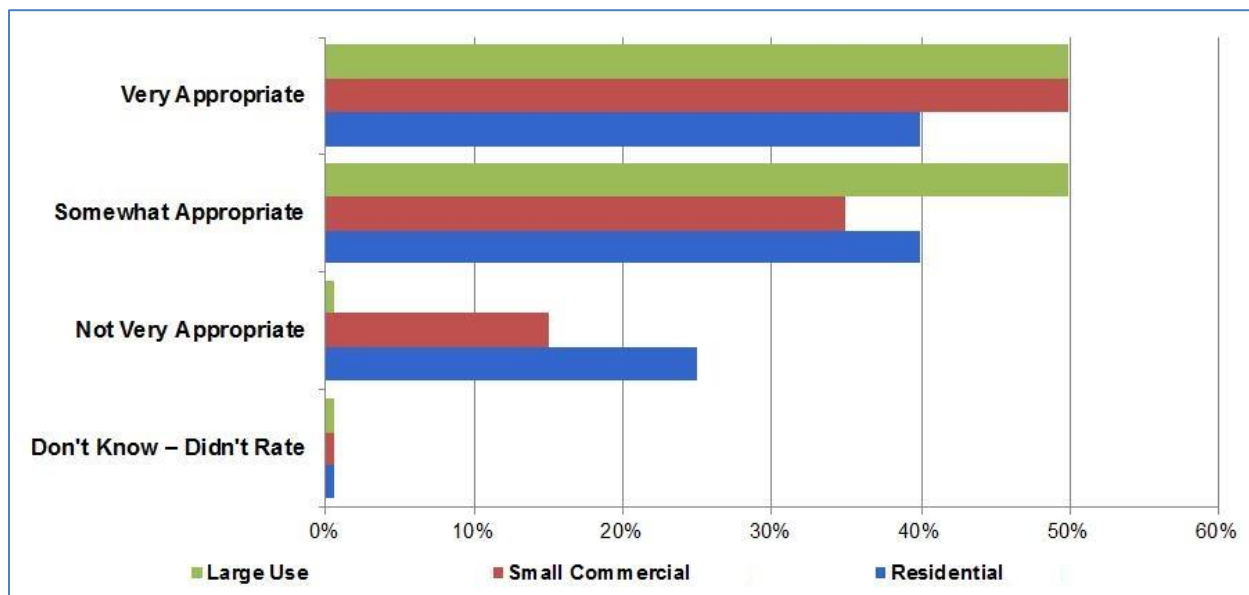


Figure 5.2.2-4 - Decision Partners: Appropriateness of Overall Investment Increase

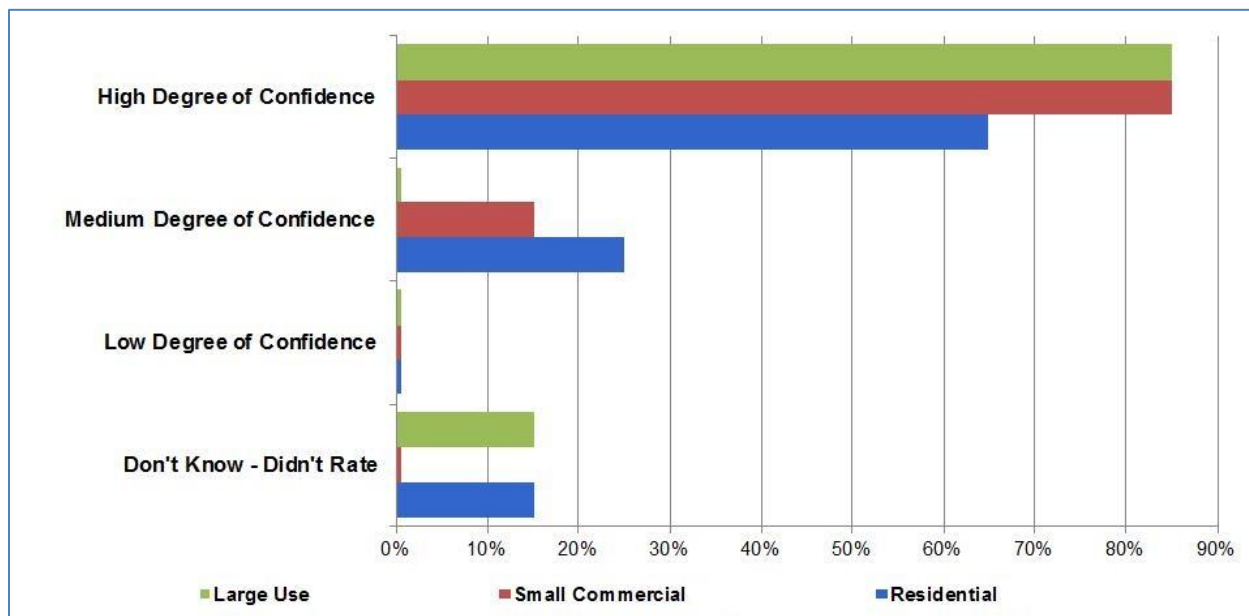


Figure 5.2.2-5 Decision Partners: Confidence in Thunder Bay Hydro

Thunder Bay Hydro is committed to educating their customers and seeking their input on various aspects of its operation. Thunder Bay Hydro believes the results of these surveys align closely with the spending levels and targets proposed in this DSP.

Thunder Bay Hydro has also sought to inform and engage its customers on the many aspects of the utility's business. It has done so utilizing several different mechanisms from initiating or participating in face-to-face engagements; website, email and social media updates; and through printed media. A summary of these techniques is available below.

Face-to-Face Events

- Social Housing Luncheon (2013)
- Spring Home & Garden Show (2013, 2014, 2015)
- peaksaver PLUS Public Information Seminars (2013)
- Retrofit Awards (2013, 2014, 2015)
- Aboriginal Conservation Workshop (2013)
- Retrofit Electrical Distributors Luncheon (2013)
- Teddy Bear Picnic (2013, 2014, 2015)
- Prosperity Northwest (2013, 2014, 2015)
- Lakehead University Thunderwolves Hockey Game (2013, 2014 2015)
- Earthcare Forum (2014)
- Demand Response3 Luncheon (2014)
- Summer in the Parks (2014, 2015)
- Chamber of Commerce After Business Event: Small Business Week
- peaksaver PLUS Children's Colouring Contest
- Social Media - Frostbites Instagram Challenge (2014, 2015)
- Routes in Our Community Event (2015)
- Community Economic Development Commission Showcase (2015)
- saveONenergy Christmas Challenge (2015)
- Better Ways Video Contest (2015)
- Retrofit "We Want You" Social Media Campaign (2015)
- Frostbites Social Media Campaign (2015)
- saveONenergy Christmas Challenge Social Media Campaign (2015)

Website and Email: (beginning 2013 and ongoing through 2016)

- Website feedback
- Changing from page features
- Customer contact form and email 2500 interactions
- Online outage map

Printed media –Bill Inserts

- Customer Newsletter, bill messages, bill inserts from 'OEB'

Targeted Audience Presentations:

- Post Secondary schools and High schools - Education on safety, renewable power, industry and careers in the industry
- Construction Association education regarding locates and dig-ups
- First Responders School Bus Drivers - downed powerlines
- Brochures and Posters to 55+ and Lakehead Social Planning Council on OESP/LEAP information and Winter Outrage readiness

Social Media: (beginning 2013 and ongoing through 2016)

- Twitter - Major Outages
- Facebook - Posting of advertisements and media releases and safety messaging

5.2.2.2 Consultation with Regional and Municipal Governments (OEB Filing Req. 5.2.2a)

Thunder Bay Hydro is a wholly owned subsidiary of the City of Thunder Bay, and as such maintains a very close working relationship with the Engineering, Planning and Administrative departments at the City.

As a key stakeholder, Thunder Bay Hydro consults with the City of Thunder Bay to ensure that it is informed and provided the opportunity to comment on all City of Thunder Bay subdivision developments during the draft plan and preliminary design stage. Typically the City of Thunder Bay initiates the consultation through the opportunity to comment and review all severances and variances which result from the committee of adjustment process. All utility owners in the City are allowed the same opportunity and the consultation results in a coordinated effort of planning. This process is ongoing and the results of these consultations inform Thunder Bay Hydro's knowledge of development activity throughout the City of Thunder Bay. These consultations have impacted the level of investment proposed in this DSP for its near term planning of system access and system renewal projects.

Consultations with regional departments such as the Ministry of Transportation ("MTO") and Ministry of the Environment ("MOE") have occurred on an as needed basis to address specific project related topics such as permitting requirement and specific details regarding certain projects. The party whose project plans impact the others (ie road widening requires movement of poles) initiates the consultation for the purpose of project discussions. The outcome of such specific project discussions include, for example, plans and direction for the project currently being constructed or a request for a concept design and estimate to relocate assets related to an upcoming project. There are no active projects at the time of writing and thus there is no expected impact on the DSP.

Most recently, Thunder Bay Hydro has assisted the Ontario Ministry of Transportation (MTO) in undertaking a Planning and Preliminary Design Class Environmental Assessment (EA) Study [G.W.P. 6001-13-00] along Highway 11/17 and 61 (Thunder Bay Expressway) from 1 km south of Arthur Street to 1 km north of Balsam Street in the City of Thunder Bay. MTO reached out to Thunder Bay Hydro to request infrastructure locations within the project plan in order to study all existing and proposed utility information from utility owners in the study area so that potential conflicts could be identified and a

relocation strategy can be developed if necessary. All other infrastructure owners in the project area were contact and continued consultation is ongoing. The consultation will not have any effect on the DSP, as the project does not yet have an approved budget in the 5 year term.

Thunder Bay Hydro is a member of the local Public Utilities Coordinating Committee (PUCC) and Subdivision Development and Coordinating subcommittee that meet on a semi-annual basis. The meetings are initiated by the City of Thunder Bay and the committee is comprised of representatives from other local infrastructure owners such as; Telecommunications, Union Gas and the City of Thunder Bay. The purpose of the PUCC meetings is to coordinate planning and development to the extent possible and share information regarding future endeavours. The purpose of the subdivision sub-committee meetings is to discuss City approved plans and upcoming potential developments within the city. Generally the outcome of these meetings provide Thunder Bay Hydro with direction on System Access projects relating to; road widening, line relocations and subdivision creation/expansion. These projects impact the DSP near-term budgeting process for Thunder Bay Hydro.

Thunder Bay Hydro has also consulted with the Fort William First Nations (FWFN) regarding subdivision development, line extensions and various other projects that may impact the near-term budgeting process. Consultation with FWFN was initiated by the band to implement the subdivision development and the connection has recently been completed. As such there are no expected impacts on the DS plan.

Thunder Bay Hydro does have a mature planning process relating to System Renewal efforts and as a result creates a path for several other infrastructure owners to follow during their respective planning processes. These meetings aid in the effective delivery of services throughout the service territory and help prevent increased costs associated with miscoordinated planning.

5.2.2.3 Consultation with Third Party Attachers (OEB Filing Req. 5.2.2a)

Thunder Bay Hydro initiates consultations with all third party attachers in its service territory and provides them with information relating to renewal efforts throughout the city. This allows the other infrastructure owners to plan their upgrades in conjunction with Thunder Bay Hydro. The intent is to reduce the occurrence of third parties attaching to infrastructure that is targeted for replacement in the near term.

Where the above scenario cannot be achieved, (for instance where a third party is targeting a large renewal/upgrade project that does not coincide with Thunder Bay Hydro's efforts) Thunder Bay Hydro asks that the third party provides detailed plans well in advance of the proposed project so that Thunder Bay Hydro can effectively determine the appropriate investment level to allow the project to proceed.

Recent investment by a telecommunication firm (Tbaytel) exemplifies this scenario. Tbaytel has provided Thunder Bay Hydro with their plans to target investments in areas where poles have not been scheduled for replacement in the 5-10 year horizon. The impact to Thunder Bay Hydro is an increase in expenditures in make-ready-work as part of Customer Recoverable System Modifications. In order to minimize these impacts, Thunder Bay Hydro has been working closely with Tbaytel using a co-ordinated

approach to capital planning. In this way Tbaytel is now able to enter neighbourhoods to install fibre while Thunder Bay Hydro is also working to replace aging infrastructure. See Appendix G on the media release of these co-ordinated efforts.

5.2.2.4 Consultation with CDM Program Partners (OEB Filing Req. 5.2.2a)

Thunder Bay Hydro has delivered CDM programs to its customers since 2005, and has regularly consulted with the IESO since its introduction as the provincial authority with electricity conservation responsibilities. This includes the IESO “Every Kilowatt Counts” 2007-2010 CDM tranche followed by the 2011-2014 IESO “saveONenergy” CDM tranche. Through these CDM frameworks Thunder Bay Hydro participated in IESO program design and change management, utilized CDM delivery funding received from the IESO, and completed a variety of regular monthly and annual reporting requirements under the Master Agreement with the IESO.

With the OPA merger with the IESO, Thunder Bay Hydro will continue to work collaboratively with the IESO under the 2015-2020 Energy Conservation Agreement for program delivery, funding, and results reporting against Thunder Bay Hydro’s six (6) year 48.4 GWh electricity savings target. As per the Minister of Energy’s directive on Conservation and Demand Management dated March 31, 2014, Thunder Bay Hydro will continue to engage and consult with its stakeholders. Thunder Bay Hydro will work together with its regional LDCs to develop a refined delivery model that best suits regional needs. Under the new framework, local distribution companies are to have increased autonomy to develop and implement customized and unique individual and regional CDM programs through a simplified and streamlined process.

b) Where a final deliverable of the Regional Planning Process is available, the final deliverable; where a final deliverable is expected but not available at the time of filing, information indicating:

- the role of the distributor in the consultation;*
- the status of the consultation process; and*
- where applicable the expected date(s) on which the final deliverables are expected to be issued.*

5.2.2.5 Integrated Regional Resource Planning (OEB Filing Req. 5.2.2b)

Thunder Bay Hydro is an active member of the working group and the Local Advisory Committee (LAC) for the Thunder Bay Sub-Region IRRP, as mentioned in 5.1.4. The objectives of the Thunder Bay IRRP are to:

- review the adequacy of electricity supply to customers in the region over the next 20-year period;
- develop a flexible, integrated plan; and
- implement recommended options in anticipation of potential demand growth scenarios.

Thunder Bay Hydro's role in the planning process was to gather data and examine the load meeting capability and reliability of the existing transmission system. In addition, Thunder Bay Hydro provided a gross peak demand forecast under a range of potential demand growth scenarios; information on existing, committed and potential distributed generation connections, and information relevant to our distribution system plans, load transfer capability under normal and emergency conditions.

The consultation is in progress and, Thunder Bay Hydro will continue to be an active participant until the final deliverables are issued December 16, 2016.

c) The comment letter provided by the OPA in relation to REG investments included in the distributor's DS Plan (see 5.2.4.2), along with any written response to the letter from the distributor, if applicable.

5.2.2.6 Renewable Energy Generation Planning (OEB Filing Req. 5.2.2c)

Thunder Bay Hydro has consulted with IESO and HONI in an effort to keep both groups up to date on the REG developments as well as to review the available thermal and short circuit current limitations for several of the transformer stations in the Thunder Bay service area. Thunder Bay Hydro prepared and submitted a REG investment plan to the IESO and received a comment letter in return on the subject on May 9, 2016. Both the REG investment plan and the IESO comment letter are attached in Appendix A. IESO specifically commented on the Upstream Transmission Constraints and understands that projects connecting on the upstream transmission system could impact the connection capability for REG projects that are downstream on Thunder Bay Hydro's distribution system. It is therefore recommended that Thunder Bay Hydro coordinate with Hydro One Networks Inc. as transmitter when assessing REG project connection capability.

5.2.3 Performance Measurement for Continuous Improvement (OEB Filing Req. 5.2.3)

As mentioned in section 5.0, good distributor planning is an essential element of the Board's performance-based rate-setting approaches. The Board understands that the distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning process.

a) Identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (i.e. formula if quantitative metric) and motivation (i.e. consumer,

legislative, regulatory, corporate). These measures and metrics are expected to address, but not be limited to:

- *Customer oriented performance (i.e. consumer bill impacts, reliability, power quality);*
- *Cost efficiency and effectiveness with respect to planning quality and DS Plan implementation (i.e. physical and financial progress vs. plan, actual vs. planned cost of work completed); and*
- *Asset and/or system operations performance.*

5.2.3.1 Metrics to Monitor DSP Process Performance (OEB Filing Req. 5.2.3a)

Thunder Bay Hydro uses a set of metrics to continuously monitor and evaluate its performance with respect to the four performance outcomes established by the OEB through the Electricity Distributors Scorecard (Scorecard). Most of these metrics are required by the OEB for the DSP filing, while some are not. There are also a few additional metrics tracked for internal performance and provided for the Filing Requirements. In aggregate, these measures allow Thunder Bay Hydro to determine changes and trends in its own performance from year to year, but also provide a means for Thunder Bay Hydro to compare its performance with other LDC's in Ontario. Five of the performance measures reported in the Scorecard, were added by the OEB in May 2014 to capture performance in value to customers, effective planning, and asset management. These metrics will only have historical records for these performance measures from 2014 onward as they were not tracked prior. The newly added measures were:

- First Contact Resolution
- Billing Accuracy
- Customer Satisfaction Survey Results
- Public Safety
- Distribution System Plan Implementation Progress

In addition to the above, the OEB requested that utilities track the Level of Public Safety Awareness beginning in 2015. Thunder Bay Hydro is in compliance with this mandate and will include results in this category from 2015 onward. A summary of the performance metrics tracked are listed in Figure 5.1.5-1. The motivation behind tracking each metric is divided into three separate categories;

- Regulatory – metrics which are required for Scorecard Reporting
- Corporate – metrics which have been deemed by Thunder Bay Hydro to be relevant to performance measurement
- Filing – metrics which are required by the OEB for DSP filing

There is one measure expected by the Chapter 5 filing requirements, but Thunder Bay Hydro has not yet developed a mechanism for measuring or tracking. This measure is;

- Cost-Efficiency and Effectiveness with respect to planning quality

Thunder Bay Hydro agrees with the expectations of the OEB and the need to track the above performance metric, and has included in this Application an interpretation of this through the corporate tracked metric of Productivity / Efficiency Performance. As a part of continuous improvement initiatives, Thunder Bay Hydro intends on implementing additional measures which will track cost efficiency and effectiveness with respect to planning quality and DS Plan implementation. This metric will be prepared for reporting in the next rate Application.

Performance Outcomes	Performance Categories	Performance Measures	Motivation
Customer Focus	Service Quality	New Residential/Small Businesses Connected On Time	Regulatory
		Scheduled Appointments Met On Time	
		Telephone Calls Answered On Time	
		Estimate to Connect Accuracy	Corporate
	Customer Satisfaction	First Contact Resolution	Regulatory
		Billing Accuracy	
		Customer Satisfaction Survey Results	
	Customer Bill Impacts	Percentage Average Total Bill Impact	Filing
		Average Dollar Impact	
	Power Quality	Power Quality and Electrical Disturbances	Filing
Operational Effectiveness	Safety	Level of Public Awareness	Regulatory
		ESA Audits (CSA 22/04 Compliance)	
		Number of General Public Incidents	
		Serious Electrical Incident Index	
	System Reliability	SAIDI (Including and Excluding LOS)	Regulatory
		SAIFI (Including and Excluding LOS)	
		CAIDI (Including and Excluding LOS)	Corporate
	Asset Management	DSP Implementation Progress	Regulatory
Public Policy Responsiveness	CDM	Net Annual Peak Demand Savings (GWh)	Regulatory
		Net Cumulative Energy Savings (GWh)	
	Renewable Generation	Renewable Generation Connection Impact Assessments Completed on Time	Regulatory
		New Micro-embedded Generation Facilities Connected On Time	Regulatory
Financial Performance	Financial Ratios	Liquidity: Current Ratio	Regulatory
		Leverage: Total Debt to Equity Ratio	
		Profitability: Achieved Regulated Return on Equity	

Figure 5.2.3-1 Performance Measures and Motivation

Definition of Customer Focus Performance Measures

I. Service Quality

New Residential/Small Businesses Connected On Time

Connections for a new service request for a low voltage (< 750 volts) service are to be completed within five business days from the day on which all applicable service conditions are satisfied. Thunder Bay Hydro's target is to meet this obligation at least 90% of the time on an annual basis.

Scheduled Appointments Met On Time

Offers to schedule an appointment must be made within a window of time that is no greater than four hours. Thunder Bay Hydro's target is to arrive for the appointment within the scheduled timeframe 90% of the time on an annual basis.

Telephone Calls Answered On Time

During regular call centre hours, the OEB mandates that calls must be answered within 30 seconds of receiving the call directly or having the call transferred to them 65% of the time. This measure is influenced by things such as the number of power outages and staffing levels, which can vary from year to year. Thunder Bay Hydro's internal customer service department is targeting to maintain a rate of 90% of calls answered within 30 seconds.

Estimate to Connect Accuracy

This measure is one that is not tracked by the Scorecard; however Thunder Bay Hydro believes it to be an important measure of service quality and budgeting accuracy. In cases where a Customer requires work (above 200A) by Thunder Bay Hydro, an Estimate to Connect is provided. Thunder Bay Hydro targets that the actual cost to connect a customer is not to be outside of +10% and -25% of the original Estimate to Connect provided.

II. Customer Satisfaction

First Contact Resolution

Thunder Bay Hydro aims to minimize and address customer complaints as quickly as possible. In doing so, the organization tracks and monitors customer service inquiries, and targets to maintain an A+.

Billing Accuracy

Thunder Bay Hydro measures the number of accurate bills it issues throughout the year. The distributor targets to achieve the prescribed accuracy of 98%.

Customer Satisfaction Survey Results

The distributor is required to measure and report a customer satisfaction results at least every other year.

Thunder Bay Hydro completed the 17th annual Electrical Utility Customer Satisfaction Survey, conducted by a 3rd party, UtilityPULSE. The survey was based on telephone interviews, and randomly sampled residential and small to medium sized business customers supplied by Thunder Bay Hydro.

The survey findings covered multiple categories: Customer Care (price and value, customer service), Company Image (company leadership, corporate stewardship) and Management Operations (operational effectiveness, power quality and reliability). As previously detailed in 5.2.2.1, the UtilityPULSE report card yielded an overall ranking of A. Thunder Bay Hydro's target is to maintain a grade of A or greater.

Customer Bill Impacts

Thunder Bay Hydro has prepared customer bill impacts as a measure of quantifying the impact of Thunder Bay Hydro's rate application on customers' electricity bills.

Customer impacts include the Percentage Average Total Bill Impact and Average Dollar Impact and include the revised distribution rates, monthly service charge, and volumetric rates, proposed retail transmission service rates, revised loss factors, proposed rate riders as requested in the Application. Thunder Bay Hydro's target is to keep the bill impact lower than 10% for all customer classes.

Power Quality

Thunder Bay Hydro responds to all customer power quality concerns. Power Quality concerns typically stem from an occurrence where the utilization of electricity is adversely affecting the performance of electrical equipment within a residence or place of business. Thunder Bay Hydro uses the appropriate industry standards such as CSA or IEEE (Institute of Electrical and Electronic Engineers) and good utility practice as a guideline for resolving such issues.

Power quality issues are difficult to track and quantify and as such targets are equally difficult to track and quantify. As a target, Thunder Bay Hydro will address every power quality concern that is raised and will attempt to reduce power quality issues on a year to year basis through its asset management and capital planning process.

Operational Effectiveness

III. Safety

Level of Public Awareness

Level of public awareness, within the distributor's service territory, of electrical safety information and precautions related to distribution system assets. Starting in 2015, the utility will carry out a survey every two years that measures the effort made to raise the public's awareness about these risks. The Electrical Safety Authority has developed the survey. Thunder Bay Hydro completed this survey in 2015 and targets to maintain its grade of 82.00 or greater in the future.

ESA Audits (CSA 22/04 Compliance)

The OEB requires all distributors to be in compliance with Ontario Regulation 22/04, which outlines electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors.

Section 13 of Ontario Regulation 22/04 mandates that all distributors engage an auditor on an annual basis to review the distributor's compliance with sections 4, 5, 6, 7 and 8 of the above regulation and provide a report of the findings. Each section is evaluated and the auditor provides findings in terms of: compliant (C), non-conformance (NC), needs improvement (NI) and not applicable (NA). Thunder Bay Hydro targets to achieve full compliance of O.Reg 22/04, meaning zero "Non-compliance" or "Needs Improvement" in future ESA audits.

Serious Electrical Incident Index

The Serious Electrical Incident Index component of the public safety measure is intended to address the resultant impact in improving public electrical safety on the distribution networks over time. It measures the number of and rate of serious electrical incidents occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line. Thunder Bay Hydro treats Health and Safety as its top priority and strives to maintain zero injury rates at all times.

IV. System Reliability Indicators

SAIDI (Including and Excluding LOS)

The system average interruption duration index (SAIDI) is an indicator of system reliability that expresses the average length of outage customers experience in the year. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served and is expressed as: normalized per customer served and is expressed as:

$$\text{SAIDI} = \frac{\text{Total Customer Hours Interruptions}}{\text{Total Customer Hours}}$$

Total Number of Customers Served

Thunder Bay Hydro's target for SAIFI is 3.03 under normal operating conditions.

SAIFI (Including and Excluding LOS)

The system average interruption frequency index (SAIFI) is an indicator of the average numbers of interruptions each customer experiences. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the number of interruptions normalized per customer served and is expressed as:

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Number of Customers Served}}$$

Thunder Bay Hydro's target for SAIFI is 3.03 under normal operating conditions.

CAIDI (Including and Excluding LOS)

Although no longer required by the Scorecard, Thunder Bay Hydro believes that this metric continues to be relevant and will continue to track it for the foreseeable future. The customer average interruption duration index (CAIDI) is an indication of the speed at which power is restored after an interruption. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the average duration of interruptions in the year and is expressed as follows:

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Number of Customers Interruptions}}$$

Thunder Bay Hydro's target for CAIDI is 0.7 under normal operating conditions.

V. *Asset Management*

DSP Implementation Progress

The DSP outlines forecasted capital expenditures over a five year period required to maintain and expand Thunder Bay Hydro's electricity system to service its current and future customers. The OEB requires that all distributor DSP's optimize investments and reflect regional and smart grid considerations; serves present and future customers; places a greater focus on delivering value for money; aligns the interests of the distributor with those of customers; and supports the achievement of public policy objectives. At the time of writing, the OEB has not currently implemented a metric to monitor this. Thunder Bay Hydro is committed to monitoring its DSP implementation progress following the OEB's recommendations.

VI. *Cost Control*

Efficiency Assessment

Total costs for all electricity distribution companies are evaluated by the Pacific Economics Group LLC (“PEG”) on behalf of the Ontario Energy Board to produce an efficiency ranking. A “predicted cost” is then calculated. The magnitude of the difference between distributor’s actual and predicted costs will assign a distributor into one of five groups.

Thunder Bay Hydro’s target is to consistently improve its estimating processes to reduce the variance between predicted and actual costs.

Total Cost per Customer

An evaluation by the Pacific Economics Group LLC (“PEG”) on behalf of the OEB produces a cost per customer metric. This measure sums the total capital and operating costs and divides the cost figure by the total number of customers.

Total costs include annual operating and capital costs. Operating costs are the costs associated with the maintenance, inspection and operation of Thunder Bay Hydro’s distribution assets, customer and general administration costs. Capital costs include enhancement, betterments and replacement of capital assets that are required each year.

Capital costs tend to fluctuate depending on the need to replace existing capital assets and additional infrastructure to support growth and develop.

Performance in this category is measured through benchmarking with other LDC’s. Thunder Bay Hydro’s target is to achieve and maintain high standards as compared to its peers for lowest cost customer.

Total Cost per km of Line

An evaluation by the Pacific Economics Group LLC (“PEG”) on behalf of the OEB produces a cost per kilometer of line metric. This measure sums the total capital and operating costs and divides the cost figure by the kilometers of line that Thunder Bay Hydro operates to serve its customers.

Total costs include annual operating and capital costs. Operating costs are the costs associated with the maintenance, inspection and operation of Thunder Bay Hydro’s distribution assets, customer and general administration costs. Capital costs include enhancement, betterments and replacement of capital assets that are required each year. Capital costs tend to fluctuate depending on the need to replace existing capital assets and additional infrastructure to support growth and develop.

Performance in this category is measured through benchmarking with other LDC’s. Thunder Bay Hydro’s target is to achieve and maintain high standards as compared to its peers for lowest total cost per km of line operated.

Productivity/Efficiency Performance

Thunder Bay Hydro has tracked various metrics over the years and one in particular has been consistently monitored, that is the average installation cost on a per pole basis. The actual cost per pole can vary widely depending on several factors including location, equipment and framing complexity. In many instances the scope of replacement is outside the control of the utility, for instance poles replaced due to an accident, safety concern etc.

However many pole replacements occur at the discretion of the utility and generally fall into two categories: those replaced during small unplanned projects and those replaced as part of large capital projects. Thunder Bay Hydro has noted that the cost per pole is more varied and difficult to predict on projects with a small scope due to the fixed costs of the project being borne across a small population of assets. Thunder Bay Hydro's target is to achieve and maintain high standards as compared to its past projects for average cost on a per pole basis.

Public Policy Responsiveness

VII. Conservation and Demand Management

Net Annual Peak Demand Savings

The Net Annual Peak Demand Savings are reported by the IESEO who administers the Conservation and Demand Management Program. These savings are measured at a point in time and are non-cumulative. The current conservation target period runs from January 2, 2015 to December 31, 2020. Peak demand savings are reductions in the overall demand (MW) during peak periods as defined by the IESO.

Net Cumulative Energy Savings

The Net Cumulative Energy Savings are reported by the IESO, who administers the Conservation and Demand Management Program. The current conservation target period runs from January 2, 2015 to December 31, 2020. Net energy savings are reductions in the total energy consumption over time (kWh). Thunder Bay Hydro's target is 48 GWh.

VIII. Renewable Generation

Renewable Energy Connection Impact Assessments Completed on Time

Thunder Bay Hydro is required to complete a Connection Impact Assessment, within the timeframe allowed in the DSC, for all facilities that have a nameplate rated capacity of greater than 10kW. Thunder Bay Hydro targets meeting the timeframe allowed in the DSC.

New Micro-embedded Generation Facilities Connected On Time

Thunder Bay Hydro is required to connect an applicant's micro-embedded generation facility to its distribution system within five business days of the applicant informing the distributor that it has satisfied all applicable service conditions. Thunder Bay Hydro's target is 5 days.

Financial Performance

IX. Financial Ratios

Liquidity: Current Ratio (Current Assets/Current Liabilities)

The current ratio measures whether or not a firm has enough resources to pay its debts over the next 12 months. A current ratio that is greater than 1 means good short term financial strength, as it indicates that short term debts and financial obligations can be met and that the organization is in good financial health.

Thunder Bay Hydro's target is a current ratio of greater than 1.1 to 1.

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

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40).

Thunder Bay Hydro's target is to maintain a solid debt to equity ratio of less than 0.6 to 1. Additionally Thunder Bay hydro has a targeted Debt Service Coverage ratio of greater than 1.2 to 1.

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

The profitability measure is defined as the approved return on equity that is embedded in Thunder Bay Hydro's distribution rates. This measure assesses whether distributors are earning a fair return on their investment.

Thunder Bay Hydro's target is to consistently achieve the deemed return on equity defined by the OEB.

b) Provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index.

5.2.3.2 Summary of Performance over the Historical Period (OEB Filing Req. 5.2.3b)

The set of performance measures summarized here are based on the four performance outcomes established by the OEB and are collectively known as the Scorecard. The majority of these measures are required to be reported by the OEB, however some are not. They have been selected in a way so as to encourage electricity distributors to operate effectively, continually seek ways to improve productivity

and focus on improvements that their customers value. Thunder Bay Hydro and other LDC's will report their scorecard performance results annually, and make the results available to the public.

Several of the measures have been implemented recently and as such to do not cover the entire historical period required to be reported on in this DSP. They will become evident as the summaries are presented.

Summary of Customer Focus Performance Measures

I. Service Quality

Metric	OEB Target	2012	2013	2014	2015
New Residential/Small Businesses Connected On Time	>=90%	99.10%	99.80%	100.00%	99.90%
Scheduled Appointments Met On Time	>=90%	99.60%	97.80%	100.00%	99.90%
Telephone Calls Answered On Time	>=65%	90.10%	91.80%	87.10%	92.40%
Estimate to Connect Accuracy	N/A	0	0	0	0

Table 5.2.3-1 Customer Service Quality Performance in Historical Period

As is evident from Table 5.2.3-1 Thunder Bay Hydro has consistently performed well above the OEB defined target.

II. Customer Satisfaction

These metrics have only been required by the OEB since 2014, as a result Thunder Bay Hydro is only able to report on results since then.

Metric	OEB Target	2014	2015
First Contact Resolution	N/A	A+	A+
Billing Accuracy	>=98%	99.97%	99.93%
Customer Satisfaction Survey Results	N/A	A	A

Table 5.2.3-2 Customer Satisfaction Performance in Historical Period

Thunder Bay Hydro has achieved and expects to maintain its high performance in customer satisfaction. Customer survey results are further discussed in section 5.2.2.1 Customer Engagement.

Customer Bill Impacts

The Bill Impact metrics are calculated by comparing the predicted 2017 Test Year bills to the actual 2016 bill at the existing rates. The results of these calculations are included in Table 5.2.3-3 below.

Line No.	Customer Class	Units	Distribution Rate Change	Total Bill Impact	
			%	\$	%
1	RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	14.6%	\$ 2.17	1.57%
2	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kWh	19.5%	\$ 8.67	2.31%
3	GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	3.8%	\$ (80.37)	-0.98%
4	GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	3.1%	\$ (1,226.10)	-1.30%
5	LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	14.7%	\$ (3,623.58)	-0.73%
6	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	10.1%	\$ 0.52	0.67%
7	SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	20.5%	\$ 2.10	8.34%
8	STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	-13.2%	\$ (2.11)	-9.96%
9	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	17.4%	\$ 308.82	1.88%
10	STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	-3.2%	\$ (2,504.22)	-1.78%
11	RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	21.3%	\$ 4.12	2.96%
12	SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	15.4%	\$ 7.49	5.85%
12	RESIDENTIAL SERVICE CLASSIFICATION - RPP- Bottom 10th Percentile	kWh	27.9%	\$ 5.38	9.16%
12	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	13.3%	\$ 5.51	1.42%

Table 5.2.3-3 Percentage Customer Bill Impacts 2016 Approved to 2017 Proposed

Power Quality

Once a power quality concern is submitted by a customer, Thunder Bay Hydro immediately investigates and makes efforts to resolve the issue at hand. As these issues are resolved on a case-by-case basis, Thunder Bay Hydro uses a number of methods to determine the causes as well as solutions. Depending on the circumstances, this may include a review of relevant power interruption and usage data and/or use of internal power quality measurement tools. Where the problem is suspected to lie on the customer side of the system, Thunder Bay Hydro subcontracts out to an experienced electrician to coordinate with the customer to obtain power quality measurements. In cases such as this, a detailed report is provided by the electrician to Thunder Bay Hydro and the customer. All resolutions are in accordance with appropriate governing bodies (e.g. ESA); industry standards (e.g. CSA or IEEE); and good industry practice.

When identified, a record of power quality concerns is kept in a customer file. While this is not a form of a tracked metric in the same manner as other metrics considered and discussed this DSP, Thunder Bay Hydro does retain this information should future concerns arise.

Summary of Operational Effectiveness Measures

III. Safety

Public Safety Awareness

Metric	OEB Target	2014	2015
Public Safety Awareness	N/A	N/A	82.00

ESA Audits (CSA 22/04 Compliance)

Year	O.Reg 22/04 Sections																			
	4. Safety Standards				5. Safety Standards Met				6. Electrical Equipment				7. Approval of Plans				8. Approval of Construction			
	C	NI	NC	NA	C	NI	NC	NA	C	NI	NC	NA	C	NI	NC	NA	C	NI	NC	NA
2012	4	0	0	0	4	0	0	0	3	0	0	0	5	0	0	0	8	0	0	2
2013	4	0	0	0	4	0	0	0	3	0	0	0	5	0	0	0	8	0	0	2
2014	4	0	0	0	4	0	0	0	3	0	0	0	5	0	0	0	8	0	0	2
2015	4	0	0	0	4	0	0	0	3	0	0	0	5	0	0	0	8	0	0	2
C – Complies; NI – Needs Improvement; NC – Non-conformance; NA – Not Applicable																				

Table 5.2.3-4 ESA Reg.22/04 Audit Results 2012-2015

Thunder Bay Hydro has been found in full compliance of the regulation for the past four years.

Serious Electrical Incident Index

Metric	OEB Target	2012	2013	2014	2015
Number of General Public Incidents	>=90%	0	0	0	0
Rate per 10, 100, 1000km of line	>=90%	0.000	0.000	0.000	0.000

Table 5.2.3-5 Serious Electrical Incident Index

Both the actual number and the rate per km of line are shown on the scorecard. Thunder Bay Hydro's Serious Electrical Incident Index is 0.0, as there have been no serious incidents.

IV. System Reliability Indicators

The following figures summarize Thunder Bay Hydro's reliability performance over the historical period 2009-2015 as measured by SAIDI, SAIFI and CAIDI. The figures contain statistics on all interruptions both including LOS and excluding LOS from the Hydro One transmission system. Thunder Bay Hydro also tracks major events that result in greater than 1000 customer hours being impacted. These events have the most significant effect on these statistics and are used as part of the integrated planning approach as an input to direct maintenance activities.

2015 will be the last year that Thunder Bay Hydro will be reporting on CAIDI to the OEB as it is no longer required to be reported on. Internally, Thunder Bay Hydro is still determining whether it will continue to track this measure for reliability purposes

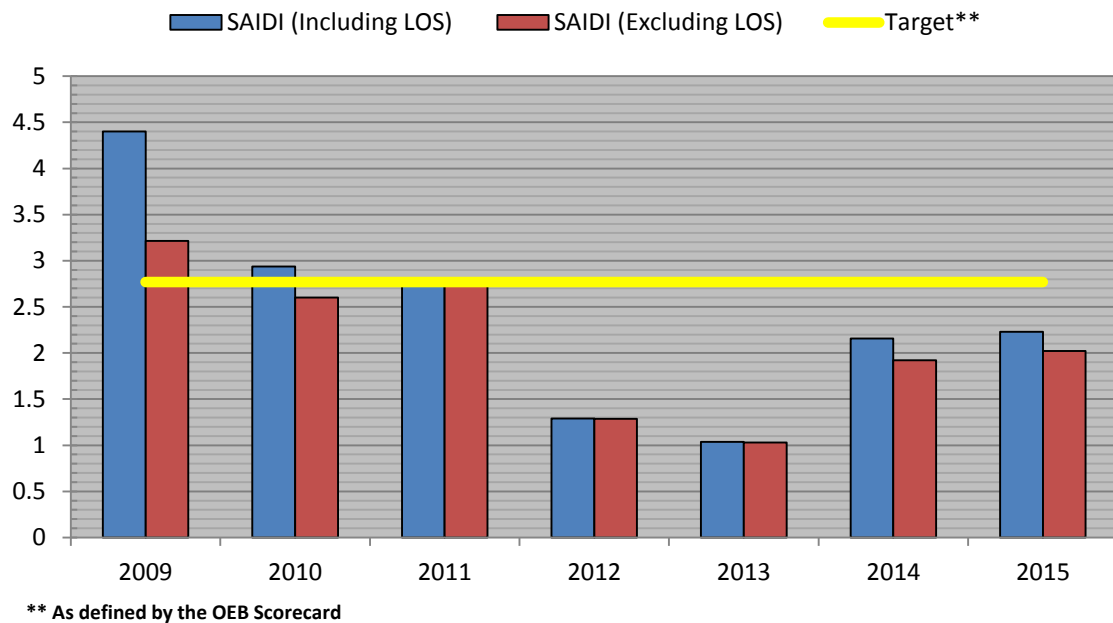


Figure 5.2.3-2 Historical SAIDI Performance

As is evident in Figure 5.2.3-2 SAIDI in years 2012 and 2013 diverge from the trend. This was in large part due to the lack of storm activity in the region, which resulted fewer outages of extended duration.

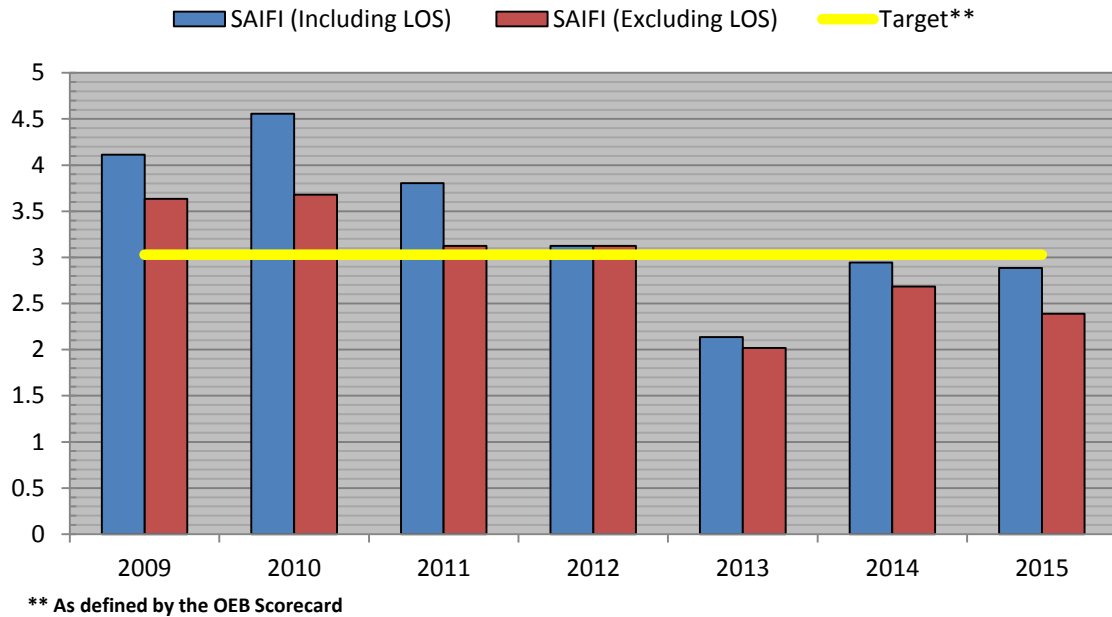


Figure 5.2.3-3 Historical SAIFI Performance

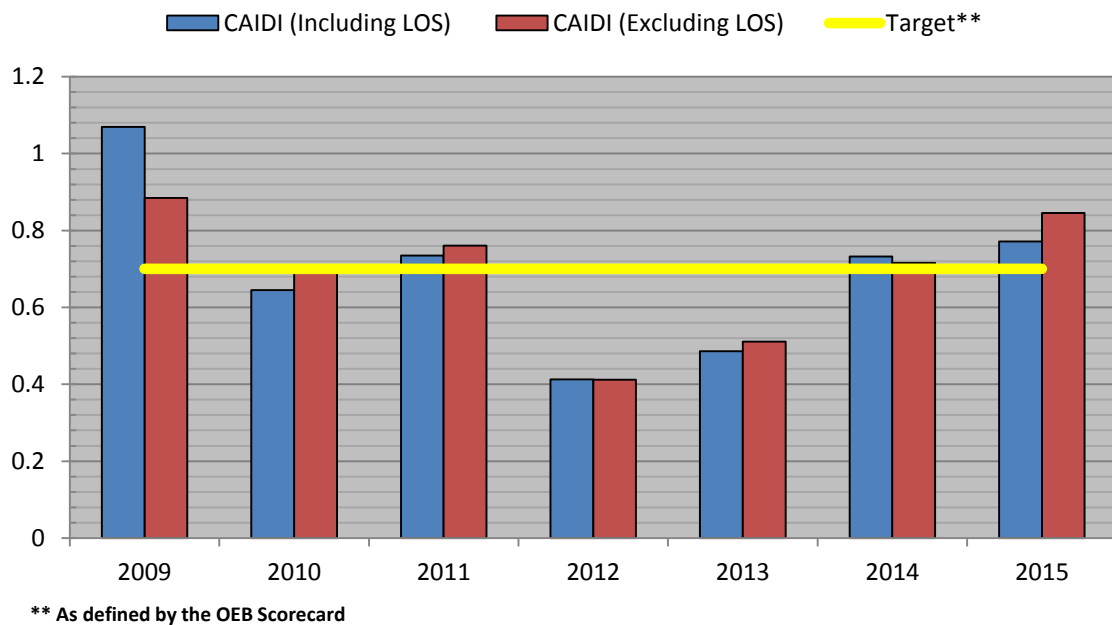


Figure 5.2.3-4 Historical CAIDI Performance

The following chart is a compilation of the root causes of outages for the period 2012-2015. Thunder Bay Hydro attributes each outage to one of the 10 OEB defined categories and includes both momentary and sustained outages. As is evident from Figure 5.2.3-5, the majority of outages can be attributed to

three categories: Defective equipment, interruptions resulting from distributor equipment failures due to age related deterioration, incorrect maintenance and/or application of equipment; Foreign Interference, interruptions resulting from sabotage, vandalism, dig-ups, vehicles and animals and are outside of the distributors control; and Unknown/other, interruptions that cannot be attributed to any particular cause. These three categories account for 70% of all recorded outages.

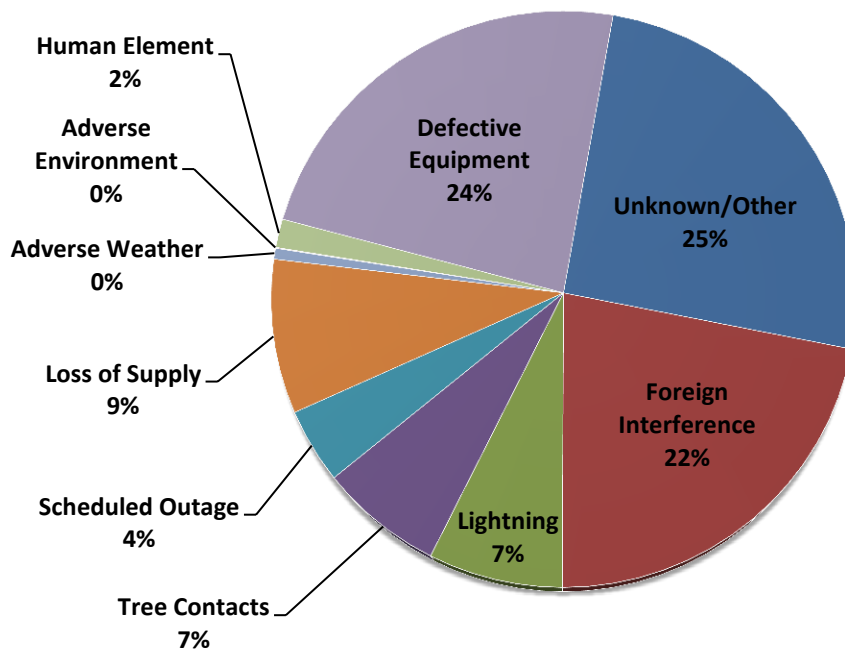


Figure 5.2.3-5 Outage Causes by Duration 2012-2015

V. *Asset Management*

DSP Implementation Progress

The DSP has been developed in support of this cost of service Application and as such it has not yet been implemented. Thunder Bay Hydro is currently executing its Asset Management Plan which closely aligns with the objectives outlined in this DSP.

The Ontario Energy Board has not yet developed a standardized reporting method for DSP progress, and until such time, Thunder Bay Hydro plans to track DSP performance with the following method.

- a) Financial performance measured as plan vs actual expenditures percentage
 - a. Over expenditure >100%
 - b. Under expenditure <100%
- b) Scope Management measured as plan vs actual quantities of assets renewed percentage

- a. Larger than planned quantities renewed >100%
- b. Less than planned quantities renewed <100%
- c) These two will factored together for a reported “On-Schedule”, “Ahead of-Schedule” or “Behind-Schedule” performance measure.

VI. *Cost Control*

Efficiency Assessment

Total costs for all electricity distribution companies are evaluated by the Pacific Economics Group LLC (“PEG”) on behalf of the Ontario Energy Board to produce an efficiency ranking. A “predicted cost” is then calculated. The magnitude of the difference between distributor’s actual and predicted costs will assign a distributor into one of five groups.

For a third year, Thunder Bay Hydro was placed in Group 3, which is defined as having actual costs within +/- 10 percent of predicted costs.

Total Cost per Customer

The figures below summarize the total cost per Thunder Bay Hydro customer. Figure 5.2.3-6 and Figure 5.2.3-8 summarize the total cost over the historical period 2012-2015. Figure 5.2.3-7 and Figure 5.2.3-9 compares Thunder Bay Hydro to other Ontario LDC’s.

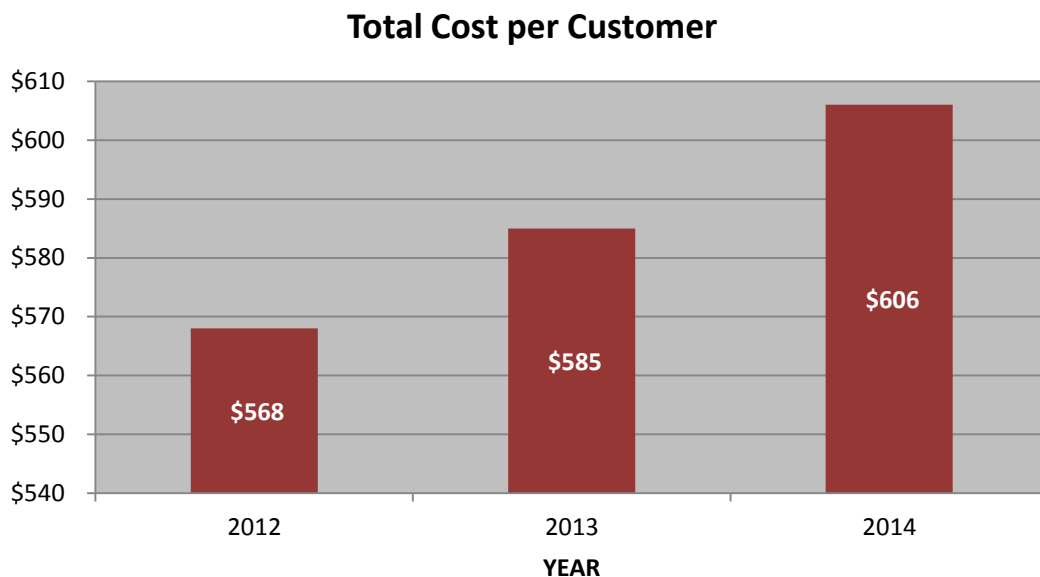


Figure 5.2.3-6 Total Cost per Customer 2012-2014 (2015 not available at time of writing)

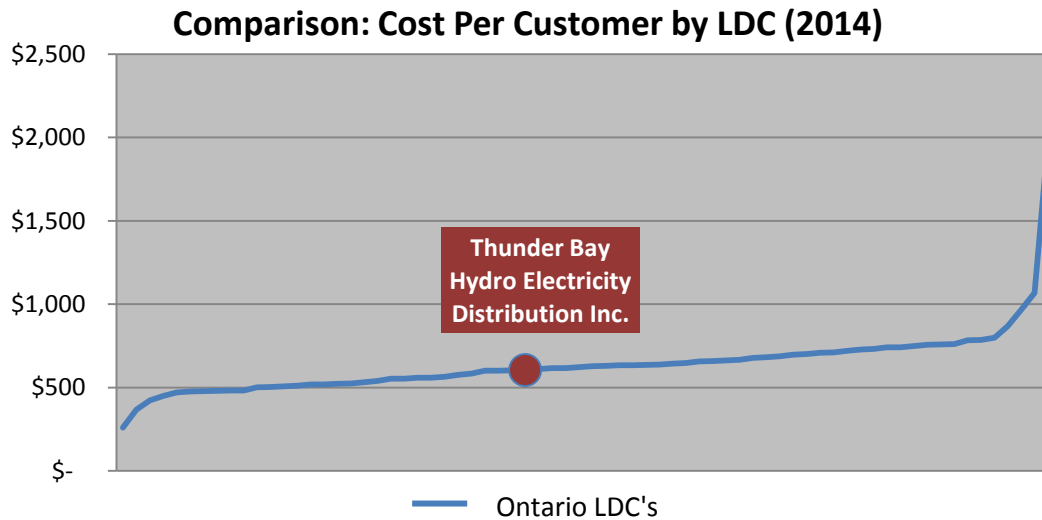


Figure 5.2.3-7 Total Cost Comparison by Ontario LDC¹

Total Cost per km of Line

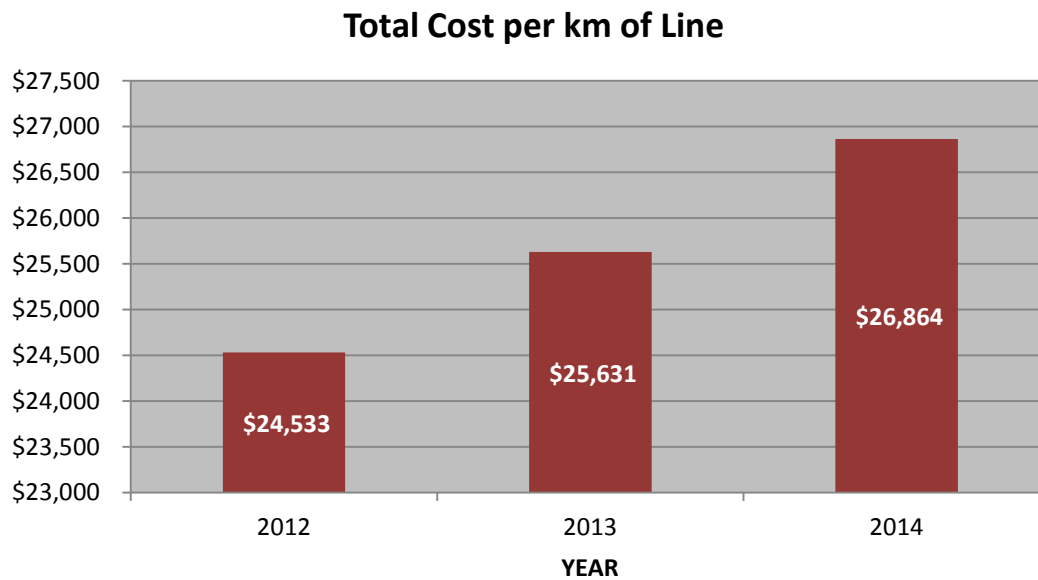


Figure 5.2.3-8 Total Cost per km of Line 2012-2014 (2015 not available at time of writing)

¹ Source: OEB Yearbook of Electricity Distributors

<http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors#elec>

Comparison: Cost Per Km (2014)

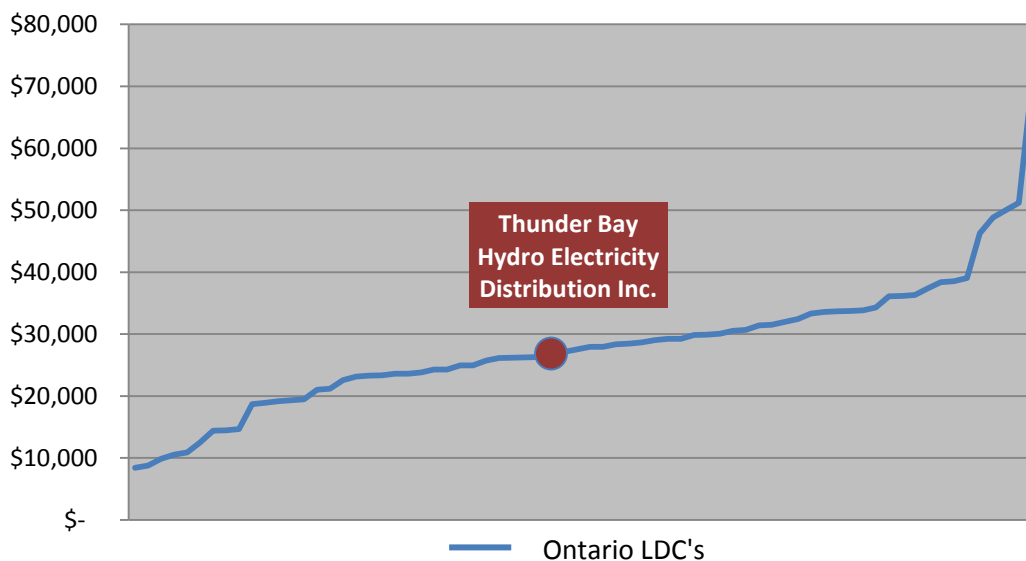


Figure 5.2.3-9 Cost per km Comparison by Ontario LDC²

Productivity / Efficiency Performance

In order to maximize productivity / efficiency performance, Thunder Bay Hydro is in the process of shifting its planning regimen to focus on larger capital replacement projects or a coordinated area of smaller projects, to the extent possible, where doing so will pose no safety or environmental hazard. This strategy relates to the economy of scale. It is much more effective to bear the fixed costs of renewal across a large quantity of assets as opposed to a small amount thereby reducing the overall per unit cost of the project.

Over the historical period, Thunder Bay Hydro has optimized its crew sizes for various aspects of its overhead and underground construction in an effort to reduce the associated labour costs. The full impact of this optimization will not be fully realized until Thunder Bay Hydro has undertaken a wide variety of projects in order to obtain metrics comparing past performance to current performance.

Thunder Bay Hydro has undertaken a seasonal planning approach to its construction activities. Understanding that some construction activities are most effectively performed for cost efficiency during specific times of the year; Thunder Bay Hydro has revised its construction practices by executing specific stages of a project at select times throughout the year and ensuring they are completed on schedule. For example, pole setting activities require less contractor and internal labour to complete

² Source: OEB Yearbook of Electricity Distributors

<http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors#elec>

during times of the year that the ground thawed. Thus project schedules have been built to reflect these requirements.

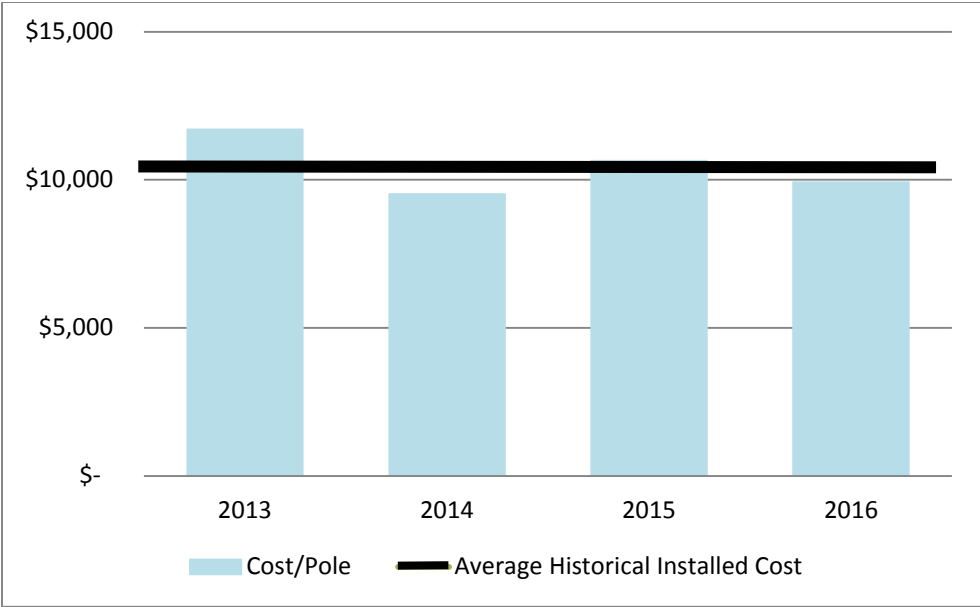


Figure 5.2.3-10 Historical Cost per Pole 2013-2016

Due to the efficiency / productivity gains discussed, Figure 5.2.3-10 Historical Cost per Pole 2013-2016 show that Thunder Bay Hydro has been able to effectively control its cost per pole despite inflation and increases in labour and material costs.

Several areas throughout Thunder Bay Hydro’s service territory contain infrastructure that cannot be accessed utilizing Thunder Bay Hydro’s standard fleet. As a result of this, Thunder Bay Hydro has been utilizing cranes to access and install infrastructure in these areas. Realizing that the crane represents a premium cost, Thunder Bay Hydro is continually looking for ways to minimize the time on site as well as the instances of mobilization and demobilization of the crane. In an attempt to improve efficiency Thunder Bay Hydro has revised its crane setting regime to ensure; that all preparatory work at each location is complete to the extent possible; and that the site has been reviewed with the crane operator to stage the crane optimally.

Public Policy Responsiveness

VII. Conservation and Demand Management

Figure 5.2.3-11 summarizes Thunder Bay Hydro’s CDM performance from 2011 to 2014. Percentages presented in the figure represent the cumulative value achieved annually as a percentage of the total CDM target.

Thunder Bay Hydro’s first CDM program spanned a three year period from 2011-2014 whereupon completion Thunder Bay Hydro had achieved 99.2% of its energy savings target of 47.38 GWh, and had achieved 69.9% of its demand target of 8.48 MW. The shortfall of Thunder Bay Hydro’s demand target was due in part to the DR3 program being discontinued in early 2014. This program was designed to reduce the demand from large volume customers during certain periods of the year.

Moving forward, Thunder Bay Hydro is targeting similar reductions in the current 2015-2020 tranche of 48 GWh with expectations of improving performance where achievable.

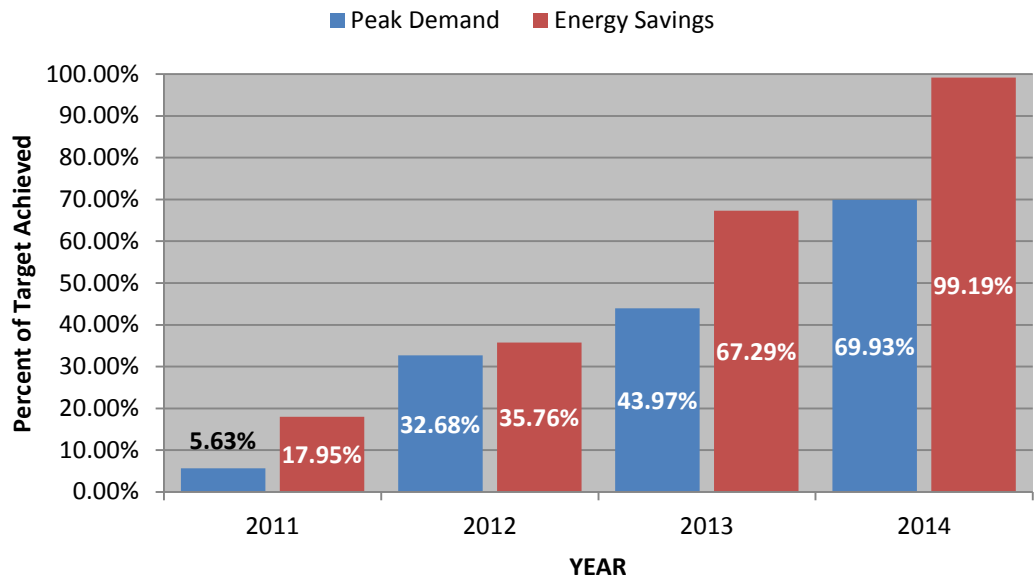


Figure 5.2.3-11 CDM Achievements 2011-2014

VIII. Renewable Generation

Renewable Energy Connection Impact Assessments Completed on Time

Thunder Bay Hydro has assessed 48 connections to date and has completed all CIA’s on time for the period 2012 to 2015.

New Micro-embedded Generation Facilities Connected On Time

Thunder Bay Hydro has connected 94 micro-embedded generators to date and has connected all of them within the allotted timeframe.

Financial Performance

IX. Financial Ratios

Figure 5.2.3-115 summarizes the financial ratios from 2012 to 2015. At 1.61, Thunder Bay Hydro maintains a strong liquidity ratio.

Profitability in both 2011 and 2012 reflects better than deemed return on equity due to unanticipated one-time transactions (Smart Meter revenue for previously expensed interest, regulatory settlement relating to payment-in-lieu of taxes (PILS) and Ministry of Finance interest on PILS assessment).

In 2014, the actual rate of 5.99% earned was lower than the approved rate of 7.00%. A lower rate is common, as annual distribution rates are adjusted between Cost of Service applications by an inflationary factor less an efficiency gain. In practice, this adjustment does not keep up with various costs such as rising salaries and wages, new initiatives and regulatory compliance requirements. As a result, there is often a decline in the regulatory rate of return in the years between Cost of Service applications.

Metric	TBH Target	2012	2013	2014	2015
Liquidity: Current Ratio	>1	1.72	1.62	1.85	1.61
Leverage: Total Debt	<=1.5	0.81	0.66	0.72	0.75
Profitability: Regulatory Return on Equity	Deemed = Achieved	Deemed 3.75% Achieved 7.74%	Deemed 7.00% Achieved 6.34%	Deemed 7.00% Achieved 5.99%	Deemed 7.00% Achieved 5.69%

Table 5.2.3-6 Financial Ratios 2012-2015

c) Explain how this information has affected the DS Plan (i.e. objectives, investment priorities, expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

5.2.3.3 Effect on the DSP (OEB Filing Req. 5.2.3c)

Service Quality

Thunder Bay Hydro has currently met or exceeded all of the OEB defined and corporately defined metrics for monitoring its quality of service as is evident in Table 5.2.3-1. For this reason these metrics are not directly influencing capital expenditures during this planning cycle. As Thunder Bay Hydro is committed to the satisfaction of its customers and expects to continue to achieve similar results through the forecast period.

Customer Satisfaction

As previously stated in section 5.2.2.1 Customer Engagement, reliability of supply while stabilizing costs is at the top of mind of Thunder Bay Hydro's customers. With this in mind, Thunder Bay Hydro has been able to steadily ramp up investments in System Renewal and System Service in an attempt to reduce the quantity and severity of outages experienced by our customers.

Feedback has indicated that while customers dislike rate increases they also understand that increased investment is necessary to maintain assets and improve functionality. Figure 5.2.2-4 and Figure 5.2.2-5 illustrate that customers feel the level of investment is appropriate and are confident that Thunder Bay Hydro is directing these investments appropriately.

Safety

Thunder Bay Hydro has currently met or exceeded all of the OEB defined metrics for monitoring safety of its employees and the public as is evident in Table 5.2.3-1. Thunder Bay Hydro is committed to the safety of its customers and personnel and in order to maintain the expected level of safety, it has prioritized projects which pose a safety risk in order to continue to achieve similar results through the forecast period.

System Reliability

As noted in Figure 5.2.3-5, nearly one quarter of all of Thunder Bay Hydro's outages can be attributed to Defective Equipment. Thunder Bay Hydro continuously monitors and analyzes reliability metrics making note of underperforming assets and the worst performing feeders. Investments can then be focused on problematic areas or assets. Thunder Bay Hydro believes that continued investments in system renewal will allow the utility to maintain its reliability targets.

System Service investments have been focused in high impact areas that will allow us to quickly identify, isolate and restore power using grid modernization techniques. High impact areas are assessed based on criticality (as those that impact large numbers of customers and/or extended outage periods), restoration time and system redundancy. This process serves to define project areas and equipment to implement in the system.

Asset Management

Asset management metrics at Thunder Bay Hydro are evolving and still in development. As previously stated for the purposes of reporting on these requirements Thunder Bay Hydro has developed the following metrics relative to cost efficiency and effectiveness with respect to the planning quality and DSP implementations:

- a) Financial performance measured as plan vs actual expenditures percentage
 - a. Over expenditure >100%
 - b. Under expenditure <100%
- b) Scope Management measured as plan vs actual quantities of assets renewed percentage
 - a. Larger than planned quantities renewed >100%
 - b. Less than planned quantities renewed <100%
- c) These two will be factored together for a reported "On-Schedule", "Ahead of-Schedule" or "Behind-Schedule" performance measure.

As part of its commitment to continuous improvement Thunder Bay Hydro actively sought ways to further improve its asset management process. As a result, Thunder Bay Hydro engaged Kinectrics Inc.,

a leader in providing life cycle management solutions for the electricity industry, to complete an Asset Condition Assessment for its major asset categories. The process included an in-depth review and analysis of the data available for these major assets, as well as a detailed report outlining the health of Thunder Bay Hydro's system (via a health index). The output of this process yields levelized renewal targets for each asset category.

The engagement of Kinectrics and subsequent report complete with health index has greatly impacted the development of this DSP. Thunder Bay Hydro has revised its previous capital plan to harmonize with results of the Kinectrics report. In doing so, Thunder Bay Hydro considered; the impact this shift would have on projects currently under execution; the impacts to the current planning cycle; and the impacts to customers, the municipality and 3rd party attachers. For these reasons, Thunder Bay Hydro has chosen a conservative approach to implementing the shift over a 3 year period.

Thunder Bay Hydro will continue seek improvements where it can, in particular in its data collection efforts, to help close any data gaps and in doing so increase the integrity of the analysis. This will further aid in informing on the asset renewal process and the decisions that influence the capital investment plan.

Cost Control

Thunder Bay Hydro continues to work diligently to reduce costs and be more efficient. For this planning cycle, Thunder Bay Hydro expects to further improve operational efficiencies through implementation of operations technology and SCADA. Over the historical period Thunder Bay Hydro has deployed several devices that assist in the timely and effective operation of the system (i.e. remotely operated switches with telemetry, fault indicators, etc.). For this planning period Thunder Bay Hydro is proposing expenditures in these areas in anticipation of further improvements in efficiencies.

Public Policy Responsiveness

Based on the current results, the metrics in this category are not directly influencing operational imperatives. However, Thunder Bay Hydro will continue to support conservation programs and other initiatives aimed at reducing consumption.

Renewable connections are expected to remain static or to continue decreasing for the forecast period. In addition to this assumption, Thunder Bay Hydro has consulted with local development groups, and anticipates minimal new Micro Generation connections due to reduced return on investment for installations, and continued constraints in the rural areas. For these reasons these metrics are not directly influencing capital expenditures during this planning cycle.

Financial Ratios

Thunder Bay Hydro has currently met or exceeded all of the internally defined metrics for financial ratios. For this reason these metrics are not directly influencing capital expenditures during this planning cycle. As Thunder Bay Hydro is committed to the satisfaction of its customers it expects to continue to achieve similar results through the forecast period.

The Corporation of the City of Thunder Bay is the sole shareholder of Thunder Bay Hydro Corporation and has deemed that Thunder Bay Hydro be operated in accordance with the rate minimization model. The model means a shareholder philosophy of minimizing electricity rates for customers by having these rates reflect the shareholder foregoing its allowable regulated return on shareholder equity.

Accordingly, the spirit of this principle is to keep electricity rates as low as possible and to encourage economic development by foregoing debt and dividend payments. The note payable to the City of Thunder Bay was set up without any provision for the payment of interest or the repayment of principal. Additionally, the Corporation of the City of Thunder Bay does not seek a dividend from Thunder Bay Hydro.

5.3 Asset Management Process (OEB Filing Req. 5.3)

As noted in the introduction, a distributor's asset management process is the systematic approach used to plan and optimize ongoing capital and operation and maintenance expenditures on its distribution system and general plant. The purpose of the information requirements set out in this section 5.3 is to provide the Board and stakeholders with an understating of the distributor's asset management process and the direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

5.3.1 Asset Management Process Overview (OEB Filing Req. 5.3.1)

This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to the requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates.

Thunder Bay Hydro strives to construct and maintain a safe, environmentally responsible, sustainable and economical distribution system that reliably delivers electricity to our customers. This statement forms the basis of our asset management process and influences all planning decisions.

The asset management process facilitates the planning, operation, maintenance and retirement of assets. The process incorporates facets of leading asset management practices; aligns long-term asset management strategies with corporate goals; continuously reports on targets and compares their intended results and; incorporates regular reviews designed to seek improvements to the process.

- a) A description of the distributor's asset management objective and related corporate goals, and the relationship between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments.*

5.3.1.1 Asset Management Process Objectives (OEB Filing Req. 5.3.1a)

All asset management initiatives implemented by Thunder Bay Hydro are designed to fulfill the intentions of the asset management strategy and strategic corporate goals. To this end Thunder Bay Hydro has adopted the following Asset Management Objectives.

- Health and Safety – Thunder Bay Hydro is obligated to ensure that the manner in which it executes its initiatives does not negatively impact the health and safety of the general public, customers or Thunder Bay Hydro’s employees.
- Environment – Thunder Bay Hydro seeks to minimize impact to the environment through consideration of the project area, the potential contaminants released during asset failure and proximity to sensitive environmental areas.
- Regulatory/Legal Obligations – Thunder Bay Hydro seeks to prioritize projects based on the successful completion of regulatory and/or legal obligations.
- Customer Driven Work – Thunder Bay Hydro is committed to executing customer work in a timely manner.
- Asset Retirement – Thunder Bay Hydro seeks to prioritize project selection based on assets that are at or beyond their useful life as determined through Thunder Bay Hydro’s ACA process.
- Operational Efficiency – 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 asset management objectives listed above are listed in order of importance and are used to inform the project selection and prioritization process found in Section 5.4.2.3 (The detailed scoring methods for determining the degree to which a project satisfies these objectives can be found here). The asset management objectives are closely related to Thunder Bay Hydro’s corporate goals and strategic initiatives (see Section 5.3.1.2 below). This relationship allows Thunder Bay Hydro to consistently identify and prioritize assets for renewal or refurbishment and uses this to inform the Capital Expenditure Plan.

5.3.1.2 Related Corporate Goals (OEB Filing Req. 5.3.1a)

AM Objectives	Corporate Values
Health & Safety	Health & Safety Culture, Human Resources, Relationships

Environment	Respect for the Environment
Regulatory/Legal Obligations	Relationships
Customer Driven Work	Customer Service Focus
Asset Retirement	Effective Asset Management, Reliability
Operational Efficiency	Resource Efficiency

Table 5.3.1-1 Asset Management Objectives

The long term corporate values are the defining characteristics that the organization seeks to maximize in its day-to-day operations. The goals and strategies defined at this level and the relationship to the asset management objectives are used to assess the degree to which projects adhere to the guiding principles of the organization.

Health & Safety

Thunder Bay Hydro is committed to creating and maintaining a corporate culture where Health and Safety are the Utility's top priority. The ultimate objective of the health and safety efforts is the pursuit of zero workplace incidents through the implementation and continued support of the Utility's committed to Safety program. In support of this goal, Thunder Bay Hydro continually focuses on incident performance trends and ensuring safe work practices and procedures documents are current.

Human Resources

Long term success requires Thunder Bay Hydro continue to offer a fulfilling, fair and challenging work environment to that allows us to attract, develop, engage and retain high quality staff. Thunder Bay Hydro regularly seeks to engage its employees through meetings and other communications that outline relevant utility developments. Formal feedback from employees is sought both through bi-annual engagement surveys that serve to inform on existing programs; as well through design and selection phase of projects to ensure that knowledge gained from past projects is integrated early on in an attempt to reduce costs and ensure the highest levels of safety are maintained.

Relationships

Thunder Bay Hydro has an ongoing commitment to the relationships it has established with its employees and customers as well with local and provincial municipalities, regulators and ministries. Through regular dialogue with these stakeholders, Thunder Bay Hydro is able to stay at the forefront of challenges facing the utility. Thunder Bay Hydro is further able to stay informed of developments, constraints and changing requirements in the industry. This knowledge is an important factor in the development and implementation of an effective distribution system plan as it informs on project selection and timing, ensuring Thunder Bay Hydro executes projects which provide the greatest benefit to the ratepayer.

Respect for the Environment

Thunder Bay Hydro has a diverse asset population that has the potential for harm to the environment. For this reason and through the inspection and design process, Thunder Bay Hydro seeks to minimize the impact that its assets have on the environment where and when it is appropriate to do so. Thunder Bay Hydro also actively seeks out ways to manage its waste streams in an effort to reduce its effect on the environment.

Customer Service Focus

At its core, Thunder Bay Hydro exists to provide safe, reliable electricity supply to its customers. Meeting this obligation requires an understanding of our customers' needs and expectations and a commitment to delivering a high level of service. Thunder Bay Hydro continuously monitors its performance in the form of OEB and corporate metrics targeted towards providing timely service and effective communication to our customers.

Effective Asset Management

In order to ensure the long-term performance of the Utility, a well-developed, long term approach to infrastructure investment and maintenance is critical. In support of this goal and in support of the DSP, Thunder Bay Hydro maintains a rolling capital expenditure and asset replacement plan that reflects the Utility's commitment to optimized, long-term fiscal sustainment and infrastructure renewal.

Reliability

Thunder Bay Hydro is committed to providing highly reliable electricity supply to its customers as is evidenced in Section 5.2.3.2. We regularly analyze our reliability statistics to determine opportunities for improvement and use this data to assess the extent to which certain projects will impact reliability and how best to effectively implement these opportunities.

Resource Efficiency

Thunder Bay Hydro dedicated to effectively and efficiently managing all of the resources required by the Utility. It is important to the long term success of the Utility that specific strategies be employed to ensure we are able to maintain capital expenditure levels and operating and maintenance costs.

b) A description of the distributor's asset management objective and related corporate goals, and the relationship between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments.

Information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets,

primary process steps and information flows used by the distributor to identify, select, prioritize and/or pace investments; i.e.:

- *asset register;*
- *asset condition assessment;*
- *asset capacity utilization/constraint assessment;*
- *historical period data on customer interruptions caused by equipment failure;*
- *reliability based ‘worst performing feeder’ information and analysis;*
- *reliability risk/consequence of failure analyses.*

Use of a flowchart illustration accompanied by explanatory text is recommended.

5.3.1.3 Asset Management Strategy (OEB Filing Req. 5.3.1b)

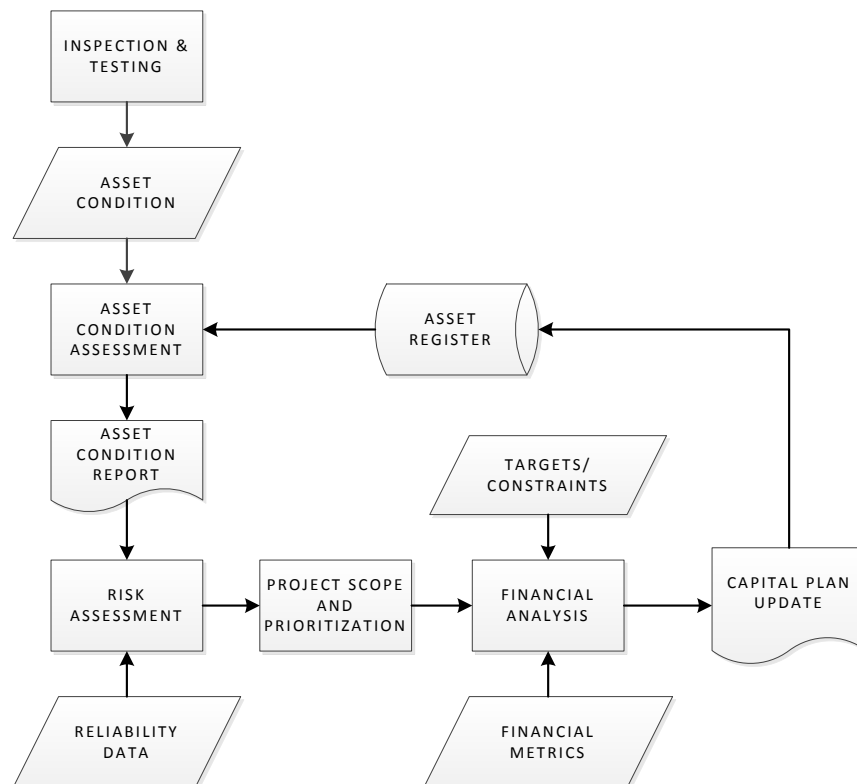


Figure 5.3.1-1 - Thunder Bay Hydro Asset Management Framework

A. Asset Management Framework Summary

Figure 5.3.1-1 above details the strategy Thunder Bay Hydro utilizes to appropriately select and prioritize asset investments. The process begins with the inspection and testing phase. Thunder Bay Hydro has a mature and comprehensive inspection and testing regime that provide details on asset condition. These

programs have been refined over time and incorporate information on industry best practice, historical findings and regulatory requirements.

An asset condition report is formed based on detailed analysis of the contents of the asset register in conjunction with the inspection and testing programs. The output of this forms the basis of the pace at which assets in the system require action to be taken. Assets identified as part of this process are then evaluated based on the risk they pose to the system. Considerations during this process include consequence of failure, redundancy, availability of temporary measures and historical reliability data.

The output of this process defines the project scope. Financial analysis of projects is then executed utilizing historical metrics driven from previously executed projects. Considerations during this process are financial targets or constraints from internal performance measures and corporate strategic initiatives. This process is further discussed in Section 5.4.2.

The final output of this process is used to inform and update the capital expenditure plan.

B. Data Sets

i. Asset Register

The asset register is made up of data from various databases and is generally available through Thunder Bay Hydro's GIS interface. The data comprises all the information that allows each asset to be uniquely identified such as serial number, nameplate data, and Thunder Bay Hydro assigned identifiers. It also contains data regarding the physical characteristics such as age and configuration of the asset as well as installation and removal data and location. The register is routinely updated as assets are installed, removed or refurbished as requirements dictate.

As part of its commitment to continuous improvement, Thunder Bay Hydro is currently contemplating implementing a formal pole testing regimen as part of its inspection process. This would provide quantitative data on the condition of the specified poles within this system and would inform the ACA with objective information. The data collected would improve the quality of the ACA analysis as well; assist in determining the condition of poles suspected to be in poor health.

ii. Asset Condition Report

An ACA study has been completed and a report has been prepared by Kinectrics to determine the current health of Thunder Bay Hydro's distribution system assets. The resulting report describes the methodology used to analyze the major assets within the distribution system and identifies data gaps where they exist. The report contains information relating to Thunder Bay Hydro's efforts to date and provides insight into opportunities for improvement in the inspection process. The report also provides a levelized asset replacement schedule which helps to inform the renewal portion of the capital expenditure plan.

iii. Historical Period Data on Customer Interruptions caused by Equipment Failure

Thunder Bay Hydro has large repository of data relating to customer interruptions, including those caused by equipment failure. The outage data is considered during the risk assessment process and involves analyzing the frequency and duration of outages and the number of customers affected by a given project. The impacts to SAIDI and SAIFI are considered at this time when selecting and prioritizing projects. These factors are also considered early on in the selection and design process where performance or reliability issues can be resolved.

iv. Reliability-Based ‘worst performing feeder’ information and analysis

Thunder Bay Hydro tracks feeder performance as a composite of all OEB defined outage categories; as well individually by OEB outage category and trends feeder performance overtime. By analyzing the data Thunder Bay Hydro is able to identify the poorest performing feeders annually, as well as feeders that have continually performed poorly. Feeder performance is further analyzed to determine how current programs will impact these statistics and consideration to this fact is given at the time of selecting and prioritizing projects.

v. Financial Metrics

Thunder Bay Hydro utilizes financial metrics on a per unit basis for its major asset categories based on actual historical replacement to estimate future capital costs for projects of similar size and scope. These metrics are updated annually to ensure that the estimating process continues to be effective and is based on the best available data each year.

vi. Targets/Constraints

This dataset contains renewal targets as well as financial, schedule and resource constraints. The renewal targets are mainly a driven from the results of the ACA report and provide information on the levels of renewal required annually for each asset class. Financial constraints are a driven from Thunder Bay Hydro’s strategic corporate goals and direction from senior management and assist in guiding the overall financial envelope annually. Schedule constraints arise from the fact that Thunder Bay Hydro schedules specific activities during certain times of the year, as they are most effectively executed at these times. Resource constraints consider internal personnel availability as well as contractor and material availability.

C. Processes

i. Inspection Data & Testing

Inputs:

- Asset Register – provides listing of assets requiring inspection.
- Inspection Forms – electronic and paper forms are utilized to collect pertinent data relating to asset condition.

Process Description:

Thunder Bay Hydro performs regular inspections of all major components of its distribution system. The asset inspection information becomes a subset of data associated to the asset. The information is used as an input to the asset condition assessment. Table 5.3.1-2 below details the frequency and inspection method for each asset category.

ASSET	INSPECTION FREQUENCY	INSPECTION METHOD
Substations	Monthly	Visual
Substation Transformers	Annual	DGA
Pole Mounted Transformers	Triannual	Visual
Pad Mounted Transformers	Triannual	Visual
Pad Mounted Transformers	9 Years	Detailed
Vault Transformers	Triannual	Detailed
Switches	Triannual	Detailed
Reclosers	Triannual	Visual
Poles	Triannual	Visual

Table 5.3.1-2 Thunder Bay Hydro Asset Inspection Frequency

Inspections are performed throughout the year and their execution and inspection content vary by asset class. The data that is collected is validated and analyzed and then linked back to the asset register. During the inspection cycle any major defects that are noted, that may potentially impact safety, are immediately reported for corrective action. An example of this may be low hanging conductor or a transformer that has shifted on its foundation. Both of these pose a safety hazard and defects such as these would be corrected immediately.

Outputs:

- Inspection Data – data is returned from the field in the form of spreadsheets, hard copies and digital records and are recorded in the asset register for further analysis and input to other processes.
- ii. Asset Condition Assessment

Inputs:

- Inspection Data – data from current and past field inspections becomes part of the criteria assessed in the ACA.
- Asset Register – provides the details that are characteristic of each asset class for the various condition criteria assessed in the ACA.

Process:

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.

Through the inspection process, Thunder Bay Hydro has identified the fact that a significant portion of its underground assets are reaching the end of their useful life as well. Increased investment in underground renewal would then also be required to reduce the backlog of assets that have reached, or will reach the end of their useful lives in the near term.

Understanding that determining the appropriate replacement levels for all of its distribution assets is a complex problem, Thunder Bay Hydro sought to engage a third party to assist with this process.

As a result, and in order to better refine its asset condition assessment, Thunder Bay Hydro engaged Kinectrics to complete an ACA of key distribution assets. The results of which are summarized in Figure 5.3.1-2 below. The full ACA report is available for review in Appendix C.

Health Index Results Summary 2015

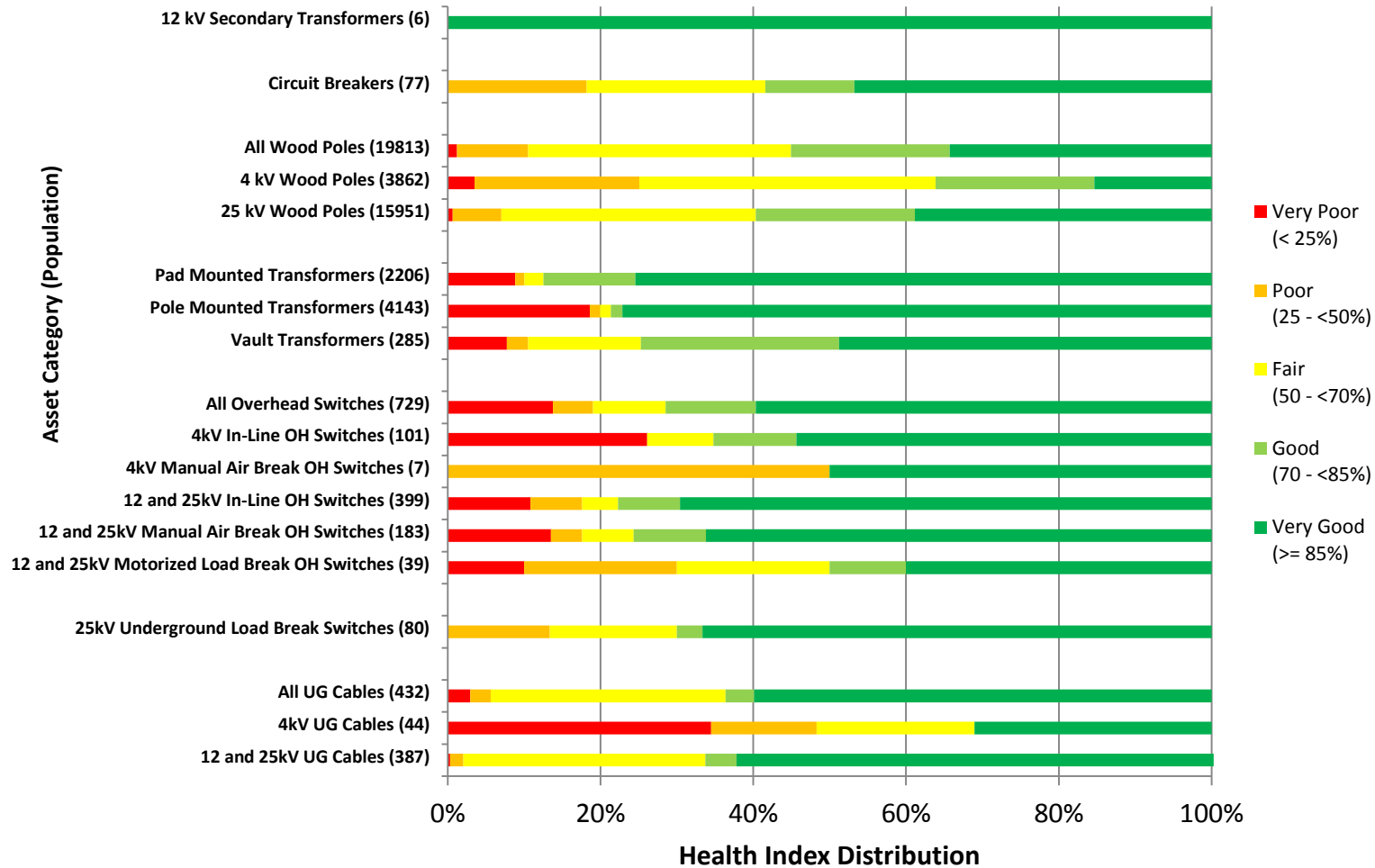


Figure 5.3.1-2 Health Index Results Summary 2015

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 estimate 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/repared 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:

Thunder Bay Hydro has leveraged its GIS system and divided its service territory into project areas based on significant electrical features (i.e. by feeder in the case of voltage conversions), system topology (i.e. overhead vs. underground distribution), as well by other considerations (i.e. areas to deploy smart devices). These project areas are assessed for the risk they pose based on the consequence of failure. In determining the consequence of failure, Thunder Bay Hydro considers the following:

- the known failure modes of the asset;
- impact to safety, both to the public and personnel;
- proximity to sensitive environmental areas;
- impact to system and reliability;
- difficulty in implementing temporary measures; and
- the impact of reactive replacement.

The project is assigned a qualitative risk score of High, Medium or Low based on the negative or positive impacts that it has on one or more of the consequences listed above.

Outputs:

- Project Area Risk – the values that result from the Reliability Risk/Consequence Assessment are input into the project listing database and are used as a variable in prioritizing projects.

iv. Project Prioritization and Selection

Inputs:

- Project Area Risk – the project area risk value for each project becomes a factor in the prioritization scheme.
- Targets/Constraints – the levelized replacement schedule is used to optimize project selection so that replacement levels are achieved annually. Resource constraints are considered to ensure the appropriate means are available to complete the work. Financial constraints are considered to optimize expenditure levels and ensure they align with corporate goals.
- Capital Project Database (GIS) – contains the listing of all project areas for under consideration for implementation.
- Financial Metrics - contain the historical per unit metrics Thunder Bay Hydro uses to estimate the budgetary costs of a particular project within the Capital Project database.

Process:

Thunder Bay Hydro prioritizes the projects in the capital project database based on several criteria. Criteria such as; overall risk values (generally the risk relative to other projects is considered more heavily than absolute risk); composite health of the assets within a project area (is the project area in good health or poor health overall); project alignment asset management objectives and hence with corporate goals and initiatives; and potential for investment efficiencies (economies of scale, coordination with 3rd parties, etc.) A projects rank is then formulated based on the degree to which it

satisfies these criteria and the entire listing is sorted in descending order based on the formulated value for each project. Projects are then selected from this list and the selection is optimized based several key considerations including: the levelized replacement plan identified in the ACA; availability of resources such as personnel, contractors and material; as well as scheduling constraints that limit the amount of certain types of work that can be executed annually. This optimization process ensures that the appropriate quantities of assets are renewed annually to maintain the overall health of the system; and that project costs are not negatively impacted by the timing and availability of resources. The investment priority and pace are set forth from this process and are used to inform Thunder Bay Hydro's DSP.

Outputs:

- Capital Plan Updates – the capital expenditure plan is updated to include the selected and forecasted projects with estimated costs and resource requirements.
- Capital Project Database – the capital project database is updated to reflect the planned year of construction for each project as well as the anticipated costs.

5.3.2 Overview of Assets managed (OEB Filing Req. 5.3.2)

Appropriate regulatory assessment of DS Plans requires an understanding of the scope and depth of the assets managed by a distributor. Distributors vary in terms of the types of assets managed (i.e. some own high voltage equipment, others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed.

a) A description and explanation of the features of the distribution service area (i.e. urban/rural, temperate/extreme weather, underground/overhead, fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable the expectations for the evolution of these features over the forecast period that have affected elements of the DSP Plan.

5.3.2.1 Features of the Distribution Service Area (OEB Filing Req. 5.3.2a)

Service Territory – Urban/Rural

Thunder Bay Hydro's service area is bounded by the limits of the City of Thunder Bay which encompasses an area covering approximately 387 square kilometers. This service area is made up of approximately 70% rural and 30% urban (by customer density). Our distribution is approximately 79% overhead and 21% underground (by length). This yields a significant number of overhead line assets per customer that require maintenance or replacement. Thunder Bay geology consists mainly of; areas of bedrock surrounded by areas of silt, sand and gravel; with interspersed areas of swamp. This geology can present installation challenges for both overhead and underground infrastructure.

Temperature/Extreme Weather

The climate in the Thunder Bay area is typical of a mid-latitude inland location with a Great Lake Moderating influence. The moderating effect of Lake Superior results in cooler summer temperatures and warmer winter temperatures for an area along the lakeshore extending inland. The large rural area previously described provides greater exposure to significant weather events such as high winds and heavy ice/snow storms. The impacts of weather related events on reliability have been described in detail in section 5.2.3.2.

Economic Growth

A load forecast was completed in 2016 as a part of the IRRP process and through the process provided Thunder Bay Hydro with insight into the economic trends and variables effecting growth in its distribution system. The economic factors that were determined to have an effect on growth in the service area are listed below:

- Commodity Prices (Timber, Grain, and Metals);
- Unemployment rates
- Consumer Price Index (CPI)
- Inflation

By reviewing these factors and their predictors over the forecast period, Thunder Bay Hydro expects economic growth to be gradual (Inflation of 2.0-2.9 %) over the forecast period. This prediction of slow economic growth is an input into the System Access category investment planning, as projects in this category are expected to remain steady over the 2017-2021 forecast periods.

b) A summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations.

5.3.2.2 System configuration (OEB Filing Req. 5.3.2b)

Thunder Bay Hydro's customers are serviced through three HONI owned and operated transformer stations:

- Port Arthur TS (P2);
- Birch TS (P17); and
- Fort William TS (P17)

These supply points distribute 25kV throughout the city. Thunder Bay Hydro further owns and operates four (4) 12kV municipal substations, and at the time of writing this DSP ten (10) 4kV municipal substations. The 12kV substations supply the majority of the rural distribution through the service territory and are generally configured in radial format with some capability to interconnect feeders. The

4kV network is, in general, heavily meshed readily allowing for load transfer throughout the system. The following tables further describe the circuit length and station utilization.

Voltage (kV)	Phase	No. of Circuits	Overhead Circuit Length (m)	%	Underground Circuit Length (m)	%	Total Circuit Length (m)
4	1	38	71988	8%	4976	2%	168986
	3		81744	9%	10279	4%	
12	1	6	187354	20%	17921	7%	304915
	3		97002	10%	2639	1%	
25	1	23	150821	16%	137817	54%	719230
	3		347970	37%	82621	32%	
Total			936880	100%	256252	100%	

Table 5.3.2-1 Primary Line Length by Voltage Level

STATION #	STATION NAME	TX ID	WINTER LTR RATING (MVA)	2015 PEAK DEMAND	% UTILIZATION
STN #2	PATS	2T1	55.26	34.2	62%
		2T2			
STN #17	BRTS	17T3	106	74	70%
		17T2			
		17T4			
STN #10	FWTS	10T5	103.9	79.2	76%
		10T6			

Table 5.3.2-2 HONI Transformer Stations Utilization

c) Information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled.

5.3.2.3 Asset Condition (OEB Filing Req. 5.3.2c)

The following Table 5.3.2-3 Thunder Bay Hydro Distribution Assets summarizes the approximate number of distribution assets within Thunder Bay Hydro's service territory. Information regarding the condition of Thunder Bay Hydro assets is presented in Figure 5.3.1-2 as a graphical overview. Both of these sources of information are current as of December 31, 2015.

Asset Description	Quantity (units*)
Power Transformers	21

Circuit Breakers	77
Wood Poles	19386
Padmount Transformers	2240
Pole Mounted Transformers	5076
Vault Transformers	285
Overhead Switches	729
Underground Switches	79
Underground Primary	256 cct-km
Reclosers	25
Metering	50000
Overhead Primary Conductor	936 cct-km
Underground Secondary Cable	485 cct-km
Underground Secondary Cable	485 cct-km

* unless otherwise noted, cct-km is the total length of conductor irrespective of configuration (ie.single phase or three phase) and will be less than total conductor length

Table 5.3.2-3 Thunder Bay Hydro Distribution Assets

Power Transformers

Thunder Bay Hydro's 4kV and 12kV networks rely on power transformers to stepdown from 25kV primary to the secondary voltage noted. These assets are located throughout Thunder Bay Hydro's distribution territory. It can be noted that from Table 5.3.2-4 that these assets are well beyond the TUL of 45 years, as identified in the Report ³provided by Kinectrics to the OEB for this asset class. Historically, Thunder Bay Hydro's replacement strategy was focused around decommissioning heavily aged substation assets in conjunction with heavily aged wood pole assets connected to the aforementioned substations; as in general there was a strong correlation in age. The implementation of this strategy has been to convert the 4kV network to 25kV through an accelerated wood pole renewal plan resulting in a decommissioning schedule whereby all 4kV power transformers would be removed from service over a 10 year period.

The decommissioning of these stations and subsequent project areas was prioritized based on several factors including: interconnectivity of the station; age of the substation; and age of the assets connected to the station. A significant influencing factor in the project selection and prioritization was the interconnectivity of a particular 4kV station with other 4kv stations. This factor would allow Thunder Bay Hydro to maintain the network mesh of heavily interconnected substations for as long as possible for several reasons:

³ "Asset Depreciation Study for the Ontario Energy Board", conducted by Kinectrics, July 8, 2010.

- 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.

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

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

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

employed for assets which are proactively maintained or those that are costly to replace on a per unit basis.

It can be noted in the Table 5.3.2-5 that that ACA provided by Kinectrics has identified several assets are in poor condition; however they are flagged for action outside of the current planning window of this DSP. The intent is to maintain the breakers to ensure that they remain in service until such time as the corresponding station is decommissioned; rather than attempt to replace these with new units.

The remainder of the assets to follow are operated on a run-to-fail basis (see Table 5.3.1-3 Thunder Bay Hydro Asset Operating Strategy for a summary of operating strategies). These types of assets are assessed as a population where no particular condition is assigned to any one asset. As a result, a condition is assigned to a percentage of the population and more specifically a quantity of assets is flagged for each category. Together these two approaches developed between Thunder Bay Hydro and Kinectrics support an effective and balanced renewal program in this DSP.

Wood Poles

The results of Kinectrics ACA for Thunder Bay Hydro's wood pole population are shown in Figure 5.3.2-1 and Figure 5.3.2-2 below. The condition is based on several factors both characteristic and extrinsic to the asset which are documented through Thunder Bay Hydro's inspection process. The figures indicate that approximately 45% of the wood pole population is in Fair to Very Poor condition. The sample size used to determine the health index equates to 100% of the population.

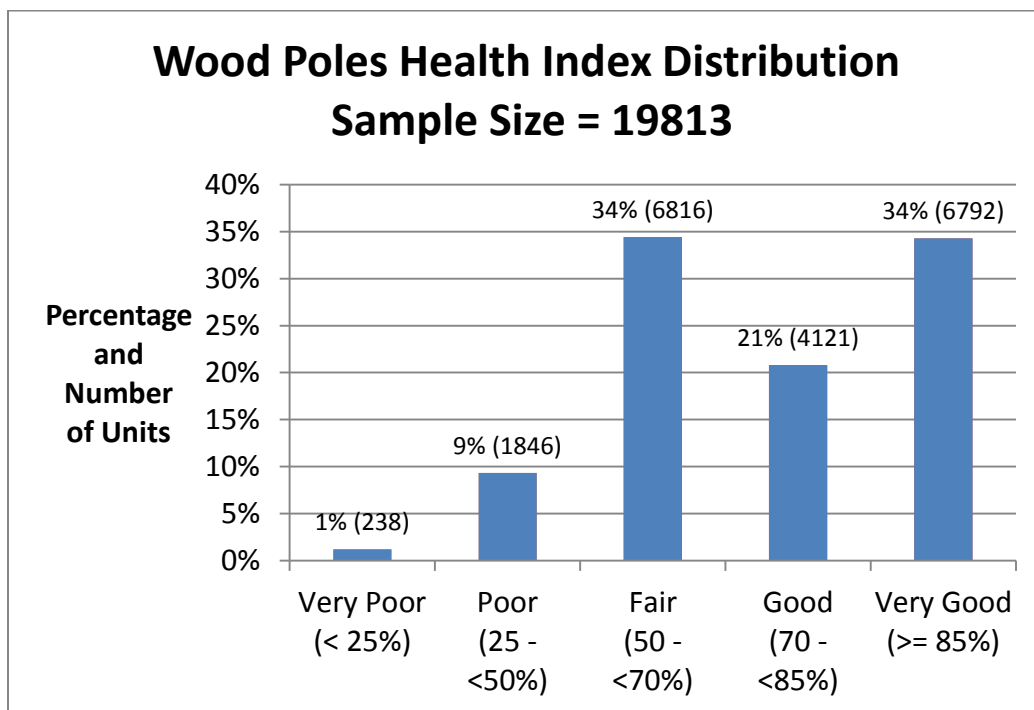


Figure 5.3.2-1 - Kinectrics ACA Wood Pole Health

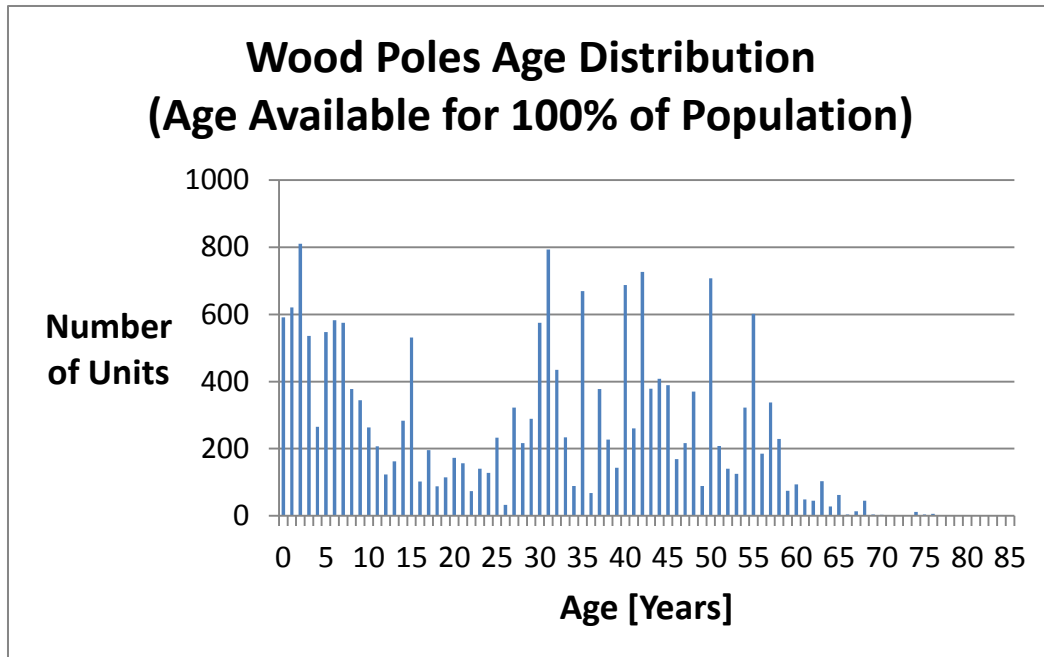


Figure 5.3.2-2 Kinectrics ACA Wood Pole Age

Pad Mounted Transformers

Pad mount transformers and pad mount equipment in general are largely impacted by external factors that lead to expedited degradation such as salt and moisture at the ground level. This information is tracked via the inspection process and is an important factor in determining the health of the assets in this category. The sample size used to determine the health index equates to 100% of the population.

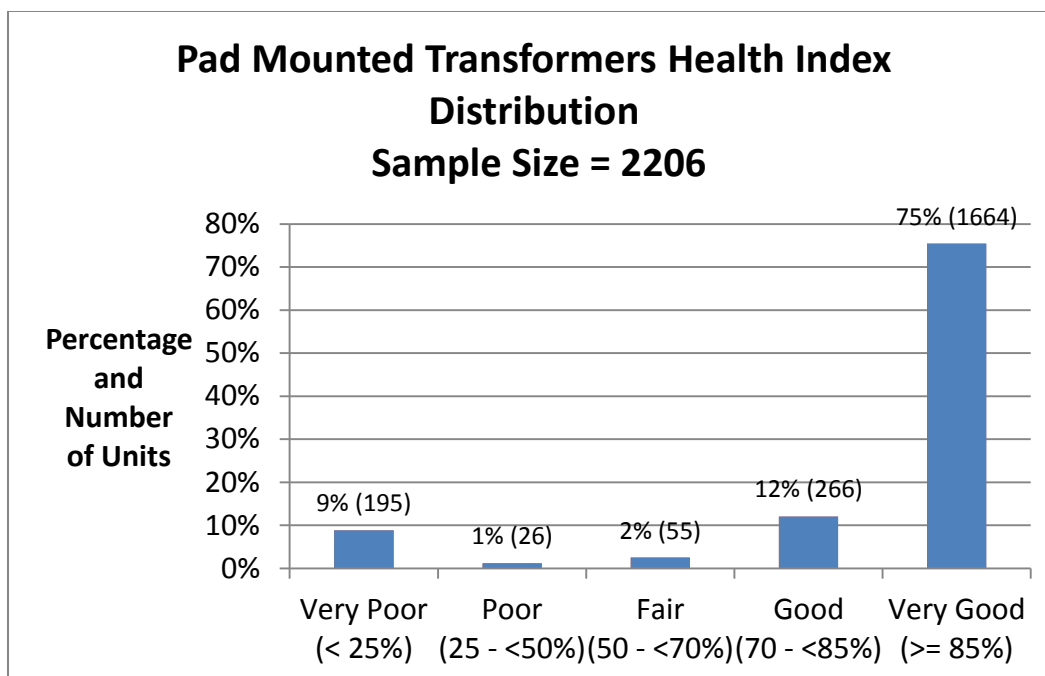


Figure 5.3.2-3 - Kinectrics ACA Pad Mounted Transformers Age

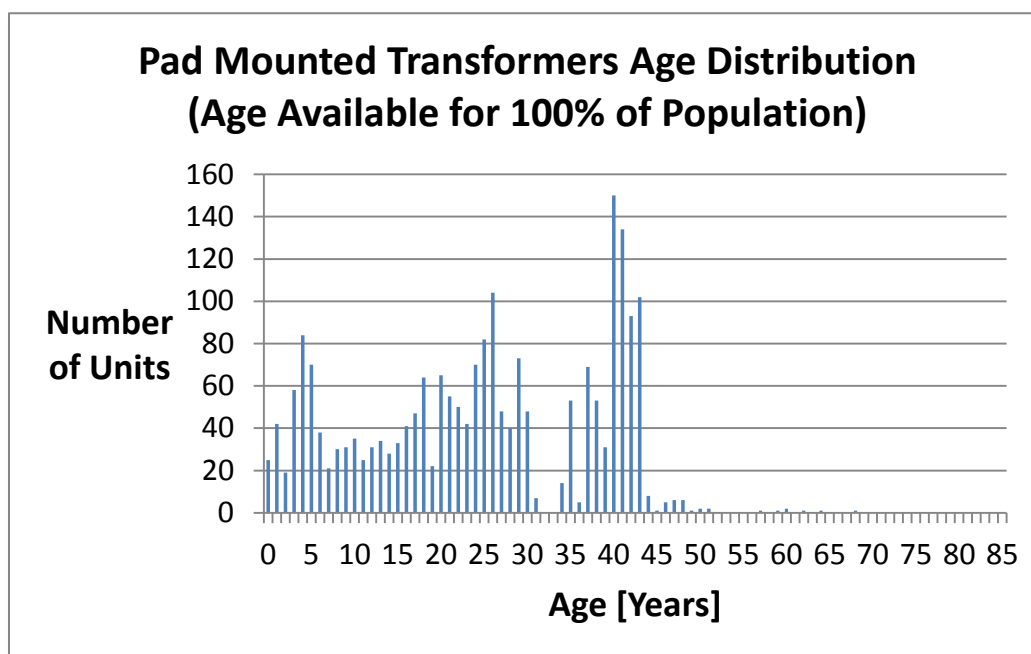


Figure 5.3.2-4 - Kinectrics ACA Pad Mounted Transformers Health

Pole Mounted Transformers

Pole mount transformers are minimally impacted by external factors and as a result the significant majority of the population are in very good health for a wide variety of ages as indicated in Figure 5.3.2-5 and Figure 5.3.2-6 below. One area of concern for this asset class is a large population of assets

containing PCB's. Thunder Bay Hydro is currently actively managing those units with 50 ppm or greater through the mandated Regulations enacted under the Canadian Environmental Protection Act, 1999. At the onset of this program, all units were suspected to contain PCB's. (note, this is based on the age of the unit, as PCB's were no longer used in the manufacture of transformers after a certain date) Once all units were tested for PCB content, the results were documented in the asset register. Thunder Bay Hydro actively replaces a percentage of the population of transformers known to have greater than 50 ppm of PCB's annually; with the intent to have all these units out of service by the mandated end-of-use dates set forth in the regulation. Otherwise these units are managed through the conversion process and through attrition. The sample size used to determine the health index equates to 100% of the population.

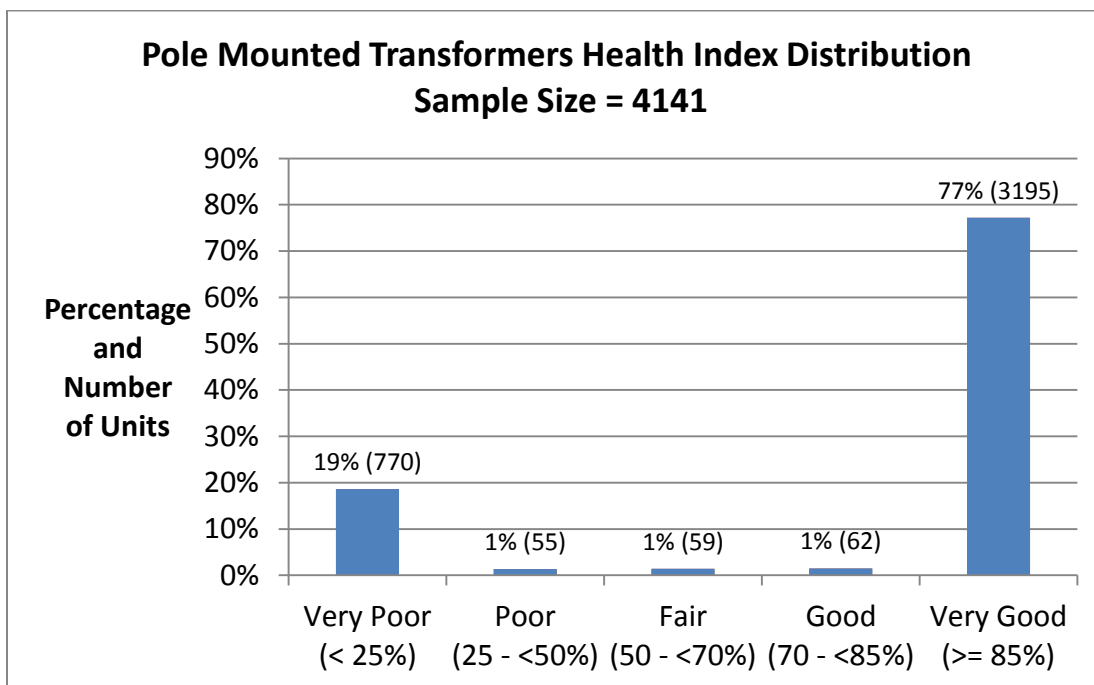


Figure 5.3.2-5 - Kinectrics ACA Pole Mounted Transformers Health

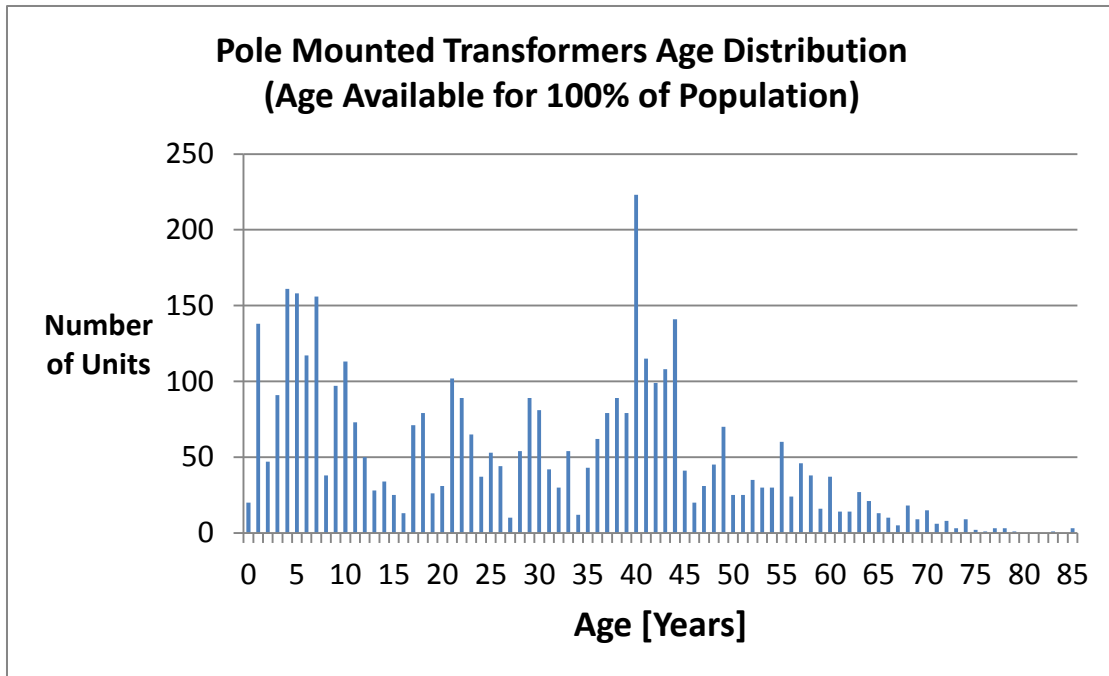


Figure 5.3.2-6 - Kinectrics ACA Pole Mounted Transformers Age

Vault Transformers

Vaults represent a relatively small asset group. However, they generally service commercial customers and subsequently their health can be of greater concern. The condition of these units is monitored closely through the inspection process and is an important factor in the overall health of the units. It can be noted from Figure 5.3.2-7 and Figure 5.3.2-8 below that older units represent a large majority of the population. The sample size used to determine the health index equates to 100% of the population.

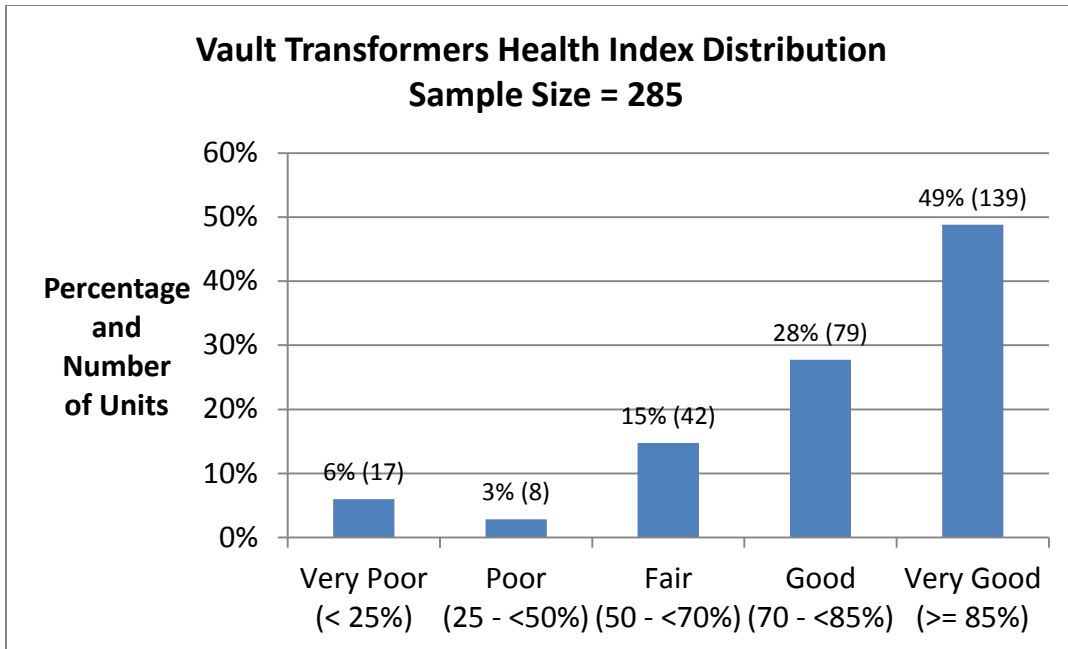


Figure 5.3.2-7 - Kinectrics ACA Vault Transformers Health

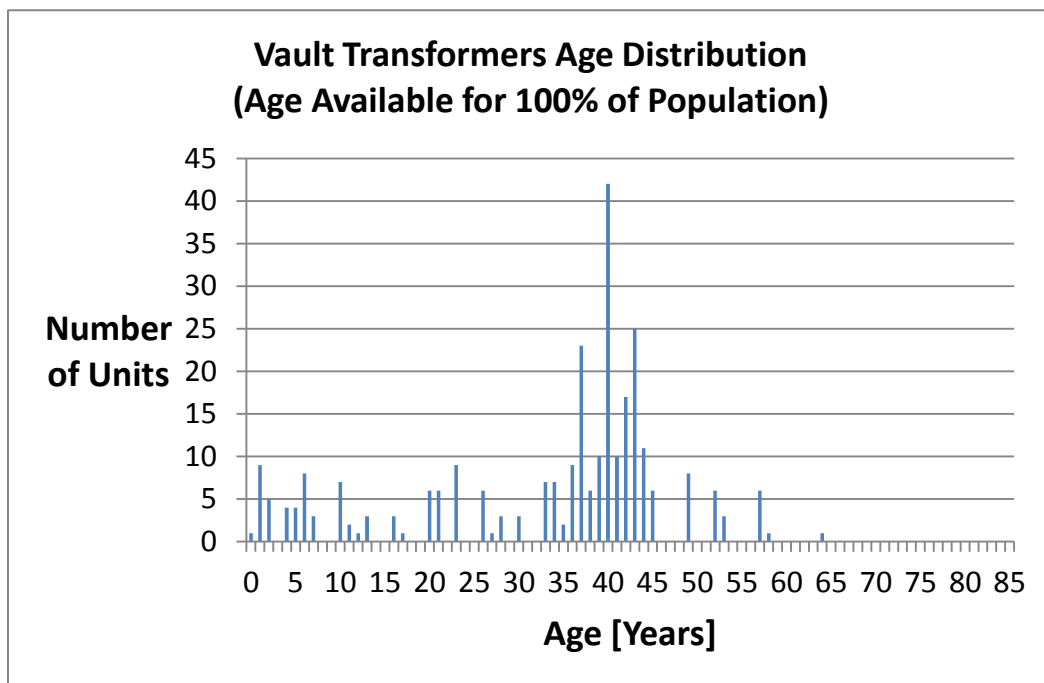


Figure 5.3.2-8 - Kinectrics ACA Vault Transformers Age

Overhead Switches

Overhead and Underground switch health is monitored through the inspection process where each switch is inspected once every three years to align with the requirements of the distribution system code. This helps to ensure that Thunder Bay Hydro can quickly and effectively isolate and restore power

to its customers to minimize outage times and provide a safe working environment for its employees. The sample size used to determine the health index equates to 49% of the population and is based on the known age data for the population which is the main consideration in the health of these assets.

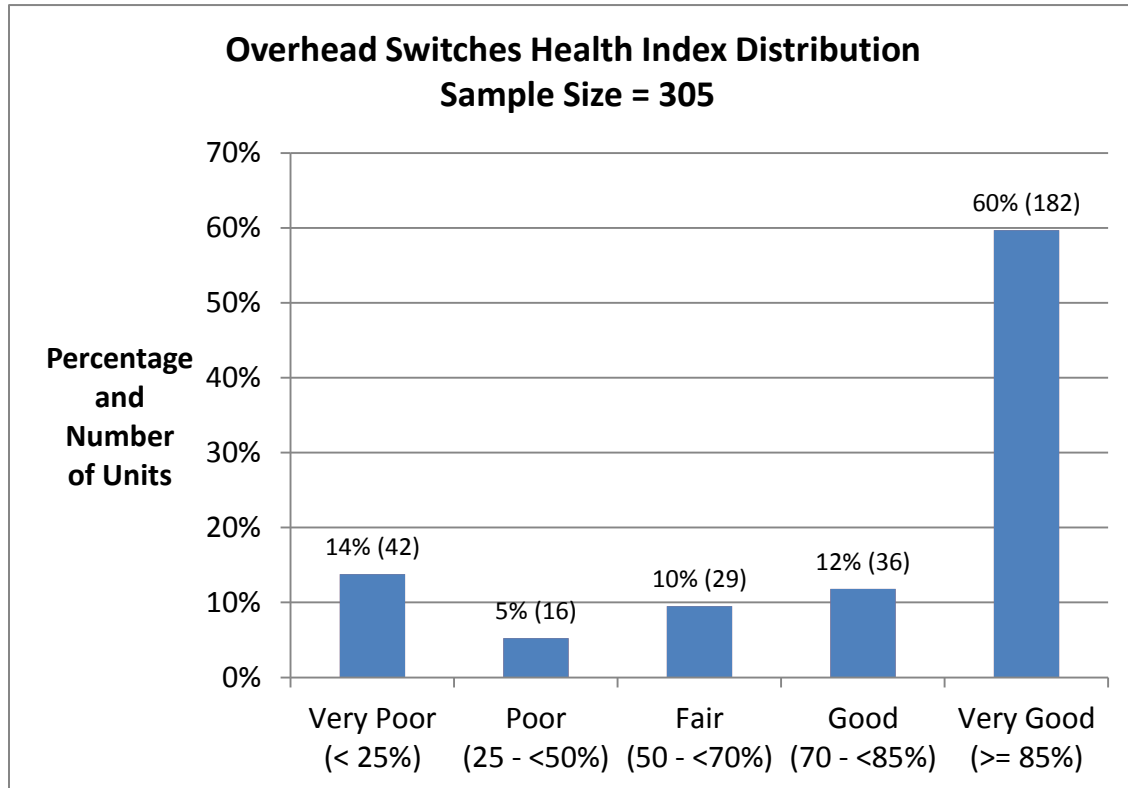


Figure 5.3.2-9 - Kinectrics ACA Overhead Switch Health

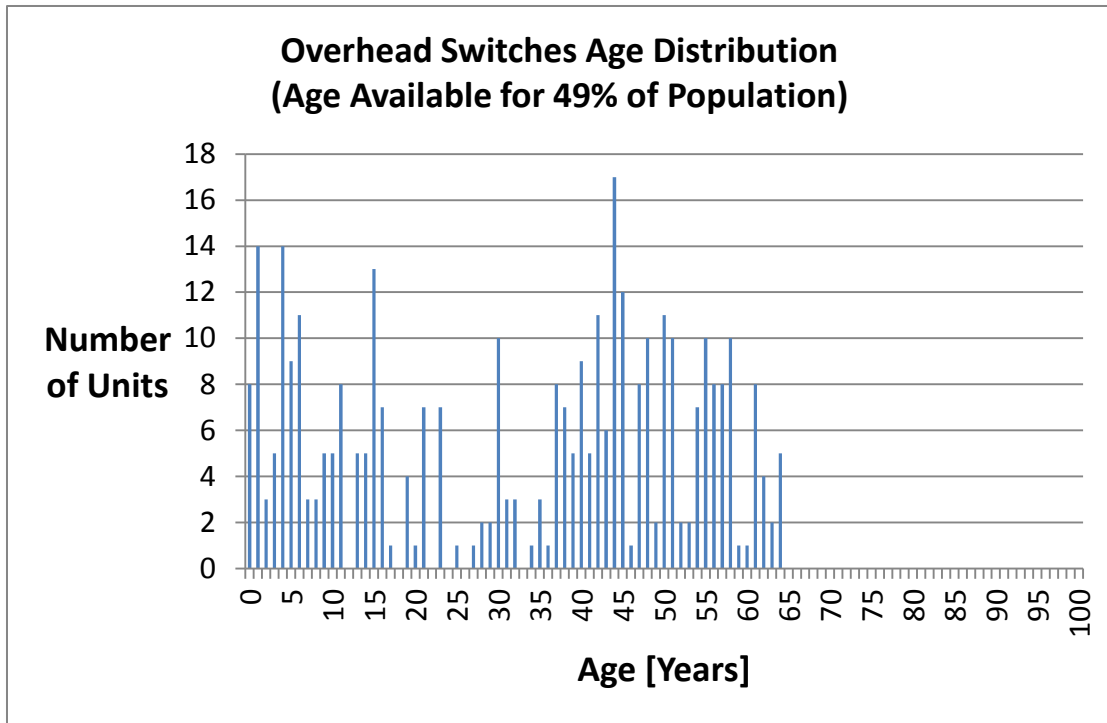


Figure 5.3.2-10 - Kinectrics ACA Overhead Switch Age

Underground Switches

The sample size used to determine the health index equates to 41% of the population and is based on the known age data for the population which is the main consideration in the health of these assets.

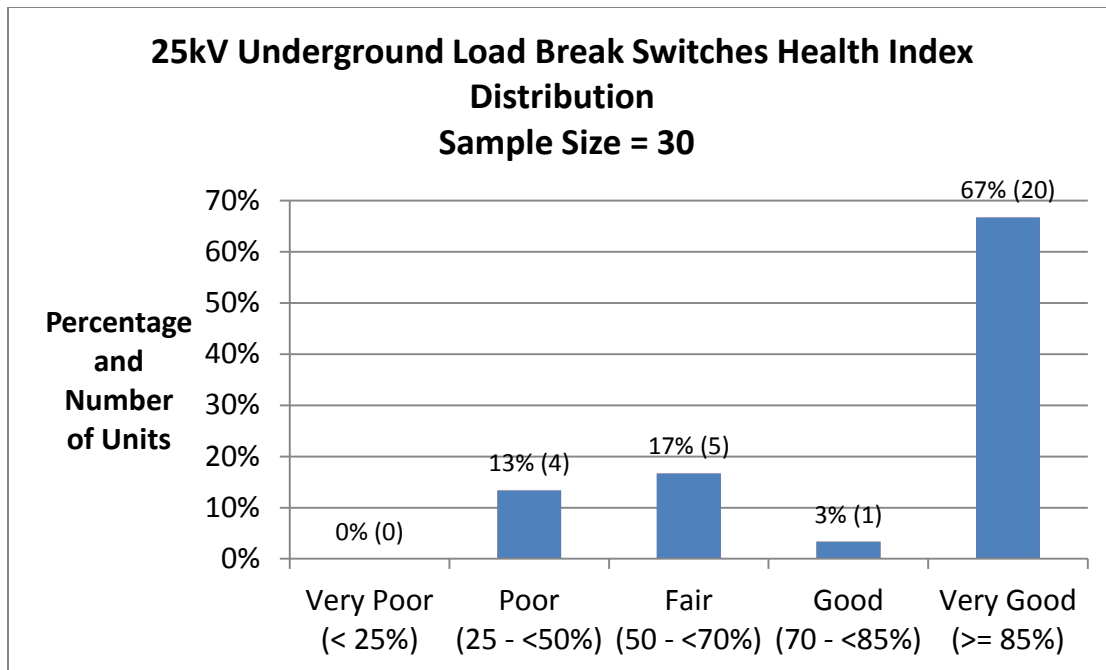


Figure 5.3.2-11 - Kinectrics ACA Underground Switch Health

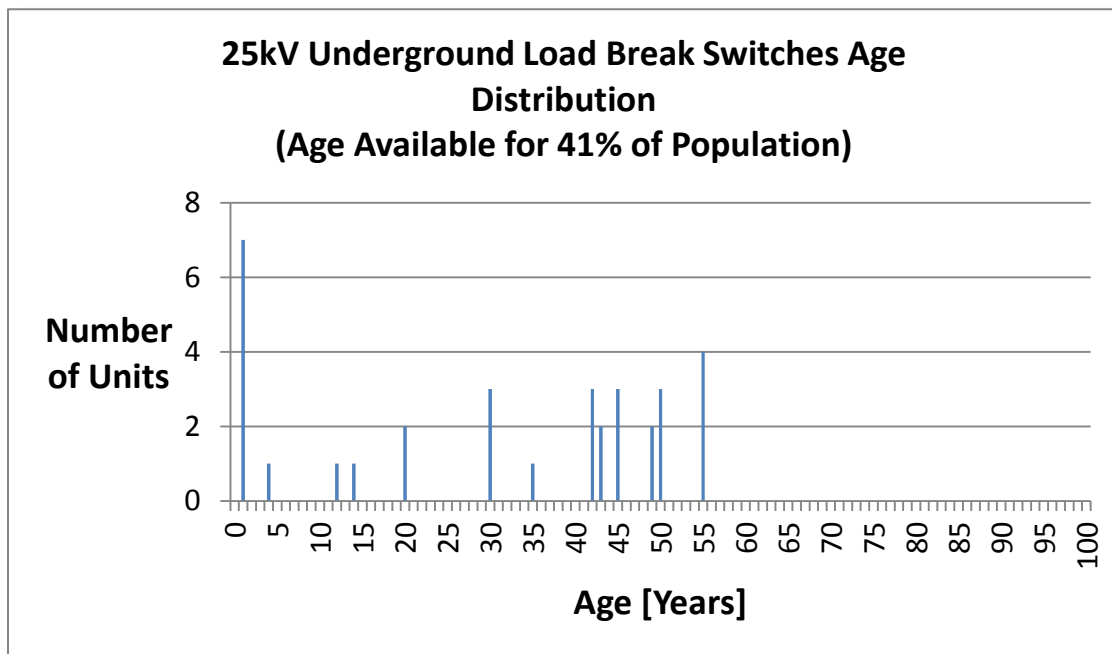


Figure 5.3.2-12 - Kinectrics ACA Underground Switch Age

Underground Cables

In general Thunder Bay Hydro has a large backlog of underground cable to address through rejuvenation or replacement. As it is comparatively expensive to replace and difficult to observe the degradation of the health of underground infrastructure as opposed to overhead, implementation of a renewal strategy

has been delayed. The results of this delay have become apparent through the findings within the ACA provide by Kinectrics and indicate that this asset class requires attention. Thunder Bay Hydro is in the process of formulating a plan on how, to cost effectively address this backlog. The sample size used to determine the health index equates to 87% of the population and is based on the known age data for the population which is the main consideration in the health of these assets.

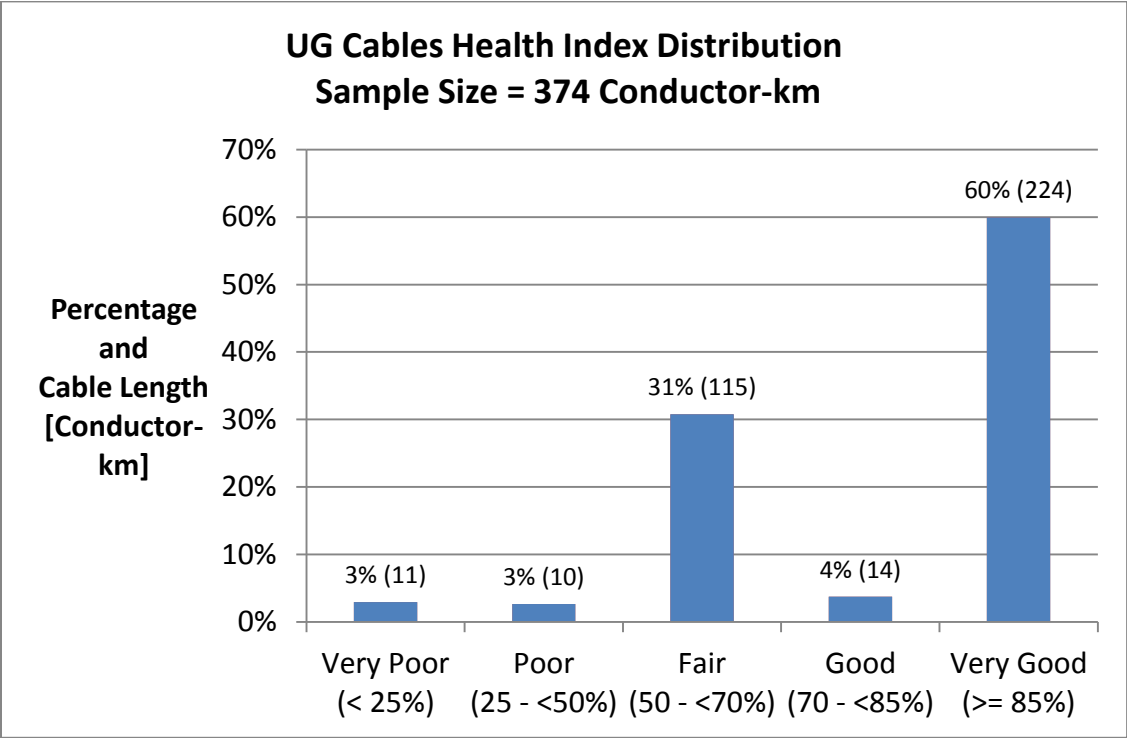


Figure 5.3.2-13 - Kinectrics ACA Underground Cable Health

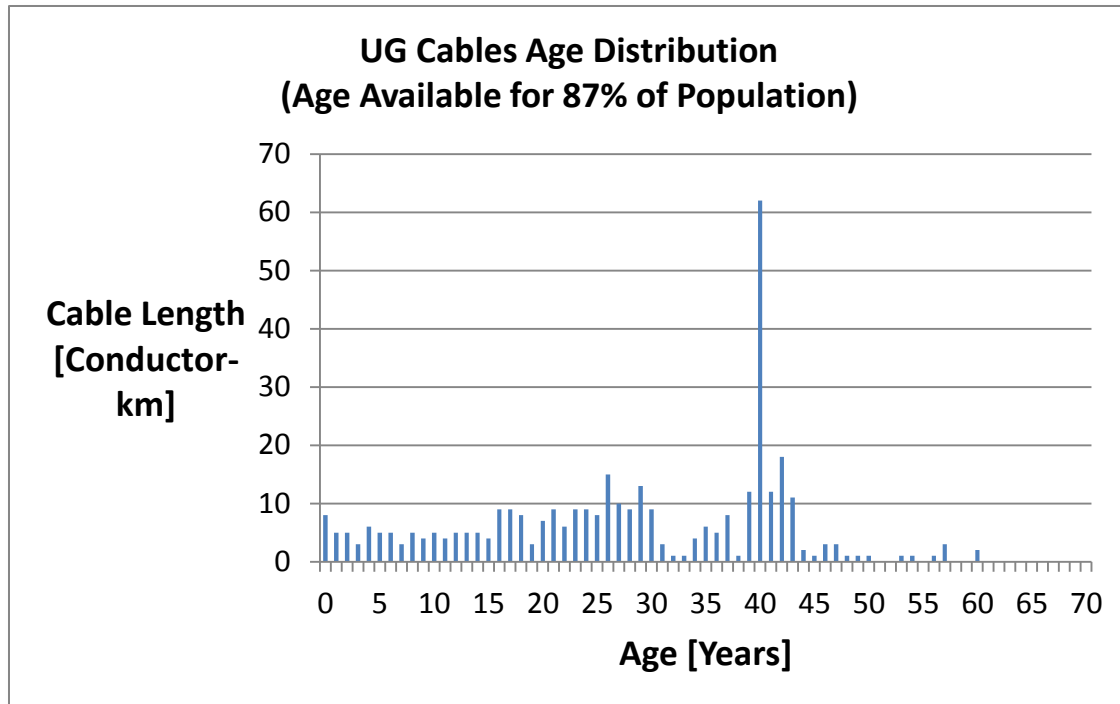


Figure 5.3.2-14 - Kinectrics ACA Underground Cable Age

Meters

Thunder Bay Hydro owns approximately 50,000 electronic smart meters, which were installed in 2009. These meters were manufactured by Elster and have 10 year seal life that will expire in 2019. As per Measurement Canada requirements a meter with an expired seal cannot be left in service for revenue / billing purposes. Thunder Bay Hydro has developed a Smart Meter Sampling Plan (Appendix F) which details all of the activities necessary to establish a smart meter pre-sampling and final compliance sampling program which aligns with the requirements detailed within Measurement Canada's (MC) Statistical Method Specification (S-S-06). This is to allow the utility to extend their smart meter's in-service life and ultimately maximize the return on investment (ROI).

Fleet/Rolling Stock

As of March 2015, Thunder Bay Hydro has 59 mobile units and 24 trailered / towed items within its fleet. There are 27 light vehicles (supervisor, crew, departmental, underground and stations vehicles), 20 line trucks (RBDs, single / double buckets) and 7 pieces of load/haul/dump (LHD) equipment, 1 fork-lift and 1 easement machine. The trailered / towed fleet items include pole trailers, equipment floats, stringing machines, pullers / tensioners, cable reel trailers, dump trailers, portable compressor and an emergency power supply trailer. For additional details, see Appendix E: Vehicle and Equipment Resource Justification Plan.

- d) *An assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets.*
- *Where cited as a 'driver' of material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.*

5.3.2.4 Asset Utilization (OEB Filing Req. 5.3.2d)

Asset Utilization is not a driver in any material investments for Thunder Bay Hydro through the forecast period of 2017-2021. In particular the HONI owned station transformers utilization is low, which can be found in Table 5.3.2-2 and details the 2015 Peak demand information and the Winter LTR rating. Table 5.3.2-2 indicates that due to the current winter peaking scenario in Thunder Bay, station transformers are not at risk for over-utilization.

5.3.3 Asset Lifecycle Optimization Policies and Practices (OEB Filing Req. 5.3.3)

An understanding of the distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment.

- a) *A description of asset lifecycle optimization policies and practices, including but not limited to:*
 - *A description of asset replacement and refurbishment policies, including an explanation of how (i.e. processes, tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes, and how the impact of system renewal investments on routine system O&M is assessed;*
 - *A description of maintenance planning criteria and assumptions; and*
 - *A description of routing and preventative inspection and maintenance policies practices and programmes (can included references to the DSC).*

5.3.3.1 Asset Lifecycle Optimization Policies and Practices (OEB Filing Req. 5.3.3a)

Thunder Bay Hydro's Operations and Maintenance (O&M) programs are designed to follow the guidelines set out in the OEB's Appendix C of the DSC for inspection and maintenance of all key distribution system assets. The results of these inspections are a key component of the asset condition assessment and are critical to the prioritization of O&M as well as capital spending. The output provides

a levelized list of assets targeted for action. This action can be refurbishment or replacement and is contingent upon the asset renewal strategy further described below.

Asset Replacement vs. Asset Renewal Strategy

For the majority of Thunder Bay Hydro's overhead distribution assets, replacement is the only viable option. Assets such as distribution transformers, conductor, insulators, lighting arrestors and poles represent a low initial capital investment and have few renewable components. Thunder Bay Hydro has explored and implemented several restorative techniques for these infrastructure types, but has not found a widely accepted maintenance practice that will cost effectively extend the life of these assets, nor reduce the instance of premature failure. As a result, these assets are replaced on a reactive basis upon failure. Thunder Bay Hydro will continue to explore and implement new techniques when deemed appropriate.

Thunder Bay Hydro is currently in the process of developing a maintenance strategy for its underground assets. Under consideration currently is surface rehabilitation for its pad mounted equipment to prevent premature deterioration in an attempt to ensure the assets are utilized to their fullest extent

Assets targeted for refurbishment are generally high value assets or those required for system protection, the majority of which are in stations and fleet. Assets such as power transformers, circuit breakers, light duty and heavy duty vehicles are inspected and maintained on a regular basis to ensure they are in proper working order. Several of these assets pose a significant capital investment and have many renewable components; the replacement of which can ensure the asset meets or exceeds its TUL.

In some instances functional obsolescence requires the replacement of assets. Distribution assets that no longer meet the demands of the system due to loading, short circuit levels or other specific criteria are generally targeted for replacement.

Several assets in Thunder Bay Hydro's distribution system are either no longer supported by manufacturers and/or the manufacturers no longer exist. Assets where; equipment suppliers no longer stock renewable components for these assets and/or where Thunder Bay Hydro has depleted any remaining collected renewable components; are often targeted for replacement. One example of this includes overhead air-break switches.

System Renewal Optimization and Budget Alignment

Thunder Bay Hydro's system renewal program is mainly driven from the outcome of the ACA which provides a levelized plan for assets in poor condition. The majority of system renewal efforts focus on assets requiring renewal in voltage conversion areas. The program considers the relative condition of the substations, the condition of the assets associated with each substation, and the targeted replacement level for each asset. A large portfolio of project areas requiring renewal is defined and is generally grouped by feeder.

Thunder Bay Hydro has developed financial metrics for each asset category on a per unit basis based on previous experience executing projects. These metrics are used to estimate the potential costs

associated with specific project areas. A baseline budget is then developed based on completing the projects which have been prioritized based on the assets optimal replacement times in conjunction with other constraints. If the estimated costs do not align with budget constraints, then alternatives are considered to achieve the targeted spending level. This iterative process continues until an optimized plan is achieved for the planning horizon. This process is illustrated below.

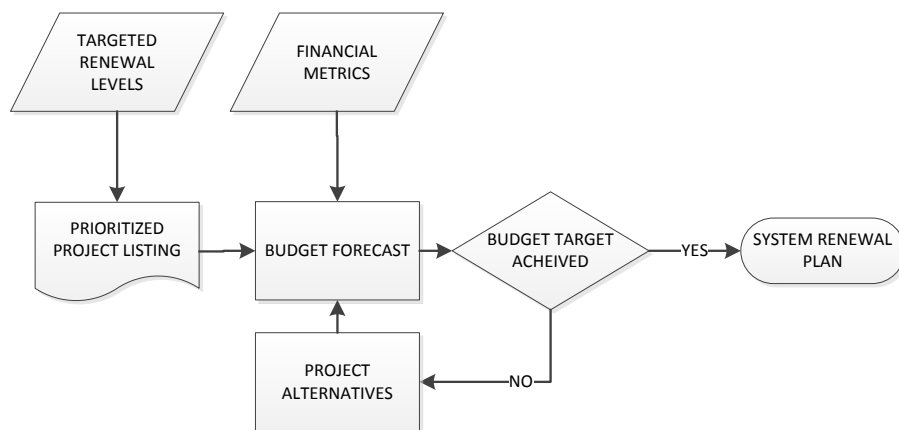


Figure 5.3.3-1 Iterative Planning & Optimization Process

Targeted Renewal Levels

The targeted renewal levels are a direct output of the ACA process as detailed in section 5.3.2.3.

Prioritized Project Listing

Thunder Bay Hydro creates a prioritized project listing to achieve the desired renewal levels utilizing the data from the ACA. As previously stated, the projects are generally grouped by feeder as the assets are commonly of similar condition. Considerations during this process are the relative condition of the substations, the condition of the assets associated with each substation and those defined in section 5.3.1.3 Asset Management Strategy (OEB Filing Req. 5.3.1b). The prioritization process is further discussed in detail in Sections 5.3.1.3 and 5.4.2.3.

Financial Metrics

Thunder Bay Hydro maintains a repository of information regarding its previous completed projects. Metrics for these projects are tracked to assist in future budgeting efforts. Data is tracked in the form of dollars as well as labour hours on a per unit basis to estimate projects costs based on the scope defined in the project listing.

Budget Forecast

A baseline budget forecast is developed based on previous execution of projects where assets are replaced at their optimal replacement time. This baseline budget is then compared against a targeted

expenditure level. If the target levels are achieved the baseline forecast becomes the final system renewal plan. If the target expenditure level is not achieved then Thunder Bay Hydro seeks out alternatives. Alternatives may include but are not limited to; delay projects when it is prudent and safe to do so; revise the scope of a project to defer costs; and split the project into stages so as to reduce the amount of work required in any given year.

As previously mentioned Thunder Bay Hydro's projects are typically grouped by feeder which can encompass a large quantity of assets. Thunder Bay Hydro will delay small renewal projects or reactive capital replacements in these areas, to the extent possible, where doing so will pose no safety or environmental hazard. This strategy relates to the economy of scale. It is much more effective to bear the fixed costs of renewal across a large quantity of assets as opposed to a small amount thereby reducing the overall per unit cost of the project.

Thunder Bay Hydro continuously revises and improves its financial metrics as data from completed projects becomes available. This process has allowed Thunder Bay Hydro to effectively estimate projects reducing the overall variance between budgeted and actual. Effective estimating and variance reduction also has the positive effect of allowing Thunder Bay Hydro to plan more work for the same amount of budget.

Impact of System Renewal on O&M

Thunder Bay Hydro will delay O&M spending in areas that align with system renewal efforts, to the extent possible, where doing so will pose no safety or environmental hazard. This strategy is of particular importance in areas of voltage conversion. The O&M costs associated with maintaining substation assets are approximately \$15,000 /year / station. The final outcome of the conversion process is to decommission the substations, resulting in elimination of maintenance associated with that station. Thunder Bay Hydro maintains an annual listing of substations targeted for decommissioning. This strategy focuses on attempting to reduce or defer spending on those substations which are being decommissioned first while ensuring the substations that will be online the longest are being appropriately attended to.

Thunder Bay Hydro also considers the impact on operational efficiencies when implementing system renewal efforts. Considerations include improving remote operability, ease of access, ease of work and implementing solutions that are both cost effective and reduce restoration times. These considerations ensure that Thunder Bay Hydro provides the best value to its customers. An example of this scenario may be to relocate end-of-life assets that are constructed in a right-of-way to a street front location.

Maintenance Planning Criteria

Thunder Bay Hydro employs a reactive based maintenance (RM) strategy for a majority of its assets outside of stations. This is often defined as breakdown maintenance and is unscheduled and immediate remediation of a failed asset. As previously indicated most of the assets managed in this manner cannot be cost effectively maintained in a way that reduces their instance of failure. Thunder Bay Hydro is open

to any new techniques and research that becomes available but does not anticipate any changes to this practice will occur over the forecast period.

Preventative maintenance (PM) is employed for some station assets that Thunder Bay Hydro owns and operates. This PM strategy is the time-based or operations-based maintenance at a particular interval to attempt to curb untimely failures. The extent and frequency to which PM is performed is based on the type of asset, industry best practice, manufacturer specifications and impact of previously mentioned untimely failures. One example of assets targeted for PM is medium voltage circuit breakers. See Table 5.3.1-3 for Thunder Bay Hydro's asset operating strategy for its major assets.

Thunder Bay Hydro regularly monitors the condition of its large value assets using industry best practice methods. These assets, aside from regular visual inspection, do not lend themselves well to routine PM as they lack routinely renewable components. These assets typically represent large capital investments and high customer impact such as station transformers. The results of these analyses are utilized to predict the future condition of these assets and determine if there is an imminent risk of failure. This condition based maintenance (CBM) approach allows for a cost effective, proactive response to mitigate the risk of failure.

Maintenance Planning Assumptions

Thunder Bay Hydro plans its maintenance and inspection activities on an annual basis. Budgets for these functions are developed utilizing historical costs for repair as well as labour hours required to perform inspections.

It is assumed that historical repair costs will be consistent with future repair costs for each asset category. The budget envelopes may be adjusted annually based on the quantity of assets assumed to require service based on health of the population and results of the inspection process.

Inspection costs are based on historical hours required to complete the asset inspections. Thunder Bay Hydro has divided its service territory into three inspection zones that contain approximately comparable quantities of assets for inspection in each zone annually. In this way Thunder Bay Hydro can predict what the typical inspection costs will be annually.

Municipal substation inspections occur monthly. As substations are removed from service over the forecast period, the labour associated with inspections is expected to be reallocated to other activities (such as increased maintenance levels at other stations to ensure they maintain their operability).

Routine and Preventative Inspection and Maintenance Programs

The following O&M programs are conducted annually to assess the condition of our assets, to perform routine maintenance and assist in identifying end-of-life assets to ensure the system continues to operate safely and reliably.

- i. Municipal Substation Inspection and Maintenance

Thunder Bay Hydro currently owns and operates 14 municipal substations within its service territory. Testing and maintenance of transformers and associated substation equipment occurs monthly, as well, some station equipment is inspected and or tested annually. Defects noted during inspection are either; corrected immediately during the inspection phase; or scheduled for corrective action, depending on the complexity of the repair. A summary of station inspection points is provided below.

	Inspection Activity	Potential Findings/Inspection Points	Frequency
Power Transformers	Visual and/or Infrared Inspection	Tank and Gasket Integrity Sampling valve seals Oil Level Oil conservator condition External tank condition Fan & pump condition Bushing external condition and termination integrity Surge arrester condition Tap changer Position Condition of pressure relief devices	Monthly
	Oil Screen & Moisture Content Testing	Soluble contaminants and oxidation products - sludging characteristics of the transformer Moisture content which may lead to degraded dielectric strength	Annual
	Dissolved Gas Analysis	Gases formed during periods of fault or overload	Annual
	Furanic Compound Testing	Dissolved compounds indicative of cellulose breakdown/decomposition caused by sustained periods of overheating	Annual
Circuit Breakers	Visual/Operational Inspection	Drawout Assembly Function Arcing Contacts Integrity Main Contacts Integrity Insulator Hygiene Tank Condition Internal Mechanisms Pallet Switch Condition Oil Condition Closing Mechanism Condition Trip Mechanism Condition Arc Chutes Closing Relay Motor Operator Function Heaters Trip Free Operation Anti-Pump Operation	Annual
	Electrical Testing	Hi-Pot Medium Voltage Terminations Hi-Pot Low Voltage Terminations Main Contacts Resistance Testing	Annual
Batteries	Standard Testing	Check Cell Float Voltage Check Battery Terminal Voltage	Quarterly
	Performance Testing	Capacity Testing Service Testing	Quinquennial
Fencing	Visual Inspection	Unauthorized access around perimeter Gaps in access Mesh Condition Barbed Wire Condition Grounding & Bonding Condition	Annual

Risk Assessments		Objects in Proximity to the Fence	
	Visual Inspection	OCB's Transformers Switchgear Structures Fencing Buildings Relays Control Equipment, Ancillaries, Battery Banks Etc.	Annual

Table 5.3.3-1 Substation Inspection and Maintenance

ii. Pad mount Transformer and Switch Inspection and Maintenance

The inspection of these units coincides with the requirements set forth in the DSC in so far as they are inspected on a three year cycle. Through the inspection process Thunder Bay Hydro assesses the current condition, through visual inspection, of the asset and the surrounding area, noting the integrity of the unit as well as any potential safety hazards. During this inspection, if defects are noted they are processed in several ways:

- defects that pose a safety hazard to personnel or the public (i.e. access to the cable chamber) are scheduled for immediate remediation;
- defects that appear to impact the integrity of the asset (i.e. significant rusting) are scheduled for a detailed inspection; and
- defects that may affect the operability of the asset or are minor in nature (i.e. vegetation in front of the door) are scheduled for remediation and are prioritized based on available resources to complete the work.

If a transformer is found to be in such poor condition or deemed unrepairable by trained inspectors, it will be replaced proactively to avoid reactive replacement in the near term.

iii. Vault Transformer Inspection and Maintenance

The inspection of these units coincides with the requirements set forth in the DSC in so far as they are inspected on a three year cycle. Vault transformers are contained within customer owned infrastructure and during the inspection process Thunder Bay Hydro inspects items related to its assets as well as those items related to the condition of the customer owned assets. This includes ensuring: the vault is secure and inaccessible to the public; lighting is working appropriately; the civil infrastructure is in good condition; ventilation functions normally; and the appropriate signage is in place. Along with this Thunder Bay Hydro inspects its transformer and connections and notes any defects that require maintenance. Due to the nature of the installation being out of the elements and in a controlled environment, vault transformers typically enjoy a long life. However due to the cost and complexity of removing and replacing these units upon failure, consideration is given to converting these installations to pad mounted infrastructure.

Where defects to customer owned infrastructure is identified, Thunder Bay Hydro notifies the Customer as to the nature of the defect and seeks a timeline for remediation.

iv. Pole Mounted Transformers Inspection and Maintenance

The inspection of these units coincides with the requirements set forth in the DSC in so far as they are inspected on a three year cycle. The inspection process checks for leaks and general tank condition; condition of the bushings; and oil discolouration which indicates flashover. Pole mount transformers have relatively few failures as a population and as such require little in the way of regular maintenance to ensure these units reach their typical useful lives. However, if a transformer is found to be in such poor condition by trained inspectors, it will be replaced proactively to avoid reactive replacement in the near term.

v. Distribution Pole Inspection and Testing

The inspection of these assets coincides with the requirements set forth in the DSC in so far as they are inspected on a three year cycle. Thunder Bay Hydro conducts a visual inspection of all the poles it owns within its service territory. The inspection considers overall pole condition and condition of pole attachments. Poles that have been identified, through visual inspection, as being in poor condition are further inspected in detail. Through non-destructive testing (hammer testing) inspectors attempt to ascertain the extent to which the asset has deteriorated. Poles identified as being a hazard or in imminent risk of failure are replaced immediately; other poles are prioritized based on their health as part of the asset management and capital planning process.

vi. Overhead Switch Inspection and Maintenance

The inspection of these assets coincides with the requirements set forth in the DSC in so far as they are inspected on a three year cycle. The intention is to ensure that every switch is at least visually inspected every three years. Visual inspection of the in-line, air-break, load-break, and recloser population is captured under this initiative. Switch maintenance activities are conducted in parallel with switch inspection activities. Where the inspection determines that maintenance of the switch is required, the inspection crew may conduct the maintenance immediately and note this on the inspection form. Where the crew is unable to immediately perform the maintenance, a deficiency is noted on the inspection form. The completed detailed inspection form is submitted for prioritization based on available resources and details of the annual inspection are then logged into the inspection database.

vii. Tree Trimming Maintenance and Inspection

Thunder Bay Hydro performs vegetation management in a reactive and proactive manner throughout its service territory. Thunder Bay Hydro receives numerous 3rd party requests annually to manage vegetation that has been identified as posing a potential threat to Thunder Bay Hydro's overhead infrastructure. These are generally safety concerns and are remediated in a reactive nature. Thunder Bay Hydro also proactively manages vegetation in areas of planned capital investment prior to executing work in these areas.

Thunder Bay Hydro has inspected its service territory to determine the density of vegetation in proximity to its overhead infrastructure. The intent is to identify areas of concern in an attempt to increase system integrity by proactively removing the vegetation from these areas.

viii. Reactive Maintenance

Reactive maintenance occurs in many forms, at many different times and across all asset categories. It can occur during regular business hours or after hours; and can be completed by an overhead or underground crew. These events can include responding to trouble calls, repairing unexpected deficiencies and equipment failures; failures which cannot be accounted for and corrected through by any other means.

As an example; a crew may respond to a customer outage caused by a tree on the line which in turn caused a line fuse to operate; and they may later respond to an outage as result of a faulted underground cable; if the cable can be isolated, and depending on the health of the cable may be replaced at a later date, or it may be spliced to extend its in service life and return service immediately.

Depending on the condition of the unit being repaired it may be considered for accelerated replacement based on its health and likelihood to continue deteriorating despite remedial efforts. This would be planned in conjunction with existing planned projects and available resources.

A more detailed description of the Inspection and Maintenance Programs can be found in Appendix K.

b) A description of asset lifecycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.

5.3.3.2 Asset Lifecycle Risk Management Policies and Practices (OEB Filing Req. 5.3.3b)

Risk can be defined as the product of criticality and probability of failure. Thunder Bay Hydro currently employs an empirical method to assess and determines the appropriate action to take regarding its discretionary projects.

Risk Assessment Methods

Risk assessment begins with the inspection of assets. Assets are inspected and the condition data is analyzed via the ACA process and arrives at a health score for each asset category. The health of an asset is linked to the probability of failure during the ACA, leveraging standard failure curve data for each asset category. Several factors are then considered in determining the consequence of failure such as; health and safety of its employees and the public; impact to the environment; and impact to reliability. By leveraging the experience of Subject Matter Experts (SME) Thunder Bay Hydro gains insight into the criticality of a variety of assets or groups of assets. Observations can include location, impact to reliability and lack of operational efficiency. These observations are then used in conjunction

with the results of the ACA to determine high risk project areas or at risk assets. The projects and/or assets are then ranked by the risk they pose.

Risk Mitigation Methods

Thunder Bay Hydro seeks to employ standard strategies for managing risk such as avoidance, acceptance, transference and limitation. Risk avoidance is a very difficult mitigation technique to implement by virtue of the vast quantities of assets required to be in service to serve our customers; there will always be some inherent risk associated with this fact. To ensure the safety of its employees and the public, risk acceptance does not happen within the Utility for all but lowest levels of risk, where all other alternatives have been exhausted. Thunder Bay Hydro employs risk transference for project duties that fall outside the core competencies of the Utility. Hiring contractors to perform these types of work allows Thunder Bay Hydro to focus on its primary service commitments. For these reasons, Thunder Bay Hydro typically employs risk limitation strategies as part of its asset lifecycle policies. Thunder Bay Hydro analyzes each project to determine what the driving factor is behind the elevated risk level for that particular project. Once the driving factor is known, Thunder Bay Hydro proceeds to outline what the most effective mitigation solution will be, these can include:

- asset renewal within the project area to reduce the likelihood of failure (i.e. replacement of wood poles);
- point solutions within the project to reduce criticality (i.e. splitting of an underground loop to reduce customer impact at time of failure);
- having readily deployable contingency plans in place (i.e. having spare units for highly critical infrastructure); and
- asset relocation within a project to increase ease of access and in-turn reduce restoration times (i.e. relocate easement and right-of-way assets to easily accessible street-front locations).

The selected action may be one of those listed above, or it may be a combination of these and others. The output of this analysis becomes an input to the project prioritization process.

Risk Conclusions and Project Prioritization

Risk is factored into the selection and prioritization of capital expenditures during the prioritization process. Thunder Bay Hydro considers the cost impact of any strategy prior to implementing a particular mitigation. This can take the form of a qualitative analysis (i.e. dollars per risk abated) for projects with low cost and low complexity, the analysis of which are more readily obtained. For highly complex projects with several risks to mitigate, the analysis is complex and the results are diminished by the time required to execute it. For these reasons Thunder Bay Hydro seeks to discuss these projects in detail with SME's within the Utility to determine what the overall risk rating should be. With this in mind, Thunder Bay Hydro continually looks for alternatives and innovative ways to reduce costs to achieve the desired results. Once the analysis is complete, the projects are integrated into the capital budget based on their relative risk ranking assigned through the risk assessment process; in conjunction with the effectiveness of the overall mitigation plan.

Thunder Bay Hydro must also undertake various mandatory projects driven through third party requests (i.e. road widening, new service connections etc.). Through various consultations and analysis of past practice (further discussed in Section 5.2.2.1 Customer Engagement) Thunder Bay Hydro seeks to plan these projects to the furthest extent possible. However, in the event of unforeseen mandatory projects arise Thunder Bay Hydro reviews its discretionary projects to determine the appropriate action to take to enable completion of the mandatory project(s). Options that are considered can be complete deferral or scope reduction of one or more discretionary projects; and acceleration of a project to achieve cost harmonies with the mandatory project. The decision to execute any one or more of these strategies is ascertained through what risks are posed by the action and whether or not that is deemed a tolerable level of risk to accept. In all cases, if project deferral becomes the only viable solution, then discretionary projects are deferred in ascending order of their risk rating.

5.4 Capital Expenditure Plan (OEB Filing Req. 5.4)

A distributor's DS Plan details the programme of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process.

As noted above, a DS Plan must include information on prospective investments over a minimum five year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five year period prior to the initial year of the forecast period.

5.4.1 Summary (OEB Filing Req. 5.4.1)

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

- a) Information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver'.*

5.4.1.1 System Capability to Connect new Load or Generation (OEB Filing Req. 5.4.1a)

Thunder Bay Hydro reviews system capability to connect new load or generation through on-going assessments of key information such as transformer station loading as well as distributed generation (“DG”) information contained in the REG investment plan in Appendix A. This information serves an important role in identifying historic and future load growth trends. The most recent load forecasting, completed in 2016 as a part of the IRRP process, showed that the requirement for additional system capacity was not needed for future load growth. Thunder Bay Hydro’s distribution system peak load (gross) has seen fluctuations over the past ten years (See Figure 5.4.1-1 below) with an overall reduction in load of approximately 4%. This load factors in efforts of CDM and DG.

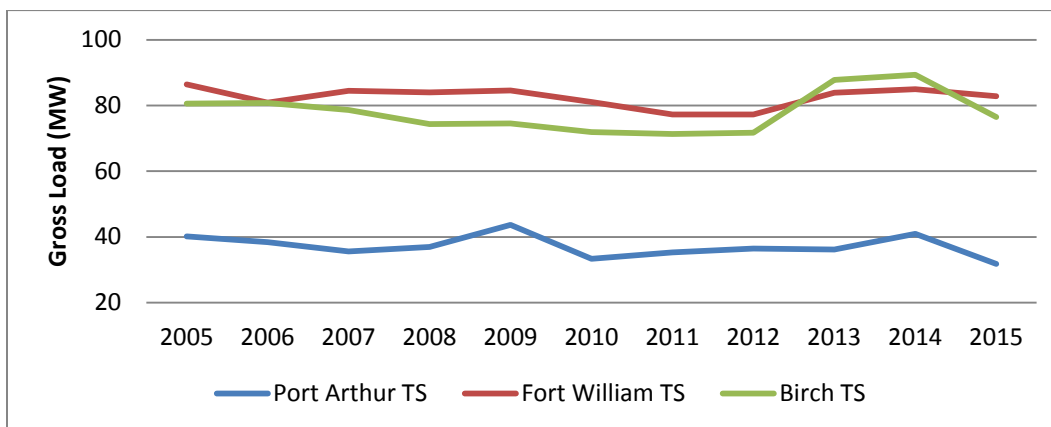


Figure 5.4.1-1 Thunder Bay Hydro Station Load 2005-2015

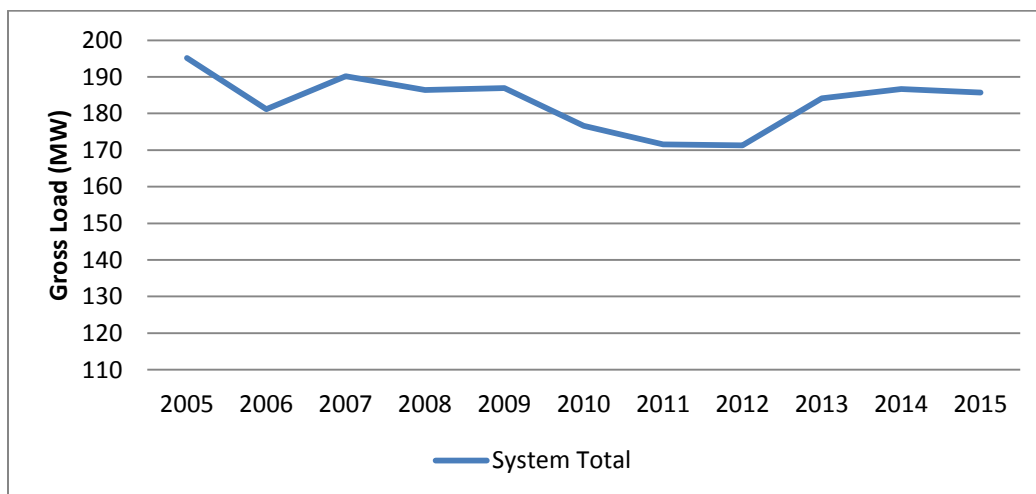


Figure 5.4.1-2 Thunder Bay Hydro System Load 2005-2015

As noted in the REG Plan (Appendix A), of the three transformer stations in our service territory, two have short circuit levels exceeding 90% of the limits set by the transmission system code, and the third has short circuit levels as high as the station equipment is rated for, leaving no short circuit capacity for generation connections. Through the IRRP planning process, Thunder Bay Hydro has been informed that

Hydro One is addressing limiting hardware on the secondary side of Port Arthur TS, which will increase the short circuit capacity on this station and allow for the accommodation of increased future renewable generation project connections.

On a feeder level, small system reconfigurations are completed to transfer load where and when required. This involves redefining boundaries of feeders and typically does not require investments in infrastructure. Thunder Bay Hydro's adjustments to its feeder load do not require or involve additional capacity being input to or added to the system as a whole, particularly as the distribution system is able to support the level of customer demand and distributed generation currently imposed and anticipated to be imposed. Therefore, as a result of this process described above, Thunder Bay Hydro does not expect any capital expenditures related to constraints that would affect the capability to connect new load or generation customers over the planning period.

b) Total annual capital expenditures over the forecast period, by investment category (see section 5.4).

5.4.1.2 Summary of Annual Capital Expenditures (OEB Filing Req. 5.4.1b)

The total annual gross capital investment over the forecast period by investment category is presented below in Figure 5.4.1-3. Thunder Bay Hydro is targeting increases in System Renewal over the forecast period, a more detailed description of variances in investment categories is provided in the following sections.

CATEGORY	Forecast Period (planned)				
	2017 Test Year	2018	2019	2020	2021
	\$ '000				
System Access	2,662	2,422	2,432	2,445	2,505
System Renewal	8,380	8,818	8,976	9,217	9,261
System Service	230	300	280	280	300
General Plant	1,168	1,360	946	901	969
TOTAL EXPENDITURE	12,440	12,900	12,634	12,842	13,036
System O&M	8,026	8,187	8,350	8,592	8,842

Figure 5.4.1-3 Total Annual Forecast Gross Capital Expenditure

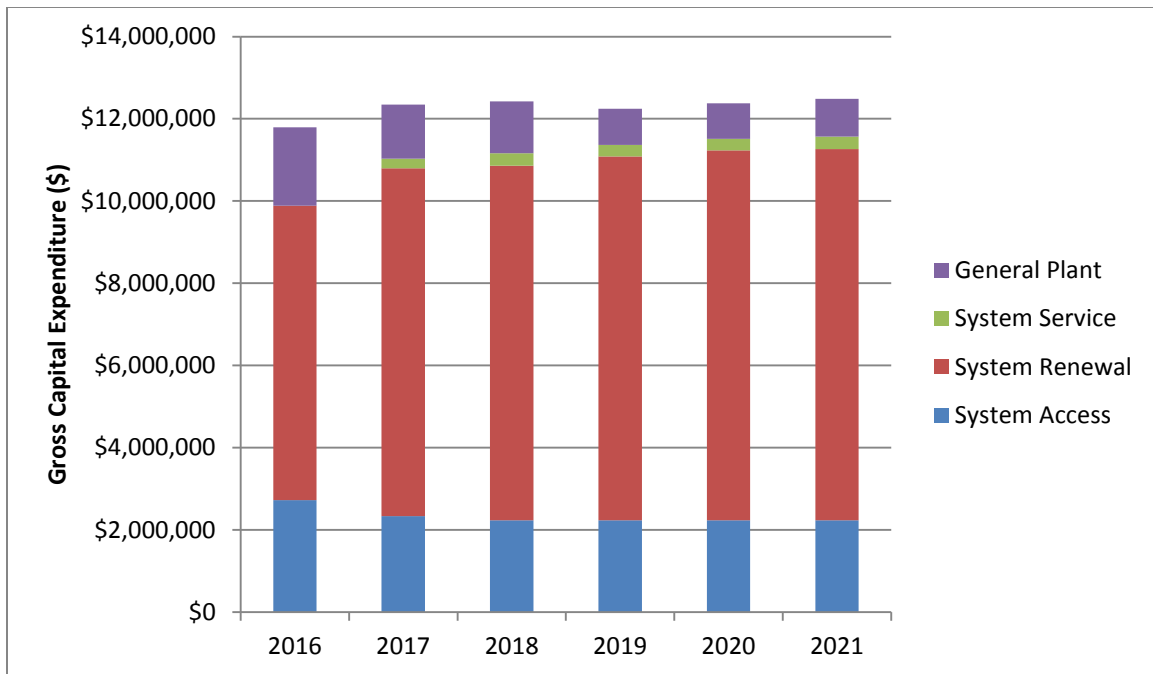


Figure 5.4.1-4 Total Annual Forecast Capital Trend

c) A brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories.

5.4.1.3 Asset Management and Capital Expenditure Planning (OEB Filing Req. 5.4.1c)

The following figures outline the overall allocation of capital budget amongst the major investment categories. A brief outline of how Thunder Bay Hydro's planning processes have affected the expenditures in each category is also provided.

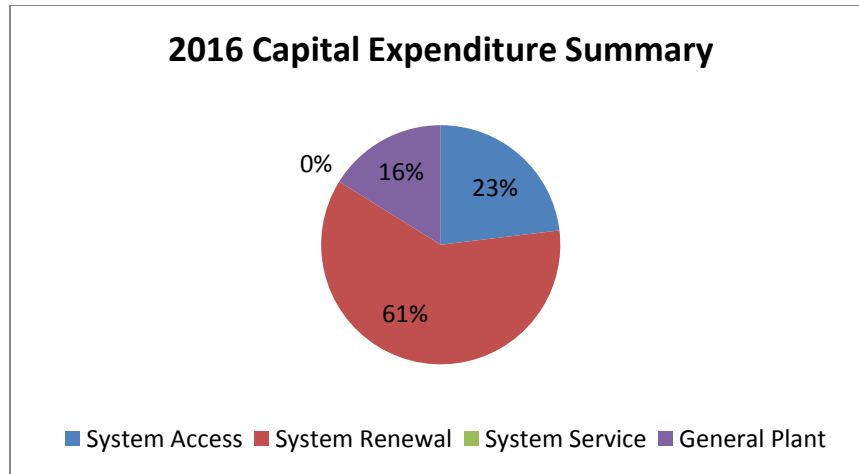


Figure 5.4.1-5 2016 Capital Expenditure Summary by Category

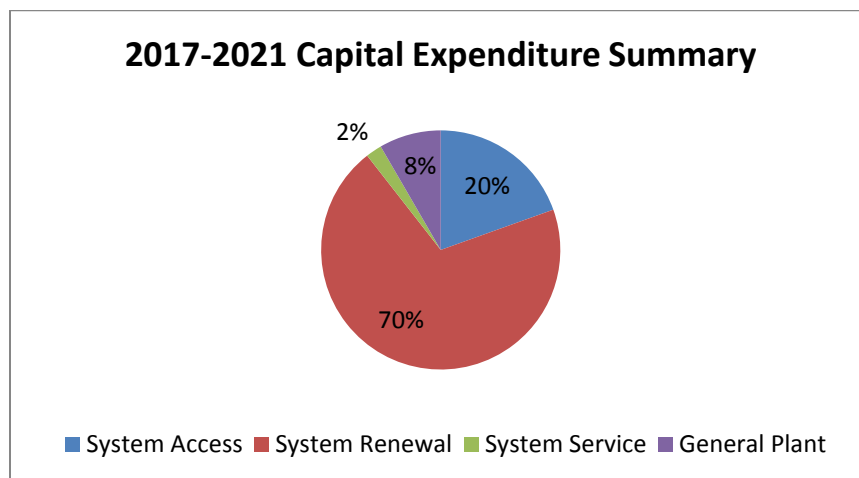


Figure 5.4.1-6 2017-2021 Capital Expenditure Summary by Category

System Access Investments

System access investments are generally non-discretionary in nature and are challenging to project as there are several outside factors that contribute to the overall expenditure level. The current level of spending accounts for approximately 23% of the overall budget and the level of spending is expected to slightly decrease to 20% over the forecast period. The portion of capital budget allocated to this category is driven from both; historical practice by the utility; and the results of consultation with third parties during the asset management and capital planning process. A number of outputs resulting from the asset management and capital expenditure process contribute to the outcome of the investment in System Access. Co-ordination planning with third parties as listed in 5.2.2 has affected the overall capital expenditures in the following ways:

- Co-ordination with Third Parties (specifically telecommunications) assists in forecasting capital expenditures Customer Recoverable System Modifications required to support new fibre attachments in support of System Access investments.
- Discussions and Consultation with City of Thunder Bay officials to understand future projects requiring relocation of distribution system assets in support of System Access investments.
- Consultation with existing customers, specifically industrial and large use customers, to gain perspective into current and future electrical needs to help plan the system accordingly in support of System Access investments.

System Renewal Investments

System renewal investments account for the largest portion (approximately 70%) of expected capital expenditure over the forecast period. Expenditures within the renewal category are highly dependent on the condition of distribution system assets and play a crucial role in the overall sustainment of the distribution system. The asset management process is managed and based upon the foundation of the of the ACA of Thunder Bay Hydro's distribution system assets. This information in turn acts as an input into the Thunder Bay Hydro renewal project prioritization process described in Section 5.4.2.3. As indicated in Section 5.3, the system is in substantial need of rehabilitation or replacement to continue to meet the expectations of; our customers; the OEB; the ESA; the DSC; and overall good utility practice. Thunder Bay Hydro recognized that assets were degrading more quickly than they were being replaced, and as such has begun increasing investment in system renewal to curb this effect. The intent is to reach a level of spending where assets are renewed more quickly than they are degrading finally returning to an investment level that corresponds to asset sustainment rather than elevated replacement. Achieving this sustainment level of replacement is not expected to occur over the forecast period.

System Service Investments

System service investments account for the smallest portion (approximately 2%) of the overall expected capital expenditure over the forecast period. The forecast consists of installing automated reclosing devices and a distributed automation modules to automate feeder switching in strategic areas. (As identified in the Grid Modernization Plan found in Appendix D). The installation of these devices aims to improve system operational objectives such as reliability and efficiency. This project has been created due to feedback resulting from the DSP consultations with Thunder Bay Hydro customers (see Section 5.2.2.1).

General Plant Investments

General plant expenditures account for approximately 8% of the overall capital expenditure over the forecast period. This category comprises assets that are not part of the distribution system but are required to execute day-to-day operations. Expenditures in general plant relate to modifications, replacements or additions to assets that are not part of its distribution system, including land and

buildings, tools and equipment, fleet and electronic devices, and software. A number of key outputs related to the asset management and capital planning process contribute to the capital expenditures for non-distribution system items in general plant. Together with the achieving specific operational objectives, assessment of the condition of these assets drives investment in this category.

Most material expenditures in this account relate to fleet replacements, and the condition of fleet is monitored closely by operations staff utilizing maintenance records containing information regarding utilization (operating hours and kilometers driven) as well as overall lifecycle costs (including fuel and regularly scheduled maintenance). Information regarding increased compliment of equipment and/or equipment targeted for replacement (as a result of condition) can be found in the Vehicle and Equipment Resource Justification Plan in Appendix E.

d) A list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category.

5.4.1.4 Material Capital Expenditure Projects (OEB Filing Req. 5.4.1d)

A summary of the proposed material investments for 2017 is shown in Table 5.4.1.5. It is important to note that Thunder Bay Hydro does not have a complete list of detailed projects contained within all of the activities for the 2017 test year due to the nature of these programs which consist of a series of individual projects below the materiality threshold. These projects include: IT (Software and Hardware and Fleet- Rolling Stock. Detailed descriptions of projects can be found in Appendix J: Material Capital Investments.

**Appendix 2-AA
Capital Projects Table**

Projects	2012	2013	2014	2015	2016 Bridge Year	2017 Test Year
Reporting Basis	Actuals	Actuals	Actuals	Actuals	Budget	Forecast
SYSTEM ACCESS						
PCB Transformer Replacements (A 01)	143,287	120,061	217,974		162,598	118,655
Customer Recoverable System Modifications (A 02)		221,636	509,842	859,513	235,458	281,092
Customer Driven System Expansions (A 11)		197,649		181,267	175,506	209,034
Residential Service Connections (A 12)	459,350	296,842	302,465	282,378	449,520	445,213
General Service Connections (A 13)	627,181	578,080	580,813	461,209	907,343	926,898
New courthouse - Miles @ Brodie (WF0376329)	323,741	391,726				
Expansions for Residential Subdivisions (A 14)			335,496	118,498	232,955	230,530
System Relocations (A 15)	447,447		428,303	176,094	162,858	164,881
Golf Links Road Widening Stage 2 (WF0482298)			285,169			
Meter Installations (A 21)		189,544	175,260	192,854	396,177	286,129
Generator Driven Expansions (A 32)	666,826					
Miscellaneous	196,098	158,117	101,558	140,464	(338)	-
Sub-Total System Access	\$ 2,863,931	\$ 2,153,655	\$ 2,936,881	\$ 2,412,277	\$ 2,722,077	\$ 2,662,432
SYSTEM SERVICE						
Grid Modernization (A 35)						230,375
Miscellaneous	-	-	-	-	-	-
Sub-Total System Service	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 230,375
SYSTEM RENEWAL						
Line Voltage Conversions (B 12)						
Brock-Ford Rebuild	1,476,051					
Georgina-Francis Conversion	940,824					
Brown-Isabella Rebuild	1,637,599					
Churchill-Edward 25kV Area Rebuild		223,674	247,555			
Ogden-McMurray Area Rebuild	1,075,188	1,624,654				
McKenzie-Dease Area Design			171,815	204,139		
Clayte-Burriss Design			1,979,501			
Huron-Otto Rebuild		196,143	1,327,820			
Dawson-Rockwood Area Rebuild				1,239,672		
Balsam-Minot Area Rebuild			619,344	1,225,645		
Elliott-Leslie Area Rebuild		664,836				
Durban-Brodie Area Conversion		593,882				
Mary-Heath Area Conversion/Rebuild		1,032,388				
Black Bay-Dewe Rebuild					664,656	1,174,110
Dewe-Rita Rebuild					700,195	1,489,302
Donald-Mountdale						310,256
Dacre-Leslie				586,778	1,439,532	
Bruswick-Legion				411,866		
Isabella-James				362,893	990,067	
MacDougall-Court						789,716
Victoria James					1,196,761	
FW TS Exit Cable Replacement						376,868
Finlayson - Brodie Conversion						893,725
Cumming - Brodie Street						580,677
25kV Pole Replacements						584,384
System Improvements (B 13)						
10M8 Reconfiguration				372,317		
U/G Installations/Replacements (B 14)						
Industrial Park - U/G Express Reinforcement	213,160			280,312		
Main St Connection 10M3 to 17M1			116,412			
Small Pole Replacements (A 16)						
Northwood - 10M9 Pole Line (WF0469253)	160,400	236,494		130,406	379,573	342,512
2M6 Pole Line Rebuild (WF0484290)			159,795	126,926		
Main St and Hammond (WF0508762)			116,798	198,919		
Lane South of Arthur between Edward and Ford Rebuild (WF0517942)				138,764		
Edward between Arthur and Mary Rebuild (WF052223)				171,493		
Edward and Churchill Rebuild (WF0525234)				261,792		
Lines Safety Reports (A 17)						
Transformer/Switch/Switchgear Replacements (A 18)	468,445	625,723	567,743	495,879	732,775	761,834
Hector Dougall Way (WF 0474031)	123,691	345,416	215,210	932,264	816,936	756,484
Waverly Park Towers Transformer Replacement (WF0484290)			119,529			
Miscellaneous			209,732			
Sub-Total System Renewal	\$ 568,886	\$ 344,417	\$ 143,199	\$ 273,402	\$ 244,208	\$ 319,888
GENERAL PLANT						
2012 Terex Digger Derrick		220,340				
2013 Material Handler		291,262				
2014 Freight liner Double Bucket			364,664			
2015 Freight Liner Double Bucket				282,464		
2016 Digger Derrick					255,160	
2016 Double Bucket					125,000	325,000
2016 Single Bucket					190,016	
2017 Mini Bucket					135,522	
2017 Double Bucket						125,000
Fleet Garage		3,277,070				
Building Improvements					131,000	
IT (Software and Hardware)	231,506		136,189	194,052	183,686	206,500
Power Operated Equipment				196,682		
Equipment - Tools, Shop, Testing, Power and Communications			160,587	158,841		
Fleet - Rolling Stock	437,900	249,002	257,949	202,974	286,430	160,000
SCADA					416,699	
Miscellaneous	207,279	208,204	69,225	309,957	182,292	351,000
Sub-Total General Plant	\$ 876,685	\$ 4,245,878	\$ 988,614	\$ 1,344,970	\$ 1,905,805	\$ 1,167,500
Total	10,404,860	12,287,160	9,919,947	11,170,715	11,792,585	12,440,063
Less Renewable Generation Facility Assets and Other Non-Rate Regulated Utility Assets (input as negative)						
Total	10,404,860	12,287,160	9,919,947	11,170,715	11,792,585	12,440,063

Table 5.4.1-1 2017 Material Capital Project Summary Appendix 2-AA

e) Information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan.

5.4.1.5 Material Impact of IRRP/RIP on the DSP (OEB Filing Req. 5.4.1e)

As a result of the IRRP planning process in the Thunder Bay Sub-Region, Thunder Bay Hydro anticipates that there will be no material impact arising from any recommendations developed during the IRRP consultation process over the forecast period 2017-2021.

f) A brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan.

5.4.1.6 Customer Preferences (OEB Filing Req. 5.4.1f)

As previously indicated in Section 5.2.2.1 Thunder Bay Hydro has engaged its customers to gain insight into customer needs and preferences for use in developing the 2016 Distribution System Plan and Cost of Service Application. The following activities were conducted to gain insight into customer preferences:

- Analysis of results of bi-annual UtilityPULSE Customer Satisfaction Survey conducted by telephone in the spring of 2015 (see Attachment 1G in Exhibit 1);
- Analysis of the results of the Decision Partners Mental Models DSP Survey, conducted by telephone with selected customers in the fall of 2015 (see Attachment 1K in Exhibit 1);
- Analysis of Online survey results developed from the Decision Partners Mental Models DSP Survey conducted Spring 2016 (see Attachment 1K in Exhibit 1); and
- Feedback from customers obtained through outreach activities, (e.g. Construction Association education regarding locates).

The general outcome of these engagement activities was to inform its customers on the proposals being considered for inclusion in this Application and the value of those proposals. The results indicated that customers thought that Thunder Bay Hydro consistently performs at or above industry expectations from across Ontario and Canada. Overall customer satisfaction is high however Thunder Bay Hydro has received feedback regarding customer priorities which were incorporated into the planning, prioritizing and justifying proposed capital expenditures in this Application. Thunder Bay Hydro plans to continue engaging its customers in an effort to stay informed of their needs and preferences.

Customer Satisfaction

The feedback received from Thunder Bay Hydro customers indicates a high level of satisfaction with the reliability of the system and the service that Thunder Bay Hydro provides. This is evidenced by the fact

that Thunder Bay Hydro achieved a score of 86% in providing overall excellent quality services to its customers. With regard to Management Operations, Thunder Bay Hydro scored higher than the Ontario and National averages on all important attributes that shape perceptions about the management of operations as shown in Figure 5.4.1-7 Survey Results on Management Operations from UtiliPULSE.

Management Operations			
Top 2 boxes, 'strongly + somewhat agree'	Thunder Bay	National	Ontario
Provides consistent, reliable electricity	91%	90%	88%
Quickly handles outages and restores power	90%	87%	85%
Makes electricity safety a top priority for employees and contractors	90%	89%	87%
Operates a cost effective electricity distribution system	71%	72%	63%
Overall the utility provides excellent quality services	86%	85%	83%

Base: total respondents with an opinion

Figure 5.4.1-7 Survey Results on Management Operations from UtiliPULSE

Furthermore, 91% of the customers who participated in the Telephone Survey in spring of 2015 rated Thunder Bay Hydro's ability to provide consistent and reliable electricity as strongly or somewhat agree. In addition Thunder Bay Hydro customers strongly agree or somewhat agree at a rate of 90% that Thunder Bay Hydro quickly handles outages and restores power. Together, these high scores have been taken as an indication that Thunder Bay Hydro's current approach to distribution system planning is meeting the needs of customers for a reliable supply of electricity. Maintaining Reliability through prudent System Renewal investment is a primary focus of this Plan.

Customer Priorities

The feedback received from the Decision Partners Mental Models research regarding overall customer priorities has helped to shape the planning, prioritizing and justifying of proposed capital expenditures in this Application. As can be seen in Figure 5.4.1-8, and as is the case across the province, reliability and overall cost effectiveness is at the top of mind for many consumers. For this reason, Thunder Bay Hydro is planning capital expenditures based on maximizing resources and improving efficiencies in an attempt to execute more work at a lower cost. This plan is reflected in this DSP.

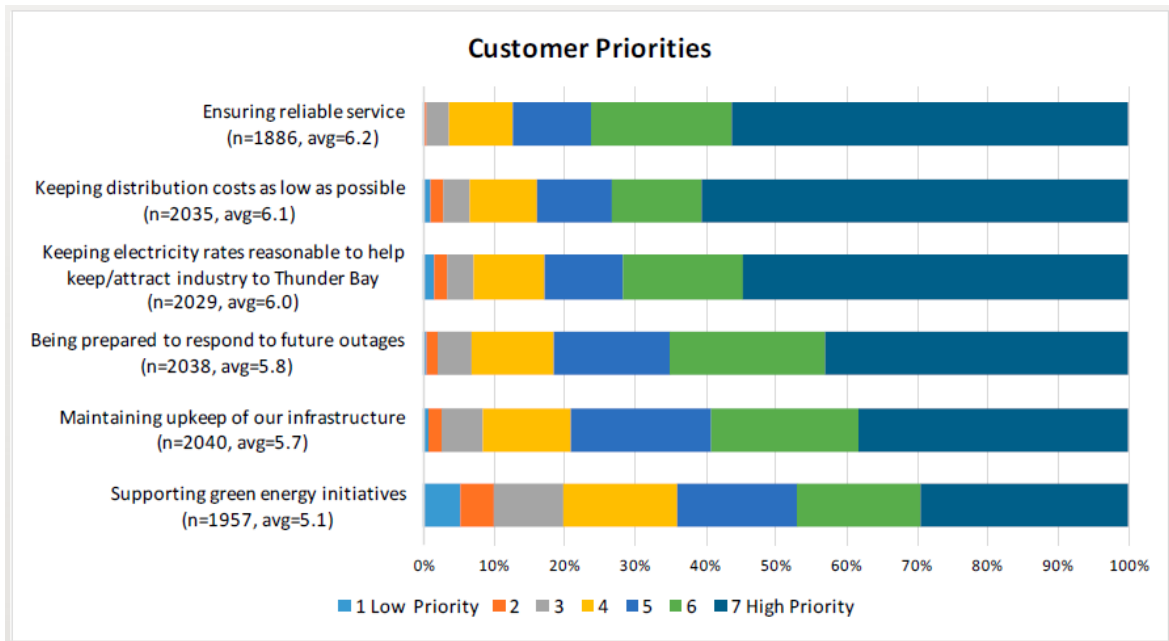


Figure 5.4.1-8 Customer Priorities – Mental Models Research

Reliability

One of the many objectives of the Mental Models research was not only to inform its customers on the proposals being considered for inclusion, but also to better understand how various customers think, feel and act towards the organization. The observations indicated that there are differing priorities for residential, small and large user classes regarding the priority of reliability. For this reason, Thunder Bay Hydro has developed a Grid Modernization plan to deploy smart devices and work towards an automated distribution system in strategic areas with large densities of small commercial and large users throughout the distribution system. The intent of these activities is to positively impact reliability for this class of customers by reducing the impact of outages to these customers.

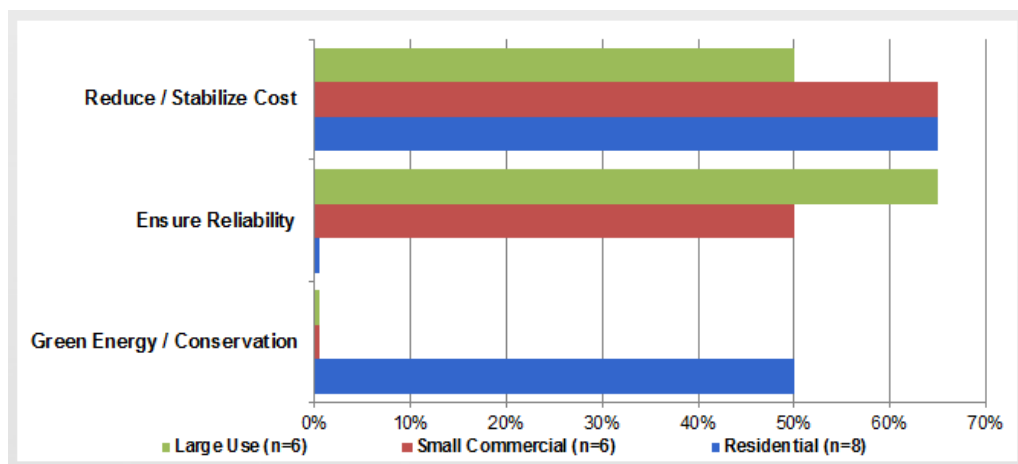


Figure 5.4.1-9 Top Priorities for Customer Classes

Customer Confidence

Thunder Bay Hydro was not only interested in determining if our customers were satisfied with our customer service but also with our implementation of customer priorities into the DSP plan. Feedback was solicited on this particular topic and the results indicated that customer's confidence in Thunder Bay Hydro's ability to implement the DSP while maintaining reliability and containing cost is medium to high as shown in Figure 5.4.1-10. During the mental models interviews, customers were educated on the DSP process and what would be included in an application; this resulted in a much higher degree of confidence than customers who were not given the education but instead, only completed the online survey. Thunder Bay Hydro has used this feedback to determine that additional education will positively affect customers understanding and acceptance of distribution system planning and activities. In order to positively impact this confidence, Thunder Bay Hydro has completed a Customer Service Strategy which will address these needs in Exhibit 1. The three objectives at the core of this strategy are; Customer Education, Customer Autonomy, and Departmental Efficiency.

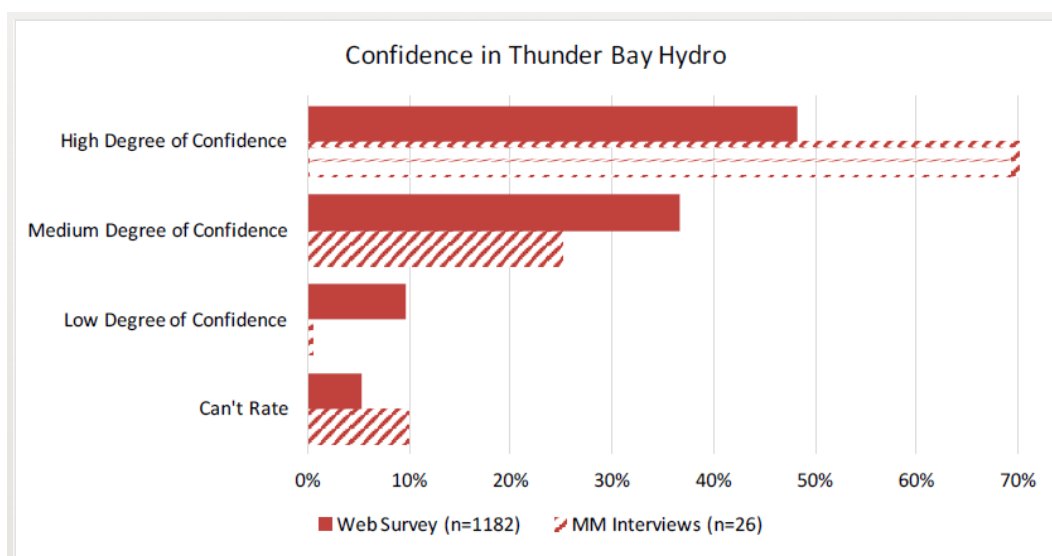


Figure 5.4.1-10 Customer Confidence in Implementing the DSP

g) A brief description of how the distributor expects its system to develop over the next five years, including in relation to lead and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects

5.4.1.7 Expected System Development over the Planning Horizon (OEB Filing Req. 5.4.1g)

Based on load forecasting activities and discussions with stakeholders, Thunder Bay Hydro does not anticipate significant customer or load growth in the service territory over the forecast period. As a result, no restrictions in the ability to connect new load is expected.

Smart grid development or grid modernization is a strategic initiative for Thunder Bay Hydro, which is expected to improve system reliability and work towards an automated distribution system. The detailed plan can be found in Appendix E.

Accommodation of forecasted renewable energy generation projects is favorable in most parts of the service territory. However, where customers are located on certain rural there are restrictions on micro generation related to the anti-islanding requirements described in the REG Plan (Appendix A). Research into solutions to mitigate the rejection of renewable connections in these rural areas has not been productive, as the presently available solutions have either not been not widely accepted across the province or are cost prohibitive. Examples of potential solutions that have been explored are discussed in the REG Plan. At this time there is currently no widely accepted industry solution to address this restriction, however, Thunder Bay Hydro is open to accommodating a solution if and when one becomes available.

h) A list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

- in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);*
- to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and*
- to study or demonstrate innovated processes, services, business models, or technologies*

5.4.1.8 Projects Relative to Customer Preferences, Technology and Innovation (OEB Filing Req. 5.4.1h)

Thunder Bay Hydro has prepared the following Table to summarize planned 2017 projects in relation to Customer Preferences, to take advantage of Technology based opportunities, and to demonstrate Innovative processes.

Projects	Customer Preference, Technology Based, Innovative Processes	2017 Test Year
SYSTEM ACCESS		
PCB Transformer Replacements (A 01)	Technology Based	118,655
Customer Recoverable System Modifications (A 02)	Customer Preference	281,092
Customer Driven System Expansions (A 11)	Customer Preference	209,034
Residential Service Connections (A 12)	Customer Preference	445,213
General Services Connections (A 13)	Customer Preference	926,898
Expansions for Residential Subdivisions (A 14)	Customer Preference	230,530
System Relocations (A 15)	Customer Preference	164,881
Meter Installations (A 21)	Innovative Processes	286,129
Sub-Total System Access		\$ 2,662,432
SYSTEM SERVICE		
Grid Modernization (A 35)	Customer Preference, Technology Based, Innovative Processes	230,375
Sub-Total System Service		\$ 230,375
SYSTEM RENEWAL		
Black Bay-Dewe Rebuild	Technology Based	1,174,110
Dewe-Rita Rebuild	Technology Based	1,489,302
Donald-Mountdale	Technology Based	310,256
MacDougall-Court	Technology Based	789,716
FW TS Exit Cable Replacement	Technology Based	376,868
Finlayson - Brodie Conversion	Technology Based	893,725
Cumming - Brodie Street	Technology Based	580,677
25kV Pole Replacements	Customer Preference, Technology Based	584,384
Small Pole Replacements (A 16)	Technology Based	342,512
Lines Safety Reports (A 17)	Customer Preference, Technology Based	761,834
Transformer & Switch Replacements (A 18)	Technology Based	756,484
Sub-Total System Renewal		\$ 8,059,868
GENERAL PLANT		
IT (Software and Hardware)	Innovative Processes, Technology Based	206,500
Fleet - Rolling Stock	Technology Based	160,000
2017 Double Bucket	Technology Based	325,000
2017 Mini Bucket	Technology Based	125,000
Sub-Total General Plant		\$ 816,500
Miscellaneous		670,888
Total		\$12,440,063

Table 5.4.1-2 2017 Planned Projects in Relation to Customer Preferences

Projects/Activities in Response to Customer Preferences

Reliability and cost containment were identified as the topics of top interest to customers during Thunder Bay Hydro's customer engagement process. The following projects and activities provide illustrative examples projects proposed in this DSP that demonstrate how the capital expenditure plan fulfills customers' needs and preferences related to these topics.

- Grid Modernization

This initiative is in response to small commercial and large user's preference for ensuring reliability. Through the installation of automated switching in select locations, Thunder Bay hydro expects to be able to address these preferences directly with these customers.

- 25 kV Pole Replacements

With this initiative Thunder Bay Hydro has taken on a more balanced view of its asset management. By investing in areas of planned 25kV pole replacements rather than reactive 25kv pole replacements, customers on this voltage will see improved system reliability, by reducing assets failures and the restoration response time of outages that have occurred. This aligns with customers' expectation on Thunder Bay Hydro to further improve its system reliability.

- Distribution System Replacement

Thunder Bay Hydro is ramping up its spending in distribution system replacement to keep pace with recommendations in the ACA. By maintaining and improving the overall health condition of distribution system assets, this program directly contributes to more reliable performance of Thunder Bay Hydro's electricity distribution network.

Projects/Activities to take advantage of technology-based opportunities

Opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads such as:

- Grid Modernization

Thunder Bay Hydro, like many LDCs, has for many years implemented "Operations Technology" to provide better, more refined and timely distribution system field device operational information. This greater visibility into distribution system operation has helped drive improved customer service and operational effectiveness through cost containment, better and more timely decision making, as well as reduced restoration times. To support this initiative Thunder Bay Hydro will continue to invest in automated switches and SCADA infrastructure with the goal of one day implementing an Outage Management System

- Equipment – Tools, Shop, Testing, Power and Communications

Ongoing technological enhancements in the handling of data and communications systems are constantly changing the opportunities for enhancing customer experience. In 2016, Thunder Bay Hydro purchased several sets of remote communicating fault indicators. These devices will improve the fault locating through enhanced data which leads to an improvement in outage duration.

Projects/Activities to study or demonstrate innovative processes

Opportunities to improve services, business models, or technologies are listed below.

- Meter Installations

The meter sampling / reverification program (see Appendix F) has been implemented so that Thunder Bay Hydro customers can extend their smart meter's in-service life and ultimately maximize the return on investment. This program directly speaks to customer's preference for cost containment through effective asset management and innovative processes.

- IT /Software Hardware

Deployment of tablets and GIS in the field are being tested in 2016 and are planned for broad distribution to field crews in 2017. The implementation of these technologies is an example of using devices to positively impact cost-effectiveness and promote efficiencies within the utility.

5.4.2 Capital Expenditure Planning Process Overview (OEB Filing Req. 5.4.2)

a) A description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities.

5.4.2.1 Capital Expenditure Planning Objectives (OEB Filing Req. 5.4.2a)

The following information provides an overview of Thunder Bay Hydro's capital expenditure planning process which includes details on planning objectives, planning criteria and assumptions used in the development of the capital expenditure plan. The asset management process is the foundation to the DSP and the capital expenditure plan which helps align each to overall corporate objectives. By following a strategic approach to the capital expenditure planning process Thunder Bay Hydro achieves efficiencies in work practices and productivity along with creating and maintaining a distribution system capable of meeting the needs of existing and future customers. During the development of the capital expenditure plan, a number of objectives and planning processes are observed which ensures the plan aligns with the asset management objectives and therefore with the overall strategic goals of the corporation (see Section 5.3.1.1). Thunder Bay Hydro's planning assumptions that have shaped the distribution system plan and capital expenditure plan include the following:

1. Provide the proper allocation of investments to meet Health and Safety obligations; ensuring the manner in which work is executed does not negatively impact the general public, customers or Thunder Bay Hydro staff.
2. Minimize environmental impact through consideration of asset retirements in the PCB Transformer replacement program.
3. Ensure proper allocation of investments to meet regulatory and customer obligations of system access projects. (e.g. metering, system relocations, residential and general service connections).
4. Ensure adequate level of investment in the renewal of distribution system assets to maintain a safe and reliable system as determined through continued ACA's.
5. Actively seek operational efficiencies that positively affect constraints on the system;

6. Review overall expenditures and determine impacts to financials, and adjust spending as required.

The assumptions made during the planning process stem from input from various sources such as:

- growth forecasts;
- co-ordination with customer and 3rd parties;
- impact of regulatory initiatives;
- asset condition forecasts; and
- impact of CDM and REG.

The degree to which each of these assumptions affects the overall capital plan varies along with the timing required to execute them. Thunder Bay Hydro strives for continuous improvement and as a result regularly audits and revises the above planning assumptions to ensure they accurately reflect reality. As part of the capital expenditure planning process, Thunder Bay Hydro has determined a number of assumptions are also made in order to support in the development of a capital expenditure plan, these key assumptions include:

- The use of historical trends in categories related to system access to forecast capital expenditures;
- The validity of information from City of Thunder Bay and third Parties with respect to future requirements of the distribution system to service new projects; and
- The use of historical growth, CDM and DG rates to assist in the forecasting future contributions to the demand of the distribution system.

Thunder Bay Hydro's asset management goal is to identify and prioritize assets for replacement in an optimal manner through the guiding principles of the Asset Management Objectives, in such a way as to minimize risks to Thunder Bay Hydro's Vision and Core Values, while maximizing long term investment benefits. Each of the asset management objectives described in Section 5.3.1.1 are considered by utilizing them as weighted criteria to assist in selection and prioritization of projects in the capital expenditure planning process.

The outlook for accommodating the connection of renewable generation facilities as outlined in the REG plan is favourable. Historical trends indicated that renewable connections have significantly decreased in numbers, and historical trends are not expected to shift without an announcement in changes to the FIT rates and program. Thunder Bay Hydro expects to have no constraints in accommodating the connection of micro-generation facilities over the forecast period.

b) If not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives.

5.4.2.2 Non-Distribution System Alternatives to Relieve System Capacity (OEB Filing Req. 5.4.2b)

Thunder Bay Hydro is not expecting any capacity constraints over the forecast period. Thunder Bay Hydro does however consider it a priority to ensure that capacity is maintained throughout the system. Thunder Bay Hydro does take steps to ensure this and it includes:

- consultation with municipal planners and the development community in the COTB;
- consultation with the IESO and HONI through the IRRP process; and
- support of CDM initiatives.

These considerations are embedded in Thunder Bay Hydro's planning processes.

c) A description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills).

5.4.2.3 Project Prioritization Tools and Methods (OEB Filing Req. 5.4.2c)

At the core of Thunder Bay Hydro's planning processes are its Corporate Vision, Values and Strategic Initiatives. These principles shape the various inputs and outputs of all asset management and investment planning processes.

It is the ultimate goal of the utility to inspect, analyze and plan all facets of the utilities operations in a holistic manner ensuring that all investments are optimized and coordinated to the fullest extent possible. Figure 5.4.2-1 below outlines the planning process with the various inputs and the final output being the finalized capital plan.

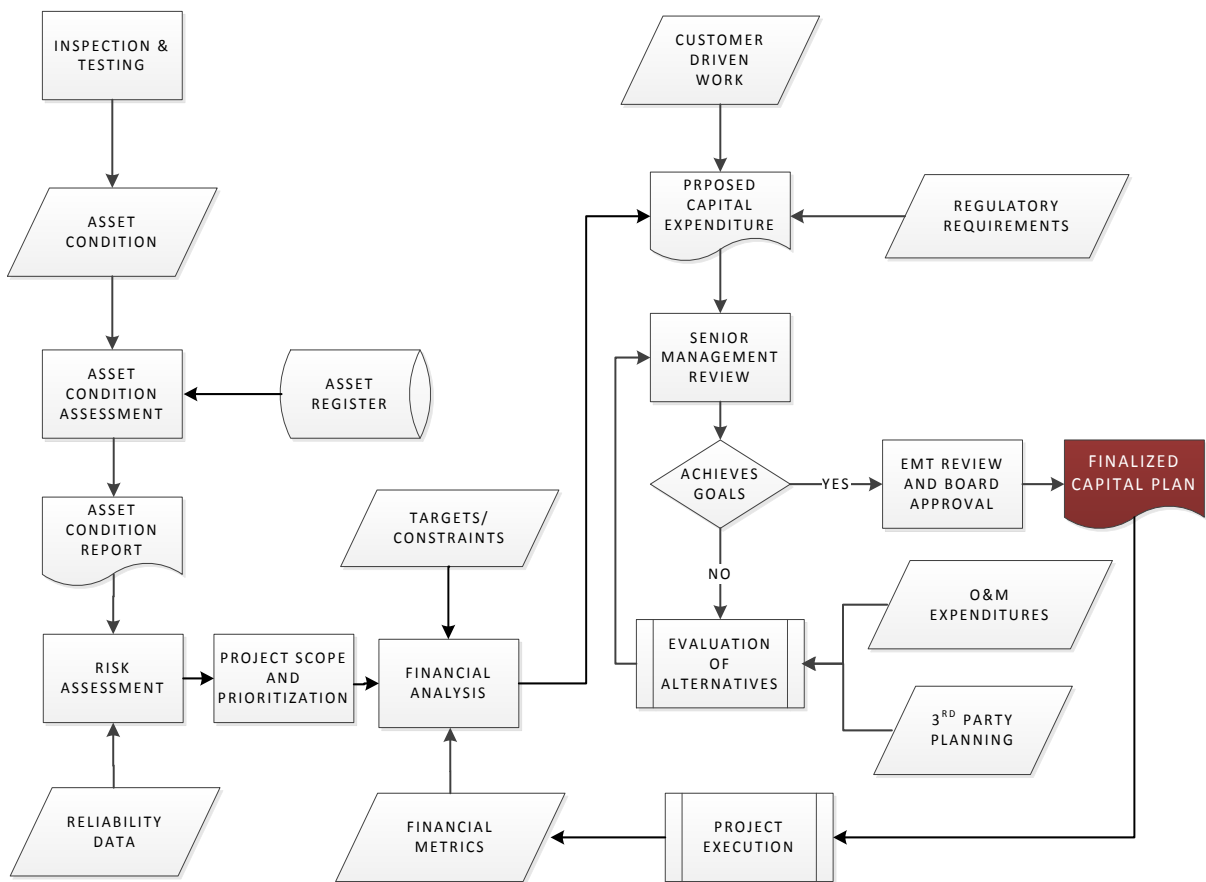


Figure 5.4.2-1 Capital Planning Process

Thunder Bay Hydro has developed a Project Prioritization Ranking Methodology as described below and quantified by Table 5.4.2-1 Qualitative Prioritization Ranking Descriptions and Table 5.4.2-2 Quantitative Project Ranking as well as the equation shown below.

Priority		Description
P1	Emergency	Safety of life or property threatened; immediate impact to or loss of supply to customers. Mitigation to begin immediately; resources diverted as necessary; overtime may be required.
P2	Urgent	Maintenance or repair work required for continued operation; should be completed to ensure continuous operation and restore health of the system. Not an emergency, respond upon completion of current work but within a specified period (such as same day or same week).
P3	High Priority	Work or projects that are non-discretionary in nature and are essential to meet project deadlines or legislative/regulatory compliance. Completed in order of receipt or paced to meet compliance deadlines.

P4	Medium Priority	Work or projects that 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.
P5	Low Priority	Work or projects that are desired but not essential to protect, preserve or restore facilities or equipment; generally new work or equipment that is not tied to a specific goal or milestone.
P6	No Priority	Work or projects that may be safely, operationally and economically postponed. The work should be completed but cannot be scheduled because of higher priority work, funds shortage, work site access or conditions outside the control of the utility. The work may be reclassified if conditions permit.

Table 5.4.2-1 Qualitative Prioritization Ranking Descriptions

Thunder Bay Hydro initially prioritizes its projects utilizing the qualitative rankings described in Table 5.4.2-1. These priorities align closely with the asset management objectives and are generally assigned to project categories. For each category, projects within that category are ranked against one another utilizing the process identified in Table 5.4.2-2.

System Access

System Access projects are non-discretionary in nature and are developed through contact with customers. Priority for this category of projects generally aligns with P3 – High Priority. Projects are paced to ensure that Thunder Bay Hydro fulfills all of its service conditions within the timeline allowed for the type of connection requested. Budgets in this category flow from consultations with the City of Thunder Bay, local developers and large users to determine the scope and extent of potential projects under development.

System Renewal

System Renewal projects are driven from the results of the ACA. The ACA determines the appropriate pace and level of renewal for various asset classes throughout the distribution system ensuring that the health of the system is either maintained or improved. Priority for this category of projects generally aligns with P4 – Medium Priority. These projects are paced by year and based on risk they pose to the system (this process is further described in Section 5.3.3.2).

System Service

System service projects are identified and assessed using a combination of expert opinion regarding load forecasts, system reliability and switching assessments; as well as feedback from customers regarding expectations of the system. The process involves identifying constraints on the system or opportunities for improvements that yield the greatest benefit to customers or allow for continued effective operation. Once projects are identified a solution is developed weighing the cost, time and resource constraints required against completing projects of higher priority. Priority for this category of projects

generally aligns with P5 – Low Priority. These projects are paced based on removing constraints in the system and then improving reliability and operability of the system.

General Plant

General plant projects are identified and assessed using a combination of inspections, expert knowledge and industry best practices. Projects include those related to Thunder Bay Hydro fleet, purchase of major tools, investments in information systems hardware and software; as well investments related to the administration and operation center buildings. The process involves identifying projects through: regular inspections of buildings and equipment; monitoring of metered interval data (i.e. odometer and/or hour meter readings); typical life expectancy of electronic equipment and rolling stock; and the requirements to maintain an effective and efficient business processes. Priority for this category of projects generally aligns with P5 – Low Priority. The pace of these projects is set forth utilizing expert knowledge and observing changes in industry best practices as well as balancing the costs of purchases with the anticipated reduction in work effort.

As there are generally several projects that fall within each priority rating, projects must be further assessed to determine how they rank against each other categorically. Projects from each qualitative priority category above are ranked against one another to determine the final prioritization. The formula below and subsequent table (Table 5.4.2-2 Quantitative Project Ranking) further describe how each project is ranked.

Each project is initially scored (identified as variable 'B') on a scale of 1-10, based on the degree to which it satisfies the criteria outlined in the table. Each score is then multiplied by the weight (identified as variable 'A') to determine the final score for that particular criteria. For example, a project that is a mandatory service obligation receives a final score of 40 (40 x 10/10), relating to the criteria of Required Service. The summary scores calculated for each criterion are then summed to produce a final project score out of 100. This score is then used to determine the project rank within its priority level.

$$\text{Project Score} = \frac{\sum_{i=1}^n \left(A_i \times \frac{B_i}{10} \right)}{100}$$

Criteria	Description	Weight (A)	Scoring (B)	
Required Service	Project, service or product is driven by legislative or regulatory compliance requirement or is necessary to supply customers.	40	Mandatory Obligation	10
			Utility Discretion	5
			Not Required	0
Strategic Alignment	Project, service or product aligns with corporate policies and/or achieves strategic initiatives.	10	Aligns with 2 or more	10
			Aligns with 1	5
			Aligns with none	0
Customer Impact	Perceived impact of project, service or product to customer base.	20	High Impact, High # of Customers	10
			High Impact, Low # of Customers	7
			Low Impact, High # of Customers	3
			Low Impact, Low # of Customers	0
Importance to Risk Mitigation	Risk posed to customer, corporation or environment by delaying / deferring / or not executing project, service or product. Includes risk to Health & Safety	20	High Risk	10
			Medium Risk	5
			Low Risk	0
Financial / Operational Impact	- Reduces Operating Expenses - Avoids Future Capital Costs - Coordinates with Other Projects - Capital Cost Recovery - Increase in Revenue - Decrease in liability or increase without action	10	Aligns with 3 or more	10
			Aligns with 1-2	5
			Aligns with none	0

Table 5.4.2-2 Quantitative Project Ranking

For example, there may be six projects identified as P3 – High priority. Through the scoring process, these six projects are then ranked as P3-1 through to P3-6, with the ‘-1’ suffix identifying the project with the highest rank in each priority category. Should their arise a requirement to defer a project to due to unforeseen or unplanned circumstances, projects that receive the lowest priority rating and corresponding lowest rank would be deferred first.

The overall ranking of each project within the test year is a result of the composite of the project priority and the project score. For example PCB Transformers is ranked P3 -5 and its overall rating within the test year is 8 of 21 projects.

The proposed capital investment plan is formed based on the analysis as previously described in Section 5.3.1.3 and Figure 5.3.1-1 and includes those investments required in order to be compliant with regulations and legislation. These required investments typically included new connections, customer requests and other requirements such as PCB Regulations. While Thunder Bay Hydro generally employs alternatives and cost reduction techniques; the timing of these types of investments generally leaves little discretion as to their execution and are integrated based on historical performance.

The proposed capital plan is then reviewed by senior management for adherence to any corporate goals, regulated requirements and overall financial fitness. Alternatives are considered at this stage that may impact the timing of certain projects. These considerations can include O&M alternatives and 3rd party projects. Once finalized, the capital expenditure plan is submitted to the Executive Management Team and Board for review and approval.

The final piece of the Thunder Bay Hydro's strategy is to continually improve the assessment process by providing feedback from executed projects in the form of financial metrics and utilizing these metrics to inform future planning processes.

d) If not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DS Plan that have been particularly affected by consideration of this information.

5.4.2.4 Mechanisms to Engage Customers (OEB Filing Req. 5.4.2d)

Thunder Bay Hydro has employed customer satisfaction surveys as a method to engage customers. This process is described in detail in Section 5.2.2.1. The information is gathered from various rate classes and includes feedback on reliability, costs, data availability (information during power outages) and overall satisfaction. Investments in grid modernization have been proposed to improve operational efficiency and reliability has been targeted as a result of this engagement effort.

Customer feedback through inquiries and complaints tend to be reactive in nature (power quality, low service, damages) and are dealt with immediately through maintenance or small unplanned capital. Repeated concerns can be escalated to become a known deficiency in the system and can inform on the inspection process, ultimately becoming embedded in the asset management process.

For other engagement activities see section 5.2.2.1 Customer Engagement.

e) If different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).

5.4.2.5 Method and Criteria used to Prioritize REG Investments (OEB Filing Req. 5.4.2e)

Thunder Bay Hydro does not employ a separate prioritization system for REG investments.

5.4.3 System Capability Assessment for Renewable Energy Generation (OEB Filing Req. 5.4.3)

This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information

identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity. In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable).

5.4.3.1 Applications from REG Connections over 10kW (OEB Filing Req. 5.4.3a)

a) Applications from renewable generators over 10kW for connection in the distributor's service area.

Thunder Bay Hydro has not received any applications for renewable generators over 10kW for the forecast period of 2017-2021.

b) The number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided).

5.4.3.2 Number and Capacity of anticipated REG Connections over the Forecast Period (OEB Filing Req. 5.4.3b)

Renewable connections are expected to remain static or to continue decreasing for the forecast period. In addition to the available historical data, Thunder Bay Hydro has consulted with local solar retailers and anticipates minimal new Micro Generation connections due to reduced return on investment for installations, and continued constraints in the rural areas. The number of connections of micro generation ($\leq 10\text{kW}$) is expected to be approximately 10 per year, which equates to a load of approximately 90kW per year for the next 5 years. For further details, refer to the REG plan included in Appendix A.

Renewable Connections	2016	2017	2018	2019	2020	2021	Total
Micro Generation (<= 10kW)	10	10	10	10	10	10	60
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	1	0	0	0	0	0	1
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	0	0
Large (> 10MW)	0	0	0	0	0	0	0
<i>Total</i>	11	10	10	10	10	10	61
Renewable Connected Load (kW)	2016	2017	2018	2019	2020	2021	Total
Micro Generation (<= 10kW)	90	90	90	90	90	90	540
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	18	0	0	0	0	0	18
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	0	0
Large (> 10MW)	0	0	0	0	0	0	0
<i>Total</i>	108	90	90	90	90	90	558

Table 5.4.3-1 Renewable Generation Connection Forecast 2017-2021

c) The capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area.

5.4.3.3 System Capacity for REG Connections (OEB Filing Req. 5.4.3c)

Currently, Thunder Bay Hydro has a gross feeder available capacity for embedded generation of approximately 25 MW of combined micro/small projects, or 350 MW of combined medium/large projects. When including short circuit and thermal limitations of Hydro One owned stations (per Hydro One, List of Station Capacity, February 26, 2016), the combined available embedded generation capacity for medium/large projects is further reduced to between 6 MW and 129 MW, depending on the type of generation; synchronous using the most short circuit capacity (assumes 25 times rated), versus inverter based (assumes 1.2 times rated). Finally, the regional capacity constraint further limits the available capacity for projects greater than 500kW, to a total of 10MW.

d) Constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter).

e) Constraints for an embedded distributor that may result from the connections.

5.4.3.4 Existing and Anticipated System Constraints (OEB Filing Req. 5.4.3d & 5.4.3e)

Thunder Bay Hydro is classified by HONI as the Northwest region of Ontario, and this region remains restricted to 10MW of "Area Availability" for projects greater than 500kW under the FIT program.

Provided that the Northwest region of Ontario remains restricted to 10MW of "Area Availability" for projects greater than 500kW under the FIT program, we do not anticipate any additional medium/large FIT generation connections, however there continues to be interest in Combined Heat and Power load displacement projects.

Thunder Bay Hydro acknowledges that the East West Tie project may lift the restrictions described above, which may have an effect on the connection of large distributed generators in the future, but this

construction will not be complete until December 2020 and as such does not materially impact the forecast presented by Thunder Bay Hydro in this DSP.

5.4.4 Capital Expenditure Summary (OEB Filing Req. 5.4.4)

The purpose of the information filed under this section is to provide the Board and stakeholders with a ‘snapshot’ of a distributor’s capital expenditures over a 10 year period, including five historical years and five forecast years. Note that where a distributor’s internal investment planning framework does not align with the investment categories defined here, best efforts are expected to ‘map’ investments to these categories.

Despite the ‘multi-purpose’ character of a project or activity, for ‘summary’ purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or ‘trigger’) driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or activity for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

Table 2 illustrates how information filed under this section includes a distributor’s actual and forecast (i.e. proposed) capital expenditures over the historical and forecast periods. System operations and maintenance (O&M) costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. Note that ‘Plan’ expenditures over the historical period refer to a distributor’s previous plan for capital expenditures after adjustments (if any) occasioned by the Board’s decision on the relevant prior application.

A summary of Thunder Bay Hydro’s capital expenditures spanning a 10 year period including the historical (2012-2016) and forecast (2017-2021) are divided into the four investment categories and shown in Table 5.4.4-1 below. As this is Thunder Bay Hydro’s first DSP filed with the OEB, previous plan data has not been provided. In addition variance reports for planned versus actual capital expenditures have not been detailed.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated
Distribution System Plan Filing Requirements

First year of Forecast Period: 2017

CATEGORY	Historical Period (previous plan ¹ & actual)															Forecast Period (planned)				
	2012			2013			2014			2015			2016 (Bridge Year)			2017	2018	2019	2020	2021
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual ⁽²⁾	Var					
	\$ '000		%	\$ '000		%	\$ '000		%	\$ '000		%	\$ '000		%	\$ '000				
	System Access	(1)	2,864	--	(1)	2,154	--	(1)	2,937	--	(1)	2,412	--	(1)	2,722	--	2,662	2,422	2,432	2,445
System Renewal	(1)	6,664	--	(1)	5,888	--	(1)	5,994	--	(1)	7,413	--	(1)	7,165	--	8,380	8,818	8,976	9,217	9,261
System Service	(1)	-	--	(1)	-	--	(1)	-	--	(1)	-	--	(1)	-	--	230	300	280	280	300
General Plant	(1)	877	--	(1)	4,246	--	(1)	989	--	(1)	1,345	--	(1)	1,906	--	1,168	1,360	946	901	969
TOTAL EXPENDITURE	-	10,405	--	-	12,287	--	-	9,920	--	-	11,171	--	-	11,793	--	12,440	12,900	12,634	12,842	13,036
System O&M	(1)	6,998	--	(1)	6,803	--	(1)	7,316	--	(1)	7,441	--	(1)	8,034	--	8,026	8,187	8,350	8,592	8,842

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed.
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 5

Table 5.4.4-1 Appendix 2-AB Capital Expenditure Summary 2012-2021

Brief explanatory notes should be provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to 'actual' spending over the historical period. For example, a large expenditure over a relatively short period for a 'one-off' project (e.g. a distribution station) can cause a temporary 'step change' in category C spending compared to the trend in actual expenditures over the historical period. While year over year 'Plan vs. Actual' variances for individual investment categories are expected, explanatory notes should be provided where for any given year "Total" 'Plan' vs. 'Actual' variances over the historical period are markedly positive or negative; or a trend for variances in a given investment category is markedly positive or negative over the historical period.

5.4.4.1 2012 Actual vs. 2013 Actual Capital Expenditure Variances

Category	2012 Actual	2013 Actual	Variance 2012 to 2013
System Access	\$2,863,931	\$2,153,655	\$(710,277)
System Renewal	\$6,664,243	\$5,887,628	\$(776,615)
System Service	\$0	\$0	\$-
General Plant	\$876,685	\$4,245,878	\$3,369,193
Total Expenditure	\$10,404,860	\$12,287,160	\$1,882,301

Table 5.4.4-2 Capital Expenditure Variances 2012 to 2013 Actual

System Access

The most significant drivers behind the variance within the System Access category can be represented by a significant decrease in projects related Renewable Enabling Improvements. Specifically the cancellation of budgeted expenditures related to the connection of two large solar projects on Thunder Bay Hydro's distribution system in 2013. Other drivers include: a reduction in System Relocation projects by the City of Thunder Bay; and a reduction in requests for connections of General Services in 2013. The majority of capital expenditures contained within the System Access category, with the exception of meters, are recoverable to some extent through capital contributions.

In addition, Thunder Bay Hydro adopted IFRS accounting standards in 2013 which led to a decrease in the extent of overheads allocable to Capital work. This led to a scaled similarly decrease in the cost of previously comparable projects completed in 2012.

Account #	Description	2012 Actual	2013 Actual	Variance
A 01	PCB Transformer Replacements	\$ 143,287	\$ 120,061	\$ (23,226)
A 02	Customer Recoverable System Modifications	\$ -	\$ 221,636	\$ 221,636
A 11	Customer Driven System Expansions	\$ 91,318	\$ 197,649	\$ 106,331
A 12	Residential Service Connections	\$ 459,350	\$ 296,842	\$ (162,508)
A 13	General Service Connections	\$ 950,922	\$ 969,806	\$ 18,884
A 14	Expansions for Residential Subdivisions	\$ 92,348	\$ 43,936	\$ (48,412)
A 15	System Relocations	\$ 447,447	\$ 88,703	\$ (358,744)
A 21	Meter Installations	\$ 3,510	\$ 189,544	\$ 186,034
A 31	Generator Driven Expansion	\$ -	\$ -	\$ -
A 32	Renewable Enabling Improvements	\$ 675,750	\$ 25,478	\$ (650,272)
	Subtotal	\$ 2,863,931	\$ 2,153,655	\$ (710,277)

Table 5.4.4-3 System Access Expenditure Variances 2012 to 2013 Actual

System Renewal

In 2013, Thunder Bay Hydro experienced a variance in System Renewal capital expenditures which can be largely attributed to decrease in planned Underground Renewal and a decrease in the cost of Voltage Conversion projects. The cost of Voltage Conversion projects was decreased due to the adoption of IFRS accounting standards in 2013 which led to a decrease in the extent of overheads allocable to Capital work. Thus a comparable amount of work was completed for a lesser expenditure.

Account #	Description	2012 Actual	2013 Actual	Variance
A 16	Small Pole Replacements	\$ 160,400	\$ 236,499	\$ 76,099
A 17	Lines Safety Reports	\$ 468,445	\$ 625,736	\$ 157,291
A 18	Transformer and Switch Replacements	\$ 123,691	\$ 345,423	\$ 221,732
A22	Operations Safety Reports	\$ 70,057	\$ 37	\$ (70,020)
B	25kV Pole Replacements		\$ 223,679	\$ 223,679
B	4kV Voltage Conversions	\$ 5,310,026	\$ 4,166,334	\$ (1,143,692)
B	Underground Renewal	\$ 213,160	\$ -	\$ (213,160)
B	Design	\$ 318,465	\$ 290,041	\$ (28,424)
	Subtotal	\$ 6,664,243	\$ 5,887,748	\$ (776,495)

Table 5.4.4-4 System Renewal Expenditure Variances 2012 to 2013 Actual

System Service

In 2013, Thunder Bay Hydro experienced no change in System Service capital expenditures.

General Plant

In 2013, Thunder Bay Hydro experienced an increase in General Plant capital expenditures of \$3,369,193. This variance is solely related to the one- time cost of the construction of a new fleet garage.

5.4.4.2 2013 Actual vs. 2014 Actual Capital Expenditure Variances

Category	2013 Actual	2014 Actual	Variance 2013 to 2014
System Access	\$2,153,655	\$2,936,881	\$783,226
System Renewal	\$5,887,628	\$5,994,452	\$106,824
System Service	\$0	\$0	\$-
General Plant	\$4,245,878	\$988,614	\$(3,257,264)
Total Expenditure	\$12,287,160	\$9,919,947	\$(2,367,214)

Table 5.4.4-5 Capital Expenditure Variances 2013 to 2014 Actual

System Access

The System Access category is primarily influenced by Customer Preferences, and can be difficult to forecast and budget. Thunder Bay Hydro uses historical figures and information from consultation with third parties to determine budgets, but in many cases connections are requested and executed within the same year, resulting in large fluctuations year over year. In 2014, Thunder Bay Hydro experienced a variance in System Access capital expenditures of \$ 786,580. The main driver of this variance was the unexpected inclusion of several Relocation projects requested by the City of Thunder Bay. There were three road widening projects which required Thunder Bay Hydro to relocate 59 poles along Golf Link Stage 1, Stage 2, and Valley Street. There was also a variance in Expansions for Residential Subdivisions. The developments that were in progress in 2014 were Parkdale, Tuscany, Hutton Park and River Terrace, which comprised of a total of 217 lots. Another driver of the variance is related to the fluctuation in General Service connections requested by customers. 2014 saw a substantial decrease in requests for general service customers, and capital recoverable work.

Account #	Description	2013 Actual	2014 Actual	Variance
A 01	PCB Transformer Replacements	\$ 120,061	\$ 217,974	\$ 97,913
A 02	Customer Recoverable System Modifications	\$ 221,636	\$ 509,842	\$ 288,205
A 11	Customer Driven System Expansions	\$ 197,649	\$ 83,248	\$ (114,401)
A 12	Residential Service Connections	\$ 296,842	\$ 302,465	\$ 5,624
A 13	General Service Connections	\$ 969,806	\$ 580,813	\$ (388,993)
A 14	Expansions for Residential Subdivisions	\$ 43,936	\$ 335,496	\$ 291,560
A 15	System Relocations	\$ 88,703	\$ 713,299	\$ 624,596
A 21	Meter Installations	\$ 189,544	\$ 175,260	\$ (14,283)
A 32	Generator Driven Expansion	\$ 25,478	\$ -	\$ (25,478)

A 33	Renewable Enabling Improvements	\$ -	\$ 11,947	\$ 11,947
A 34	Event Centre	\$ -	\$ 6,536	\$ 6,536
	Subtotal	\$ 2,153,655	\$ 2,936,881	\$ 783,226

Table 5.4.4-6 System Access Expenditure Variances 2013 to 2014 Actual

System Renewal

In 2014, Thunder Bay Hydro experienced an increase in System Renewal capital expenditures of \$106,702, based on Thunder Bay Hydro's materiality threshold, this amount is deemed immaterial.

System Service

In 2014, Thunder Bay Hydro experienced no change in System Service capital expenditures.

General Plant

In 2013, Thunder Bay Hydro experienced a decrease in General Plant capital expenditures of \$3,257,264, due to the completion of the construction of new fleet garage.

5.4.4.3 2014 Actual vs. 2015 Actual Capital Expenditure Variances

Category	2014 Actual	2015 Actual	Variance 2014 to 2015
System Access	\$2,936,881	\$2,412,277	\$(524,604)
System Renewal	\$5,994,452	\$7,413,468	\$1,419,016
System Service	\$0	\$0	\$-
General Plant	\$988,614	\$1,344,970	\$356,356
Total Expenditure	\$9,919,947	\$11,170,715	\$1,250,769

Table 5.4.4-7 Capital Expenditure Variances 2014 to 2015 Actuals

System Access

The main contributors to the variance in capital expenditures in System Access between 2014 and 2015 can be linked to a decrease in System Relocations work required by the City of Thunder Bay as compared to 2014 due to budgetary constraints and fluctuating priorities. In addition there was a decrease in expansions for new residential subdivision as a result of fewer developments within the year.

Account #	Description	2014 Actual	2015 Actual	Variance
A 01	PCB Transformer Replacements	\$ 217,974	\$ 100,942	\$ (117,031)
A 02	Customer Recoverable System Modifications	\$ 509,842	\$ 859,513	\$ 349,671
A 11	Customer Driven System Expansions	\$ 83,248	\$ 181,267	\$ 98,019

A 12	Residential Service Connections	\$ 302,465	\$ 282,378	\$ (20,088)
A 13	General Service Connections	\$ 580,813	\$ 461,209	\$ (119,604)
A 14	Expansions for Residential Subdivisions	\$ 335,496	\$ 118,498	\$ (216,999)
A 15	System Relocations	\$ 713,299	\$ 233,939	\$ (479,360)
A 21	Meter Installations	\$ 175,260	\$ 193,236	\$ 17,975
A 32	Generator Driven Expansion	\$ -	\$ -	\$ -
A 33	Renewable Enabling Improvements	\$ 11,947	\$ (12,141)	\$ (24,088)
A 34	Event Centre	\$ 6,536	\$ (6,563)	\$ (13,099)
	Subtotal	\$ 2,936,881	\$ 2,412,277	\$ (524,604)

Table 5.4.4-8 System Access Expenditure Variances 2014 to 2015 Actuals

System Renewal

In 2015, Thunder Bay Hydro experienced an increase in System Renewal capital expenditures of \$1,419,018. The main driver of the increase was due to the poles identified for replacement as part of Small Pole Replacements project. This work is driven by internal and external requests and inspections identifying assets that pose an immediate risk to public and / or worker safety. In addition there was an increase in the identification of defective and failed transformers that required environmental remediation (\$413,653). Another driver of expenditures was the increased investment in underground infrastructure (\$491,205) for; the 10M8 overhead project, which needed to be routed underground due to public opinion; and the Industrial park project which renewed infrastructure to several industrial customers. An increase in design work was (\$116,940) completed to ensure that design prints were available 3 years in advance for planning purposes.

Account #	Description	2014 Actual	2015 Actual	Variance
A 16	Small Pole Replacements	\$ 278,405	\$ 1,028,301	\$ 749,896
A 17	Lines Safety Reports	\$ 567,743	\$ 495,879	\$ (71,864)
A 18	Transformer and Switch Replacements	\$ 544,471	\$ 958,123	\$ 413,652
B	25kV Pole Replacements	\$ -	\$ -	\$ -
B	4kV Voltage Conversions	\$ 4,346,316	\$ 4,065,504	\$ (280,812)
B	Underground Renewal	\$ 174,054	\$ 665,259	\$ 491,205
B	Design	\$ 83,463	\$ 200,403	\$ 116,940
	Subtotal	\$ 5,994,452	\$ 7,413,468	\$ 1,419,016

Table 5.4.4-9 System Renewal Expenditure Variances 2014 to 2015 Actuals

System Service

In 2015, Thunder Bay Hydro experienced no change in System Service capital expenditures.

General Plant

In 2015, Thunder Bay Hydro experienced an increase in General Plant capital expenditures of \$356,356. This increase is due to replacement of equipment required for lines work (\$194,936) and new survey equipment purchased for the Engineering department (\$65,000).

5.4.4.4 2015 Actual vs. 2016 Forecast Capital Expenditure Variances

Category	2015 Actual	2016 Projection	Variance 2015 to 2016
System Access	\$2,412,277	\$2,722,077	\$309,800
System Renewal	\$7,413,468	\$7,164,703	\$(248,765)
System Service	\$0	\$0	\$-
General Plant	\$1,344,970	\$1,905,805	\$560,835
Total Expenditure	\$11,170,715	\$11,792,585	\$621,870

Table 5.4.4-10 Capital Expenditure Variances 2015 Actual to 2016 Projection

System Access

The planned expenditures in the 2016 System Access category are expected to differ from 2015 by \$310,520. This variance is generally due to an increase in the size of typical requested connections in the General Service connections project, as well as an increase in the cost of installation of Residential Services. The Meter Installation project increased in 2016 due to the purchase of 750 new residential meters in preparation for execution of the Meter Sampling program, as detailed in Appendix F: Smart Meter Sampling Plan.

Account #	Description	2015 Actual	2016 Actual	Variance
A 01	PCB Transformer Replacements	\$ 100,942	\$ 162,598	\$ 61,656
A 02	Customer Recoverable System Modifications	\$ 859,513	\$ 235,458	\$ (624,055)
A 11	Customer Driven System Expansions	\$ 181,267	\$ 175,506	\$ (5,761)
A 12	Residential Service Connections	\$ 282,378	\$ 449,520	\$ 167,142
A 13	General Service Connections	\$ 461,209	\$ 907,343	\$ 446,134
A 14	Expansions for Residential Subdivisions	\$ 118,498	\$ 232,955	\$ 114,457
A 15	System Relocations	\$ 233,939	\$ 162,858	\$ (71,081)
A 21	Meter Installations	\$ 193,236	\$ 395,839	\$ 202,603
A 32	Generator Driven Expansion	\$ -	\$ -	\$ -
A 33	Renewable Enabling Improvements	\$ (12,141)	\$ -	\$ 12,141
A 34	Event Centre	\$ (6,563)	\$ -	\$ 6,563
	Subtotal	\$ 2,412,277	\$ 2,722,077	\$ 309,800

Table 5.4.4-11 System Access Expenditure Variances 2015 Actual to 2016 Projection

System Renewal

The variance within the System Renewal category is in large part due to a decrease in Small Pole replacements. This account returned to historical levels following 2015, when a larger than expected number of poles were identified for replacement through the inspection and risk assessment process. In 2016 Engineering and Lines worked together to create a more objective inspection regime and to ensure these areas were addressed in planned replacement projects. A decrease was also seen in the underground account to offset the increase in the 4kV conversions.

Account #	Description	2015 Actual	2016 Actual	Variance
A 16	Small Pole Replacements	\$ 1,028,301	\$ 379,573	\$ (648,728)
A 17	Lines Safety Reports	\$ 495,879	\$ 732,775	\$ 236,896
A 18	Transformer and Switch Replacements	\$ 958,123	\$ 816,936	\$ (141,187)
B	25kV Pole Replacements	\$ -	\$ -	\$ -
B	4kV Voltage Conversions	\$ 4,065,504	\$ 5,092,976	\$ 1,027,472
B	Underground Renewal	\$ 665,259	\$ -	\$ (665,259)
B	Design	\$ 200,403	\$ 142,443	\$ (57,960)
	Subtotal	\$ 7,413,468	\$ 7,164,703	\$ (248,765)

Table 5.4.4-12 System Renewal Expenditure Variances 2015 Actual to 2016 Projection

System Service

In 2016, Thunder Bay Hydro experienced no change in System Service capital expenditures.

General Plant

The main driver behind the variance in General Plant capital expenditures of \$560,835, is primarily due to the replacement of the end of life SCADA system consisting of \$416,699. In addition there are required Leasehold Improvements at the Cumberland Street Office Building consisting of \$50,000.

5.4.4.5 2016 Forecast vs. 2017 Forecast Capital Expenditure Variances

Category	2016 Projection	2017 Plan	Variance 2016 to 2017
System Access	\$2,722,077	\$2,662,432	\$(59,645)
System Renewal	\$7,164,703	\$8,379,756	\$1,215,053
System Service	\$0	\$230,375	\$230,375
General Plant	\$1,905,805	\$1,167,500	\$(738,305)
Total Expenditure	\$11,792,585	\$12,440,063	\$647,478

Table 5.4.4-13 Capital Expenditure Variances 2016 Projection to 2017 Forecast

System Access

For the 2017 Forecast period, Thunder Bay Hydro expects expenditures in System Access to decrease by \$59,645, based on Thunder Bay Hydro's materiality threshold, this amount is deemed immaterial.

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.

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)

A 14	Expansions for Residential Subdivisions	\$ 230,530	\$ 225,000	\$ (5,530)
A 15	System Relocations	\$ 164,881	\$ 250,000	\$ 85,119
A 21	Meter Installations	\$ 286,129	\$ 185,773	\$ (100,356)
	Subtotal	\$ 2,662,432	\$ 2,414,273	\$ (248,159)

Table 5.4.4-16 System Access Variances 2017 Forecast to 2018 Forecast

System Renewal

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.

Account #	Description	2017 Plan	2018 Plan	Variance
A 16	Small Pole Replacements	\$ 342,512	\$ 336,871	\$ (5,641)
A 17	Lines Safety Reports	\$ 761,834	\$ 740,558	\$ (21,276)
A 18	Transformer and Switch Replacements	\$ 756,484	\$ 742,348	\$ (14,136)
B	25kV Pole Replacements	\$ 584,384	\$ 2,104,000	\$ 1,519,616
B	4kV Voltage Conversions	\$ 5,367,788	\$ 3,924,167	\$ (1,443,621)
B	Underground Renewal	\$ 376,868	\$ 800,000	\$ 423,132
B	Design	\$ 189,888	\$ 170,425	\$ (19,463)
	Subtotal	\$ 8,379,756	\$ 8,818,369	\$ 438,611

Table 5.4.4-17 System Renewal Variances 2017 Forecast to 2018 Forecast

System Service

For the 2018 Forecast period, Thunder Bay Hydro expects expenditures in System Service to increase by \$69,625, based on Thunder Bay Hydro's materiality threshold, this amount is deemed immaterial.

General Plant

For the 2018 Forecast period, Thunder Bay Hydro expects expenditures in General Plant to increase by \$192,268. This increase in spending is primarily due to the replacement of IT hardware being completed in 2018.

5.4.4.7 2018-2021 Forecast Capital Expenditure Variance Trending Analysis

Overall trending for the forecast period of 2018 to 2021 between categories is consistent in the System Access, System Renewal and System Service categories. Inflationary increases are expected to account for minor year over year increases of approximately 2%, as their variance falls below the materiality

threshold. A decrease in expenditures in the General Plant category accounts for a slight variability in total expenditure over the forecast period.

Category	Forecast Period			
	2018	2019	2020	2021
System Access	\$2,422,273	\$2,432,053	\$2,444,765	\$2,505,497
System Renewal	\$8,818,369	\$8,975,721	\$9,216,828	\$9,261,478
System Service	\$300,000	\$280,000	\$280,000	\$300,000
General Plant	\$1,359,760	\$946,131	\$900,514	\$969,308
Total Expenditure	\$12,900,402	\$12,633,905	\$12,842,107	\$13,036,284

Table 5.4.4-18 Capital Expenditure 2018-2021 Forecast

System Access

Year over year average variance and trending for the forecast period of 2018 to 2021 are very consistent with historical values with an inflationary increase of approximately 2%.

Account #	Description	2018	2019	2020	2021
A 01	PCB Transformer Replacements	\$50,000	\$51,000	\$52,020	\$53,060
A 02	Customer Recoverable System Modifications	\$300,000	\$306,000	\$312,120	\$318,362
A 11	Customer Driven System Expansions	\$180,000	\$183,600	\$187,272	\$191,017
A 12	Residential Service Connections	\$323,500	\$329,970	\$336,569	\$343,301
A 13	General Service Connections	\$900,000	\$918,000	\$936,360	\$955,087
A 14	Expansions for Residential Subdivisions	\$225,000	\$229,500	\$234,090	\$238,772
A 15	System Relocations	\$250,000	\$255,000	\$260,100	\$265,302
A 21	Meter Installations	\$185,773	\$150,983	\$118,234	\$132,595
	Subtotal	\$2,422,273	\$2,432,053	\$2,444,765	\$2,505,497

Table 5.4.4-19 System Access Expenditure Forecast 2018-2021

System Renewal

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.

Account #	Description	2018 Plan	2019 Plan	2020 Plan	2021 Plan
A 16	Small Pole Replacements	\$336,871	\$439,900	\$448,698	\$457,672
A 17	Lines Safety Reports	\$740,558	\$592,100	\$603,942	\$616,021
A 18	Transformer and Switch Replacements	\$742,348	\$757,195	\$772,339	\$787,786
B	25kV Replacements	\$2,104,000	\$2,766,667	\$2,833,333	\$2,850,000
B	4kV Conversions	\$3,924,167	\$2,948,334	\$2,991,666	\$3,000,000
B	Underground Renewal	\$800,000	\$1,300,000	\$1,400,000	\$1,400,000
B	Design	\$170,425	\$171,525	\$166,850	\$150,000
	Total	\$8,818,369	\$8,975,721	\$9,216,828	\$9,261,478

Table 5.4.4-20 System Renewal Expenditure Forecast 2018-2021

System Service

Over the 2018 to 2021 Forecast period, Thunder Bay Hydro expects expenditures in System Service to remain steady. Budgetary Forecasts for reliability improvements are an initiative of the 'Grid Modernization Plan' attached as Appendix D. These expenditures are in alignment with Ontario's Long Term Energy Plan by implementing devices that allow Thunder Bay Hydro to provide cost-effective, customer driven solutions to reliability issues.

Category	2018	2019	2020	2021
System Service	\$300,000	\$280,000	\$280,000	\$300,000

Table 5.4.4-21 System Service Expenditure Forecast 2017-2021

General Plant

Over the 2018 to 2021 Forecast period, Thunder Bay Hydro expects expenditures in General Plant to gradually decrease. These decreases are due to decreased spending on Fleet and Rolling Stock.

Category	2018	2019	2020	2021
General Plant	\$1,359,760	\$946,131	\$900,514	\$969,308

Table 5.4.4-22 General Plant Expenditure Forecast 2017-2021

5.4.4.8 Summary of Variations in the Total Investment – Forecast Period to Historical Period

An overview of the variations in the total investment within each category for the historical and forecast period is shown below in Figure 5.4.4-1 Investment by Category for 2012 to 2021 with specific focus on any trend for variances in a given investment category that is markedly positive or negative over the historical period. Variations between categories for historical vs forecast can be explained based on the following reasons:

- In 2013 Thunder Bay Hydro adopted IFRS accounting standards which led to a decrease in the extent of overheads allocated to Capital work
- An increase in General Plant expenditures in 2013 due to the construction of a new Fleet Garage
- An increase in General Plant expenditures in 2016 due to the replacement of the vintage SCADA system
- An increase in System Renewal in 2015 due to defective assets being reported in the Lines Safety Reports and Transformer and Switch replacements.
- An overall increase in System Renewal in 2017 in order to more effectively manage and proactively address sustainment levels of assets as a result of the ACA provided by Kinectrics in 2016. This levelized approach to the replacement of assets is being implemented through an increase in 2017 and subsequent gradual increases over the study period (2018-2021).
- An increase in 2017 due to spending within the System Service categories to implement the 'Grid Modernization Plan.
- A decline in System Access expenditures from 2012 due in part to slowed economic growth in the region

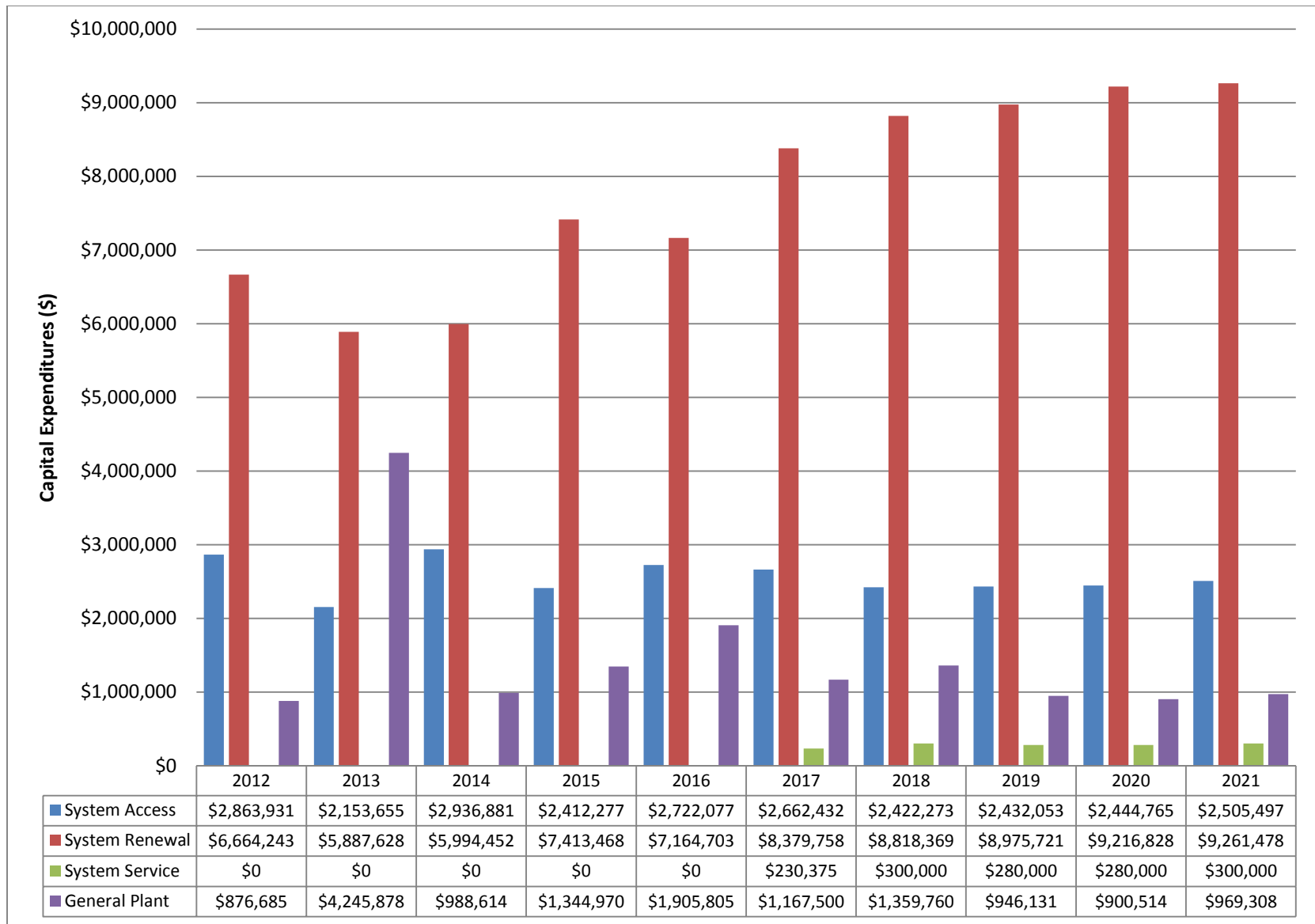


Figure 5.4.4-1 Investment by Category for 2012 to 2021

5.4.5 Justifying Capital Expenditures (OEB Filing Req. 5.4.5)

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the Board to assess whether and how a distributor's DS Plan delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

5.4.5.1 Overall Plan (OEB Filing Req. 5.4.5.1)

The Board's assessment of DS Plans includes the costs of material projects/activities included in the DS Plan, as well as the costs represented by the respective shares of the overall DS Plan budget allocated to each of the four investment categories. Information to be provided in this section pertains to the latter; the former is addressed in section 5.4.5.2. To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:

- comparative expenditures by category over the historical period;*

Comparative Expenditures by Category over the Historical Period

Table 5.4.5-1 summarizes the level of expenditure each year over the historical period. It is evident from the table that the level of spending in each category as a percentage of the total has varied; analysis of the variances of historic expenditures is summarized in Section 5.4.4. For comparative purposes, capital expenditures for the Forecast Period are also shown in Table 5.4.5-2.

Category	Historical Period				Bridge Year
	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Projections
System Access	\$2,863,931	\$2,153,655	\$2,936,881	\$2,412,277	\$2,722,077
System Renewal	\$6,664,243	\$5,887,628	\$5,994,452	\$7,413,468	\$7,164,703
System Service	\$0	\$0	\$0	\$0	\$0
General Plant	\$876,685	\$4,245,878	\$988,614	\$1,344,970	\$1,905,805
Total Expenditure	\$10,404,860	\$12,287,160	\$9,919,947	\$11,170,715	\$11,792,585

Table 5.4.5-1 Summary of Average Historical Capital Expenditure

Test Year	Forecast Period			
2017	2018	2019	2020	2021
\$2,662,432	\$2,422,273	\$2,432,053	\$2,444,765	\$2,505,497
\$8,379,756	\$8,818,369	\$8,975,721	\$9,216,828	\$9,261,478
\$230,375	\$300,000	\$280,000	\$280,000	\$300,000
\$1,167,500	\$1,359,760	\$946,131	\$900,514	\$969,308
\$12,440,063	\$12,900,402	\$12,633,905	\$12,842,107	\$13,036,284

Table 5.4.5-2 Summary of Average Forecast Capital Expenditure

The following figures detail the normalized investments in each OEB category over the historical and forecast period. The historical values have been normalized to a value between 0 and 100% of the largest annual investment per category for the years 2012-2016. The forecast values for years 2017-2021 have been normalized by the same maximum historical investment level to indicate an upward, downward or neutral trend. This allows for better comparison of the level of investment historically and where the investment level is trending into the future.

Graphical Representations of Comparative Expenditures

Figure 5.4.5-1, Figure 5.4.5-2, Figure 5.4.5-3 and below summarizes the historical and forecast expenditure trends in the System Access, System Renewal and System Service Categories.

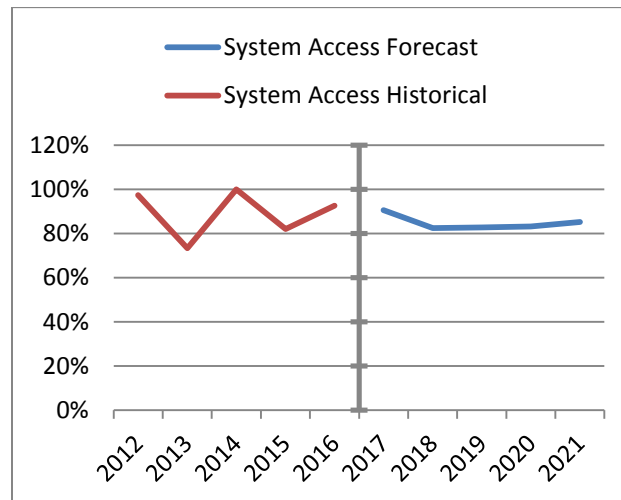


Figure 5.4.5-1 System Access Summary Trend

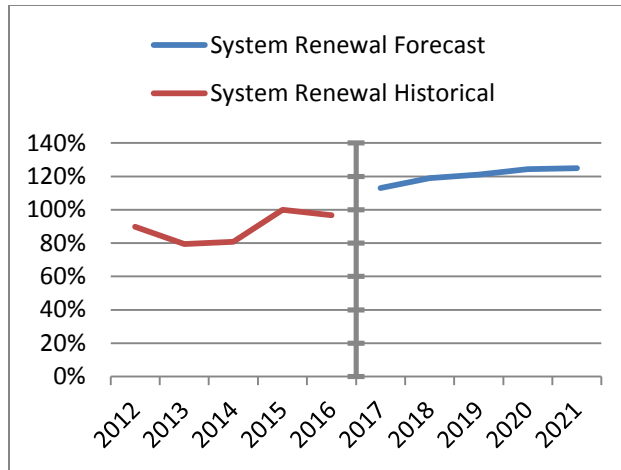


Figure 5.4.5-2 System Renewal Summary Trend

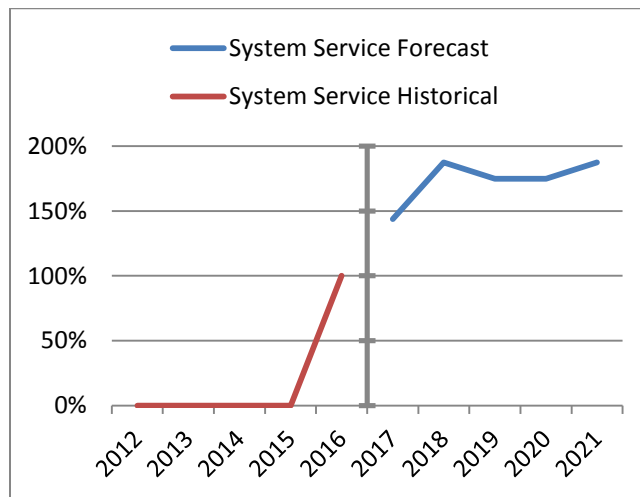


Figure 5.4.5-3 System Service Summary Trend

Figure 5.4.5-4 below summarizes the historical and forecast expenditures in the General Plant category. The dashed grey line represents the normalized trend removing the one time expenditure related to a new fleet service garage in 2013 and SCADA in 2016. This dashed grey line better reflects the general trend of expenditure in this category.

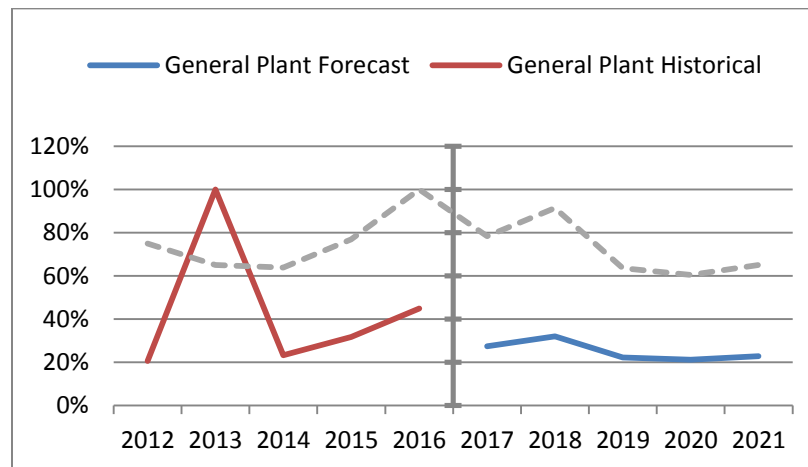


Figure 5.4.5-4 General Plant Summary Trend

- *the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;*

Forecasted Impact of System Investments on O&M

While Thunder Bay Hydro does not expect to see any material reductions in System O&M over the forecast period, there are a number of programs that are being implemented that will have the potential to positively impact future O&M costs. One such program is the renewal of distribution line assets and subsequent uprating of line voltage from 4kV to 25kV has allowed a portion of Thunder Bay Hydro's substation assets to be decommissioned over time. As these stations are removed from service the fixed and variable costs pertaining to these stations is eliminated. The costs can include inspection, testing, repair and inventory maintenance, and equate to approximately \$15,000 / year / station. (See Table 5.4.5-3 Station O&M Drivers for required station activities) Thunder Bay Hydro expects to remove 3 substations from service during the forecast period 2017-2021. While this results in cost savings, there are several programs which require increased investment to address a back-log of work and improve inspection and testing processes. Examples of such O&M work include; enhanced pole testing, vegetation management activities and porcelain insulator replacements.

Station Maintenance and Inspection	Frequency
Station Inspections	Monthly
Breaker Maintenance	Annual
Transformer Oil Sampling and Testing	Annual
Lawn and Grounds Maintenance	Bi-weekly (seasonal)
Battery Testing	Annual
Property Taxes	Annual
Insurance	Annual
Building Maintenance and Repair	As Required
Snow Removal	As Required

Table 5.4.5-3 Station O&M Drivers

Thunder Bay Hydro also plans to deploy several smart devices strategically throughout the distribution system which will allow the system to be restored and/or reconfigured remotely. With the addition of these devices Thunder Bay Hydro aims; to maintain or improve its reliability; and concurrently reduce the labour and equipment historically required under O&M to achieve these results.

- *the ‘drivers’ of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor’s asset related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);*

Drivers of Investment

Thunder Bay Hydro expects the key drivers for investment to remain relatively unchanged over the forecast period. These drivers for investment are further discussed in Section 5.1.1. Outlined in Table 5.4.5-4 is information that categorizes the capital expenditure projects by:

- investment driver – the projects within each category are referred back to the primary investment driver outlined in Table 5.1.1-1;
- asset management objective – the projects within each category are referred back to section 5.3 via the primary asset management objective outlined in Table 5.3.1-1;
- capital expenditure priority – the projects within each category are referred back to section 5.4 via the capital expenditure priority outlined in Table 5.4.2-1;
- asset related performance outcomes – the projects within each category are referred back to the desired performance outcome defined by the OEB outlined in Figure 5.2.3-1; and
- asset related performance targets – these targets are the desired effect of executing the project and is how Thunder Bay Hydro monitors the adequacy of its performance.

Categories	Projects	Primary Investment Driver	Primary Asset Management Objectives	Capital Expenditure Prioritization	Asset Related Performance Outcomes	Asset Related Performance Targets
SYSTEM ACCESS	PCB Transformer Replacements (A 01)	Mandated Service Obligations	Regulatory/Legal Obligation	P3 - High Priority	Public Policy Responsiveness	Meet Regulatory Deadlines
	Customer Recoverable System Modifications (A 02)	Other Third Party Requests	Customer Driven Work	P3 - High Priority	Service Quality	Meet Customer Deadlines
	Customer Driven System Expansions (A 11)	Customer Service Obligations	Customer Driven Work	P3 - High Priority	Service Quality	Meet Customer Deadlines
	Residential Service Connections (A 12)	Customer Service Obligations	Customer Driven Work	P3 - High Priority	Service Quality	Meet Customer Deadlines
	General Services Connections (A 13)	Customer Service Obligations	Customer Driven Work	P3 - High Priority	Service Quality	Meet Customer Deadlines
	Expansions for Residential Subdivisions (A 14)	Customer Service Obligations	Customer Driven Work	P3 - High Priority	Service Quality	Meet Customer Deadlines
	System Relocations (A 15)	Other Third Party Requests	Customer Driven Work	P3 - High Priority	Service Quality	Meet Customer Deadlines
	Meter Installations (A 21)	Mandated Service Obligations	Regulatory/Legal Obligation	P3 - High Priority	Public Policy Responsiveness	Execute scope within 10% of budget
	Generator Driven Expansions (A 31)	Customer Service Obligations	Customer Driven Work	P3 - High Priority	Service Quality	Meet Customer Deadlines
	Renewable Enabling Improvements (A 32)	Customer Service Obligations	Customer Driven Work	P3 - High Priority	Service Quality	Execute scope within 10% of budget
	Event Center (A 34)	Other Third Party Requests	Customer Driven Work	P3 - High Priority	Service Quality	Meet Customer Deadlines
SYSTEM SERVICE	Grid Modernization (A 35)	System Reliability and Efficiency	Operational Efficiency	P5 - Low Priority	System Reliability	Positively impact reliability in select areas
SYSTEM RENEWAL	Small Pole Replacements (A 16)	Failure Risk	Asset Retirement	P2 - Urgent	Asset Management	Execute scope within 10% of budget
	Lines Safety Reports (A 17)	Failure Risk	Health and Safety	P2 - Urgent	Safety	Execute scope within 10% of budget
	Transformer & Switch Replacements (A 18)	Failure	Health and Safety	P2 - Urgent	Safety	Execute scope within 10% of budget
	Voltage Conversions (B)	Failure Risk	Asset Retirement	P4 - Medium Priority	Asset Management	Execute scope within 10% of budget
	Underground Renewal	Failure Risk	Asset Retirement	P4 - Medium Priority	Asset Management	Execute scope within 10% of budget
	25kV Pole Replacements	Failure Risk	Asset Retirement	P4 - Medium Priority	Asset Management	Execute scope within 10% of budget
GENERAL PLANT	IT (Software and Hardware)	System Maintenance Support	Asset Retirement	N/A*	Asset Management	N/A*
	Fleet - Rolling Stock	System Maintenance Support	Asset Retirement	P5 - Low Priority	Asset Management	Return on Investment
	Office Furniture & Equipment	Non-System Physical Plant	Operational Efficiency	N/A*	Operational Effectiveness	N/A*
	Equipment - Tools, Shop, Testing, Power and Communications	System Maintenance Support	Operational Efficiency	N/A*	Operational Effectiveness	N/A*
	Fleet Garage	Non-System Physical Plant	Asset Retirement	P5 - Low Priority	Asset Management	Execute scope within 10% of budget
	Building Improvements	Non-System Physical Plant	Asset Retirement	N/A*	Asset Management	N/A*

Table 5.4.5-4 Capital Investments and Related Drivers

Note:

N/A* - Investments marked thusly are below the materiality threshold.

- *information related to the distributor's system capability assessment (see section 5.4.3)*

Information Related to the Distributor's System Capability Assessment

As outlined in Sections 5.4.3 and 5.4.1.1, Thunder Bay Hydro's distribution system is generally capable of meeting future demands with respect to load customers. Overall Thunder Bay Hydro's distribution system is capable of connecting and accepting moderate amounts of renewable generation. As a significant amount of local generation has connected to our system, the short circuit levels at the Hydro One transformer stations have risen. Currently, of the three transformer stations in our service territory, two have short circuit levels exceeding 90% of the limits set by the transmission system code, and the third has short circuit levels as high as the station equipment is rated for, leaving no short circuit capacity for generation connections. Hydro One has reported a commitment to invest in upgrading low voltage components in order to accommodate future renewable generation project connections.

Thunder Bay Hydro has reviewed the need for capital and OM&A investments related to the connection of REG projects as it applies to the expansion of the distribution system and renewable enabling improvements. Based on this review and historic trends within our service territory, Thunder Bay Hydro does not expect any REG investments for the period of 2017-2021.

5.4.5.2 Material Investments (OEB Filing Req. 5.4.5.2)

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g. unique characteristics; marked divergence from previous trend) are supported by evidence that enables the Board's assessment according to the evaluation criteria set out below. The level of detail characterizing the evidence filed by a distributor to support a given investment project/activity should be proportional to the materiality of the investment.

The following Table 5.4.5-5 2017 Material Capital Projects and Programs details information related to projects and/or activities that meet Thunder Bay Hydro's materiality threshold for the 2017 year. Information, including evaluation criteria and category specific information for each project is included in Appendix J: Material Investment Justifications. It is important to note that Thunder Bay Hydro does not have a complete list of detailed projects contained within all of the activities for the 2017 test year due to the nature of these programs which consist of a series of individual projects below the materiality threshold. These projects include: IT (Software and Hardware and Fleet- Rolling Stock.

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

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Appendix A: Thunder Bay Hydro Renewable Energy Generation Plan &
IESO Letter of Comment

IESO Letter of Comment

Thunder Bay Hydro Distribution Inc.

Renewable Energy Generation Plan

May 9, 2016

Introduction

On March 28, 2013, the Ontario Energy Board (“the OEB” or “Board”) issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board’s policy direction on ‘an integrated approach to distribution network planning’, outlined in the Board’s October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority¹ (“OPA”) comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor’s service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation (“REG”) investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Thunder Bay Hydro Distribution Inc. – Renewable Energy Generation Plan

On April 11, 2016, the IESO received Thunder Bay Hydro Distribution Inc.’s (“TBHEDI”) Renewable Energy Generation Plan (“Plan”) for the 5-year period 2016-2021. The IESO has reviewed the Plan and provides the following comments.

OPA FIT/microFIT Applications Received

Section 2 of the Plan states that 207 microFIT projects and 18 “FIT and other Small and Mid-Sized Renewable projects”, totalling 24.1 MW, are connected to TBHEDI’s distribution system.

According to the IESO’s information, as of March 31, 2016, the IESO has offered contracts to 207 microFIT projects totalling 1.9 MW of capacity, 13 FIT projects totalling 1.57 MW of capacity, four (4) Renewable Energy Standard Offer Procurement (“RESOP”) projects totalling 20.8 MW of capacity, and one (1) - 500 kW Hydroelectric Contract Initiative (“HCI”) project – totalling 24.8 MW of nameplate capacity; all of which are connected to TBHEDI’s distribution system. The renewable energy generation connections information in TBHEDI’s Plan is therefore substantially consistent with that of the IESO.

¹ On January 1, 2015, the Ontario Power Authority (“OPA”) merged with the Independent Electricity System Operator (“IESO”) to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Upstream Transmission Constraints

The IESO understands that projects connecting on the upstream transmission system could impact the connection capability for REG projects that are downstream on TBHEDI's distribution system. It is therefore recommended that TBHEDI coordinate with Hydro One Networks Inc. as transmitter when assessing REG project connection capability.

The updated Transmission Availability Table ("TAT Table") is available on the OPA's FIT website as follows:

<http://fit.powerauthority.on.ca/sites/default/files/version4/FIT-4-TS-TAT-table-final-July-9-2015.pdf>

Based on the information from the TAT Table, transmission constraints applicable to TBHEDI's system currently exist at Port Arthur TS.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

For regional planning purposes, TBHEDI is part of the "Group 1" Northwest Ontario Region, which contains the Thunder Bay sub-region.

On January 28, 2015, the IESO posted the Northwest Region [Scoping Assessment Outcome Report](#) and subsequently kicked off the Integrated Regional Resource Planning ("IRRP") process for the Thunder Bay sub-region. As a Working Group member, TBHEDI has been actively involved in the Thunder Bay sub-region IRRP along with the IESO, Hydro One Networks Inc. (Transmission) and Hydro One Distribution. The Working Group is currently developing medium and long-term plans for the Thunder Bay area and expects the final IRRP to be completed and published in 2016. More information on the Thunder Bay sub-region IRRP can be found [here](#).

The IESO looks forward to working further with TBHEDI on regional planning for the Northwest Ontario Region, specifically the Thunder Bay sub-region IRRP, and appreciates the opportunity to comment on the information it received as part of TBHEDI's Plan at this time.



Thunder Bay Hydro Electricity Distribution Inc.

Renewable Energy Generation Plan

2016-05-06

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1. Executive Summary

Thunder Bay Hydro Electricity Distribution Inc. (TBHEDI) is a local electricity distributor serving approximately 50,000 customers in Thunder Bay, Ontario. In accordance with the Ontario Energy Board's (OEB) filing Requirements for Electricity Transmission and Distribution Applications, chapter 5, Consolidated Distribution System Plan Filing Requirements, TBHEDI has prepared the following Renewable Energy Generation (REG) Investment Plan. The REG Plan is based on current information and presents TBHEDI's near-term and long-term plans that are intended to accommodate the connection of renewable generation facilities.

Given the current trends and capacity limitations associated with regional and Hydro One Networks (HONI) transformer station constraints in the TBHEDI service territory, we anticipate very minimal solar project connection requests. It is notable that in recent years we have connected 2 combined heat and power (CHP) projects with natural gas generators that generate in parallel with our distribution system. Although these generators are not considered renewable, they do compete for the same available generation capacities as renewable projects.

Overall TBHEDI's distribution system is capable of connecting and accepting moderate amounts of renewable generation. As a significant amount of local generation has connected to our system, the short circuit levels at the Hydro One transformer stations have risen. Currently, of the three transformer stations in our service territory, two have short circuit levels exceeding 90% of the limits set by the transmission system code, and the third has short circuit levels as high as the station equipment is rated for, leaving no short circuit capacity for generation connections. Through the IRRP planning process, TBHEDI is aware that Hydro One is addressing limiting hardware on the secondary side of Port Arthur TS, which will increase the short circuit capacity on this station and accommodate future renewable generation project connections.

Beyond short circuit limitations, TBHEDI has started to encounter capacity limitations related to the passive anti-islanding technique utilized by micro and small embedded generators. To date, these limits have been exceeded on only a few rural feeders, where minimum loads are much lower than their urban equivalent circuits. Although TBHEDI has considered projects that would open some capacity on these feeders, a combination of issues; including wide acceptance of these solutions by other LDC's, research and development costs, and the limited amount of interest in generation projects that would benefit from this investment, has pushed interest in these types of renewable enabling projects to at least beyond the study period.

TBHEDI does not expect any capital expenditures related to renewable energy generation in its Distribution System Plan. As well, no additional Operating, Maintenance and Administrative (“OM&A”) costs related to renewable generation connections are anticipated, as TBHEDI is capable of processing both microFIT and FIT applications utilizing existing employees.

2. Overview of the TBHEDI Distribution System

Initial interest in renewable generation development in the TBHEDI service territory was high and since the introduction of the Feed-In-Tariff (“FIT”) program by the former OPA in 2009, TBHEDI has facilitated the connection of a number of projects.

As of January 2016, TBHEDI has a connected capacity of;

- 207 microFIT projects;
- 18 FIT and other Small and Mid-Sized Renewable projects;
- 24.1 MW total nameplate capacity

The City of Thunder Bay is serviced from three, Hydro One owned transformer stations (TS); Birch TS, Fort William TS, and Port Arthur TS. These transformer stations supply TBHEDI with a distribution level voltage of 25kV.

The majority of TBHEDI customers (71%) are served from distribution transformers fed directly from 25kV feeders, originating from one of three Hydro One transformer stations. The city’s older urban districts (22% of all customers) are served from distribution transformers fed from 4kV feeders originating from ten TBHEDI owned distribution sub-stations (DS’s), which are in turn fed from 25kV circuits. The remaining 7% of customers, (generally rural), are serviced from distribution transformers fed by 12kV feeders, originating from four TBHEDI owned DS’s, also fed from 25kV circuits. The following table lists the ownership, voltage level and designation of each TS and DS which is directly connected to the TBHEDI network.

Designation		Voltage Level	Ownership
P02	Port Arthur TS	25kV	Hydro One
P17	Birch TS	25kV	Hydro One
P10	Fort William TS	25kV	Hydro One
3	Hardisty	4kV	TBHEDI
4	Vickers	4kV	TBHEDI
5	Donald	4kV	TBHEDI

Designation		Voltage Level	Ownership
9	Mountdale	4kV	TBHEDI
11	High	4kV	TBHEDI
12	Camelot	4kV	TBHEDI
14	Algoma	4kV	TBHEDI
15	Grenville	4kV	TBHEDI
16	MacDonnell	4kV	TBHEDI
18	Balsam	12kV	TBHEDI
19	Broadway	12kV	TBHEDI
21	Windemere	4kV	TBHEDI
23	Alice	12kV	TBHEDI
36	Mapleward	12kV	TBHEDI

Table 1 - TBHEDI System Transformer/Distribution Stations

2.1 Overview of the Capacity Assessment Process

Over the past 5 years, TBHEDI has been committed to supporting the introduction of renewable generation into our distribution system. However, the distribution system was not designed to accommodate fully bidirectional flows, or the many sources associated with embedded generation and distributed resources. In order to ensure that TBHEDI is able to operate a safe, efficient, and reliable distribution system, we must place limits on the amount of generation which is allowed on our system. When establishing the generation limits of our system, we consider the following; Available Short Circuit Capacity, Available Thermal Capacity and Anti-Islanding Requirements. These limits are evaluated independently for each station and circuit (feeder) within our system, and are explained in detail below.

2.1.1 Available Short Circuit Capacity

All of the equipment on our system must be rated for the amount of electrical current that would be supplied during a short circuit condition. The addition of generation on our system increases the amount of electrical current that will flow during a short circuit condition. TBHEDI therefore needs to constantly monitor the amount of available short circuit current, and ensure that ratings are not exceeded. This is a safety concern in that, if equipment is exposed to currents which exceed their rating, they can fail violently.

2.1.2 Available Thermal Capacity

All of the equipment on the TBHEDI system must be rated for the amount of electrical current that could be supplied during normal and contingency operation. The addition of exporting type generation on our system can increase the amount of electrical current that flows during normal operation. We therefore need to keep track of the maximum electrical current that could flow through our equipment in all situations. Operating equipment within its thermal limit is important to minimize line loss (maximize operating efficiency) and to minimize premature failure (maximize reliability and minimize operating cost) of TBHEDI's assets.

2.1.3 Anti-Islanding Requirements

When generation operates in parallel with our distribution system, it introduces the possibility that when protection or switching operations isolate sections of our network, the generator(s) and load customers form a small island. When power is restored (which often happens within 0.5 seconds of interruption for re-close operations), the island may have drifted out of phase from the main system, resulting in a close operation which effectively creates a fault involving all of the participants of the island. In this scenario, all of the customers who participate in that island could have equipment and/or property damaged as a result of this operation, which is why TBHEDI must avoid even the smallest possibility of this occurring.

Anti-islanding is achieved differently in micro and small generation installations, as compared to medium and large generator installations. For micro and small generation installations, it is achieved via two mechanisms. The first mechanism is a requirement for generation equipment to comply with IEEE 1547, which ensures equipment has the ability to sense voltage and frequency distortions, which are characteristics of a very short term (unstable) island. The second mechanism protects against medium-long term (slightly more stable) islands, and is achieved by the utility ensuring that there is less generation on a given circuit than can support the minimum load of that circuit. The second mechanism is a requirement in order to ensure that the first mechanism works as designed. Presently, capacity for the connection of microFIT generation facilities in select rural areas of the TBHEDI distribution system has been reduced to zero as a result of the second mechanism (See Table 4 for details).

For medium and large generation installations, where the amount of generation exceeds the minimum load of the circuit, the generator must implement a scheme

called “transfer trip”. This type of protection scheme effectively forces the generation offline by means of a high speed communication link, anytime a protection or switching event occurs, and blocks reclose operations until such time as the generator end is confirmed open. For these types of generators, it is not necessary to limit generation to less than minimum feeder loads. The trade-off however, is the added cost of implementing a highly reliable high speed communication link to facilitate the transfer trip.

2.1.4 Hydro One TS available Capacity

Hydro One determines the generation capacity of the Port Arthur, Birch, and Fort William transformer stations separately from the TBHEDI process. The available capacity for each station is publicly available at www.hydroone.com and is listed on the “Hydro One List of Station Capacity” (last updated January, 26th, 2016). Transformer station capacities are given as “Short Circuit Capacity” and “Thermal Capacity” and applied as a capacity pool to the entire station. The net station capacity is the gross capacity less the aggregation of the existing downstream generator’s short circuit and thermal contributions. Presently, capacity for the connection of renewable generation facilities to the TBHEDI network is limited by the Hydro One TS capacities.

2.1.5 Northwest Region Capacity

Finally, the City of Thunder Bay falls within the ‘Northwest’ region of the provincial transmission system (as defined by the Independent Electricity Service Operator). Pending upgrades to the transmission system, it has been determined (Per the ‘Hydro One List of Station Capacity’ found on the Hydro One website. Last updated January, 26th, 2016) that the global capacity for additional generation development in this region is restricted to a total of 10MW. This limitation is due to weak loading in the region, resulting in an excess of power production.

In order to address the northwest region capacity issues, OPA released “Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion” on June 30, 2011;

“Currently, the development of new renewable generation in the Northwest is constrained by the ability to transfer power out of the Northwest toward Southern Ontario. An expanded E-W Tie would remove the largest barrier to renewable generation development in the Northwest, which is the limited capability of the existing E-W Tie to transfer surplus power out of the Northwest. While other

transmission congestion currently limits additional flow from new generation in the Northwest, increased demand and/or changes in the operation of generation in the Northeast, combined with the expansion of the E-W Tie, would provide opportunities for further resource development in the Northwest.”

Subsequent to this paper, a decision to move forward with the construction of the East-West Tie was approved with an expected in-service date of December 2020.

2.2 Present Levels of Distributed Generation Connections

TBHEDI has connected a significant number of microFIT and FIT projects to the distribution system along with providing connection to non-renewable generators. The following tables summarize the number of projects and their installed capacity of renewable and non-renewable connections.

Renewable Connections	2010	2011	2012	2013	2014	2015	Total
Micro Generation (<= 10kW)	38	61	55	37	10	6	207
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	0	2	2	6	2	1	13
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	3	1	1	0	0	0	5
Large (> 10MW)	0	0	0	0	0	0	0
Total	41	64	58	43	12	7	225
Renewable Connected Load (kW)	2010	2011	2012	2013	2014	2015	Total
Micro Generation (<= 10kW)	309	532	512	342	96	56	1847
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	0	100	135	725	600	18	1578
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	4730	7000	8900	0	0	0	20630
Large (> 10MW)	0	0	0	0	0	0	0
Total	5039	7632	9547	1067	696	74	24055

Table 2 – Existing Renewable Distributed Generation Connections

Non-Renewable Connections	2010	2011	2012	2013	2014	2015	Total
Micro Generation (<= 10kW)	0	0	0	0	0	0	0
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	0	0	0	0	0	0	0
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	1	1
Large (> 10MW)	0	0	0	0	0	0	0
Total	0	0	0	0	0	1	1
Non-Renewable Connected Load (kW)	2010	2011	2012	2013	2014	2015	Total
Micro Generation (<= 10kW)	0	0	0	0	0	0	0
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	0	0	0	0	0	0	0
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	2000	2000
Large (> 10MW)	0	0	0	0	0	0	0
Total	0	0	0	0	0	2000	2000

Table 3 - Existing Non-Renewable Distributed Generation Connections

2.3 Present Capacity for the Connection of Distributed Generation

The following table provides the present capacity at a station level for the TBHEDI 25kV distribution system to accommodate generation. Generation connections on 4kV and 12kV are reflected in their respective parent 25kV feeder capacity.

Hydro One Owned Transformer Station	TBHEDI Feeder	Existing FIT Connections	Existing micro-FIT connections	Existing Other DG connections	DG In Progress	Net Station Capacity for Generator Connections *	
						Short Circuit Capacity (MVA)	Thermal Capacity (MW)
Port Arthur TS	02M1	-	-	-	-	0	31
	02M2	-	20	-	-		
	02M3	-	-	-	-		
	02M4	-	107	530	-		
	02M5	-	8	-	-		
Fort William TS	10M1	350	49	-	-	76.6	69.7
	10M2	-	-	-	-		
	10M3	-	60	600	-		
	10M4	100	49	-	-		
	10M5	-	-	8,900	-		
	10M6	-	162	-	-		
	10M7	-	37	-	-		
	10M8	175	73	7,000	-		
	10M9	75	62	-	-		
	10M10	-	20	3,200	-		
Birch TS	17M1	500	10	-	-	78.6	65.1
	17M2	60	85	-	18		
	17M3	-	63	-	2,000		
	17M4	-	44	-	-		
	17M5	100	60	-	-		
	17M6	100	70	-	-		
	17M7	100	-	-	-		
	17M8	-	30	2,050	-		

* Information obtained from Hydro One website

Table 4 - TBHEDI Capacity to Accommodate Renewable Generation

2.4 Factors Limiting Full Utilization of Available Capacity

Currently, TBHEDI has a gross feeder available capacity for embedded generation of approximately 25 MW of combined micro/small projects, or 350 MW of combined medium/large projects. When including short circuit and thermal limitations of Hydro One owned stations (per Hydro One, List of Station Capacity, February 26, 2016), the combined available embedded generation capacity for medium/large projects is further reduced to between 6 MW and 129 MW, depending on the type of generation; synchronous using the most short circuit capacity (assumes 25 times rated), versus inverter based (assumes 1.2 times rated). Finally, the regional capacity constraint further limits the available capacity for projects greater than 500kW, to a total of 10MW.

Starting in 2014, where customers located on a certain rural feeders have requested micro/small generation connections, they have been rejected due to restrictions related to the anti-islanding requirements described in section 2.1.3. In particular, because the load can be very small in rural areas, the amount of generation that can be supported is also minimal. As TBHEDI has had a number of generation connections in these areas over the last few years, the limits associated with anti-islanding for micro/small generators have been exceeded on feeders 23F1 23F2, and 36F1, while the other two rural feeders (36F2 and 18F7) have less than 170kW of micro/small capacity remaining.

Research into solutions to mitigate the rejection of renewable connections in these rural areas has not been favorable. The presently available solutions have either not been not widely accepted across the province, are cost prohibitive to the customer, cost prohibitive to the utility (in terms of the large amount of dollars required to spend in order to enable very small amounts of generation), and present significant challenges in terms of compatibility with existing incentive programs, our conditions of service, and our system reliability. Examples of potential solutions that have been explored include, moving additional load to restricted feeders, designing and implementing either a generation rejection or a low cost transfer trip scheme, disabling automatic reclose, or implementing a new protection scheme to test for potential island conditions prior to automatic reclose. Until such time that there are acceptable, and fully developed solutions, TBHEDI will continue to see limitations in the rural areas of its distribution system.

3. 5 Year Distributed Generation Forecast

At present, it is difficult to predict the levels of renewable generation development under the FIT program; however historical trends are not expected to shift without an announcement in changes to the FIT rates and program. Therefore forecasts of connections are based on the assumption that the existing FIT / microFIT rates will remain static or continue decreasing for the forecast period. In addition to this assumption TBHEDI has consulted with local development groups, and TBHEDI anticipates minimal new Micro Generation connections due to reduced return on investment for installations, and continued constraints in the rural areas.

TBHEDI acknowledges that the East West Tie may have an effect on the connection of large distributed generators in the future, but as the construction will not be complete until December 2020 and TBHEDI is unable to predict the effect until such time that the construction is complete, there is no material effect on the generation forecast to 2021.

In the event that the proposed hardware upgrades by HONI to PA TS are not performed, further development of projects with a nameplate ratings between 10kW and 500kW will continue to be restricted from connecting to feeders originating from PA TS.

Provided that the Northwest region of Ontario remains restricted to 10MW of “Area Availability” for projects greater than 500kW under the FIT program, we do not anticipate any additional medium/large FIT generation connections in the forecast period. TBHEDI continues to see interest in Combined Heat and Power load displacement projects. Based on local interest, and available short circuit capacity, we are forecasting one additional mid-sized load displacement (non-renewable) generator, within the next few years.

Renewable Connections	2016	2017	2018	2019	2020	2021	Total
Micro Generation (<= 10kW)	10	10	10	10	10	10	60
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	1	0	0	0	0	0	1
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	0	0
Large (> 10MW)	0	0	0	0	0	0	0
Total	11	10	10	10	10	10	61
Renewable Connected Load (kW)	2016	2017	2018	2019	2020	2021	Total
Micro Generation (<= 10kW)	90	90	90	90	90	90	540
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	18	0	0	0	0	0	18
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	0	0	0	0	0	0	0
Large (> 10MW)	0	0	0	0	0	0	0
Total	108	90	90	90	90	90	558

Table 5 – Forecast of Renewable Distributed Generation Connections

Non-Renewable Connections	2016	2017	2018	2019	2020	2021	Total
Micro Generation (<= 10kW)	0	0	0	0	0	0	0
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	0	0	0	0	0	0	0
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	1	0	1	0	0	0	2
Large (> 10MW)	0	0	0	0	0	0	0
<i>Total</i>	1	0	1	0	0	0	2
Non-Renewable Connected Load (kW)	2016	2017	2018	2019	2020	2021	Total
Micro Generation (<= 10kW)	0	0	0	0	0	0	0
Small Generation (<= 1 MW @ 25kV, <= 500kW @ 4kV)	0	0	0	0	0	0	0
Mid-Sized (>1MW @ 25kV, > 500kW @ 4kV)	2000	0	2000	0	0	0	4000
Large (> 10MW)	0	0	0	0	0	0	0
<i>Total</i>	2000	0	2000	0	0	0	4000

Table 6 – Forecast of Non-Renewable Distributed Generation Connections

4. Planning and Consultation

TBHEDI has consulted with the IESO on numerous occasions and specifically during the current development of the Northwest Integrated Regional Resource Plan (IRRP). Although the main focus of the meetings has been on load demand in the region, capacity limitations at the HONI transformer stations has also been discussed. Capacity limitations in the Northwest region have also been a topic of discussion during the working group meetings.

TBHEDI has been in regular communication with several personnel at Hydro One throughout the development and connection phases of several renewable generation facilities in the past couple of years. These consultations have included collaboration in the 'Connection Impact Assessment' phase, coordination of technical and construction requirements with respect to facility upgrades and protection schemes, and partnership throughout the commissioning of the projects.

In 2011, TBHEDI and Hydro One reached a consensus on tolerable fault levels which allowed for a significant increase in Fort William and Birch TS' ability to accommodate further renewable generation. The available capacities in section 2 are reflective of this change. Documentation supporting TBHEDI's collaboration with Hydro One in these matters is available upon request. Although TBHEDI has agreed that it has the ability to accept the increased short circuit levels on its system, should any one renewable generation project request to connect, increasing levels well beyond current limits, and causing the need to upgrade or add devices to accommodate these new levels, TBHEDI would at that point request the upgrades be funded under a renewable enabling improvement project.

5. Investments to Facilitate Renewable Energy Generation

TBHEDI has reviewed the need for capital and OM&A investments related to the connection of REG projects as it applies to the expansion of the distribution system and renewable enabling improvements. Based on this review and historic trends within our service territory, TBHEDI does not expect any REG investments for the period of 2016-2021. From an OM&A perspective, no additional OM&A expenses are anticipated as TBHEDI is able to process both microFIT and FIT applications using existing employees.

TBHEDI shall continue to fully comply with its responsibility under the Distribution System Code as it relates to distribution expansion and renewable enabling improvements to the distribution system to support REG projects.

Appendix B: HONI Regional Planning Status Letter
for Thunder Bay Sub-Region

Hydro One Networks Inc.

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July 25, 2016

Karla Bailey
Asset Management & Engineering Manager
Thunder Bay Hydro
34 Cumberland St N,
Thunder Bay, ON P7A 4L4

Dear Ms. Bailey,

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that Thunder Bay Hydro belongs to the Northwest Ontario region which is in Group 1. A map showing details about the 21 regions and a list of Local Distribution Companies (LDCs) in each region is attached in Appendix A and B, respectively.

A summary of the regional planning status for the region is outlined below:

Northwest Ontario

In March 2014, WG members from the LDCs, OPA (now IESO), IESO and Hydro One collected the LDC load forecast and concluded that the primary objective of the Needs Screening to identify needs in the region had been already established in the region. As a result, WG decided that a Needs Assessment report is not required and IESO should initiate the Scoping Assessment (SA) for this region. SA report was completed in January 2015 and Northwest Ontario region was divided into 5 sub-regions: City of Thunder Bay, West of Thunder Bay, North of Dryden, Greenstone-Marathon and Remote Communities. Thunder Bay Hydro supplies customers in the Thunder Bay sub-region.

An Integrated Regional Resource Plan (IRRP) for North of Dryden and Greenstone-Marathon sub-regions was released in January 2015 and June 2016, respectively. The IRRP for Thunder Bay and West of Thunder Bay sub-regions is currently being developed.

The IRRP has currently identified the following needs:

- Transformer station capacity limitation at Port Arthur TS.
- Thermal limitations on 115 kV circuit R2LB following loss of L3/4P.
- Ensuring continuity of supply to the area following loss of both Lakehead auto-transformers.

Station capacity limitation at Port Arthur is forecasted to be beyond 10 years. This is anticipated to be revisited in the next planning cycle because no investments are required at this time. In addition, once the IESO led IRRPs for the sub-regions are complete, Hydro One will initiate the RIP process and formally notify your organization and other stakeholders. Further details will be discussed with the Working Group and communicated to you as they become available. Hydro One looks forward to continue working with Thunder Bay Hydro in addressing your needs and executing the new regional planning process.

Please feel free to contact me if you have any questions.

Sincerely,

A handwritten signature in black ink, appearing to be 'A' followed by a long, sweeping horizontal stroke.

Ajay Garg, Manager - Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Southern Ontario



Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo- Cambridge-Guelph ("KWCG")		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

Appendix B: List of LDCs for Each Region
[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc.

	• Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-

	Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A → This region is not within Hydro One's territory
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.

13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc.

	Westario Power Inc.
17. Niagara	- Canadian Niagara Power Inc. [Port Colborne] - Grimsby Power Inc. - Haldimand County Hydro Inc.* - Horizon Utilities Corporation - Hydro One Networks Inc. - Niagara Peninsula Energy Inc. - Niagara-On-The-Lake Hydro Inc. - Welland Hydro-Electric System Corp. - Niagara West Transformation Corporation* *Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A → This region is not within Hydro One's territory
19. North/East of Sudbury	- Greater Sudbury Hydro Inc. - Hearst Power Distribution Company Limited - Hydro One Networks Inc. - North Bay Hydro Distribution Ltd. - Northern Ontario Wires Inc.
20. Renfrew	- Hydro One Networks Inc. - Ottawa River Power Corporation - Renfrew Hydro Inc.
21. St. Lawrence	- Cooperative Hydro Embrun Inc. - Hydro One Networks Inc. - Rideau St. Lawrence Distribution Inc.

Appendix C: Kinectrics Asset Condition Assessment



THUNDER BAY HYDRO

2015 ASSET CONDITION ASSESSMENT

August 11, 2016

Confidential & Proprietary Information
Contents of this report shall not be disclosed
without authority of client.

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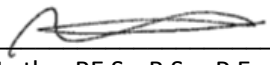
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THUNDER BAY HYDRO 2015 ASSET CONDITION ASSESSMENT

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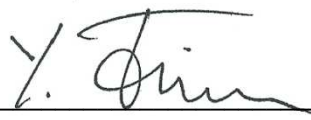
August 11, 2016

Prepared by:



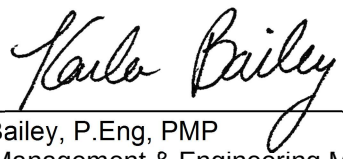
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Karla Bailey, P.Eng, PMP
Asset Management & Engineering Manager
Thunder Bay Hydro

Dated: August 17, 2016

Thunder Bay Hydro
2015 Asset Condition Assessment

To: Karla Bailey, P.Eng, PMP
Asset Management & Engineering Manager
Thunder Bay Hydro

Revision History

Revision Number	Date	Comments	Approved
R00	August 11, 2016	Final Report	Yury Tsimberg

SUMMARY

In 2015 Thunder Bay Hydro Electricity Distribution Inc. (TBH) determined a need to perform a condition assessment of its key distribution assets. This would result in a quantifiable evaluation of asset condition, aid in prioritizing and allocating sustainment resources, and facilitate the development of a Distribution System Plan.

The asset groups included in the 2015 asset condition assessment (ACA) were as follows: substation transformers, breakers, wood poles, distribution transformers, overhead line switches, underground switches, and underground cables. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at this year, this amounts to over 450 poles. Approximately 9% of 4 kV wood poles were also flagged for action this year. Because of the considerably smaller population, however, this equates to just over 230 poles. Approximately 19% of pole mounted transformers were classified under the very poor category. As such, 170 transformers need to be addressed.

Many asset groups (i.e. distribution transformers, overhead switches, and underground cables) had only age data available. Data gaps for these and all other asset categories were identified. It is recommended that TBH begin collecting information to fill these data gaps and to use such information for future assessments.

It is important to note that the flagged for action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence TBH's Distribution System Plan.

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I INTRODUCTION

Thunder Bay Hydro Electricity Distribution Inc. (TBH) is a private local distribution company responsible for distributing electricity to over 50,000 customers via a network of more than 1,300 kilometers of overhead and underground power lines in the City of Thunder Bay. TBH is owned by the City of Thunder Bay and is operated by the Thunder Bay Hydro Board.

TBH recently recognized a need to perform an Asset Condition Assessment (ACA) on its key distribution assets. Such an assessment produces a quantifiable evaluation of asset condition, aids in prioritizing and allocating sustainment resources, and facilitates the development of a Distribution System Plan.

In 2015 TBH engaged Kinectrics Inc. (Kinectrics) to perform the first ACA on TBH's key distribution assets. This report presents the results of the study.

I.1 Objective and Scope of Work

The category and sub-categories of assets included in this study are as follows:

- Substation Transformers
 - o 4 kV
 - o 12 kV
- Breakers
- Wood Poles
 - o 4 kV
 - o 25 kV
- Distribution Transformers
 - o Pad Mounted Transformers
 - o Pole Mounted Transformers
 - o Vault Transformers
- OH Switches
 - o 4kV In-Line
 - o 4kV Manual Air Break
 - o 12 and 25kV In-Line
 - o 12 and 25kV Manual Air Break
 - o 25kV Motorized Load Break
- Underground Switches
 - o 25kV Underground Load Break Switches
- Underground Cables
 - o 4kV
 - o 12 and 25kV

I.2 Deliverables

The deliverable in this study is a Report that includes the following information:

- Description of the Asset Condition Assessment methodology
- For each asset category the following are included:
 - Health Index formula
 - Age distribution
 - Health Index distribution
 - Condition-based Flagged For Action Plan
 - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis.

II ASSET CONDITION ASSESSMENT METHODOLOGY

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Color".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weights, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.max} \times WCP_m)} \times DR$$

Equation 1

where

$$CPS_m = \frac{\sum_{n=1}^{\forall n} \beta_n (SCPS_n \times WSCP_n) \times DR_n}{\sum_{n=1}^{\forall n} \beta_n (WSCP_n)} \times DR_m$$

Equation 2

CPS	Condition Parameter (CP) Score, 0-4
WCP	Weight of Condition Parameter
α_m / β_n	Data availability coefficient for condition parameter (1 if input data available; 0 if not available)
SCPS	Sub-Condition Parameter (SCP) Score, 0-4
WSCP	Weight of Sub-Condition Parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. In the Kinectrics methodology, a condition criteria scoring system of 0 through 4 is used. A score of 0 is the "worst" possible score; a score of 4 is the "best" score. I.e. $CPS_{max} = SCPS_{max} = 4$.

Note: From the formula, it can be seen that each parameter (condition or sub-condition) will have the following properties:

1. Weight
2. Availability coefficient (1 if asset has data for such parameter available; 0 otherwise)
3. Score (real value from 0 through 4)
4. Multiplier (real value)

II.1.1 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	$25 \leq \text{Health Index} < 50\%$
Fair	$50 \leq \text{Health Index} < 70\%$
Good	$70 \leq \text{Health Index} < 85\%$
Very Good	Health Index $\geq 85\%$

Note that for critical asset groups, such as Power Transformers, the Health Index of each individual unit is given.

II.2 Condition Based Flagged for Action Plan

The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides a good model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f = failure rate per unit time
 t = time
 γ, β = constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in failure rate studies of multiple power system asset groups, the following variation of the failure rate formula has been adopted:

$$f(t) = e^{\beta(t-\alpha)}$$

Equation 4

f = failure rate of an asset (percent of failure per unit time)
 t = age (years)
 α, β = constant parameters that control the rise of the curve

The corresponding cumulative probability of failure function is therefore:

$$P_f(t) = 1 - e^{-(f - e^{-\alpha\beta})/\beta}$$

Equation 5

P_f = cumulative probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 45 and 65 the asset has cumulative probabilities of failure of 20% and 95% respectively. It follows that when using Equation 5, α and β are calculated as 72 and 0.131 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{-\alpha\beta})/\beta} = 1 - e^{-(e^{0.131(t-72)} - e^{-9.432})/0.131}$$

The failure rate and probability of failure graphs are as shown:

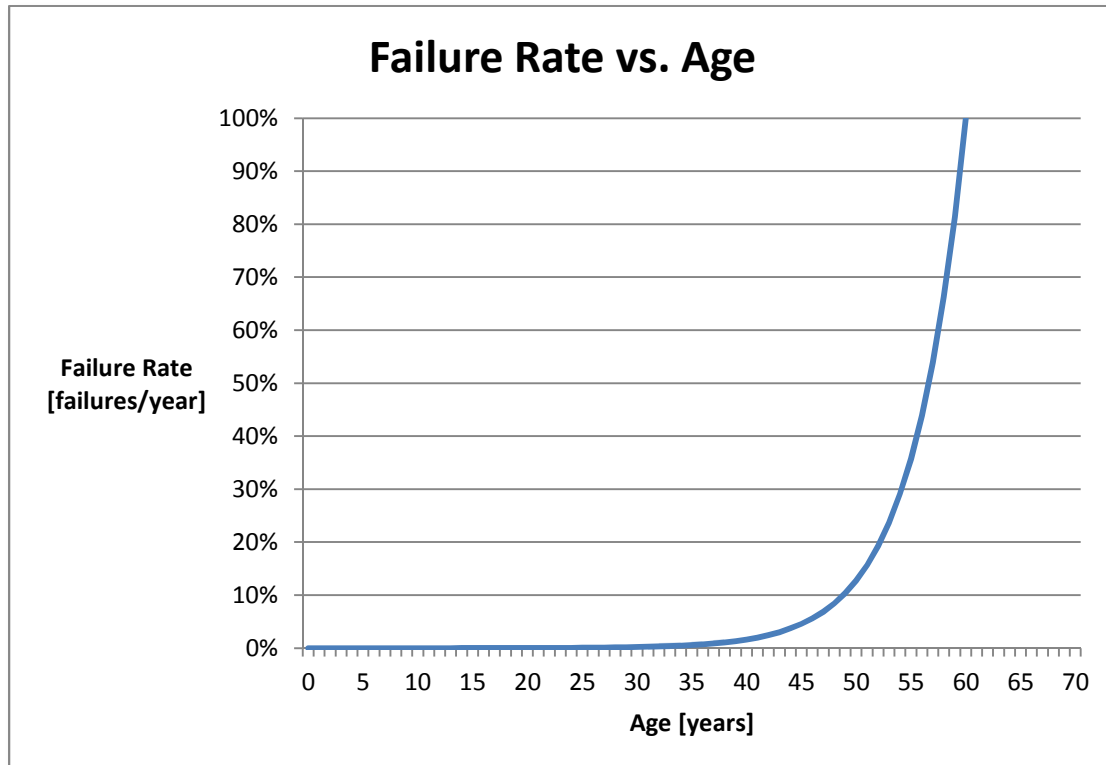


Figure II-1 Failure Rate vs. Age

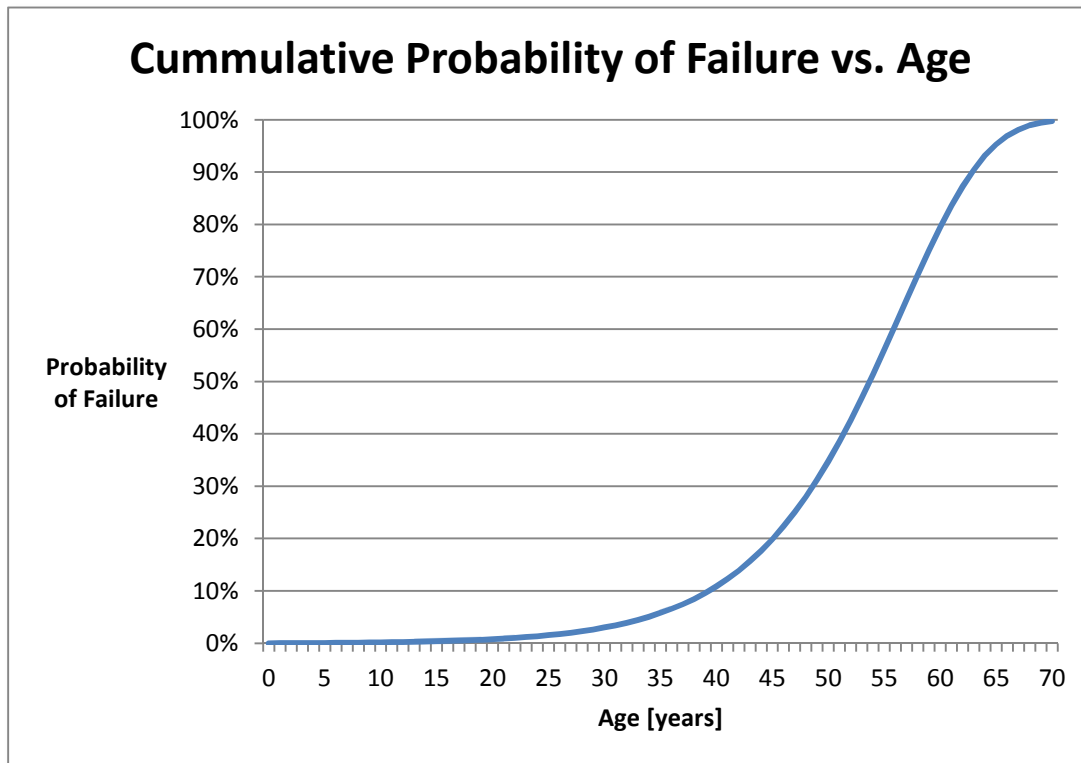


Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Flagged for Action Plan Using a Reactive Approach

Because the consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

$$f(t) = e^{\beta(t-\alpha)}$$

with α and β determined from the probability of failure of each asset class.

An example of such a Flagged for Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 - 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are $f_5 = 0.02$, $f_{10} = 0.05$, $f_{20} = 0.1$ failures / year respectively. In the current year, the total number of replacements is $100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8$.

In the following year, the expected asset distribution is, as a result, as follows: 8 - 1 year old units, 98 - 6 year old units, 19 - 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore $8(f_1) + 19(f_6) + 45(f_{11}) + 45(f_{21})$.

Note that in this study the "age" used is in fact "effective age", or condition-based age if available, as opposed to the chronological age of the asset.

The Levelized Flagged for Action plan smooths or levelizes the peaks and valleys of the flagged for action plan.

II.2.3 Projected Flagged for Action Plan Using a Proactive Approach

For certain asset classes, the consequence of an asset failure is significant, and, as such, these assets are proactively addressed prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

If there are no dominant sources, it can be assumed that the stress to which an asset is exposed is not constant and will have a somewhat normal frequency distribution. This is illustrated by the probability density curve of stress below. The vertical lines in the figure represent condition or strength (Health Index) of an asset.

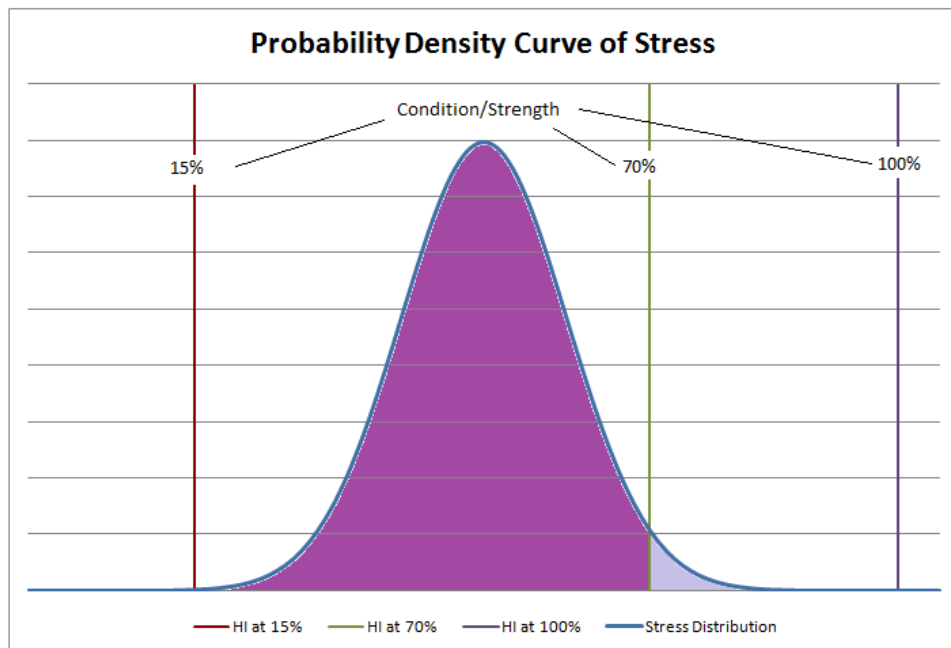


Figure II-3 Stress Curve

An asset is in as-new condition (100% strength) should be able to withstand most levels of stress. As the condition of the asset deteriorates, it may be less able to withstand higher levels of stress. Consider, for example, the green vertical line that represents 70% condition/strength. The asset should be able to withstand magnitudes of stress to left of the green line. If, however, the stress is of a magnitude to the right of the green line, the asset will fail.

To create a relationship between the Health Index and probability of failure, assume two "points" on the stress curve that correspond to two different Health Index values. In this example, assume that an asset that has a condition/strength (Health Index) of 100% can withstand all magnitudes of stress to the left of the purple line. It then follows that probability that an asset in 100% condition will fail is the probability that the magnitude of stress is at levels

to the right of the purple line. This corresponds to the area under the stress density curve to the right of the purple line. Similarly, if it assumed that an asset with a condition of 15% will fail if subjected to stress at magnitudes to the right of the red line, the probability of failure at 15% condition is the area under the stress density curve to the right of the red line.

The probability of failure at a particular Health Index is found from plotting the Health Index on X-axis and the area under the probability density curve to the right of the Health Index line on Y-axis, as shown on the graph of the figure below.

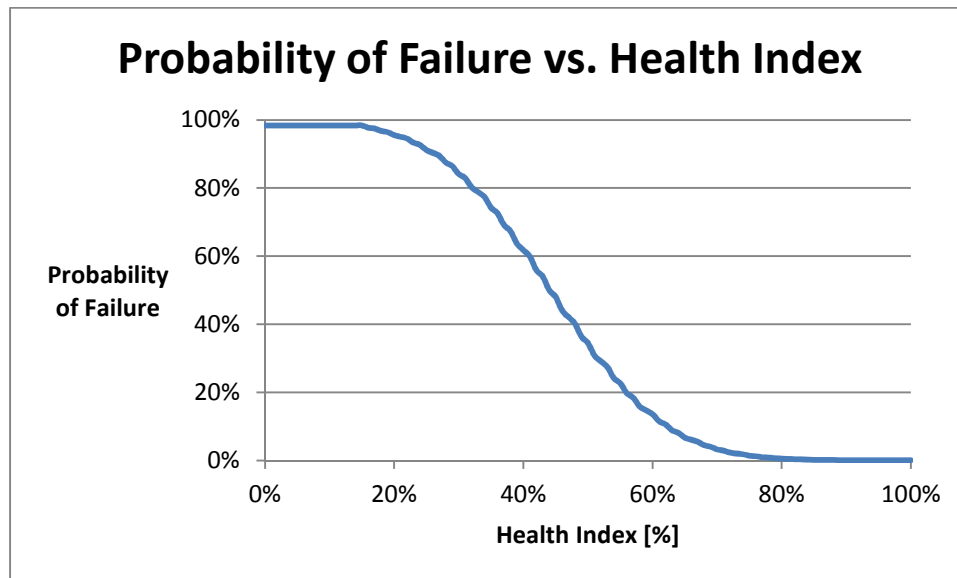


Figure II-4 Probability of Failure vs. Health Index

Condition-Based Flagged for Action Plan

To develop a Flagged for Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure. The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Substation Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is its consequence of failure.

In this study, it is assumed that the unit that has the highest relative consequence of failure has a criticality of 1.43. When its risk value, the product of its probability of failure and criticality, is greater than or equal to 1, the unit is flagged for action. In this case, if the unit with the criticality value of 1.43 has a POF = 70%, its risk will be $1.43 \times 0.7 = 1$ and it will be flagged for action.

II.3 Data Assessment

The condition data used in this study were provided by TBH and included the following:

- Test Results (e.g. Oil Quality, DGA, PCB)
- Inspection Records via Non-Conformance Logs
- Loading
- Make, Model, and Type
- Age

There are two components that assess the availability and quality of data used in this study: data availability indicator (DAI) and data gap.

II.3.1 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the “best” overall weighted, total condition parameters score. The formula is given by:

$$DAI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\ m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n \times WCPF_n}{\sum_{n=1}^{\forall n} (WCPF_n)}$$

Equation 7

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

For example, consider an asset with the following condition parameters and sub-condition parameters:

Condition Parameter		Condition Parameter Weight (WCP)	Sub-Condition Parameter		Sub-Condition Parameter Weight (WCF)	Data Available? ($\beta = 1$ if available; 0 if not)
m	Name		n	Name		
1	A	1	1	A_1	1	1
2	B	2	1	B_1	2	1
			2	B_2	4	1
			3	B_3	5	0
3	C	3	1	C_1	1	0

The Data Availability Indicator is calculated as follows:

$$DAI_{CP1} = (1 \cdot 1) / (1) = 1$$

$$DAI_{CP2} = (1 \cdot 2 + 1 \cdot 4 + 0 \cdot 5) / (2 + 4 + 5) = 0.545$$

$$DAI_{CP3} = (0 \cdot 1) / (1) = 0$$

$$\begin{aligned} DAI &= (DAI_{CP1} \cdot WCP_1 + DAI_{CP2} \cdot WCP_2 + DAI_{CP3} \cdot WCP_3) / (WCP_1 + WCP_2 + WCP_3) \\ &= (1 \cdot 1 + 0.545 \cdot 2 + 0 \cdot 3) / (1 + 2 + 3) \\ &= 35\% \end{aligned}$$

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score. Provided that the condition parameters used in the Health Index formula are of good quality and there are little data gaps, there will be a high degree of confidence that the Health Index score accurately reflects the asset's condition.

II.3.2 Data Gap

The Health Index formulations developed and used in this study are based only on TBH's available data. There are additional parameters or tests that TBH may not collect but that are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	☆☆☆
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	☆☆
Low	Helpful data; least indicative of asset deterioration	☆

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulas.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for “Tank Corrosion” on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Tank Corrosion	Physical Condition	☆☆	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

III RESULTS

This section summarizes the findings of this study.

III.1 Health Index Results

A summary of the Health Index evaluation results is shown in Table III-1. For each asset category the population, sample size (number of assets with sufficient data for Health Indexing), and average age are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in **Error! Reference source not found.** Note that the Health Index distribution percentages are based on the asset group's sample size.

The 4 kV underground cables, on average as an asset group, were found to be in the worst condition. A total of 34% were in very poor condition, where another 14% were found in poor condition. This is primarily because with the average age of the population at 43 years, the population is fairly old. However, since the population size is minimal (44 conductor-km), this is not a significant concern.

A large percentage of overhead switches, 14%, were classified as very poor; another 5% were found to be in poor condition. Many distribution transformers were also found to be in bad condition. Approximately 9%, 19%, and 8% of pad-mounted, pole-mounted, and vault transformers respectively were classified under the very poor category. These include units that are leaking and that contain PCBs.

The wood pole asset category is also concerning. A total of 10% of all wood poles are in poor or very poor condition.

III.2 Condition-Based Flagged for Action Plan

When there is a large quantity of assets that are at or near the end of their service lives, there may be large quantities of assets flagged for action in the first year. This represents a “backlog” of assets that required attention from past years. As it would not be feasible or practical for a utility to address all assets immediately, a levelized flagged for action plan, where quantities to address are spread over subsequent years, is also given. The unlevelized and levelized flagged for action plans are shown in Table III-2, Table III-3, Figure III-6, and

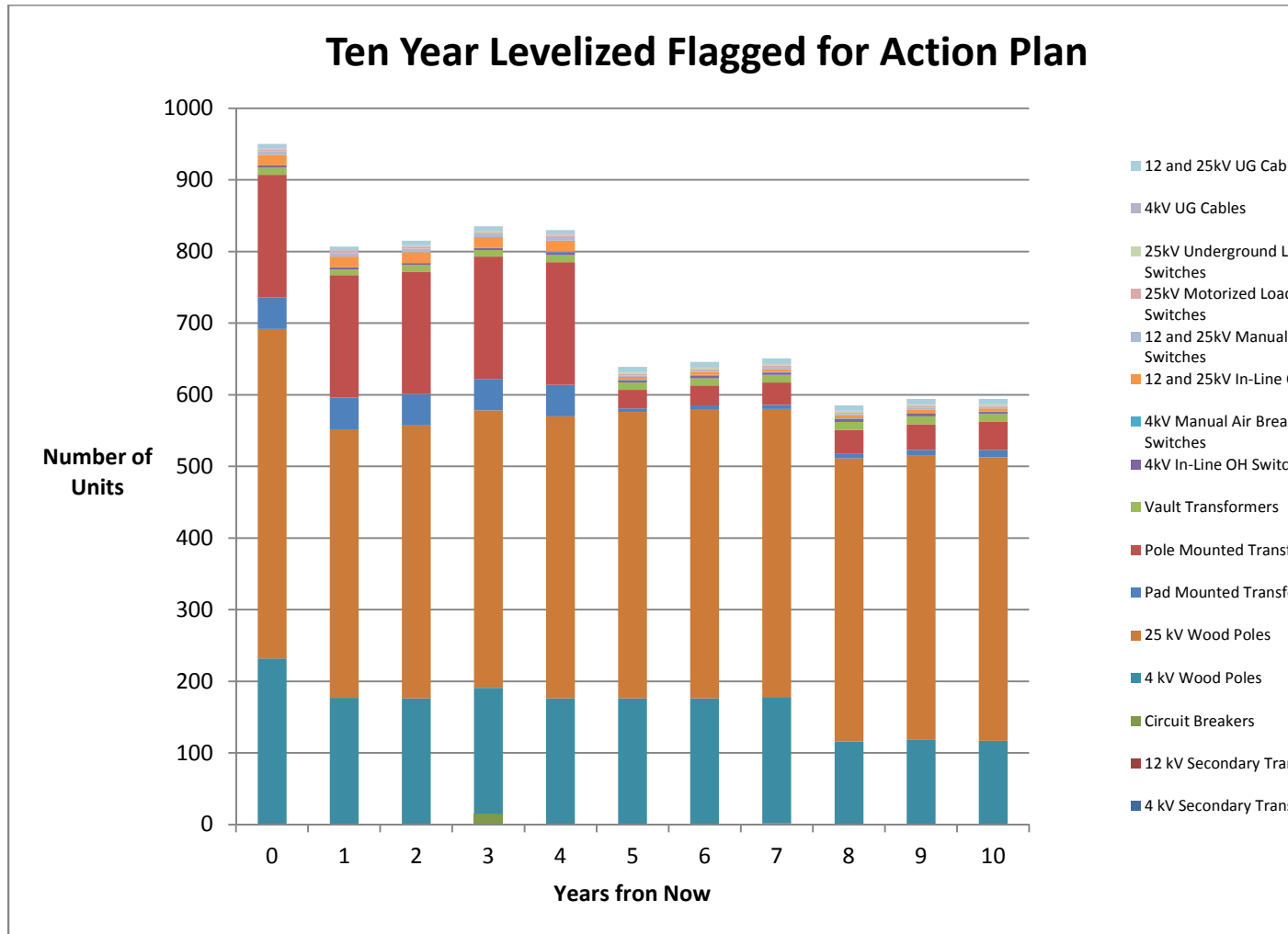


Figure III-7.

In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at in the first year (per the Levelized Plan in Table III-2), this amounts to over 450 poles. Approximately 6% of 4 kV wood poles were also flagged for action in the first year. Because of the considerably smaller population, however, this equates to just over 230 poles. Pole mounted transformers also have large quantities requiring action in year 1. Per the Levelized Plan, more than 170 transformers (4% of the population) are flagged.

Table III-1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	
Station Transformers	All	23	23	88%	0%	4%	9%	4%	83%	52
	4 kV	17	17	86%	0%	6%	6%	12%	76%	54
	12 kV	6	6	94%	0%	0%	0%	0%	100%	47
Breakers	Breakers	77	77	72%	0%	18%	23%	12%	47%	56
Wood Poles	All	19813	19813	75%	1%	9%	34%	21%	34%	28
	4 kV	3862	3862	63%	4%	22%	39%	21%	15%	36
	25 kV	15951	15951	77%	< 1%	6%	33%	21%	39%	27
Distribution Transformers	Pad Mounted Transformers	2206	2206	87%	9%	1%	2%	12%	75%	25
	Pole Mounted Transformers	4143	4141	81%	19%	1%	1%	1%	77%	29
	Vault Transformers	285	285	78%	8%	3%	15%	26%	49%	33
OH Switches	All	729	305	76%	14%	5%	10%	12%	60%	32
	4kV In-Line	101	46	71%	26%	0%	9%	11%	54%	32
	4kV Manual Air Break	7	2	70%	0%	50%	0%	0%	50%	32
	12 and 25kV In-Line	399	148	80%	11%	7%	5%	8%	70%	31
	12 and 25kV Manual Air Break	183	74	78%	14%	4%	7%	9%	66%	33
	25kV Motorized Load Break	39	10	67%	10%	20%	20%	10%	40%	39
Underground Switches	25kV Underground Load Break Switches	80	30	81%	0%	13%	17%	3%	67%	31
Underground Cables*	All	432	374	80%	3%	3%	31%	4%	60%	29
	4kV	44	29	44%	34%	14%	21%	0%	31%	43
	12 and 25kV	387	344	84%	< 1%	2%	32%	4%	63%	28

* data is in conductor-km

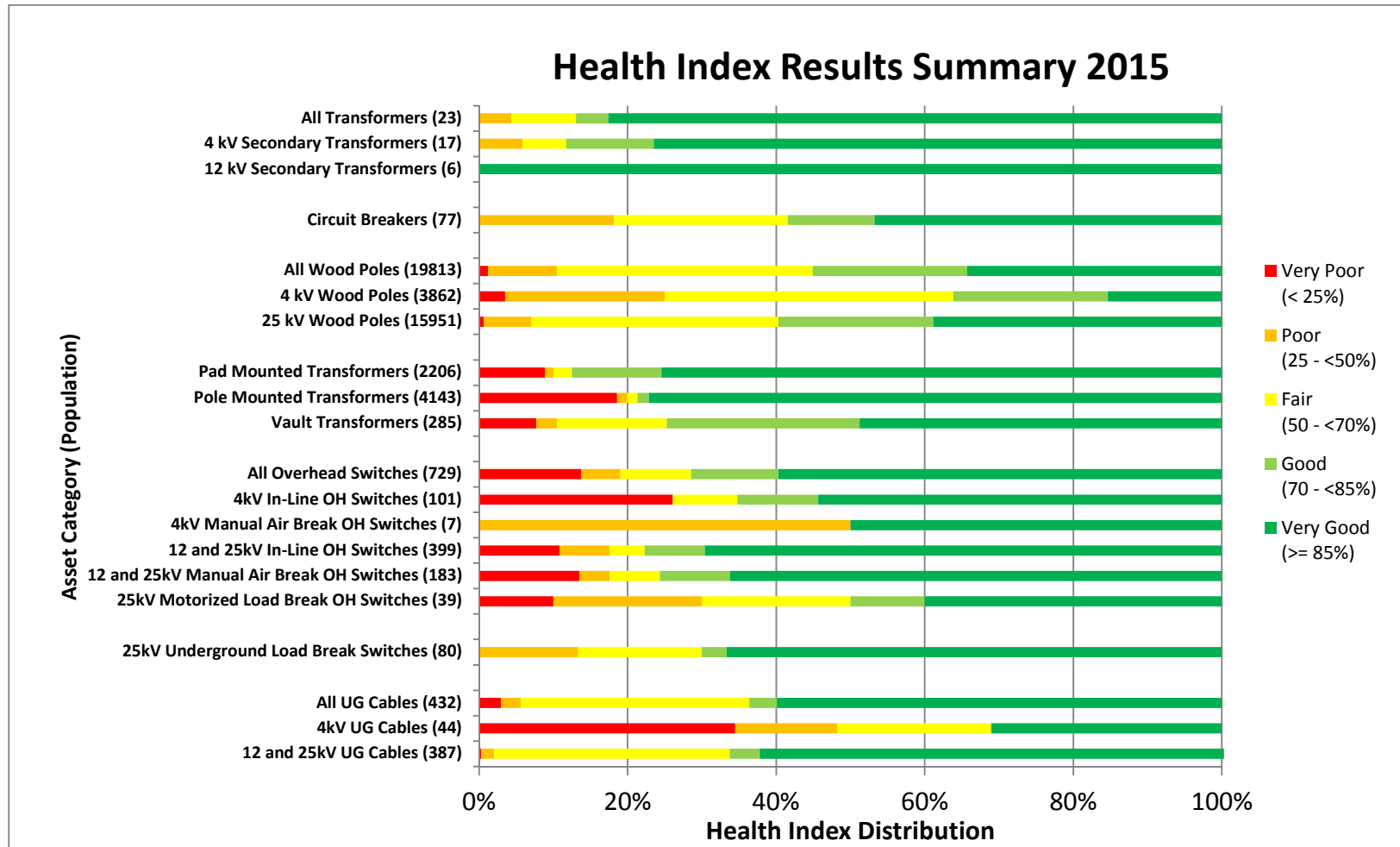


Figure III-5 Health Index Results Summary (Graphical)

Table III-2 Total Year 1 and 10-Year Total Flagged for Action Plan

Asset Category		10 Year Unlevelized 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%	3	18%	0	0%	3	18%	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 Poles	364	9%	1636	42%	232	6%	1636	42%	proactive
	25 kV Wood Poles	544	3%	3964	25%	460	3%	3964	25%	proactive
Distribution Transformers	Pad Mounted Transformers	204	9%	240	11%	44	2%	240	11%	proactive
	Pole Mounted Transformers	625	15%	974	24%	171	4%	974	24%	reactive
	Vault Transformers	14	5%	93	33%	10	4%	93	33%	reactive
Overhead Switches	4kV In-Line OH Switches	3	3%	36	36%	3	3%	36	36%	reactive
	4kV Manual Air Break OH Switches	0	0%	4	57%	0	0%	4	57%	reactive

Thunder Bay Hydro
2015 Asset Condition Assessment

Asset Category		10 Year Unlevelized 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	
	12 and 25kV In-Line OH Switches	30	8%	92	23%	15	4%	92	23%	reactive
	12 and 25kV Manual Air Break OH Switches	20	11%	36	20%	5	3%	36	20%	reactive
	12 and 25kV Motorized Load Break OH Switches	0	0%	16	41%	2	5%	16	41%	reactive
Underground Switches	25kV Underground Load Break Switches	0	0%	13	16%	1	1%	13	16%	reactive
Underground Cables*	4kV UG Cables	2	5%	4	9%	1	2%	4	9%	reactive
	12 and 25kV UG Cables	4	1%	59	15%	6	2%	59	15%	reactive

* data is in conductor-km

Table III-3 Ten Year Flagged for Action Plan

Replacement Year	Type (L = Levelized; Blank = Unlevelized)	Asset Category															
		Substation Transformers		Circuit Breakers	Wood Poles		Distribution Transformers			Overhead Switches					Underground Switches	Underground Cables*	
		4 kV Secondary Transformers	12 kV Secondary Transformers	Circuit Breakers	4 kV Wood Poles	25 kV Wood Poles	Pad Mounted Transformers	Pole Mounted Transformers	Vault Transformers	4kV In-Line OH Switches	4kV Manual Air Break OH Switches	12 and 25kV In-Line OH Switches	12 and 25kV Manual Air Break OH Switches	25kV Motorized Load Break OH Switches	25kV Underground Load Break Switches	4kV UG Cables	12 and 25kV UG Cables
0	L	0	0	0	232	460	44	171	10	3	0	15	5	2	1	1	6
		0	0	0	364	544	204	625	14	3	0	30	20	0	0	2	4
1	L	0	0	0	177	375	44	171	8	3	0	15	5	2	1	1	5
		0	0	0	253	473	7	130	9	2	0	13	5	0	5	0	4
2	L	0	0	0	176	381	44	171	9	3	0	15	5	3	1	1	6
		0	0	0	210	447	3	42	10	7	0	8	2	4	0	1	6
3	L	1	0	14	176	387	44	171	9	3	0	15	5	2	1	1	6
		1	0	14	182	424	2	30	8	3	0	22	0	8	1	0	7
4	L	0	0	0	176	394	44	171	10	4	1	15	5	2	1	1	6
		0	0	0	153	412	2	28	10	2	0	0	0	0	0	0	7
5	L	0	0	0	176	400	5	26	10	3	1	4	2	2	2	1	7
		0	0	0	132	409	5	28	9	2	0	8	5	0	1	0	8
6	L	0	0	0	176	403	6	28	10	4	1	4	2	2	2	1	7
		0	0	0	119	411	6	27	12	7	0	3	2	4	3	0	8
7	L	2	0	0	176	402	6	31	11	3	1	4	3	2	2	1	7
		2	0	0	112	416	5	32	10	3	0	5	2	0	2	0	8
8	L	0	0	0	116	395	7	33	11	4	1	4	2	2	2	1	7
		0	0	0	111	428	6	32	11	7	4	3	0	0	1	1	7
9	L	1	0	0	117	397	8	36	11	4	1	4	3	2	2	1	7
		1	0	0	114	425	5	36	11	2	0	3	5	0	1	0	9
10	L	0	0	0	117	396	10	39	11	3	1	4	2	1	2	1	7
		0	0	0	115	418	9	39	12	3	0	0	0	0	1	1	7

* data is in conductor-km

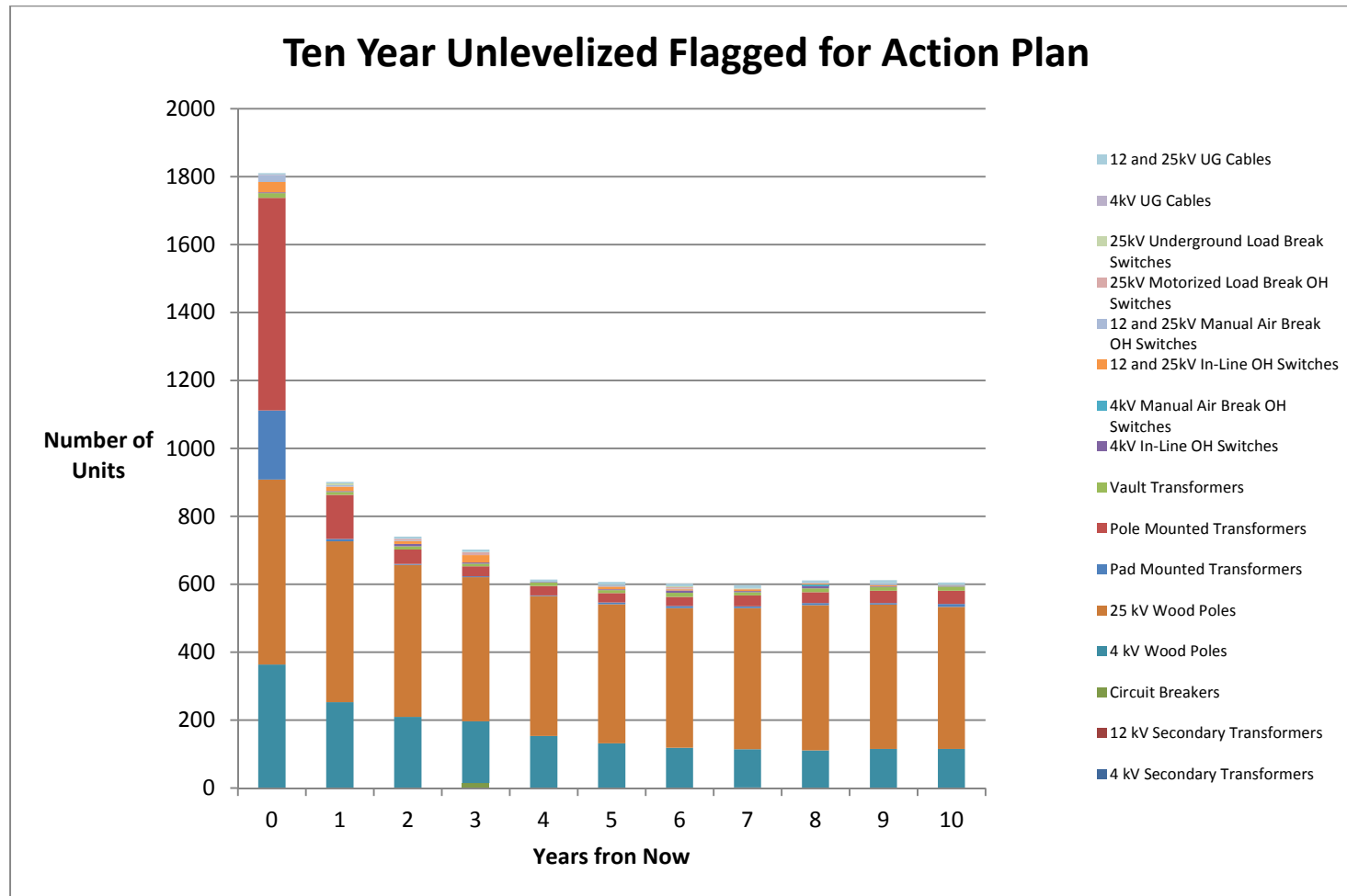


Figure III-6 Ten Year Unlevelized Flagged for Action Plan (Graphical)

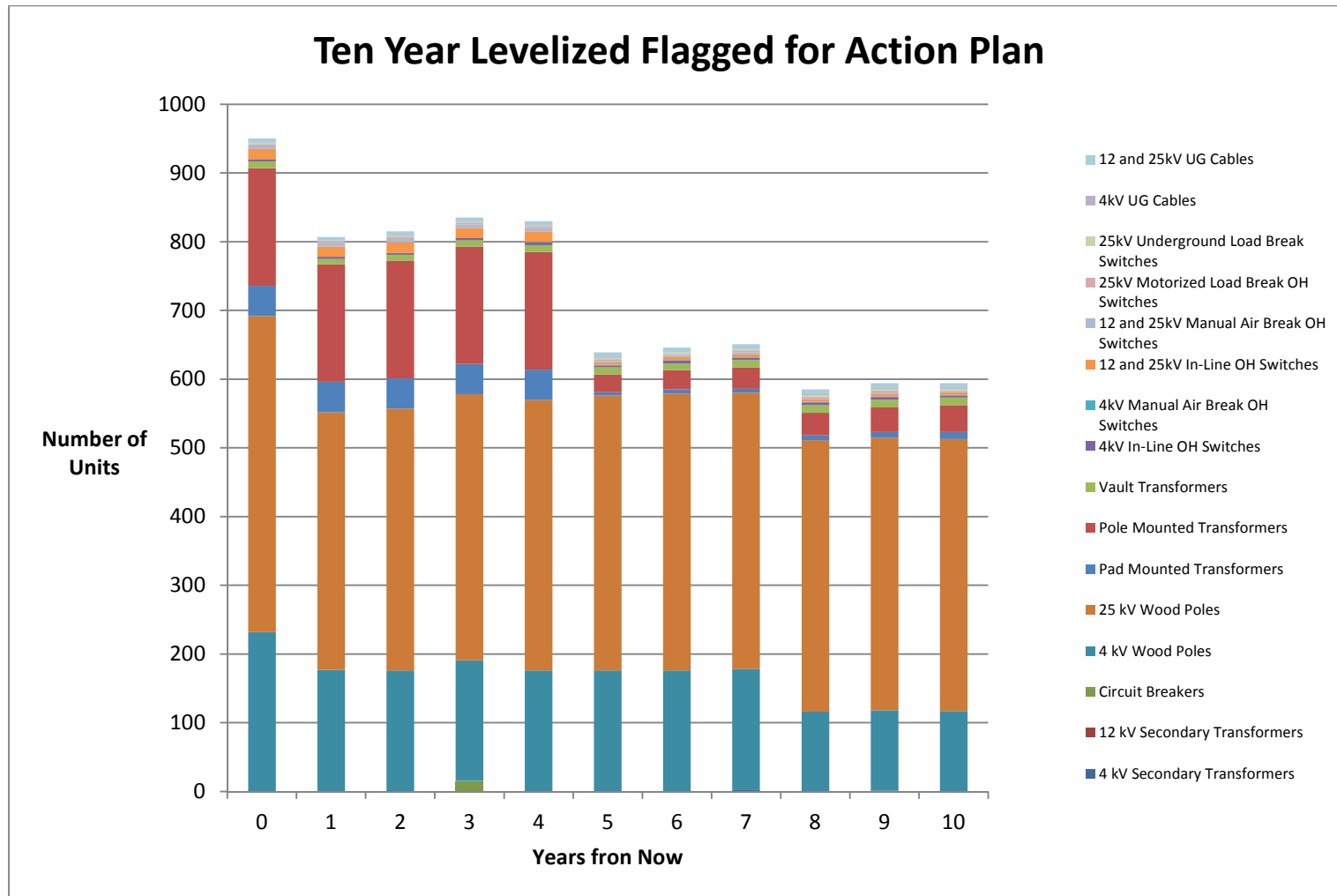


Figure III-7 Ten Year Levelized Flagged for Action Plan (Graphical)

III.3 Data Assessment Results

As mentioned described in Section II.3, the assessment of the available data was done by looking at the data availability indicator (DAI) and data gaps. Recall that the DAI is measurement that is relative to the information that TBH currently collects, whereas data gaps are information that TBH does not collect. As such, even if an asset group has a high DAI, this does not mean information for this asset group is complete. i.e. if there are numerous data gaps, the degree of confidence that the Health Index reflects true condition may still be low. Table III-4 shows the average DAI for each category. The Data Gap column indicates the extent of the data gap (i.e. “high” indicates that a significant amount of condition information can be collected for future assessments). Overall assessments for each asset category are summarized below. Additional details, including prioritized data gaps, are given in the data gap sections of Appendix A: Results for Each Asset Category.

Age, loading, oil quality and dissolved gas analysis tests were available for all Substation Transformers. Data that would be helpful for future assessments include power dissipation factor tests, inspection and/or corrective maintenance records.

For circuit breakers, age and maintenance reports that had information on the following were available: internal, closing, trip mechanisms; tolerance; close and trip timing; contacts; arc chute (Air Blast), heater and tank leak (oil); Insulation. The DAI for this asset group, however, is only 61%. Efforts should be made to ensure that the information is available for all breakers. Data that would be helpful include the operation counts, fault interruption counts, and fault level interrupted.

Age and overall risk rating based on inspection records were available for wood poles. Data gaps include more detailed inspection records and strength tests that give an objective, quantified assessment of the condition of wood poles.

Age, PCB content, and inspection records that provide information on transformer base, enclosure, leaks, and overall hazard condition were available for pad mounted transformers. Loading and inspection/corrective maintenance information related to the connections (elbows/inserts) would be helpful for future assessments.

Only age and PCB content were available for pole-mounted and vault transformers. Loading and inspection/corrective maintenance information related to transformer condition (e.g. leaks, tank/enclosure condition, corrosion, connections).

Age was the only information available for overhead and underground switches. Further, as can be seen from the low DAIs of these asset categories, fewer than half of the switches had age information. Operations records and inspection/corrective maintenance records should be collected (e.g. condition related to switch, operating mechanism, insulation, arc extinguishing mechanism). Such information would provide insight to actual condition.

Underground cables had only age information. However, fewer than half of the cable population had such information. TBH should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan

Delta). Such information will provide good, objective condition data as input into the Health Index.

Table III-4 Data Assessment

Asset Category		Average DAI	Data Gap
Station Transformers	All	93%	Low-Medium
	4 kV	92%	
	12 kV	93%	
Breakers	Breakers	61%	Low-Medium
Wood Poles	All	100%	Medium-High
	4 kV	100%	
	25 kV	100%	
Distribution Transformers	Pad Mounted Transformers	85%	Low-Medium
	Pole Mounted Transformers	100%	Medium-High
	Vault Transformers	100%	Medium-High
OH Switches	All	42%	High
	4kV In-Line	46%	
	4kV Manual Air Break	29%	
	12 and 25kV In-Line	37%	
	12 and 25kV Manual Air Break	40%	
	12 and 25kV Motorized Load Break	26%	
Underground Switches	25kV Underground Load Break Switches	38%	High
Underground Cables	All	48%	High
	4kV	65%	
	12 and 25kV	47%	

IV CONCLUSIONS AND RECOMMENDATIONS

1. An Asset Condition Assessment was conducted for TBH's key distribution assets, namely substation transformers, breakers, wood poles, distribution transformers, overhead line switches, underground switches, and underground cables. For each asset category, the Health Index distribution was determined and a condition-based replacement plan was developed.
2. Of all the asset groups, 4kV underground cables were found, on average, to be in the worst condition. A total of 48% were found to be in poor or very poor condition. However, because of the small population, this is not a significant cause for concern.
3. A large percentage of overhead switches, 14%, were classified as very poor; another 5% were found to be in poor condition. Because the population of switches is relatively small, the number of assets flagged for action is not significant.
4. Approximately 19% of pole mounted transformers were classified under the very poor category. Per the levelized flagged for action plan over 170 transformers require action in the first year.
5. In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at in the first year, this amounts to over 450 poles.

Approximately 6% of 4 kV wood poles were also flagged for action in the first year. Because of the considerably smaller population than the 25 kV poles, however, this equates to just over 230 poles.

6. Age and inspection information were available for substation transformers, breakers, wood poles, and pad-mounted transformers. Additionally substation transformers had loading and oil tests. Only age was available for pole-mounted transformers, vault transformers, overhead and underground switches, and underground cables. Further, the age was only available for less than half of the switches and cables.
7. It is recommended that the data availability indicator (DAI) for each asset category be brought to 100% and maintained at that level. i.e. Data for all condition parameters used in the HI formulas should be collected for all assets. The low DAIs of switches and cables are of particular concern.
8. Data gaps were identified for each asset category, prioritized in the order of importance, in the Appendix of this report. It is recommended that the data be gathered in prioritized manner. Data may be gathered from inspections or corrective maintenance records. Additional sources of data would come from testing (e.g. pole strength testing or cable testing).
9. Because only limited failure statistics was available at this time, an exponentially increasing failure rate and corresponding probability of failure model were assumed in this study. It is

recommended that TBH begin collecting failure information so failure models can be developed and used in future assessments.

10. It is important to note that the replacement plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence TBH's Asset Management Plan.

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APPENDIX A: RESULTS FOR EACH ASSET CATEGORY

1 Substation Transformers

1.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

1.1.1 Condition and Sub-Condition Parameters

Table 1-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	Description	Weight (WCP)	De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)	De-Rating Multiplier (DR_SCP)	SCP Criteria
1	Insulation	3	1	1	Oil Quality (MT Oil)	2	1	Table 1-2
				2	Oil DGA (MT DGA)	3	1	Table 1-3
				3	Power Dissipation Factor (Doble)	0*	1	Table 1-4
				4	Bushing Issues	0*	1	Table 1-5
2	Cooling	0*	1	1	Winding Temp Gauge	0*	1	Table 1-5
3`	Sealing & Connection	0*	1	1	Corrosion	0*	1	Table 1-5
				2	Paint	0*	1	Table 1-5
				3	Oil Leak	0*	1	Table 1-5
				4	Connection	0*	1	Table 1-5
				5	Grounding	0*	1	Table 1-5
4	Service Record	5	1	1	Loading	1	Table 1-6	Table 1-6
Overall HI De-Rating Multiplier (DR)				DGA Trend				Table 1-3
AGE Limiter				The final Health Index value will be limited by the asset age				Equation 8
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

1.1.2 Condition Criteria

Oil Quality

The “Oil Quality” parameter is a composite of the following oil properties: moisture, dielectric strength, interfacial tension, color, and acidity.

Table 1-2 Oil Quality Test Criteria

Score	Description
4	Overall Factor is less than 1.2
3	Overall Factor between 1.2 and 1.5
2	Overall Factor is between 1.5 and 2.0
1	Overall Factor is between 2.0 and 3.0
0	Overall Factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

		Scores				
		1	2	3	4	Weight
Moisture PPM (T °C Corrected) (From DGA test)		<=20	<=30	<=40	>40	4
Dielectric Str. [kV] D877		>40	>30	>20	Less than 20	3
Interfacial Tension (IFT)* [dynes/cm]	230 kV ≤ V	>32	25-32	20-25	Less than 20	2 *
	69 kV <V< 230	>30	23-30	18-23	Less than 18	
	V ≤ 69 kV	>25	20-25	15-20	Less than 15	
Color		Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number*	230 kV ≤ V	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
	69 kV <V< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
	V ≤ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Select the row applicable to the equipment rating

$$\text{Overall Factor} = \frac{\sum \text{Score}_i \times \text{Weight}_i}{\sum \text{Weight}}$$

$$\text{For example if all data is available, Overall Factor} = \frac{\sum \text{Score}_i \times \text{Weight}_i}{12}$$

Oil DGA

Table 1-3 Transformer DGA Criteria

Score	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

Where the DGA overall factor is the weighted average of the following gas scores:

Dissolved Gas	Scores						Weight
	1	2	3	4	5	6	
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	3
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	3
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	5
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	1
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	1

$$\text{Overall Factor} = \frac{\sum \text{Score}_i \times \text{Weight}_i}{\sum \text{Weight}}$$

Winding Doble Test

Table 1-4 Winding Doble Test Criteria

Score	Description
4	power factor reading $\leq 0.5\%$
3	$0.5\% < \text{power factor reading} \leq 0.7\%$
2	$0.7\% < \text{power factor reading} \leq 1.0\%$
1	$1.0\% < \text{power factor reading} \leq 2.0\%$
0	power factor reading $> 2.0\%$

Visual Inspections

Table 1-5 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 1-6 Loading History

Data: S1, S2, S3, ..., SN recorded data (average daily loading)
SB= rated MVA
NA=Number of Si/SB which is lower than 0.6
NB= Number of Si/SB which is between 0.6 and 0.8
NC= Number of Si/SB which is between 0.8 and 1.0
ND= Number of Si/SB which is between 1 and 1.2
NE= Number of Si/SB which is greater than 1.2
Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age Limiter

The final Health Index value is limited by the age of the asset shown below:

$$\text{Final Health Index} = \text{Minimum}\{ \text{HI}, S_i(t) \}$$

Equation 8

Where $S_i(t)$ is the survival function calculated as follows:

Assume that the failure rate Substation Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f(t) = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
 t = time
 α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f(t) = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
 P_f = cumulative probability of failure

Assuming that at the ages of 60 and 70 years the probability of failures (P_f) for Substation Transformers are 20% and 95% respectively results in the survival curve shown below.

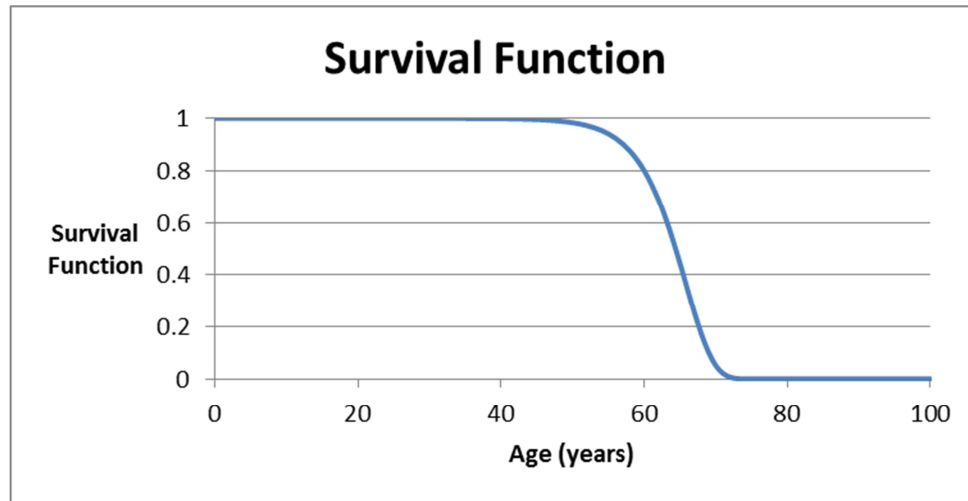


Figure 1-1 Substation Transformers Survival Function

1.2 Age Distribution

The average age of all in service units was 52. All transformers are more than 44 years old. The age distribution for in service Substation Transformers was as follows:

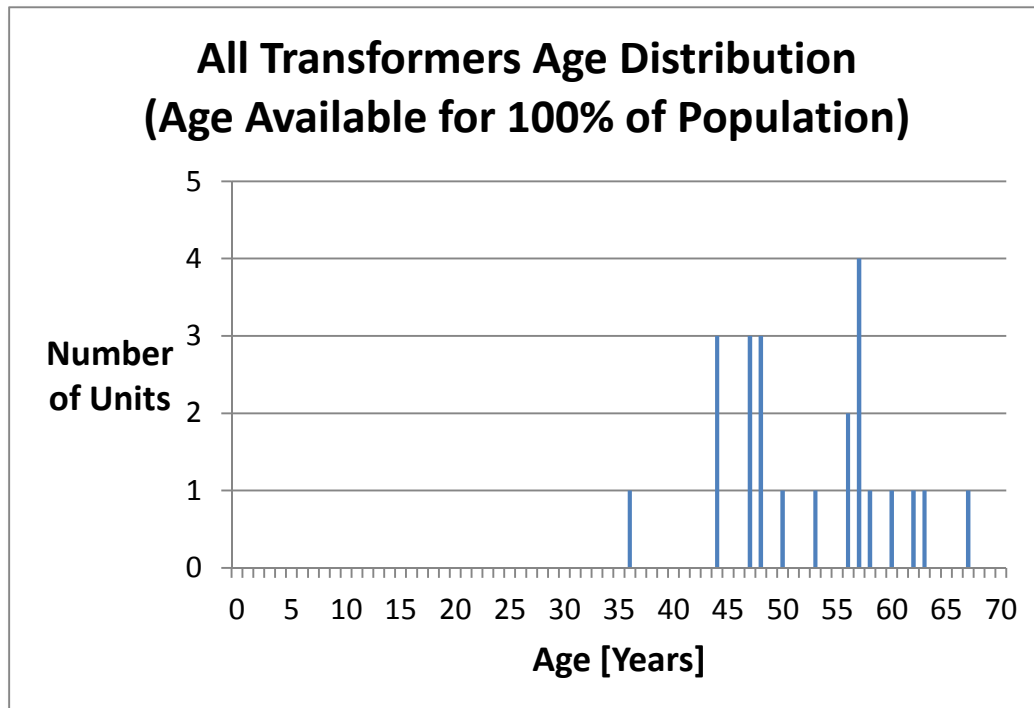


Figure 1-2 Substation Transformers Age Distribution

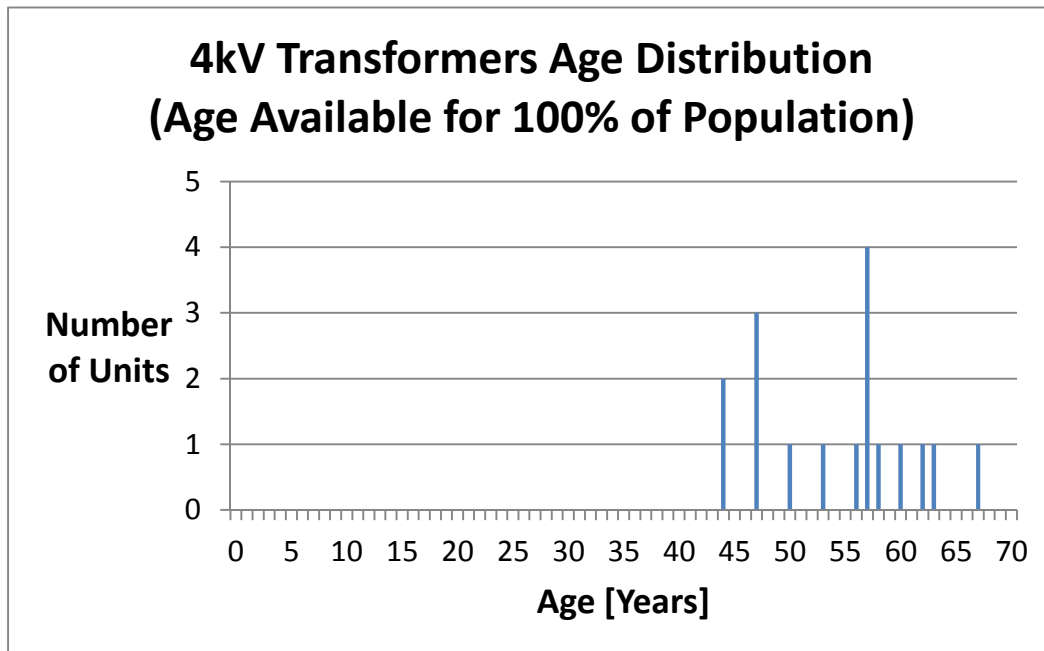


Figure 1-3 4KV Secondary Substation Transformers Age Distribution

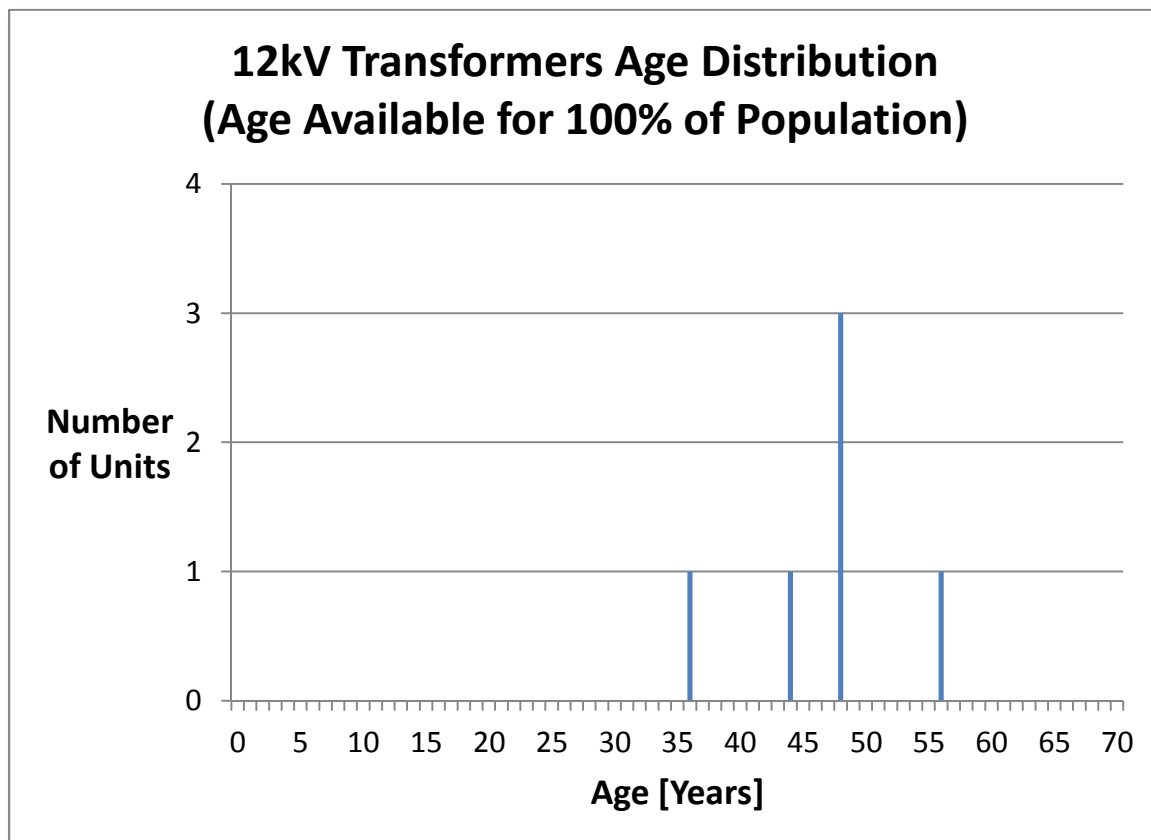


Figure 1-4 12KV Secondary Substation Transformers Age Distribution

1.1 Health Index Results

There are 23 in service Substation Transformers at TBH. Of these, all had sufficient data for Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units are shown below. The average Health Index for this asset group was 88%. Only 1 was found to be in “poor” condition.

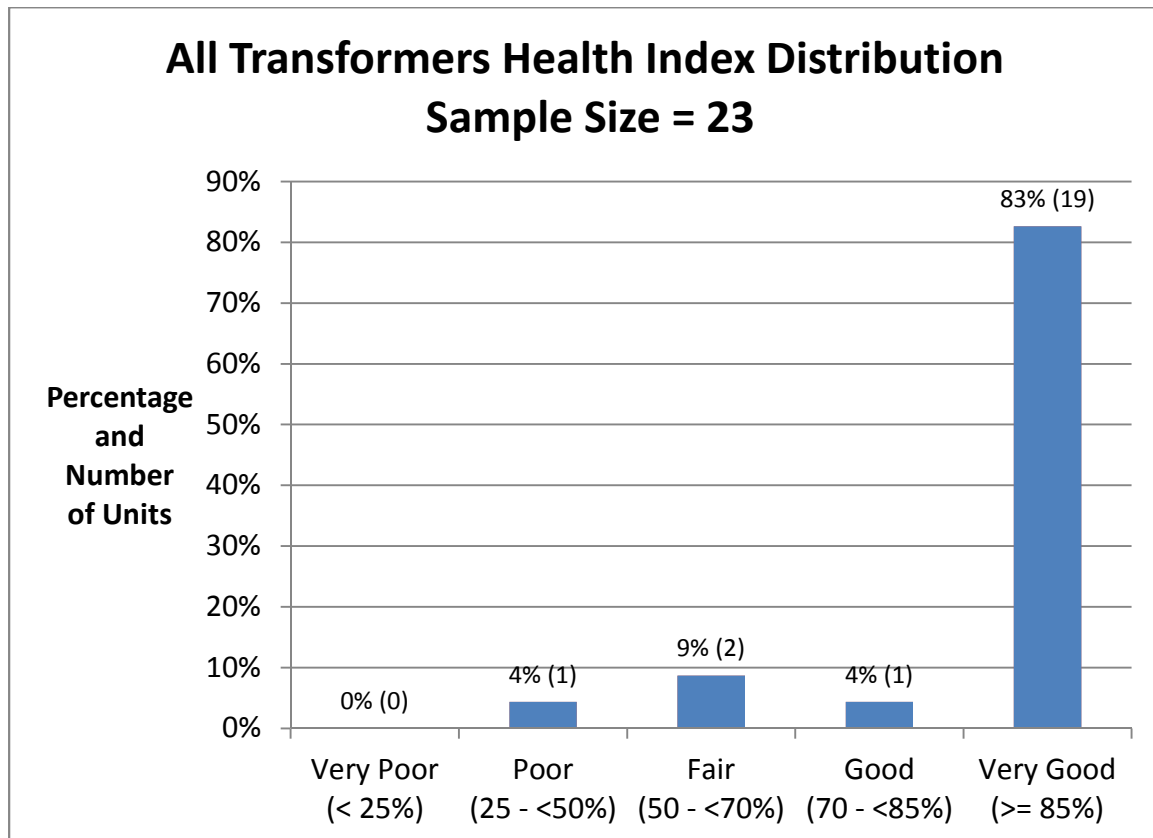


Figure 1-5 Substation Transformers Health Index Distribution

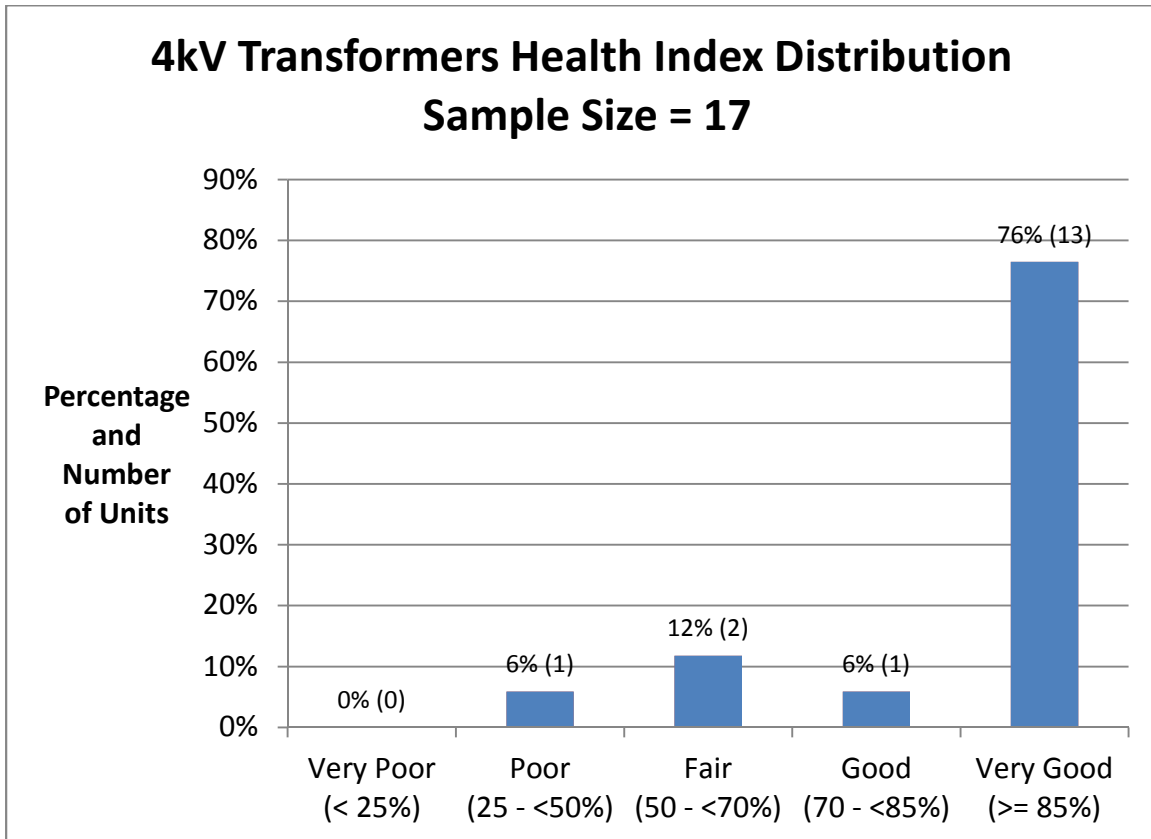


Figure 1-6 4KV Secondary Substation Transformers Health Index Distribution

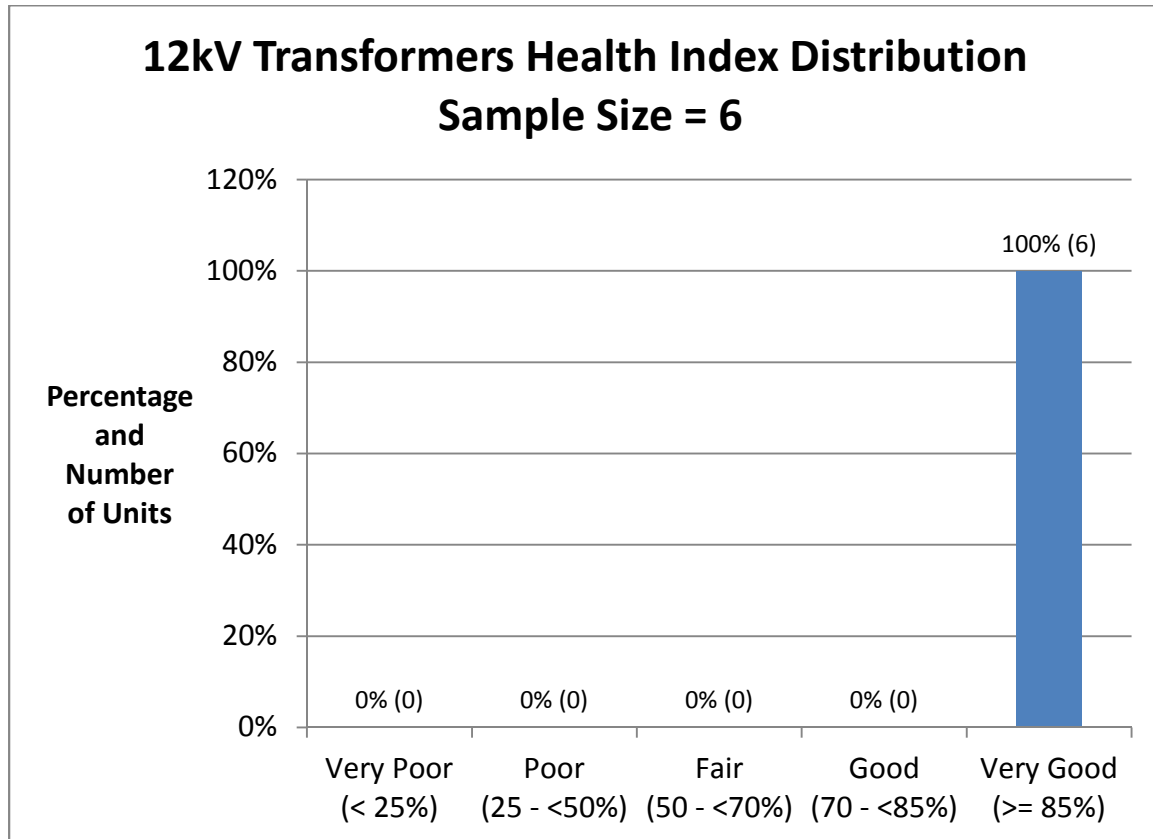


Figure 1-7 12KV Secondary Substation Transformers Health Index Distribution

1.2 Flagged for Action Plan

It is assumed that Substation Transformers are proactively replaced.

In this study, a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one.

Each unit's criticality is defined as follows:

$$\text{Criticality} = (\text{Criticality}_{\max} - \text{Criticality}_{\min}) * \text{Criticality\_Index} + \text{Criticality}_{\min}$$

where:

$$\text{Criticality}_{\max} = 1/(70\%) = 1.43 \quad (\text{the units with highest relative importance should be replaced when their POF reaches 70\%})$$

$$\text{Criticality}_{\min} = 1/(90\%) = 1.11 \quad (\text{the units with lowest relative importance can wait until their POF reaches 95\% to be replaced})$$

Similar to the Health Index (HI), the *Criticality Index* (CI) is a sum-product of scores and weights of parameters that represent a unit's consequence of failure. CI ranges from 0 to 100%, with 100% representing the unit with the highest possible consequence of failure.

$$Criticality\_Index = \frac{\sum_{i=1}^{\forall i} (SCR P_i \times WCR P_i)}{\sum_{i=1}^{\forall i} (WCR P_i)}$$

The Criticality Parameters (CRPs) and possible scoring system used in this study are shown below. Parameters, weights, and scoring systems will be unique to each utility and should be customized accordingly.

Criticality Parameter (CRP)	Description	Weight (WCRP)	Score (SCR P)	
Load Criticality	hospitals, government buildings, restoration time sensitive customers	5	Low	0
			High	1
Customer Impact	# of customers	15	<1,000	0
			>=1,000	1
Physical and Environmental Exposure (Employees safety)	Oil containment, blast wall, deluge system	5	Yes	0
			No	1
Location	Proximity to public places (school, residential, park)	5	No	0
			Yes	1
Interconnection	Interconnection	50	Connected to more than 2	0
			Connected up to 2	0.5
			Connected to none	1
Obsolescence	No Spare Parts	10	None Available	0
			Some Available	1
PCB Content	PCB Content PPM	10	<2	0
			>=2	1

The table below shows examples of criticalities for three separate units.

	Example 1			Example 2			Example 3		
Criticality Factor	Values	CF S	CFS x WCF	Values	CF S	CFS x WCF	Values	CF S	CFS x WCF
Load Criticality	Low	0	0	High	1	5	High	1	5
Customer Impact	500	0	0	2000	1	15	2000	1	15
Physical and Environmental Exposure	Yes	0	0	Yes	0	0	No	1	5
Location	No	0	0	No	0	0	Yes	1	5
Interconnection	Connected to more than 2	0	0	Connected to more than 2	0	0	No connections	1	50
Obsolescence	No spares available	0	0	No spares available	0	0	Spare parts available	1	20
PCB Content	PCB < 2 PPM	0	0	10 PPM	1	10	10 PPM	1	10
	Criticality Multiple		0	Criticality Multiple		0.35	Criticality Multiple		1
	Criticality		(1.43-1.11)*0 + 1.11 = 1.11	Criticality		(1.43-1.05)*0.35 + 1.05 = 1.18	Criticality		(1.43-1.05)*1 + 1.05 = 1.43

As previously noted a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. The flagged for action plan for in service Substation Transformers was as follows:

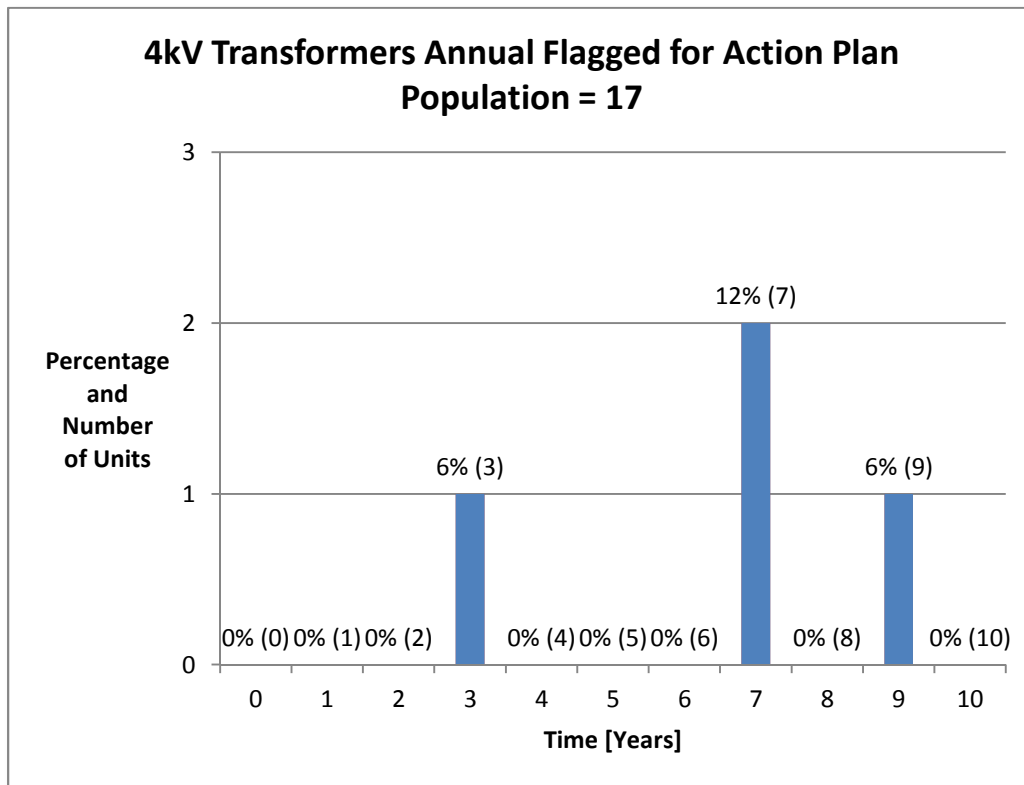


Figure 1-8 4kV Secondary Substation Transformers Risk Based Flagged for Action Plan

No 12kV Transformers are flagged for action in the next 10 years.

1.3 Summary of Results

A summary of all above results are tabulated in the table below.

Table 1-7 Transformers Results Summary

ID	Serial Number	Station Number	Location	Manufacturer	MVA	Primary Voltage (kV)	Secondary Voltage (kV)	Age	DAI	HI (Condition)	HI	HI Category	Flagged for Action Year	Station MVA	Total 4 kV Poles in Station	Average 4kV Poles based on MVA	Total 25 kV Poles in Station	Average 4kV Poles based on MVA
3T1	237994	3	STN #3 HARDISTY	GENERAL ELECTRIC	3	22	4	67	93%	99.0%	25.4%	Poor	3	7	245	105	3	1
3T2	239722	3	STN #3 HARDISTY	GENERAL ELECTRIC	4	22	4	63	93%	84.0%	61.5%	Fair	7	7	245	140	3	2
16T1	276459	16	STN#16 MACDONNEL	GENERAL ELECTRIC	4	23	4	62	100%	92.5%	68.7%	Fair	7	8	137	69	0	0
21T1	245193	21	STN 21 WINDEMERE	ENGLISH ELECTRIC	4	23	4	60	93%	84.2%	80.0%	Good	9	8	592	296	3	2
5T1	281875	5	STN 5 DONALD	GENERAL ELECTRIC	4	22	4	58	93%	100.0%	87.5%	Very Good	12	8	162	81	24	12
16T2	282816	16	STN#16 MACDONNEL	GENERAL ELECTRIC	4	23	4	57	93%	100.0%	90.2%	Very Good	12	8	137	69	0	0
4T1	282960	4	STN #4 VICKER	GENERAL ELECTRIC	4	22	4	57	93%	95.6%	90.2%	Very Good	13	4	203	203	0	0
21T2	290663	21	STN 21 WINDEMERE	WESTINGHOUSE	4	23	4	57	93%	99.2%	90.2%	Very Good	12	8	592	296	3	2
14T1	282815	14	STN#14 ALGOMA	GENERAL ELECTRIC	4	23	4	57	93%	98.7%	90.2%	Very Good	14	4	335	335	3	3
18T1	11117	18	BALSALM	FERRANTI PACKARD	6.667	23	12	56	93%	100.0%	92.4%	Very Good	13	13.334	0	0	842	421
11T1	11118	11	STN 11 HIGH ST	FERRANTI PACKARD	5	23	4	56	93%	97.5%	92.4%	Very Good	14	5	398	398	2	2
5T2	284751	5	STN 5 DONALD	GENERAL ELECTRIC	4	22	4	53	93%	100.0%	96.4%	Very Good	17	8	162	81	24	12
9T1	230831	9	STN 9 MOUNTDALE	MOLONEY ELECTRIC	4	22	4	50	93%	99.2%	98.3%	Very Good	20	4	207	207	0	0
15T1	WT15841	15	STN #15 GRENVILLE	PIONEER ELECTRIC	6.667	24	4	47	93%	99.9%	99.2%	Very Good	20+ years	6.667	496	496	1	1
12T1	WT15842	12	STN#12 CAMELOT	PIONEER ELECTRIC	6.667	24	4	47	93%	100.0%	99.2%	Very Good	20+ years	13.334	603	302	34	17
12T2	WT15843	12	STN#12 CAMELOT	PIONEER ELECTRIC	6.667	24	4	47	93%	100.0%	99.2%	Very Good	20+ years	13.334	603	302	34	17
23T1	255104	23	STN#23	MOLONEY ELECTRIC	6.667	24.94	12	44	93%	88.7%	88.7%	Very Good	20+ years	6.667	0	0	979	979
36T1B	29751	36	STN 36 MAPLEWARD	PIONEER ELECTRIC	2	22	12	48	93%	94.7%	94.7%	Very Good	20+ years	6	0	0	1703	568
36T1R	29754	36	STN #36 MAPLEWARD	PENNSYLVANIA TRANSFORMER	2	22	12	48	93%	94.7%	94.7%	Very Good	20+ years	6	0	0	1703	568
36T1W	29753	36	STN #36 MAPLEWARD	PIONEER ELECTRIC	2	22	12	48	93%	94.7%	94.7%	Very Good	20+ years	6	0	0	1703	568
Northwood	S391201	Northwood	NORTHWOOD PLAZA	PIONEER ELECTRIC	1.69	24.94	4	44	68%	100.0%	99.6%	Very Good	20+ years	1.69	0	0	0	0
18T2	255105	18	STN#18	MOLONEY ELECTRIC	6.667	24.94	4	44	93%	100.0%	99.6%	Very Good	20+ years	13.334	0	0	842	421
19T1	41171	19	STN 19 BROADWAY	MOLONEY ELECTRIC	6.667	24.94	12	36	93%	100.0%	100.0%	Very Good	20+ years	6.667	0	0	392	392

1.3 Data Assessment

Age, loading, oil quality and dissolved gas analysis tests were available for all Substation Transformers. The average DAI for this asset category is 93%, indicating that a majority of the assets have the above information.

Additional data that, if available in a useable format, can be incorporated into the assessment is shown below.

Table 1-8 Substation Transformers Data Gaps

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Power Dissipation Factor	Insulation	☆☆☆	Insulation	Doble Test Results	Tests
Bushing		☆	Bushing	condition of busing	Visual Inspection/ Corrective Maintenance Records
Cooling	Cooling	☆☆	Cooling oil	Abnormal oil flow	Visual Inspection / On-site Reading / Corrective Maintenance Records
				Abnormal oil pump motor	
			Cooling fan	Abnormal fan operation	
			Radiator	Plugged radiator	
			Valves	Broken valves	
			Transformer tank	High top oil temperature	
			Winding	High winding temperature	
Corrosion	Sealing and Connection	☆	Enclosure Condition	Signs of corrosion	Visual Inspection/ Corrective Maintenance Records
Paint		☆		Paint condition	
Oil Leak		☆		Signs of oil leak	
Connection		☆	Connections	Hot connection	
Grounding		☆	Grounding issues	Poor grounding	

2 Circuit Breakers

2.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

2.1.1 Condition and Sub-Condition Parameters

Table 2-1 Condition Parameter and Weights

Condition Parameter (CP)						Sub-Condition Parameter (SCP)						
n	Description	Weight (WCP)			De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)			De-Rating Multiplier (DR_SCP)	SCP Criteria
		Oil	Air Blast	Vacuum				Oil	Air Blast	Vacuum		
1	Operating Mechanism	14	14	7	1	1	Internal Mechanism	1	0	0	1	Table 2-2
						2	Closing Mechanism	1	1	1	1	Table 2-2
						3	Trip Mechanism	1	1	1	1	Table 2-2
						4	Tolerance	1	0	0	1	Table 2-2
2	Contact Performance	7	7	7	1	1	Closing timing	6	6	6	1	Table 2-2
						2	Trip timing	3	3	3	1	Table 2-2
						3	Arcing contact	3	3	0	1	Table 2-2
						4	Main contact	3	3	0	1	Table 2-2
						5	Contact Resistance	3	3	3	1	Table 2-2
						6	Other	1	1	1	1	Table 2-2
3	Arc Extinction	9	9	9	1	1	Arc Chute	0	2	0	1	Table 2-2
						2	Heater	1	0	0	1	Table 2-2
						3	Tank Leak	1	0	0	1	Table 2-2
4	Insulation	2	2	2	1	1	Insulation	1	1	1	1	Table 2-2
5	Service Record	5	5	5	1	1	Operating Counter	1	1	1	1	Table 2-2
AGE Limiter							The final Health Index value will be limited by the asset age					Equation 9

2.1.2 Condition Criteria

Visual Inspection

Table 2-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age Limiter

The final Health Index value is limited by the age of the asset shown below:

$$\text{Final Health Index} = \text{Minimum}\{ \text{HI}, S_f(t) \}$$

Equation 9

Where $S_f(t)$ is the survival function calculated as follows:

Assume that the failure rate Circuit Breakers exponentially increases with age and that the failure rate equation is as follows:

$$f(t) = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
 t = time
 α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f(t) = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
 P_f = cumulative probability of failure

Assuming that at the ages of 60 and 70 years the probability of failures (P_f) for Circuit Breakers are 20% and 95% respectively results in the survival curve shown below.

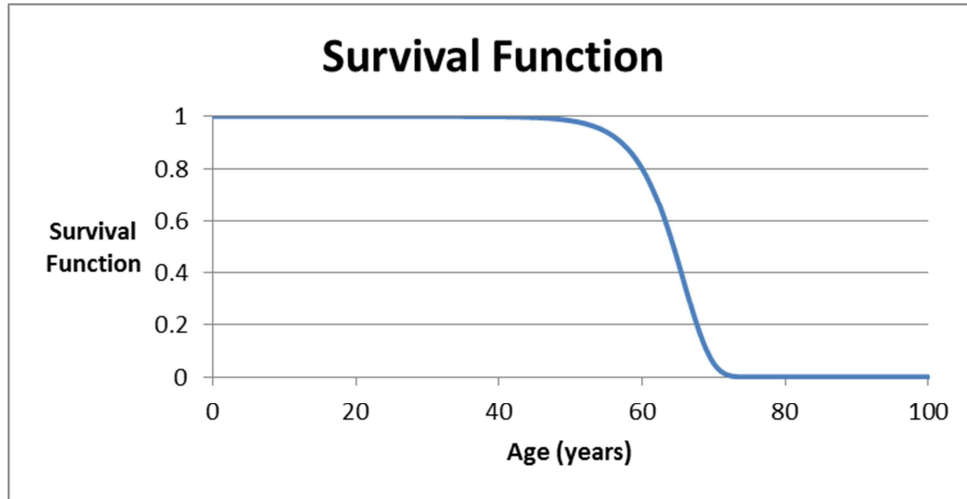


Figure 2-1 Circuit Breakers Survival Function

2.2 Age Distribution

The average age of the population was 56 years. The overwhelming majority, 94%, of the population is 45 years or older. The age distribution for this asset class was as follows:

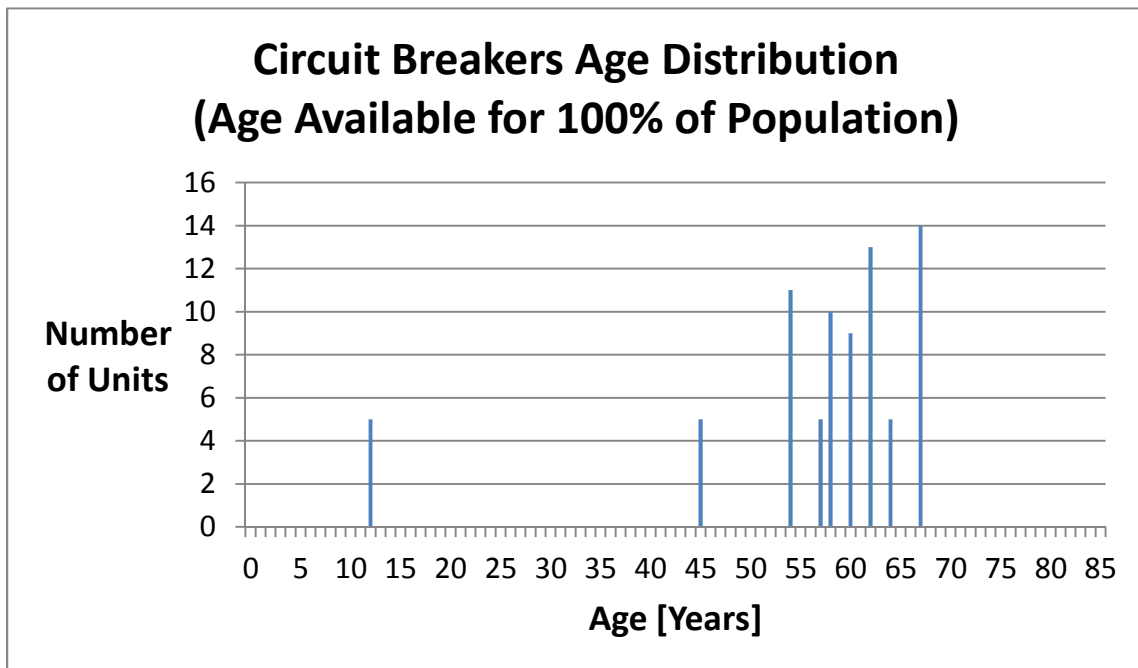


Figure 2-2 Circuit Breakers Age Distribution

2.3 Health Index Results

There are a total of 77 Circuit Breakers. All had sufficient data for Health Indexing.

The average Health Index for this asset group was 94%. Approximately 18% of the population was found to be in “poor” condition.

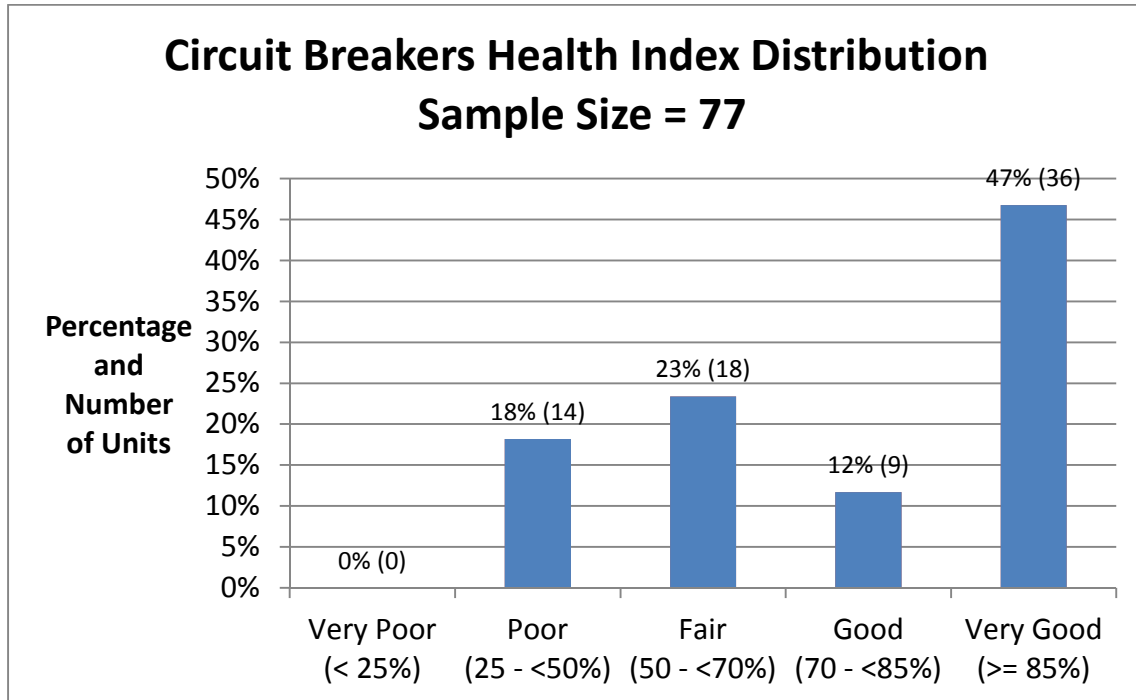


Figure 2-3 Circuit Breakers Health Index Distribution

2.4 Flagged for Action Plan

It is assumed that Circuit Breakers were proactively replaced.

A unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. All units are assumed to have equal criticalities, selected such that a unit with a probability of failure of 70% becomes a candidate for replacement. i.e. Criticality = 1.43.

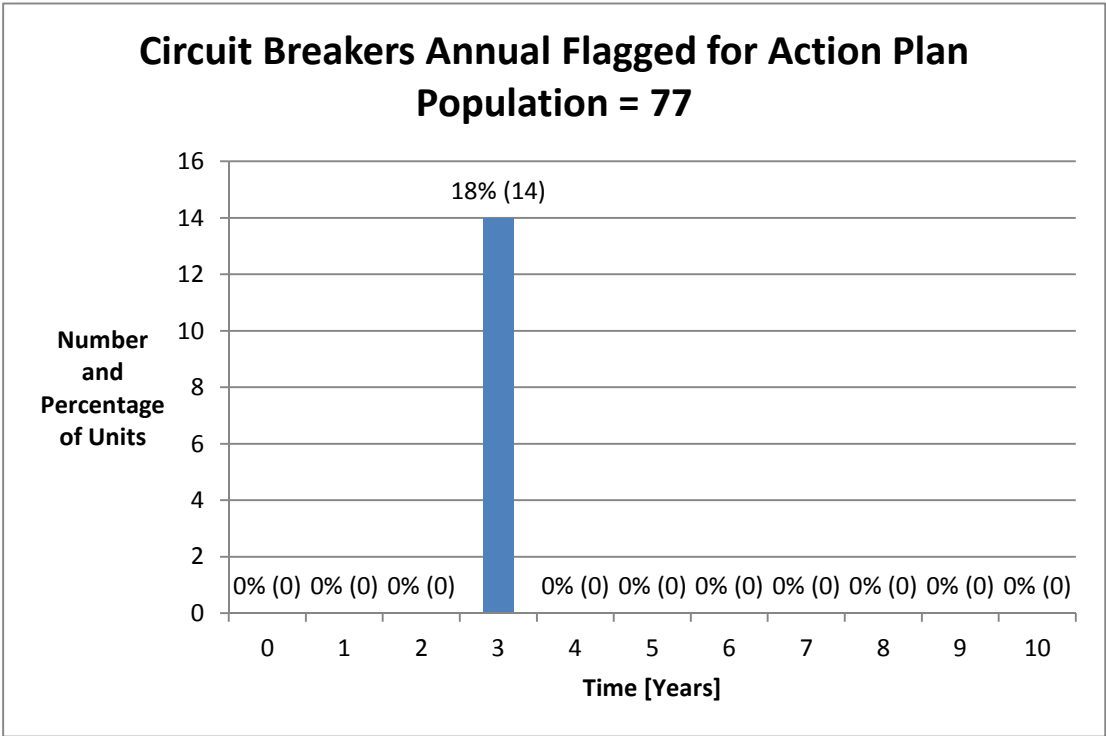


Figure 2-4 Circuit Breakers Risk Based Flagged for Action Plan

2.5 Summary of Results

A summary of all above results are tabulated in the table below.

Table 2-3 Circuit Breakers Results Summary

ID	Serial Number	Station	Location	Type	Manufacturer	Age	DAI	HI (Condition)	HI	HI Category	FFA Year
36557	36557	3	Hardisty	OCB	General Electric	67	53%	93.8%	25.4%	Poor	3
36558	36558	3	Hardisty	OCB	General Electric	67	77%	94.0%	25.4%	Poor	3
36559	36559	3	Hardisty	OCB	General Electric	67	77%	94.4%	25.4%	Poor	3
36560	36560	3	Hardisty	OCB	General Electric	67	77%	93.1%	25.4%	Poor	3
37979	37979	3	Hardisty	OCB	General Electric	67	73%	93.1%	25.4%	Poor	3
37980	37980	3	Hardisty	OCB	General Electric	67	3%	100.0%	25.4%	Poor	3
37981	37981	3	Hardisty	OCB	General Electric	67	3%	100.0%	25.4%	Poor	3
37982	37982	3	Hardisty	OCB	General Electric	67	3%	100.0%	25.4%	Poor	3
38306	38306	3	Hardisty	OCB	General Electric	67	3%	100.0%	25.4%	Poor	3
34912	34912	14	Algoma St.	OCB	General Electric	67	54%	95.3%	25.4%	Poor	3
34913	34913	14	Algoma St.	OCB	General Electric	67	57%	94.7%	25.4%	Poor	3
34914	34914	14	Algoma St.	OCB	General Electric	67	57%	94.7%	25.4%	Poor	3
34915	34915	14	Algoma St.	OCB	General Electric	67	56%	94.4%	25.4%	Poor	3
34916	34916	14	Algoma St.	OCB	General Electric	67	57%	94.7%	25.4%	Poor	3
85782	85782	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.4%	53.3%	Fair	16
85783	85783	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.0%	53.3%	Fair	16
85784	85784	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.0%	53.3%	Fair	16
85785	85785	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.0%	53.3%	Fair	16
85786	85786	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.4%	53.3%	Fair	16
2-0444-1	2-0444-1	4	Vickers	ACB	Allis Chalmers	62	82%	92.0%	68.7%	Fair	20+ years
2-0444-2	2-0444-2	4	Vickers	ACB	Allis Chalmers	62	82%	92.0%	68.7%	Fair	20+ years
2-0444-3	2-0444-3	4	Vickers	ACB	Allis Chalmers	62	82%	92.0%	68.7%	Fair	20+ years
2-0444-4	2-0444-4	4	Vickers	ACB	Allis Chalmers	62	81%	92.0%	68.7%	Fair	20+ years
38923	38923	16	MacDonnell St.	OCB	General Electric	62	60%	95.1%	68.7%	Fair	20+ years
38924	38924	16	MacDonnell St.	OCB	General Electric	62	60%	95.1%	68.7%	Fair	20+ years
38925	38925	16	MacDonnell St.	OCB	General Electric	62	60%	94.5%	68.7%	Fair	20+ years
38926	38926	16	MacDonnell St.	OCB	General Electric	62	60%	94.9%	68.7%	Fair	20+ years
38927	38927	16	MacDonnell St.	OCB	General Electric	62	60%	94.9%	68.7%	Fair	20+ years
52775	52775	16	MacDonnell St.	OCB	General Electric	62	60%	95.1%	68.7%	Fair	20+ years
52776	52776	16	MacDonnell St.	OCB	General Electric	62	60%	94.4%	68.7%	Fair	20+ years
52777	52777	16	MacDonnell St.	OCB	General Electric	62	60%	94.8%	68.7%	Fair	20+ years
52781	52781	16	MacDonnell St.	OCB	General Electric	62	60%	95.1%	68.7%	Fair	20+ years
201097	201097	21	Windemere	OCB	English Electric	60	60%	94.4%	80.0%	Good	20+ years

ID	Serial Number	Station	Location	Type	Manufacturer	Age	DAI	HI (Condition)	HI	HI Category	FFA Year
201131	201131	21	Windemere	OCB	English Electric	60	60%	94.4%	80.0%	Good	20+ years
201133	201133	21	Windemere	OCB	English Electric	60	59%	94.0%	80.0%	Good	20+ years
231986	231986	21	Windemere	OCB	English Electric	60	59%	94.0%	80.0%	Good	20+ years
231987	231987	21	Windemere	OCB	English Electric	60	60%	93.5%	80.0%	Good	20+ years
52778	52778	21	Windemere	OCB	General Electric	60	50%	96.9%	80.0%	Good	20+ years
52782	52782	21	Windemere	OCB	General Electric	60	60%	95.1%	80.0%	Good	20+ years
52784	52784	21	Windemere	OCB	General Electric	60	60%	95.1%	80.0%	Good	20+ years
52785	52785	21	Windemere	OCB	General Electric	60	60%	95.1%	80.0%	Good	20+ years
51854	51854	5	Donald	OCB	General Electric	58	57%	94.4%	87.5%	Very Good	20+ years
51853	51853	5	Donald	OCB	General Electric	58	57%	94.4%	87.5%	Very Good	20+ years
51855	51855	5	Donald	OCB	General Electric	58	57%	94.4%	87.5%	Very Good	20+ years
51856	51856	5	Donald	OCB	General Electric	58	59%	94.1%	87.5%	Very Good	20+ years
51857	51857	5	Donald	OCB	General Electric	58	54%	94.3%	87.5%	Very Good	20+ years
55979	55979	5	Donald	OCB	General Electric	58	60%	93.5%	87.5%	Very Good	20+ years
55980	55980	5	Donald	OCB	General Electric	58	44%	92.7%	87.5%	Very Good	20+ years
55981	55981	5	Donald	OCB	General Electric	58	60%	93.5%	87.5%	Very Good	20+ years
55982	55982	5	Donald	OCB	General Electric	58	60%	93.5%	87.5%	Very Good	20+ years
55983	55983	5	Donald	OCB	General Electric	58	51%	93.6%	87.5%	Very Good	20+ years
52774	52774	18	Balsam St.	OCB	General Electric	57	60%	93.6%	90.2%	Very Good	20+ years
52779	52779	18	Balsam St.	OCB	General Electric	57	60%	94.5%	90.2%	Very Good	20+ years
52780	52780	18	Balsam St.	OCB	General Electric	57	60%	94.4%	90.2%	Very Good	20+ years
52783	52783	18	Balsam St.	OCB	General Electric	57	60%	95.1%	90.2%	Very Good	20+ years
52786	52786	18	Balsam St.	OCB	General Electric	57	60%	94.4%	90.2%	Very Good	20+ years
55560	55560	12	Camelot St.	ACB	General Electric	54	81%	90.6%	90.6%	Very Good	20+ years
55565	55565	12	Camelot St.	ACB	General Electric	54	81%	91.1%	91.1%	Very Good	20+ years
W2090-5	W2090-5	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	91.2%	91.2%	Very Good	20+ years
55561	55561	12	Camelot St.	ACB	General Electric	54	81%	91.2%	91.2%	Very Good	20+ years
55563	55563	12	Camelot St.	ACB	General Electric	54	81%	91.2%	91.2%	Very Good	20+ years
55570	55570	12	Camelot St.	ACB	General Electric	54	81%	91.2%	91.2%	Very Good	20+ years

ID	Serial Number	Station	Location	Type	Manufacturer	Age	DAI	HI (Condition)	HI	HI Category	FFA Year
55559	55559	12	Camelot St.	ACB	General Electric	54	81%	91.7%	91.7%	Very Good	20+ years
55562	55562	12	Camelot St.	ACB	General Electric	54	81%	91.7%	91.7%	Very Good	20+ years
W2090-4	W2090-4	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	92.4%	92.4%	Very Good	20+ years
55564	55564	12	Camelot St.	ACB	General Electric	54	81%	92.9%	92.9%	Very Good	20+ years
55566	55566	12	Camelot St.	ACB	General Electric	54	3%	100.0%	95.4%	Very Good	20+ years
55567 (SPARE)	55567 (SPARE)	12	Camelot St.	ACB	General Electric	54	3%	100.0%	95.4%	Very Good	20+ years
55569	55569	12	Camelot St.	ACB	General Electric	54	3%	100.0%	95.4%	Very Good	20+ years
W2090-1	W2090-1	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	92.5%	92.5%	Very Good	20+ years
W2090-2	W2090-2	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	92.9%	92.9%	Very Good	20+ years
W2090-3	W2090-3	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	92.9%	92.9%	Very Good	20+ years
1742876	1742876	11	High St.	VAC	Square D	12	61%	97.3%	97.3%	Very Good	20+ years
1742877	1742877	11	High St.	VAC	Square D	12	61%	97.3%	97.3%	Very Good	20+ years
1742875	1742875	11	High St.	VAC	Square D	12	61%	97.9%	97.9%	Very Good	20+ years
1742878	1742878	11	High St.	VAC	Square D	12	61%	97.9%	97.9%	Very Good	20+ years
1742879	1742879	11	High St.	VAC	Square D	12	61%	97.9%	97.9%	Very Good	20+ years

2.6 Data Analysis

For circuit breakers, age and maintenance reports that had information on the following were available: internal, closing, trip mechanisms; tolerance; close and trip timing; contacts; arc chute (Air Blast), heater and tank leak (oil); Insulation. The DAI for this asset group, however, is only 61%. Efforts should be made to ensure that the information is available for all breakers. Data that would be helpful include the actual operation counter and fault counter and fault level interrupted.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Total Operations Counts	Contact Performance	★ ★	Contact	Total number of operations	On-Site Reading
Fault Operations Counts		★ ★		Total number of fault operations	
Fault Level Interrupted		★ ★		Fault levels interrupted	Operation Records

3 Wood Poles

3.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

3.1.1 Condition and Sub-Condition Parameters

Table 3-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	Description	Weight (WCP)	De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)	De-Rating Multiplier (DR_SCP)	SCP Criteria
1	Pole Strength	0*	1	1	Pole Strength	0*	1	Based on test results
2	Physical Condition	0*	1	1	Rot	0*	1	Table 3-2
				2	Damage	0*	1	Table 3-2
				3	Animal Damage	0*	1	Table 3-2
				4	Lean	0*	1	Table 3-2
3	Accessories	0*	1	1	Guy Wire & Anchor	0*	1	Table 3-2
				2	Ground Wire	0*	1	Table 3-2
				3	Crossarm	0*	1	Table 3-2
4	Service Record	1	1	1	Age	1	1	Figure 3-1 Figure 3-2
				2	Risk Rating	4	1	Table 3-3
AGE Limiter				The final Health Index value will be limited by the asset age				Equation 10
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

3.1.2 Condition Criteria

Visual Inspection

Table 3-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Risk Rating

Table 3-3 Risk Rating Criteria

Score	TBH Risk Rating Description
0	Red
1	Orange
2	Yellow
3	Purple
4	Blue

Age

Assume that the failure rate Wood Poles exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
 t = time
 α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
 P_f = cumulative probability of failure

Assuming that at the ages of 60 and 75 years the probability of failures (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

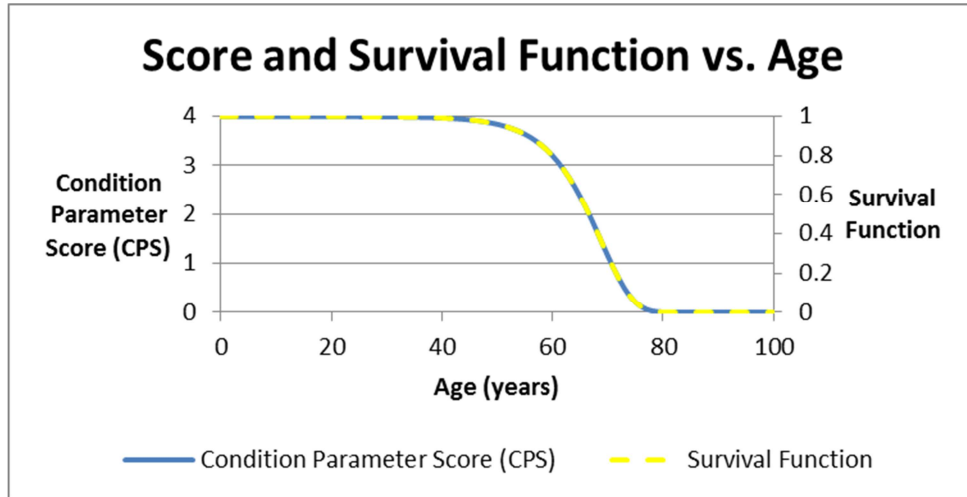


Figure 3-1 Wood Poles Age Criteria

Painted poles and poles in poor soil are assumed to have a shorter lifespan, i.e. the ages of 45 and 60 years correspond to 20% and 95% probability of failure respectively.

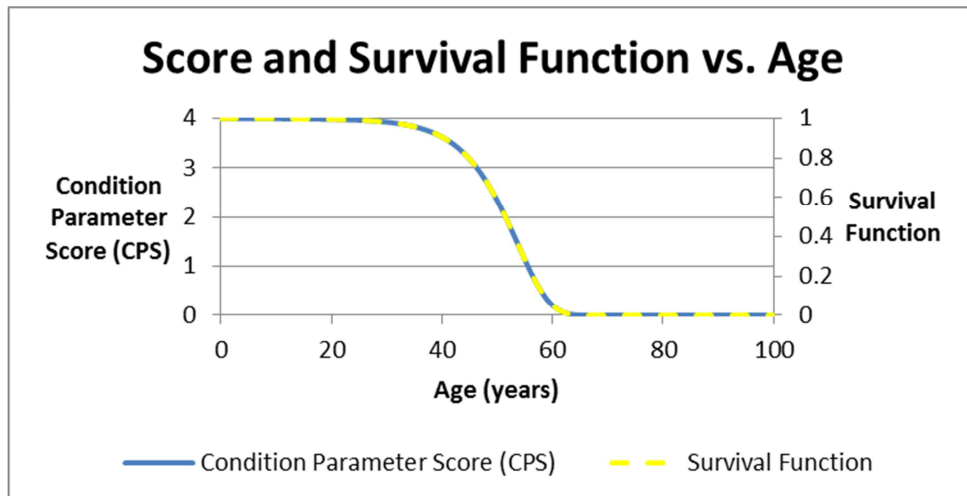


Figure 3-2 Painted Wood Poles and Wood Poles in Poor Soil Age Criteria

Age Limiter

The final Health Index value is limited by the age of the asset shown below:

$$\text{Final Health Index} = \text{Minimum}\{ \text{HI}, S_i(t) \}$$

Equation 10

Where $S_i(t)$ is the survival function shown in Figure 3-1 and Figure 3-2.

3.2 Age Distribution

The average age of all poles was 26 years.

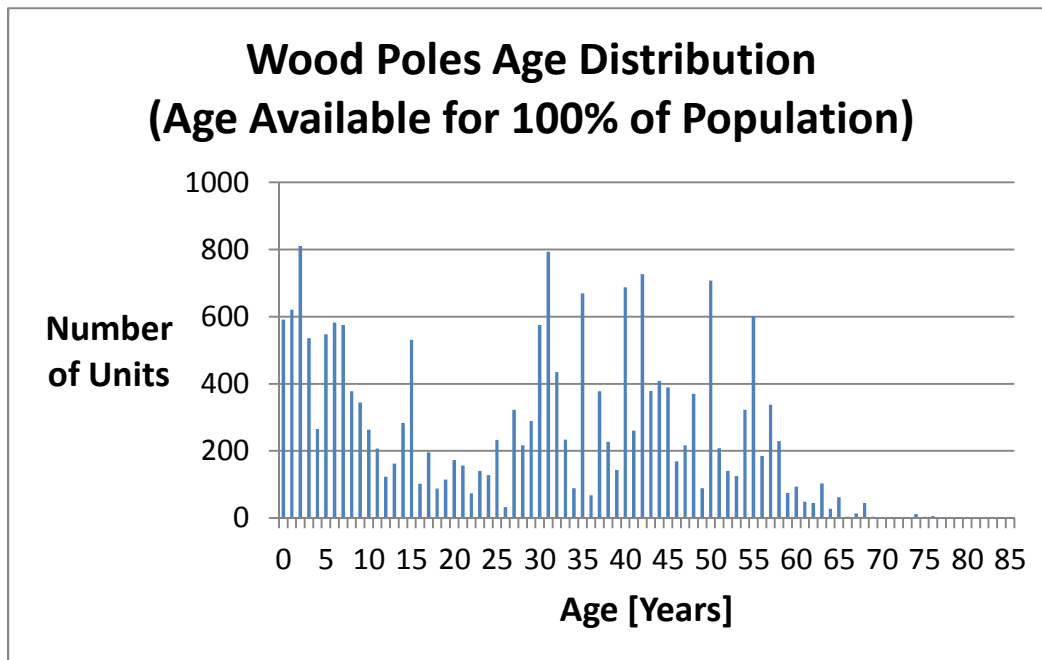


Figure 3-3 ALL Wood Poles Age Distribution

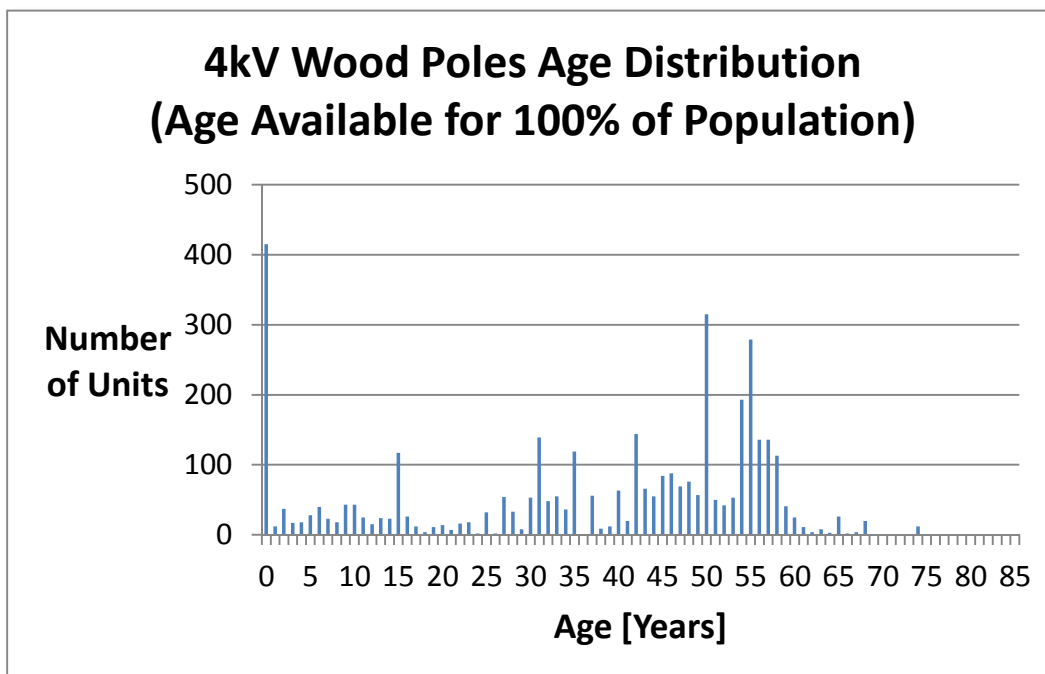


Figure 3-4 4kV Wood Poles Age Distribution

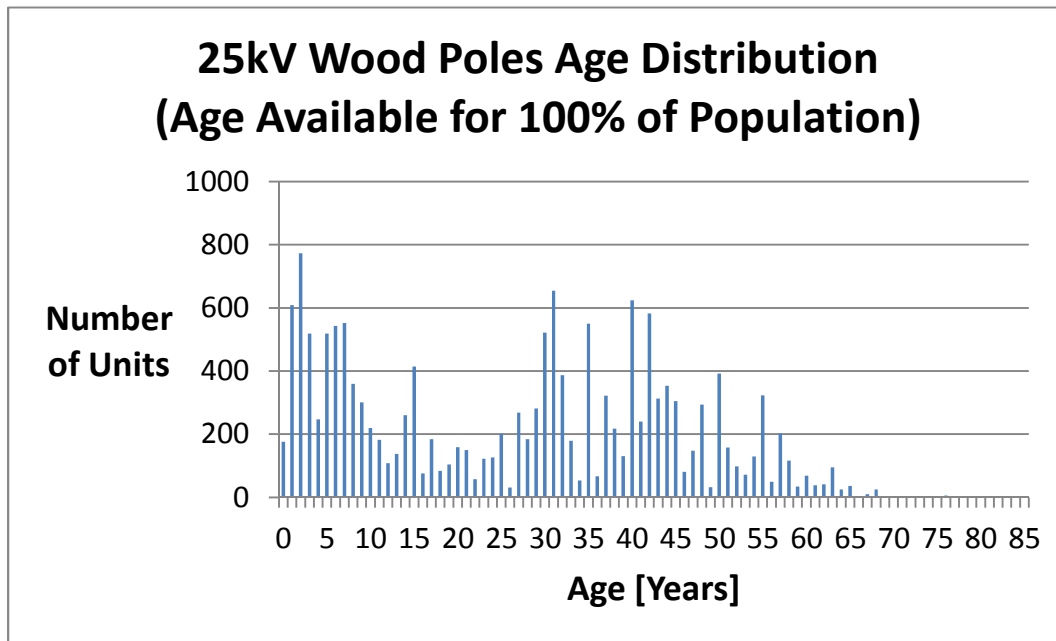


Figure 3-5 25kV Wood Poles Age Distribution

3.3 Health Index Results

There are a total of 19813 Wood Poles. Of these, all had sufficient data for Health Indexing. Approximately 10% of all poles are in poor or very poor condition.

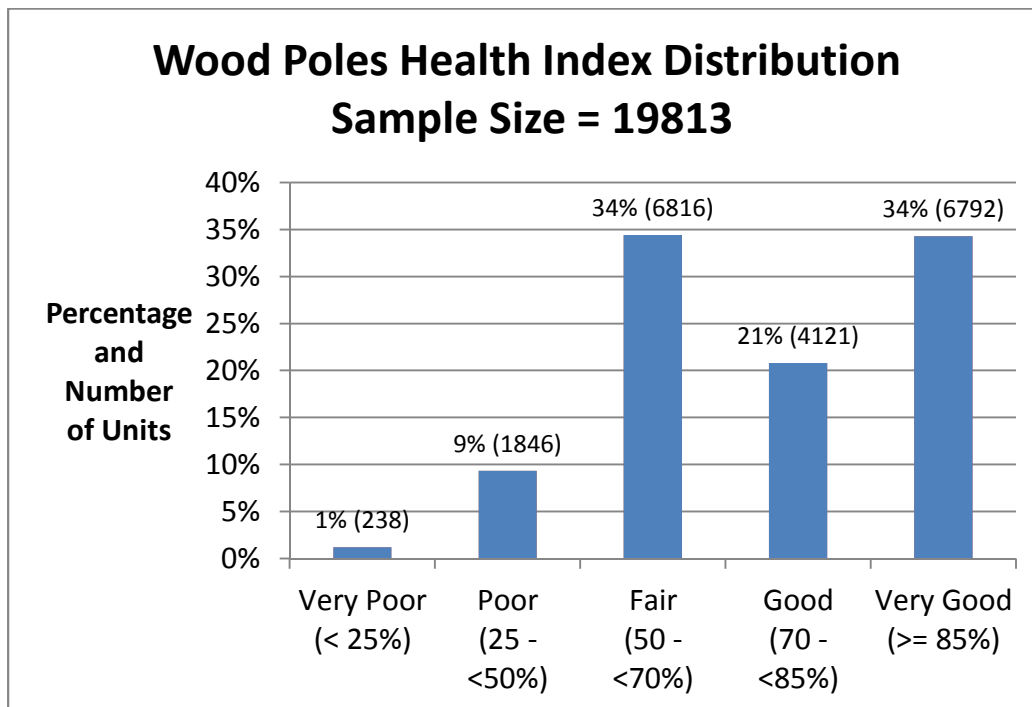


Figure 3-6 ALL Wood Poles Health Index Distribution

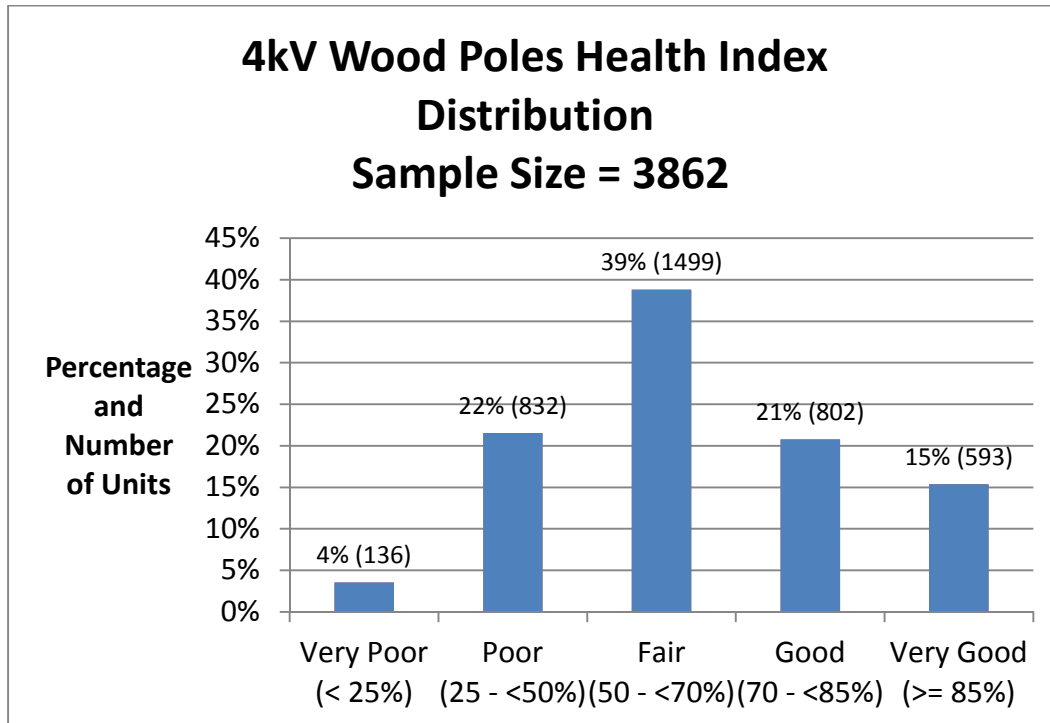


Figure 3-7 4kV Wood Poles Health Index Distribution

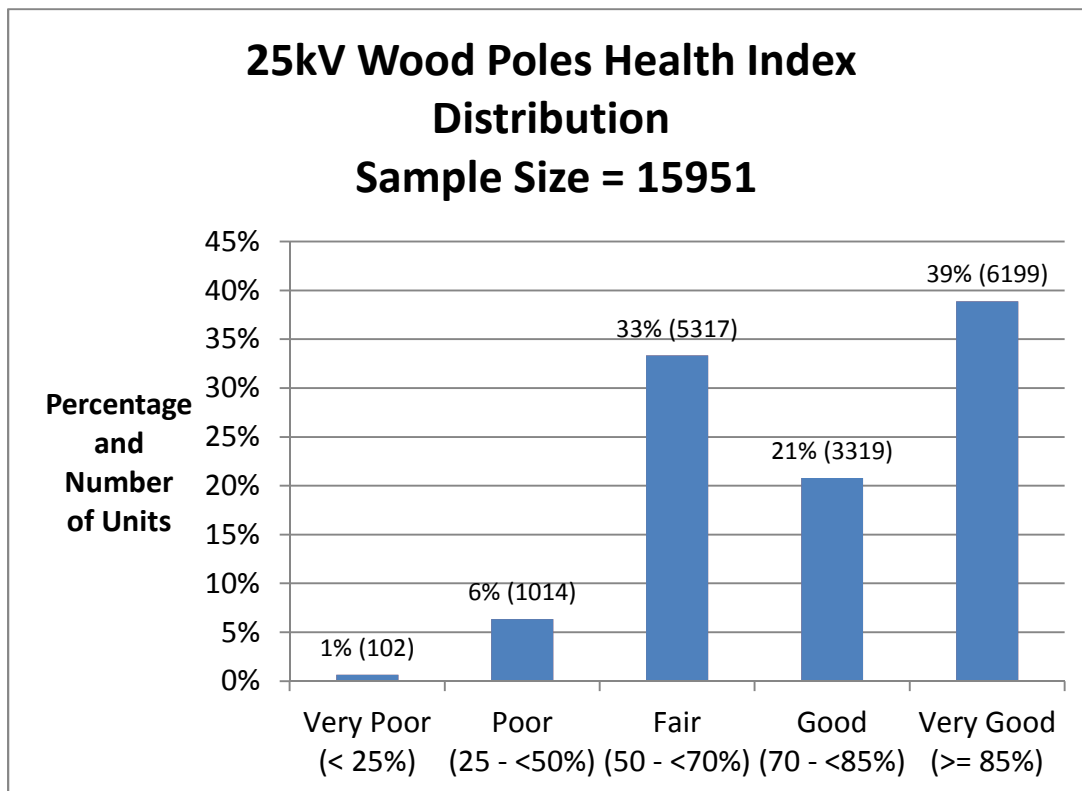


Figure 3-8 25kV Wood Poles Health Index Distribution

3.4 Flagged for Action Plan

The flagged for action plan are as follows:

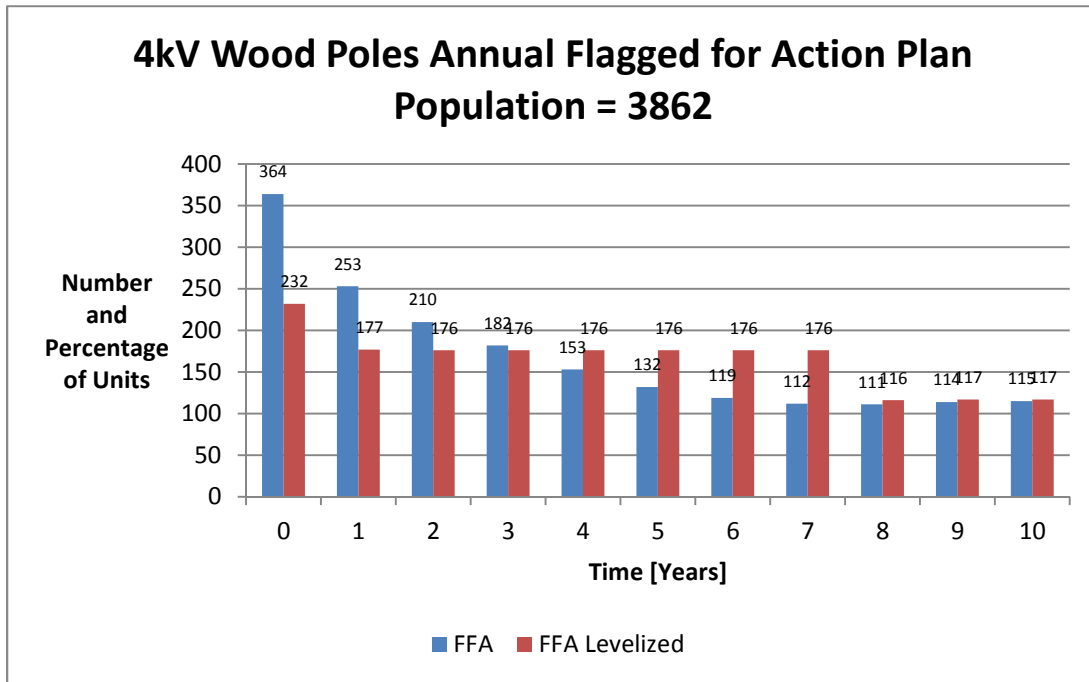


Figure 3-9 4kV Wood Poles Flagged for Action Plan

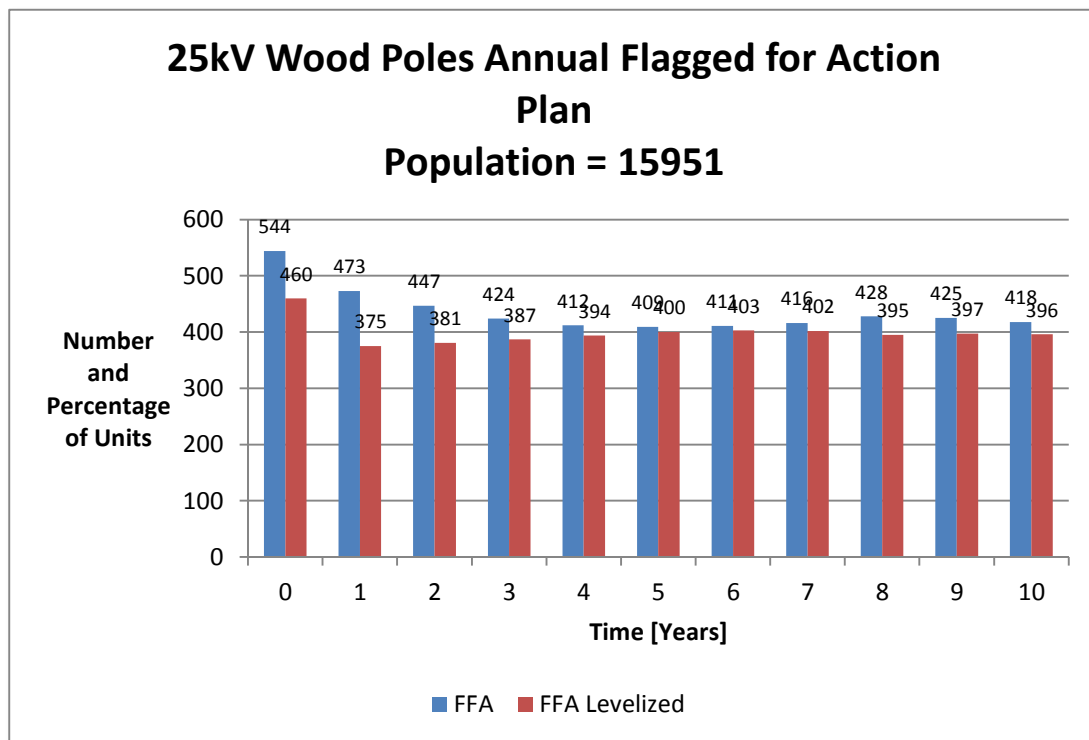


Figure 3-10 25kV Wood Poles Flagged for Action Plan

3.5 Data Analysis

Age and overall risk rating based on inspection records were available for wood poles. The DAI was 100% meaning all poles had the above information. Data gaps include more detailed inspection records and strength tests that give an objective assessment of the condition of wood poles.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Pole Strength	Pole Strength	☆☆☆	Pole Circumference	Ratio of actual circumference over the original circumference	On-site Testing
			Pole Strength	Ratio of actual strength (psi) over the design strength (psi) Primarily used for wood poles, however core sample tests may be possible for concrete poles	
Rot	Physical Condition	☆☆	Pole	Top feathering	Visual inspection/ Corrective Maintenance
Animal Damage				Woodpecker, ant, or other type of animal damage	
Separation				Pole breaking apart	
Voids / Holes				Hole due to degradation	
Cracks				Surface crack due to deterioration or fatigue	
Guy Wire and Anchor	Accessories	☆	Pole Accessories	Condition of guy wire	Visual inspection/ Corrective Maintenance

Cross-Arm		☆	Pole Accessories	Condition of cross arm	Visual inspection/ Corrective Maintenance
Ground Wire		☆	Pole Accessories	Condition of ground wire	Visual inspection/ Corrective Maintenance

4 Pad Mounted Transformers

4.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

4.1.1 Condition and Sub-Condition Parameters

Table 4-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	Description	Weight (WCP)	De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)	De-Rating Multiplier (DR_SCP)	SCP Criteria
1	Physical Condition	1	1	1	Enclosure Damage	5	1	Table 4-2
				2	Access	0*	1	Table 4-2
				3	Base	2	1	Table 4-2
2	Connection and Insulation	1	1	1	Oil Leak	1	1	Table 4-2
				2	Connection	0*	1	Table 4-2
3	Service Record	3	1	1	Hazardous Condition	4	1	Table 4-2
				2	Age	3	1	Figure 4-1
				3	Loading	0*	1	Table 4-3
Overall HI De-Rating Multiplier (DR)				PCB and/or Leaker and/or Hazardous Condition				Table 4-4
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

4.1.2 Condition Criteria

Visual Inspection

Table 4-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 4-3 Loading History

Data: S1, S2, S3, ..., SN recorded data (average daily loading)
SB= rated MVA
NA=Number of Si/SB which is lower than 0.6
NB= Number of Si/SB which is between 0.6 and 0.8
NC= Number of Si/SB which is between 0.8 and 1.0
ND= Number of Si/SB which is between 1 and 1.2
NE= Number of Si/SB which is greater than 1.2
Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age

Assume that the failure rate Pad Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
 t = time
 α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
 P_f = cumulative probability of failure

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

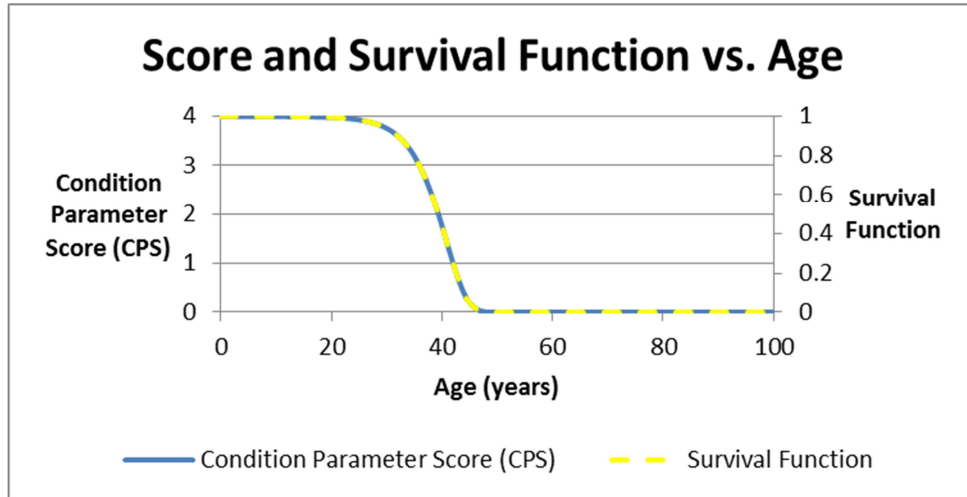


Figure 4-1 Pad Mounted Transformers Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units that have a certain level of PCB and/or are leakers.

Table 4-4 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	(PCB > 2 ppm) AND (Leaker)	0.1
Else if	PCB >= 2 ppm	0.25
Else if	Hazardous Condition	0.5
Else		1

4.2 Age Distribution

The average age of all single phase units was 25 years.

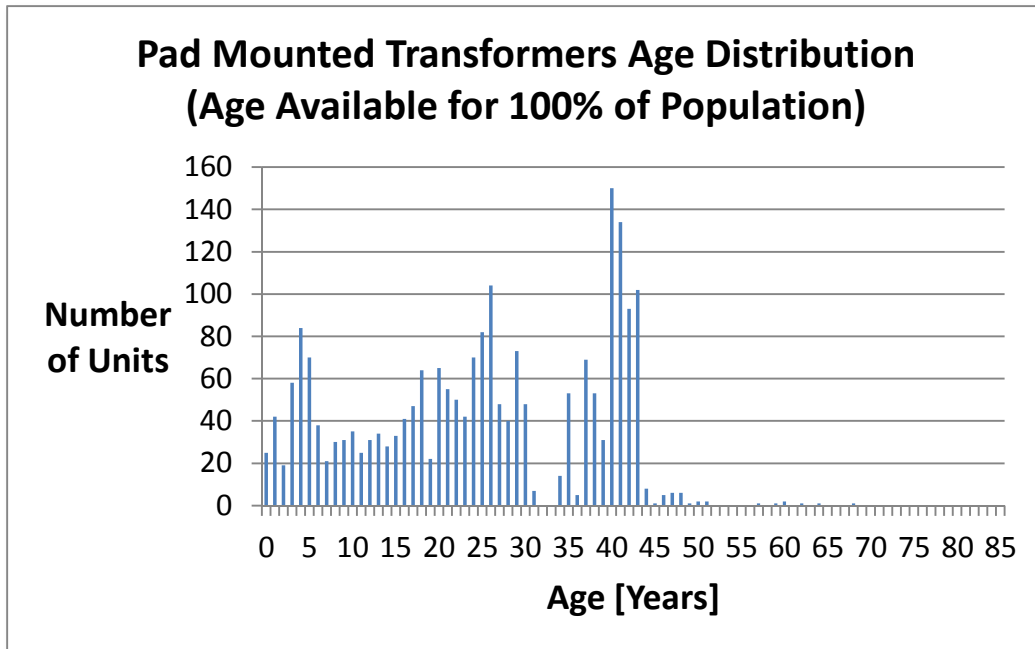


Figure 4-2 Pad Mounted Transformers Age Distribution

4.3 Health Index Results

There are a total of 2206 Pad Mounted Transformers at TBH. Of these, all had sufficient data for Health Indexing. A total of 10% were found to be in poor or very poor condition. These include units that have PCBs and/or are leakers.

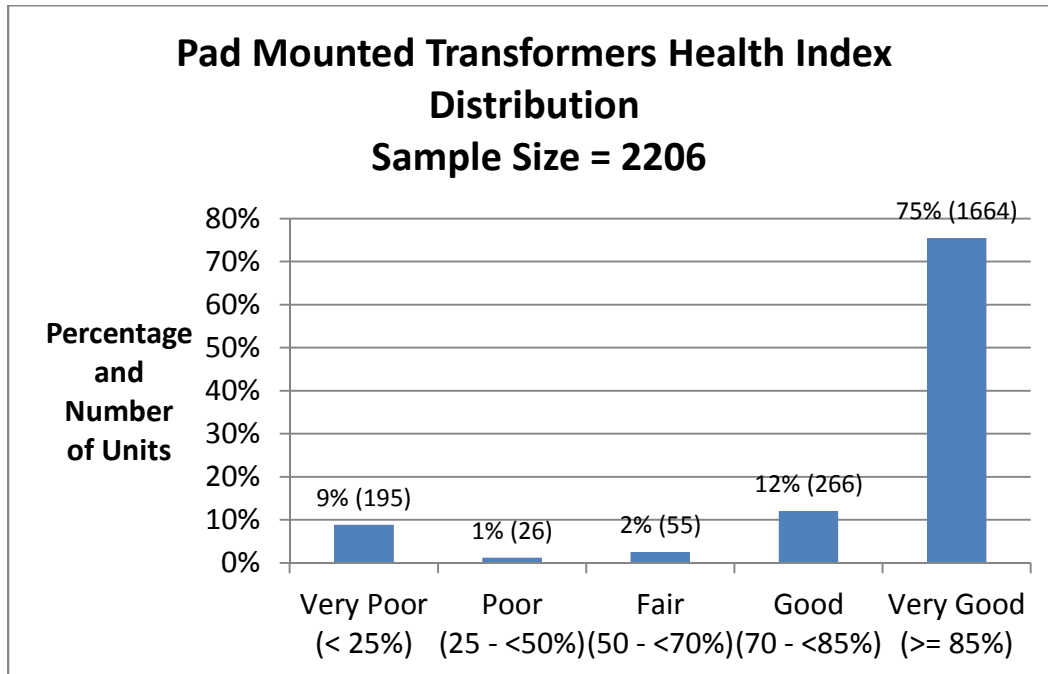


Figure 4-3 Pad Mounted Transformers Health Index Distribution

4.4 Flagged for Action Plan

As it is assumed that Pad Mounted Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate.

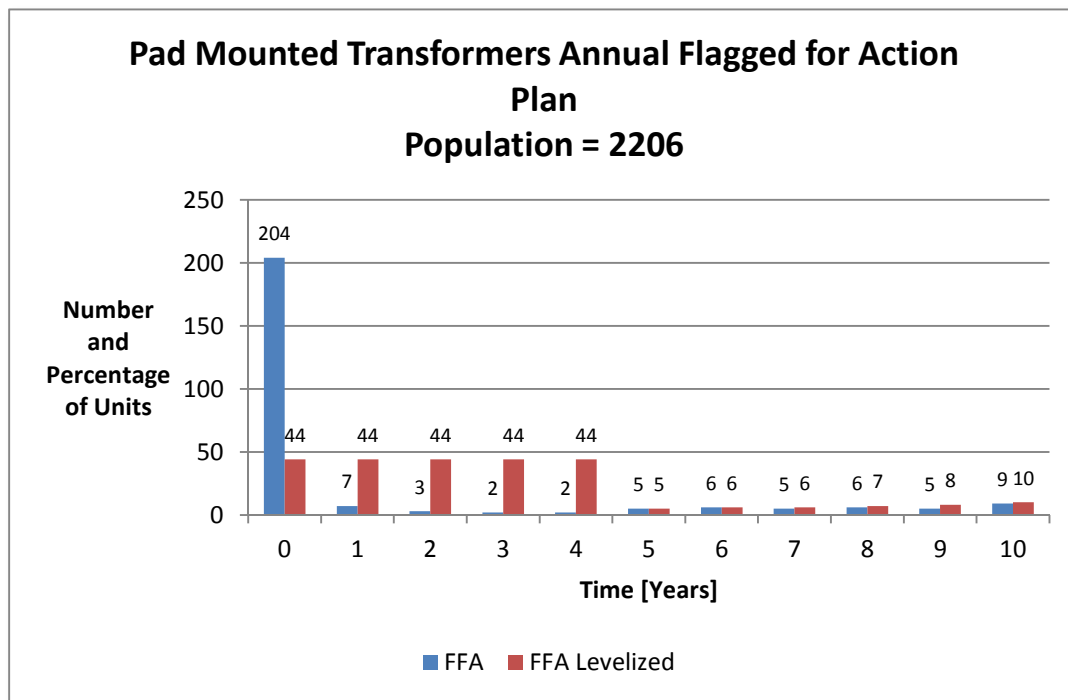


Figure 4-4 Pad Mounted Transformers Flagged for Action Plan

4.5 Data Analysis

Age, PCB content, and inspection records that provide information on transformer base, enclosure, leaks, and overall hazard condition were available for pad mounted transformers. The DAI was 85% meaning that a majority of all units had the above information. Loading and inspection/corrective maintenance information related to the connections (elbows/inserts) would be helpful for future assessments.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Transformer Access	Physical Condition	★	Transformer	Accessibility	Visual inspection/ Corrective Maintenance
Connection	Connection & Insulation	★★★	Elbows and Inserts	Condition of elbows/inserts	Visual inspection/ Corrective Maintenance
Loading	Service Record	★★★	Transformer load	Monthly 15 min peak load throughout years	Operation record

5 Pole Mounted Transformers

5.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

5.1.1 Condition and Sub-Condition Parameters

Table 5-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	Description	Weight (WCP)	De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)	De-Rating Multiplier (DR_SCP)	SCP Criteria
1	Physical Condition	0*	1	1	Tank Corrosion	0*	1	Table 5-2
2	Connection and Insulation	0*	1	1	Oil Leak	0*	1	Table 5-2
				2	Connection	0*	1	Table 5-2
3	Service Record	4	1	1	Overall	0*	1	Table 5-2
				2	Age	1	1	Figure 5-1
				4	Loading	0*	1	Table 5-3
Overall HI De-Rating Multiplier (DR)				PCB				Table 5-4
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

5.1.2 Condition Criteria

Visual Inspection

Table 5-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 5-3 Loading History

Data: S1, S2, S3, ..., SN recorded data (average daily loading)
SB= rated MVA
NA=Number of Si/SB which is lower than 0.6
NB= Number of Si/SB which is between 0.6 and 0.8
NC= Number of Si/SB which is between 0.8 and 1.0
ND= Number of Si/SB which is between 1 and 1.2
NE= Number of Si/SB which is greater than 1.2
Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age

Assume that the failure rate Pole Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
 t = time
 α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
 P_f = cumulative probability of failure

Assuming that at the ages of 50 and 65 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

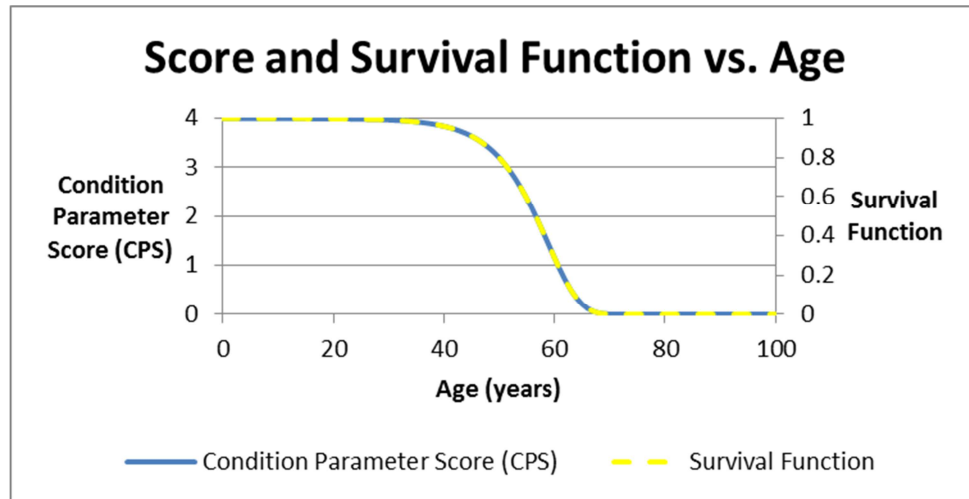


Figure 5-1 Pole Mounted Transformers Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units that have a certain level of PCB and/or are leakers.

Table 5-4 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	PCB > 2 ppm	0.25
Else		1

5.2 Age Distribution

The average age of is 29 years.

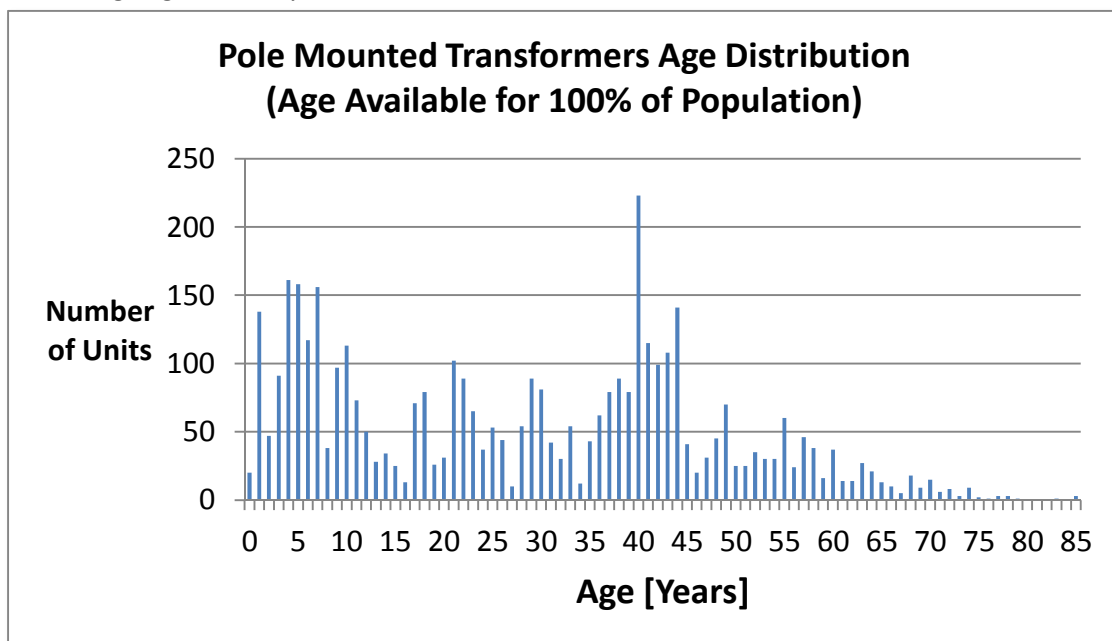


Figure 5-2 Pole Mounted Transformers Age Distribution

5.3 Health Index Results

There are 4143 Pole Mounted Transformers at TBH. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 81. Approximately 20% of the population was found to be in “poor” or “very poor” condition. These include units that have PCBs.

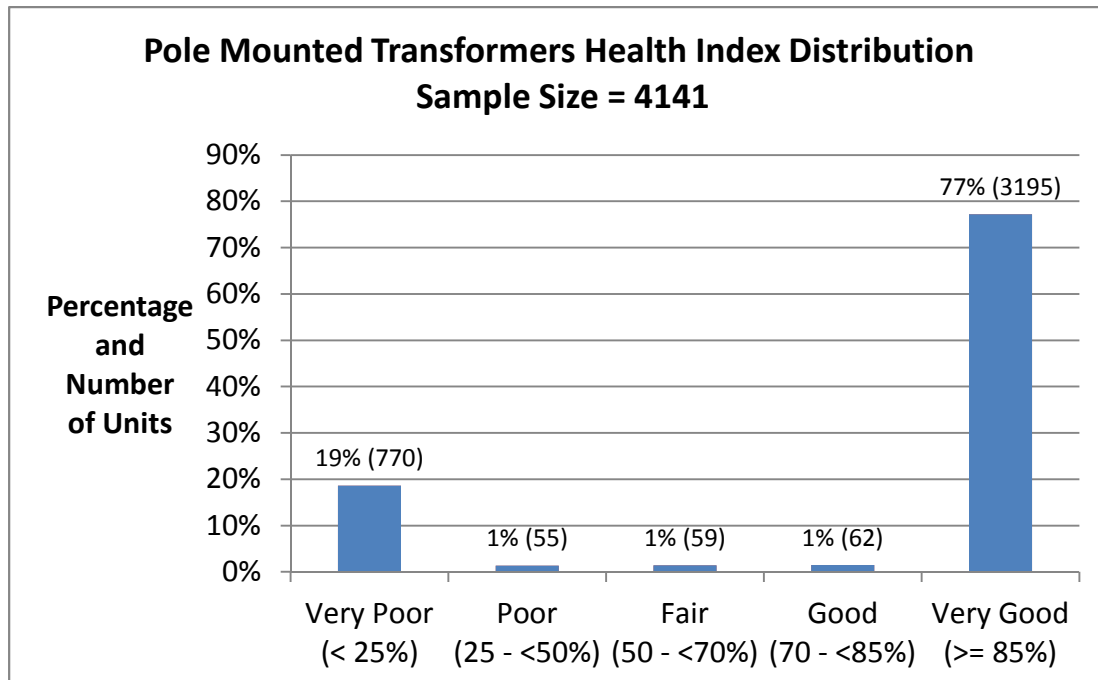


Figure 5-3 ALL Pole Mounted Transformers Health Index Distribution

5.4 Flagged for Action Plan

As it is assumed that Pole Mounted Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate. The flagged for action plan for Pole Mounted Transformers is as follows:

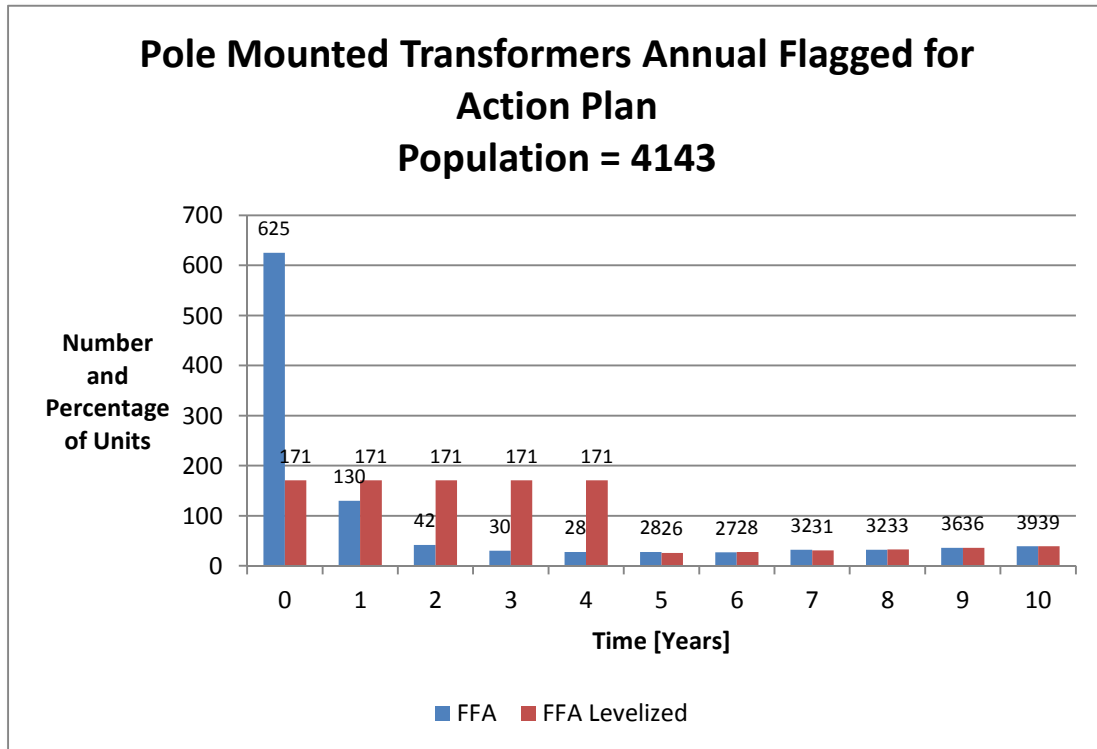


Figure 5-4 Pole Mounted Transformers Flagged for Action Plan

5.5 Data Analysis

The data available for Pole Mounted Transformers were age and PCB content. The average DAI was 100%. The data gaps, which are primarily from inspections, are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Tank Corrosion	Physical Condition	☆☆	Transformer oil tank	Tank surface rust or deterioration due to environmental factors	Visual inspection/ Corrective Maintenance
Oil Leak	Connection & Insulation	☆☆☆	Transformer tank	Leakage	Visual inspection/ Corrective Maintenance
Connection		☆☆	Transformer connection	Poor connection	Visual inspection/ Corrective Maintenance
Overall	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Visual inspection/ Corrective Maintenance
Loading		☆☆	Transformer load	Monthly 15 min peak load throughout years	Operation record

6 Vault Transformers

6.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

6.1.1 Condition and Sub-Condition Parameters

Table 6-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	Description	Weight (WCP)	De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)	De-Rating Multiplier (DR_SCP)	SCP Criteria
1	Physical Condition	0*	1	1	Enclosure	0*	1	Table 6-2
				2	Access	0*	1	Table 6-2
2	Connection and Insulation	0*	1	1	Oil Leak	0*	1	Table 6-2
				2	Connection	0*	1	Table 6-2
3	Service Record	1	1	1	Overall	0*	1	Table 6-2
				2	Age	1	1	Figure 6-1
				4	Loading	0*	1	Table 6-3
Overall HI De-Rating Multiplier (DR)				PCB				Table 6-4
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

6.1.2 Condition Criteria

Visual Inspections

Table 6-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 6-3 Loading History

Data: S1, S2, S3, ..., SN recorded data (average daily loading)
SB= rated MVA
NA=Number of Si/SB which is lower than 0.6
NB= Number of Si/SB which is between 0.6 and 0.8
NC= Number of Si/SB which is between 0.8 and 1.0
ND= Number of Si/SB which is between 1 and 1.2
NE= Number of Si/SB which is greater than 1.2
Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age

Assume that the failure rate Vault Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
 t = time
 α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
 P_f = cumulative probability of failure

Assuming that at the ages of 40 and 55 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

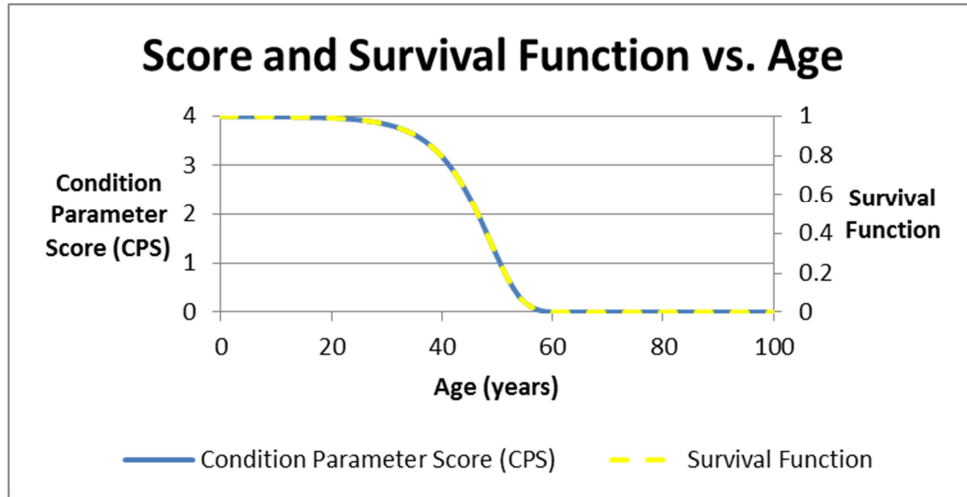


Figure 6-1 Vault Transformers Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units that have a certain level of PCB.

Table 6-4 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	PCB > 2 ppm	0.25
Else		1

6.2 Age Distribution

The average age of all single phase units was 33 years.

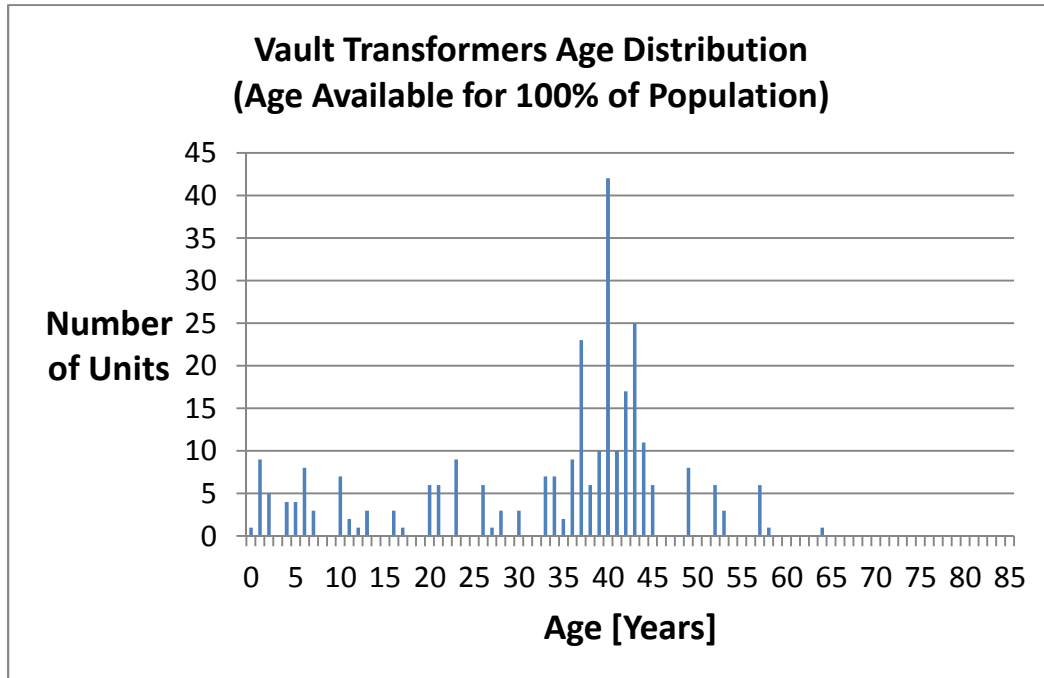


Figure 6-2 Vault Transformers Age Distribution

6.3 Health Index Results

There are 285 Vault Transformers at TBH. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 87%. Approximately 9% of the population was in “poor” or “very poor” condition. These include units that have PCBs.

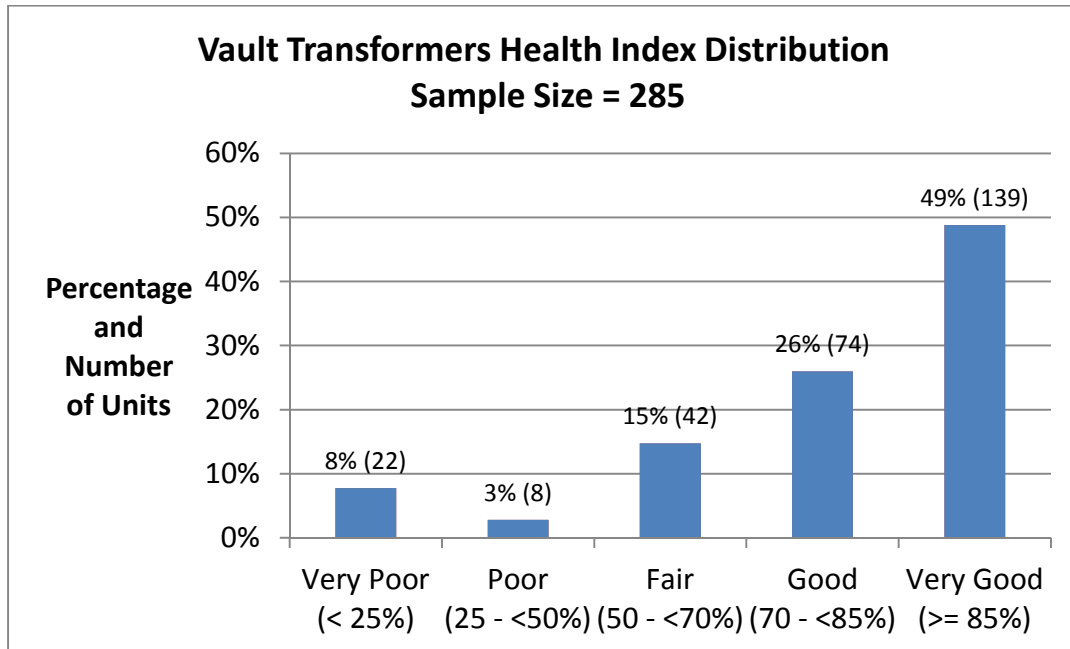


Figure 6-3 Vault Transformers Health Index Distribution

6.4 Flagged for Action Plan

As it is assumed that Vault Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate. The Flagged for Action Plan was as follows:

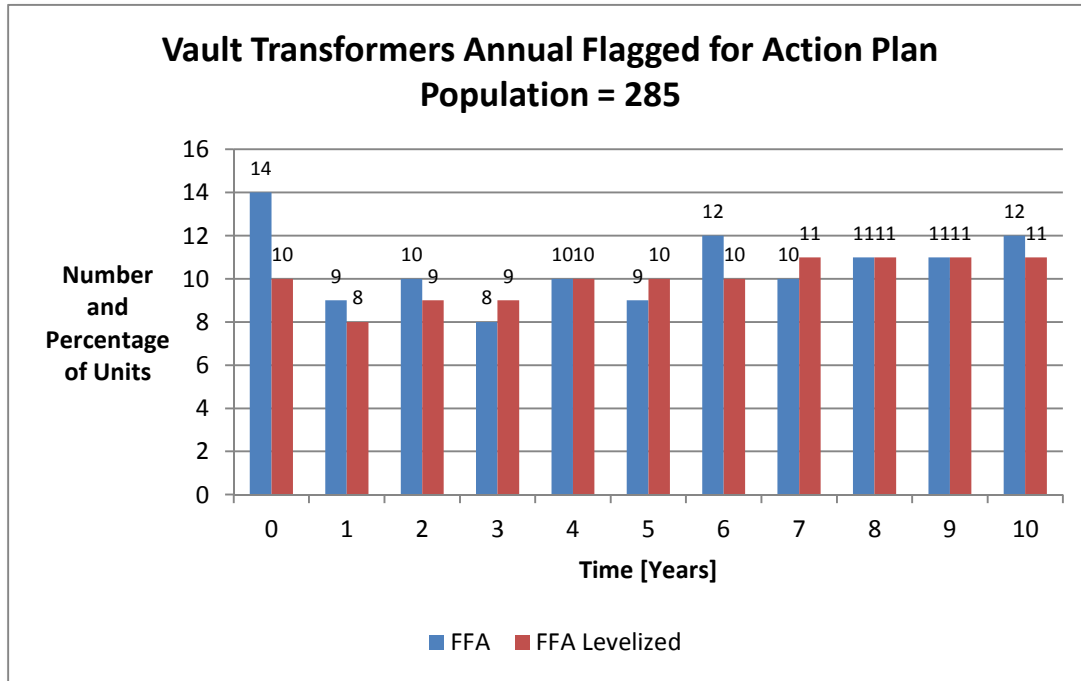


Figure 6-4 Vault Transformers Flagged for Action Plan

6.5 Data Analysis

The data available for Vault Transformers are age and PCB content. The average DAI was 100%. The data gaps, which are primarily from inspections, are as follows:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Enclosure	Physical Condition	☆☆	Transformer oil tank	Tank surface rust or deterioration due to environmental factors	Visual inspection/ Corrective Maintenance
Access		☆	Transformer	Access to transformer	Visual inspection/ Corrective Maintenance
Oil Leak	Connection & Insulation	☆☆☆	Transformer tank	Leakage	Visual inspection/ Corrective Maintenance
Connection		☆☆	Transformer connection	Poor connection	Visual inspection/ Corrective Maintenance
Overall	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Visual inspection/ Corrective Maintenance
Loading		☆☆	Transformer load	Monthly 15 min peak load throughout years	Operation record

7 Overhead Switches

7.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

7.1.1 Condition and Sub-Condition Parameters

Table 7-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	Description	Weight (WCP)	De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)	De-Rating Multiplier (DR_SCP)	SCP Criteria
1	Operating Mechanism	0*	1	1	Motor/ Manual/ Switch Mounting	0*	1	Table 7-3
2	Arc Extinction / Switch	0*	1	1	Arc Suppressor / Switch Blade	0*	1	Table 7-2
3	Insulation	0*	1	1	Insulator	0*	1	Table 7-2
4	Service Record	1	1	1	Age	1	1	Figure 7-1 Error! Reference source not found.
				2	Operations Record	0*	0*	Table 7-2
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

7.1.2 Condition Criteria

Operations Record

Table 7-2 Operations Records Criteria

Score	Condition Description
4	Operated in Last Year
3.5	Operated in Last 3 Years
3	Operated in Last 5 Years
0	Not Operated in Last Year

Visual Inspections

Table 7-3 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age

Assume that the failure rate Overhead Switches exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
 t = time
 α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
 P_f = cumulative probability of failure

Assuming that at the ages of 45 and 60 years the probability of failures (P_f) for 27.6 kV, 44 kV, and Inline Switches are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

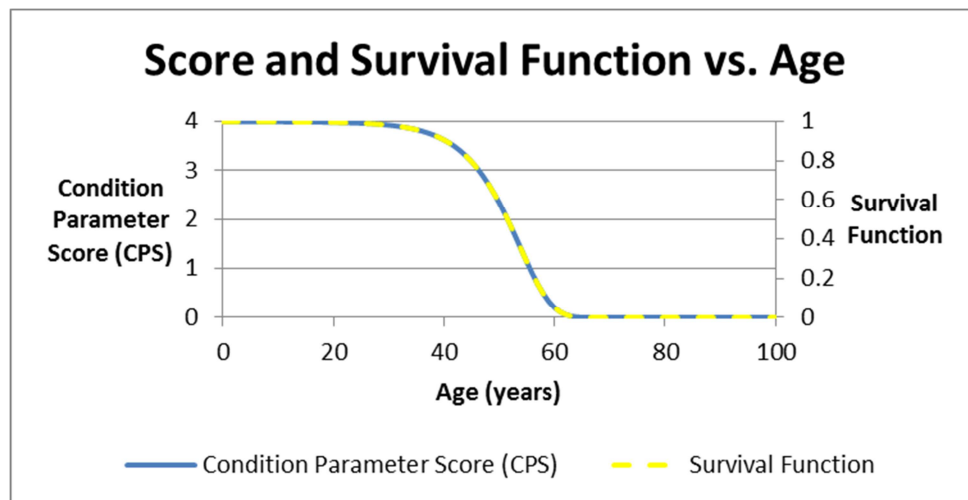


Figure 7-1 Overhead Switches Age Criteria

7.2 Age Distribution

The average age of all units was 32 years. Age distributions for all sub-categories are shown.

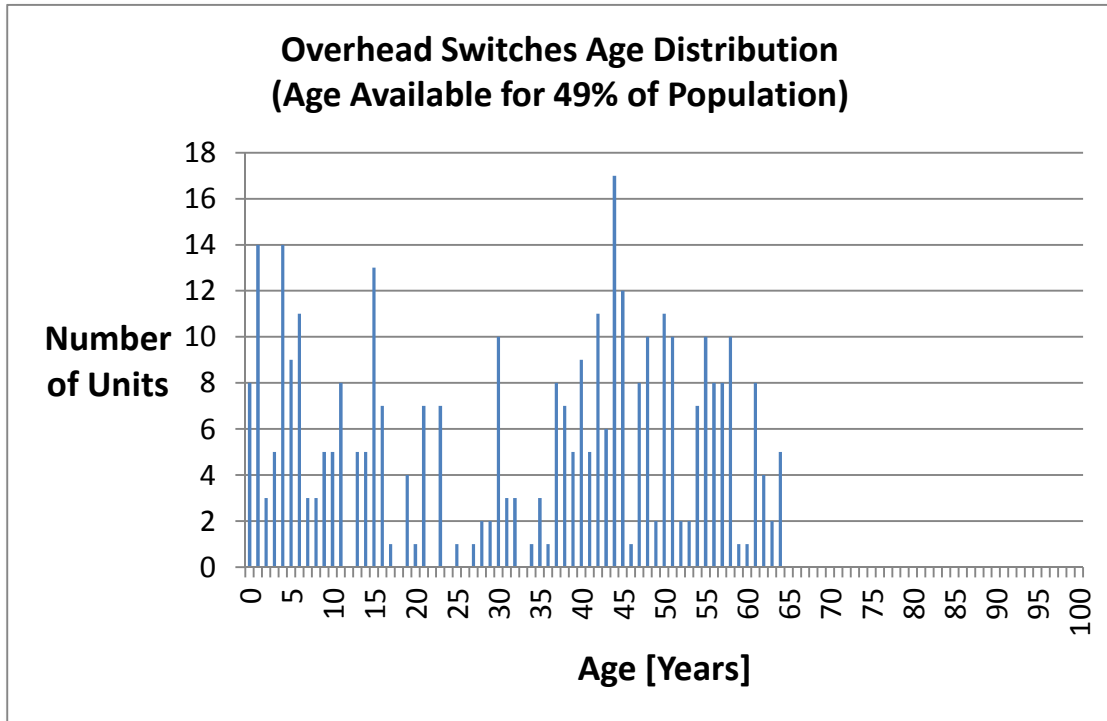


Figure 7-2 ALL Overhead Switches Age Distribution

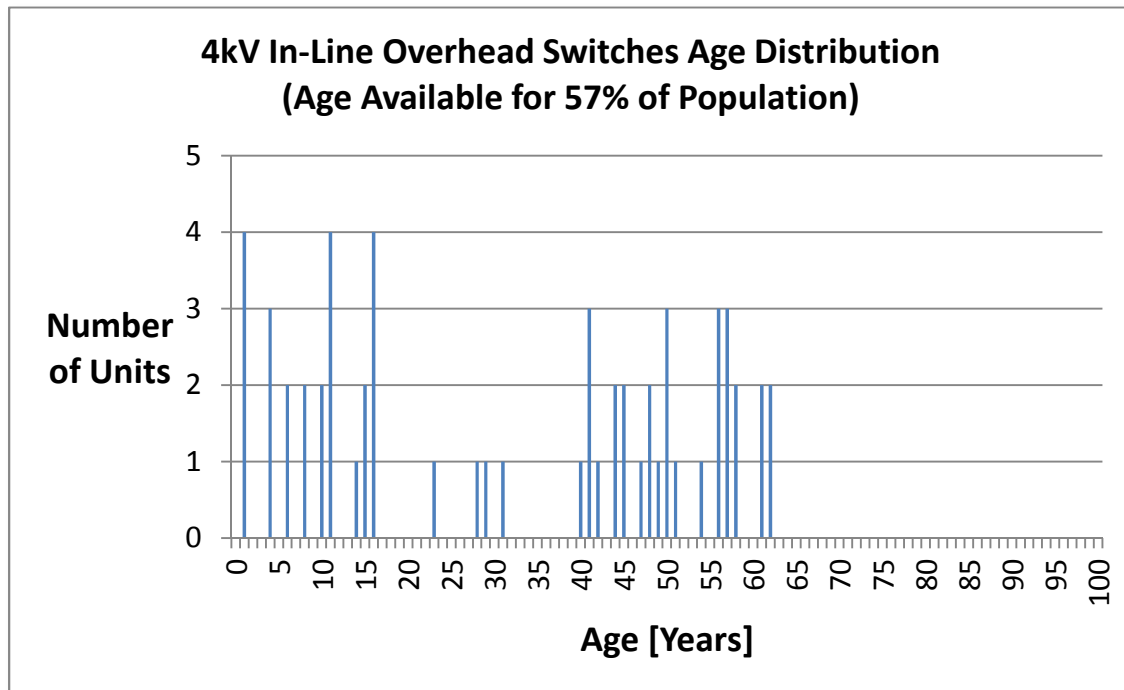


Figure 7-3 4kV In-Line Overhead Switches Age Distribution

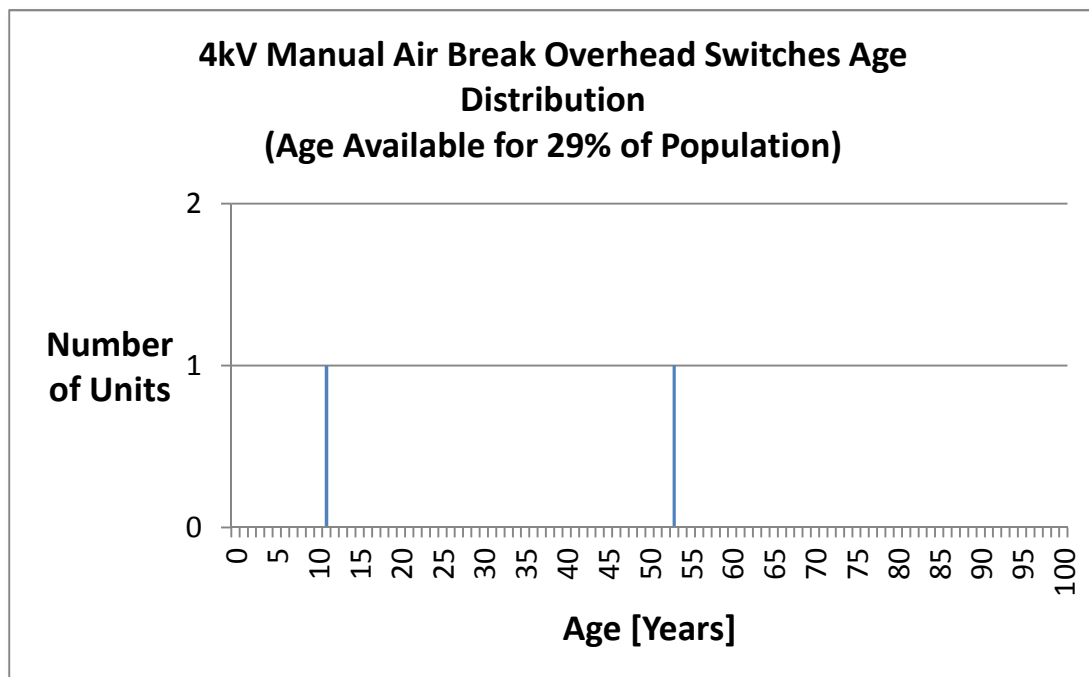


Figure 7-4 4kV Manual Air Break Overhead Switches Age Distribution

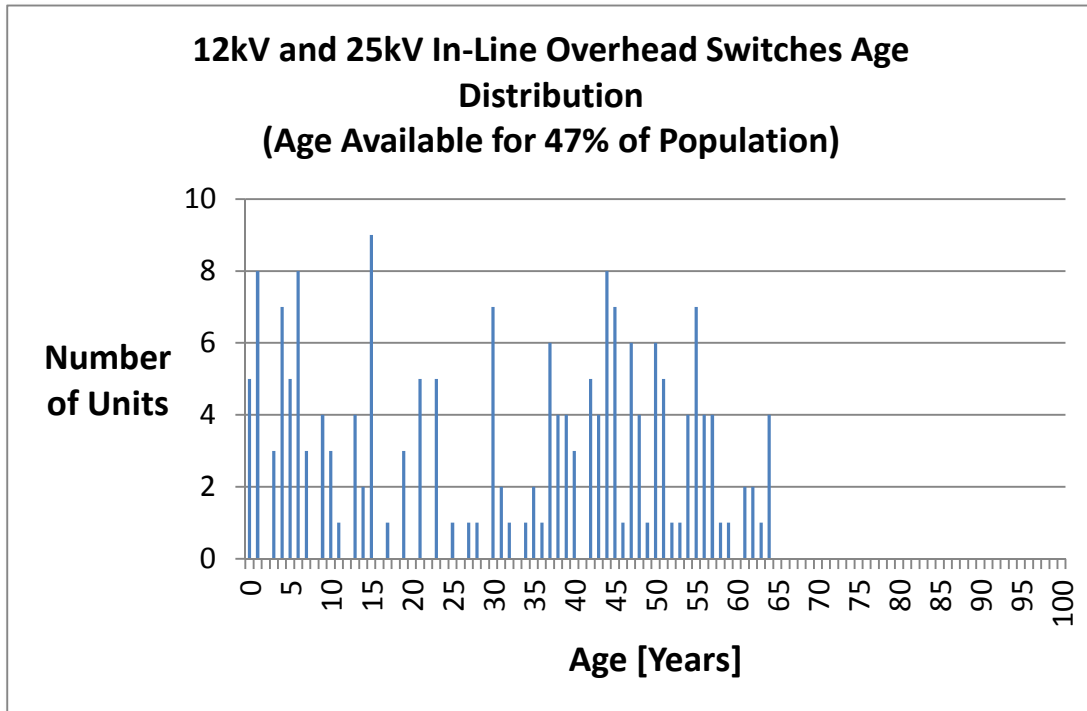


Figure 7-5 12 and 25kV In-Line Overhead Switches Age Distribution

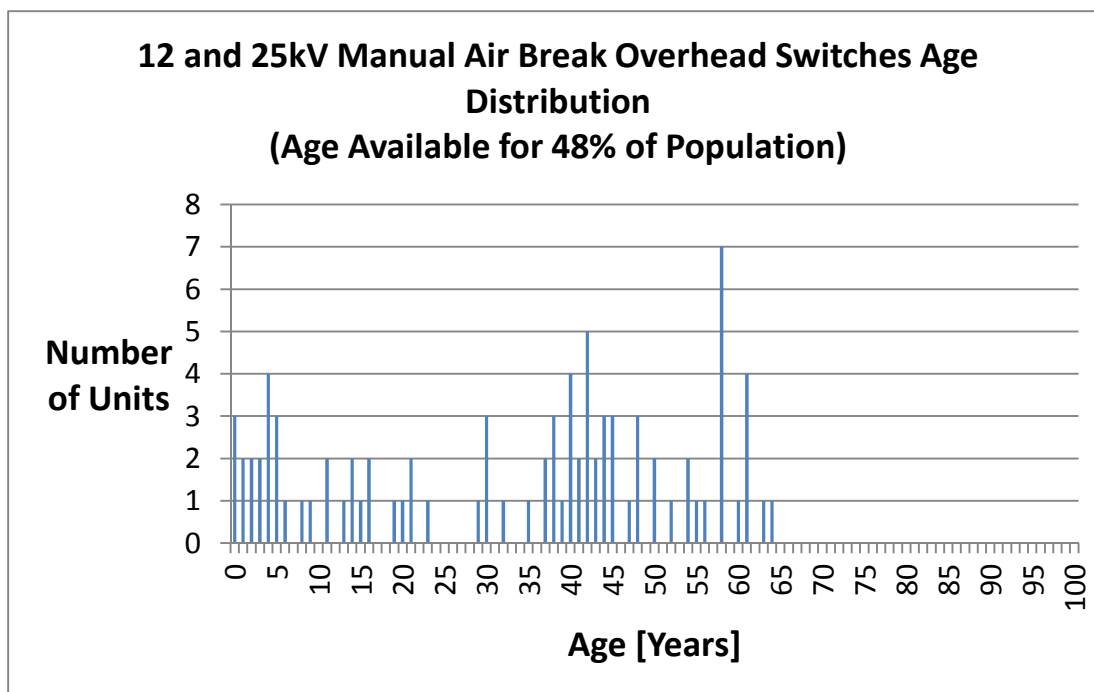


Figure 7-6 12 and 25kV Manual Air Break Overhead Switches Age Distribution

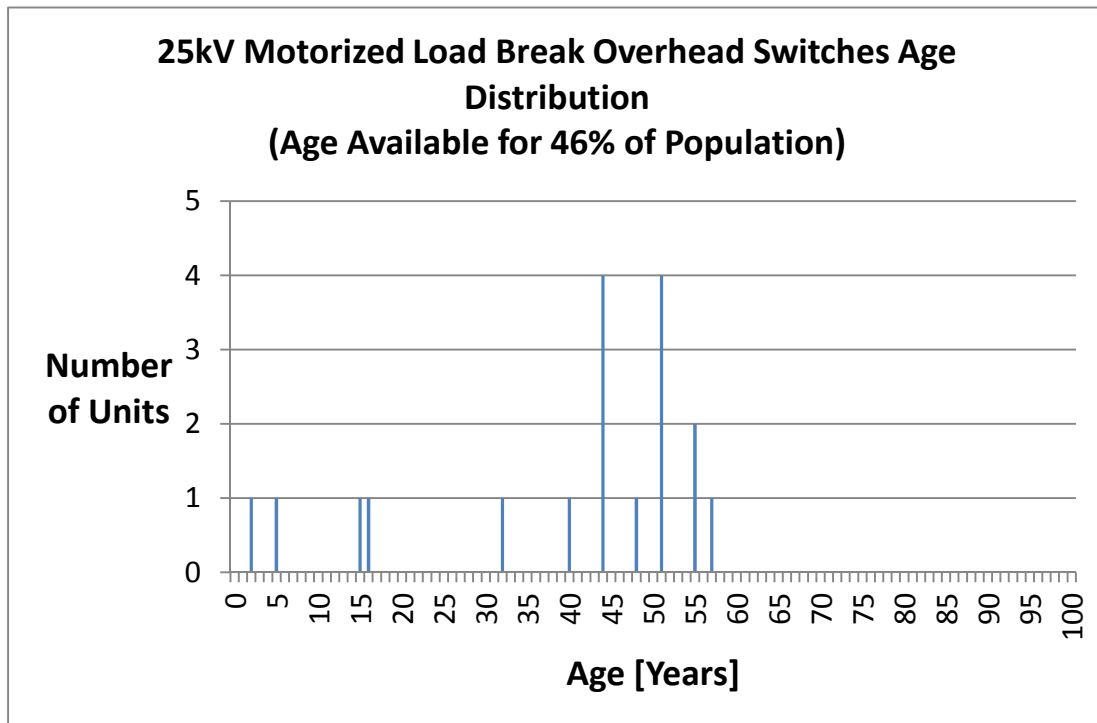


Figure 7-7 12 and 25kV Motorized Load Break Overhead Switches Age Distribution

7.3 Health Index Results

There are 729 Overhead Switches at TBH. Of these, only 305 units had sufficient data for Health Indexing. The average Health Index for this asset group was 76%. Approximately 19% were in “poor” or “very poor” condition. Broken down into sub-categories, the results are summarized as follows:

Sub-Category	Population	Sample Size	Average HI	% in Poor/Very Poor
ALL	729	305	76%	19%
4kV In-Line	101	46	71%	26%
4kV Manual Air Break	7	2	70%	50%
12 and 25kV In-Line	399	148	80%	18%
12 and 25kV Manual Air Break	183	74	78%	18%
25kV Motorized Load Break	39	10	67%	30%

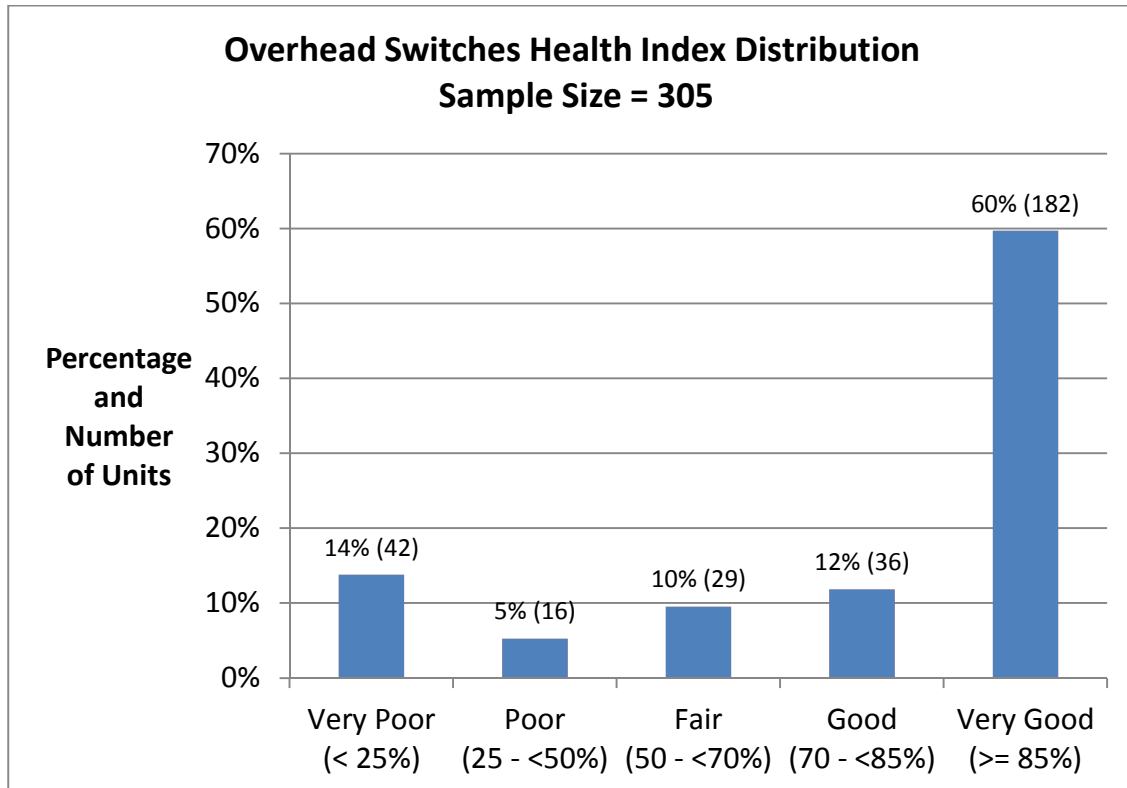


Figure 7-8 ALL Overhead Switches Health Index Distribution

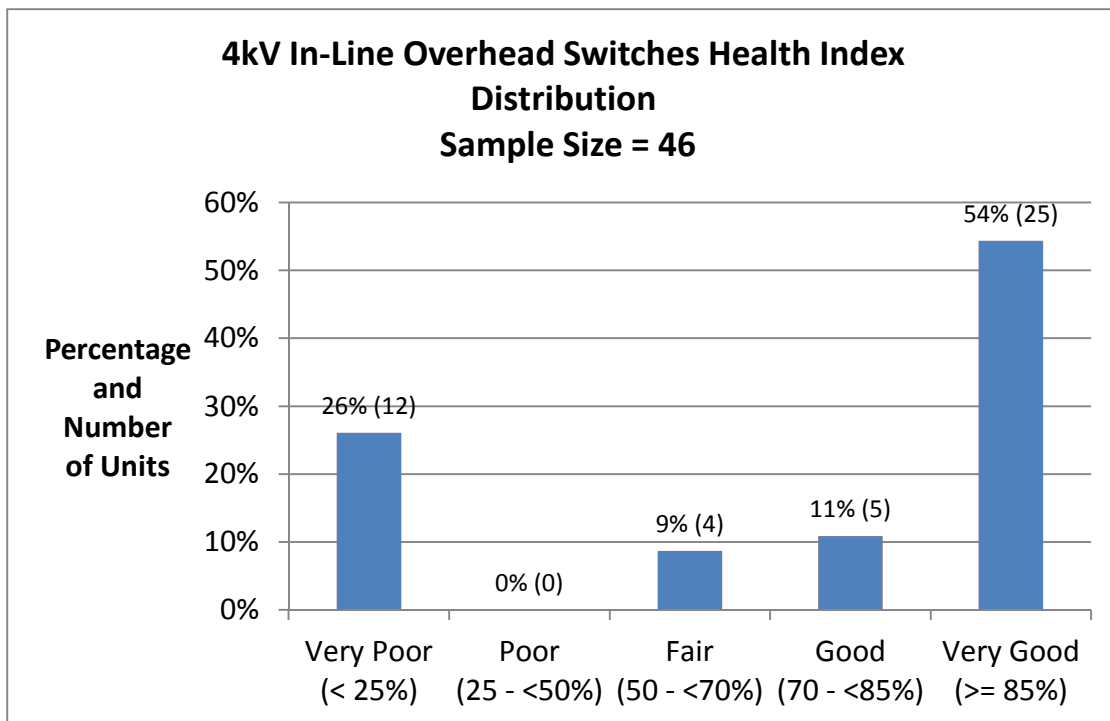


Figure 7-9 4kV In-Line Overhead Switches Health Index Distribution

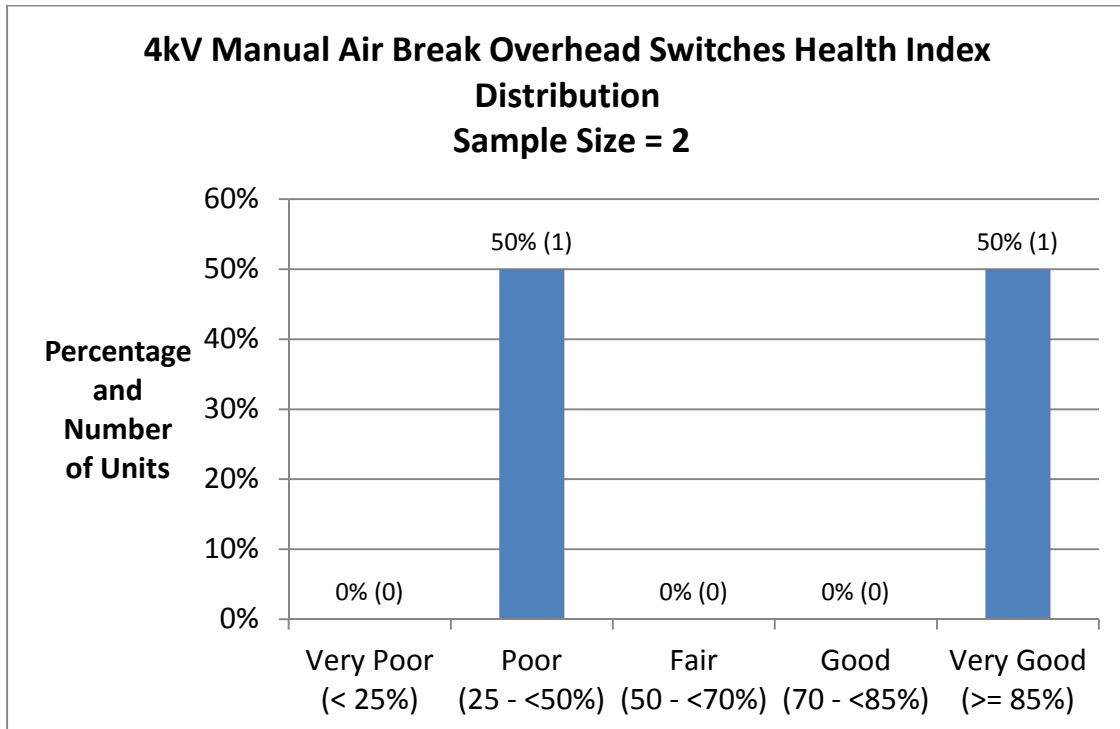


Figure 7-10 4kV Manual Air Break Overhead Switches Health Index Distribution

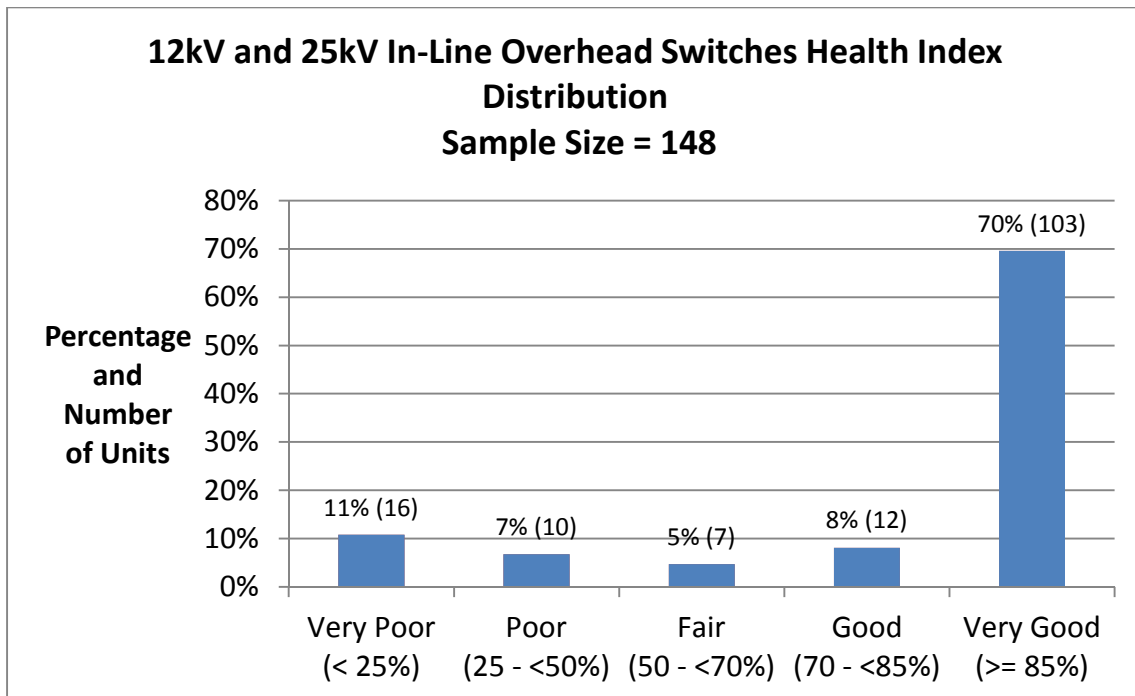


Figure 7-11 12 and 25kV In-Line Overhead Switches Health Index Distribution

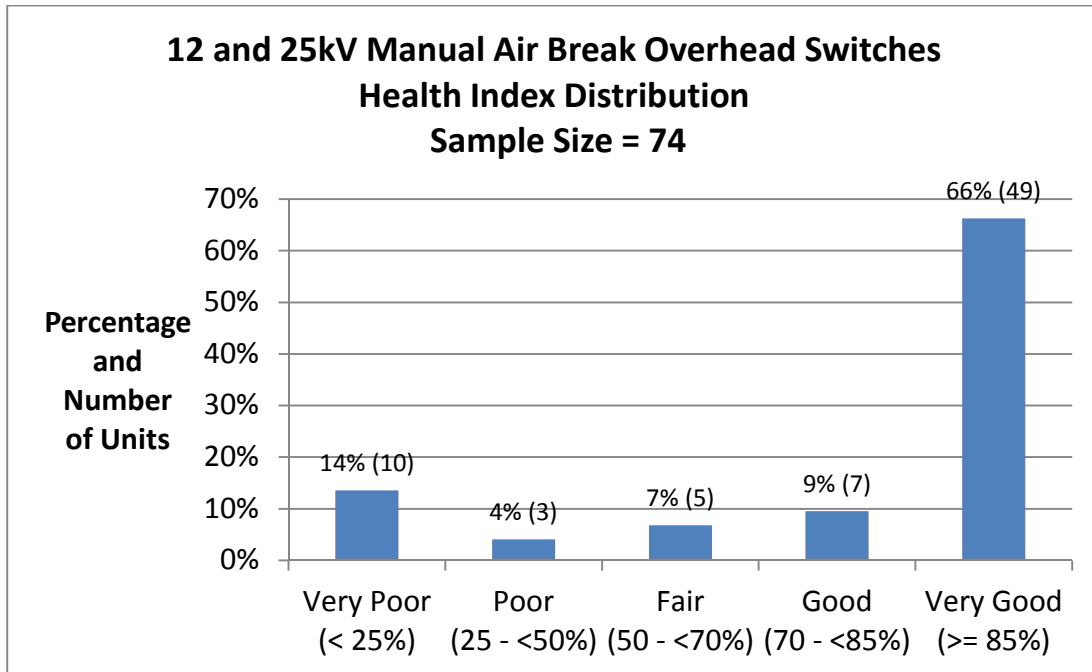


Figure 7-12 12 and 25kV Manual Air Break Overhead Switches Health Index Distribution

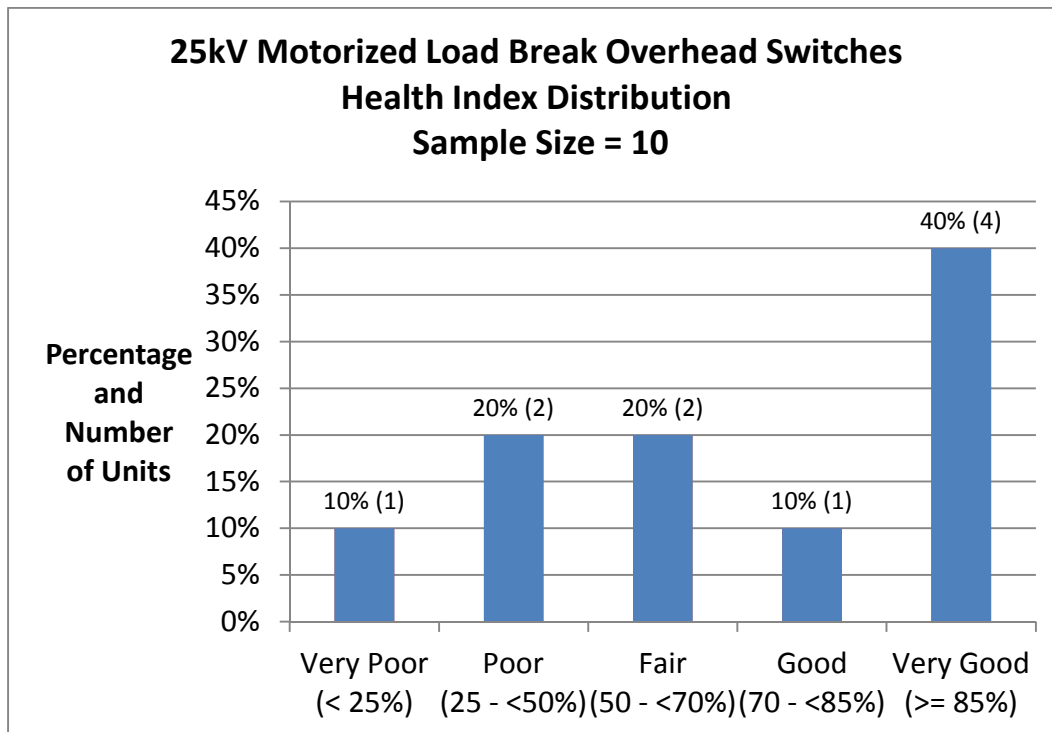


Figure 7-13 12 and 25kV Motorized Load Break Overhead Switches Health Index Distribution

7.4 Flagged for Action Plan

As it is assumed that Overhead Switches were reactively replaced, the flagged for action plan was based on the asset failure rate.

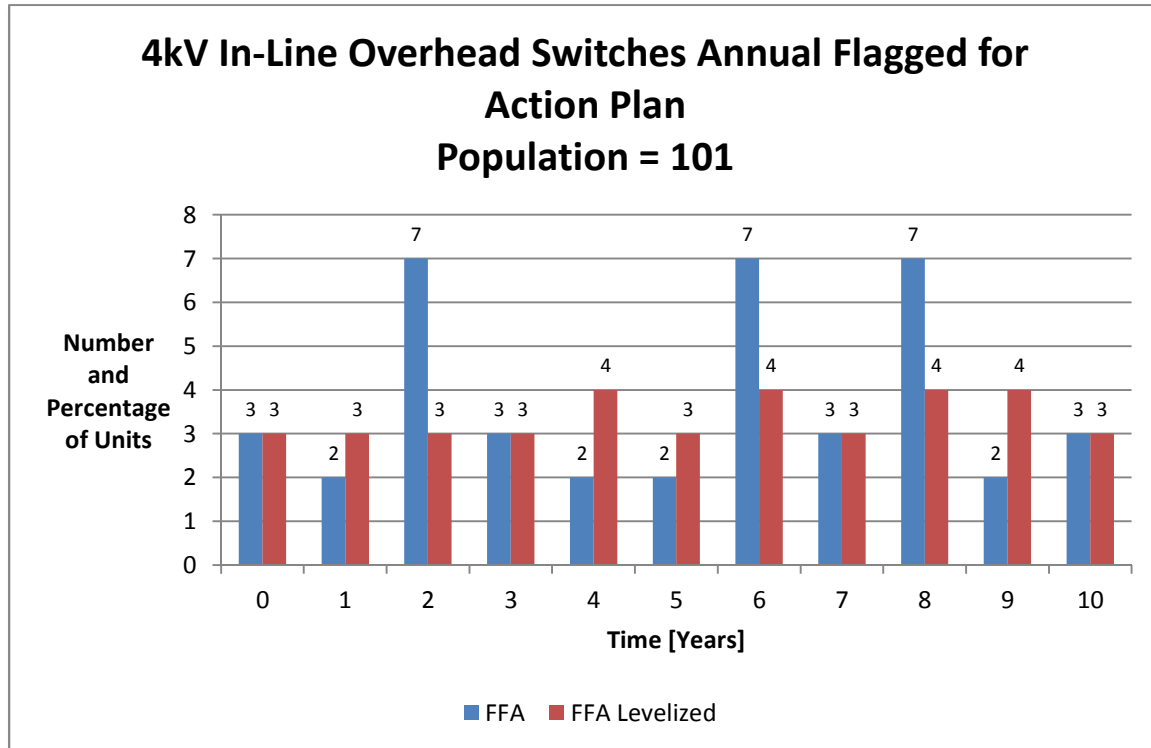


Figure 7-14 4kV In-Line Overhead Switches Flagged for Action Plan

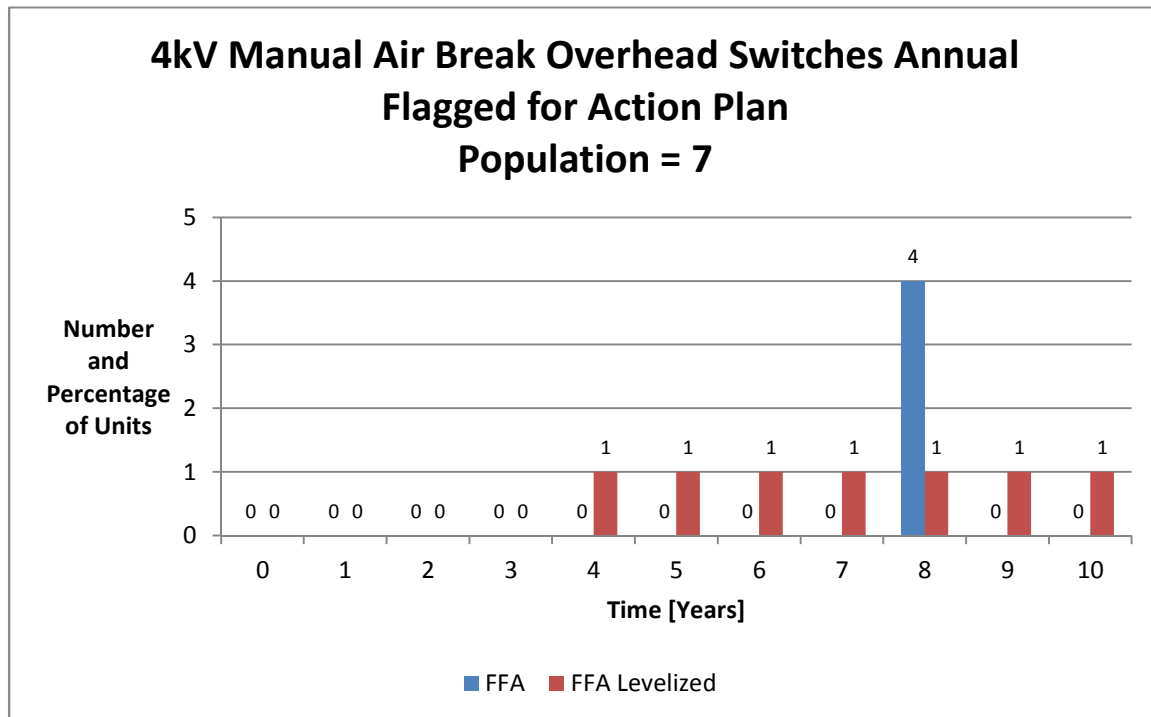


Figure 7-15 4kV Manual Air Break Overhead Switches Flagged for Action Plan

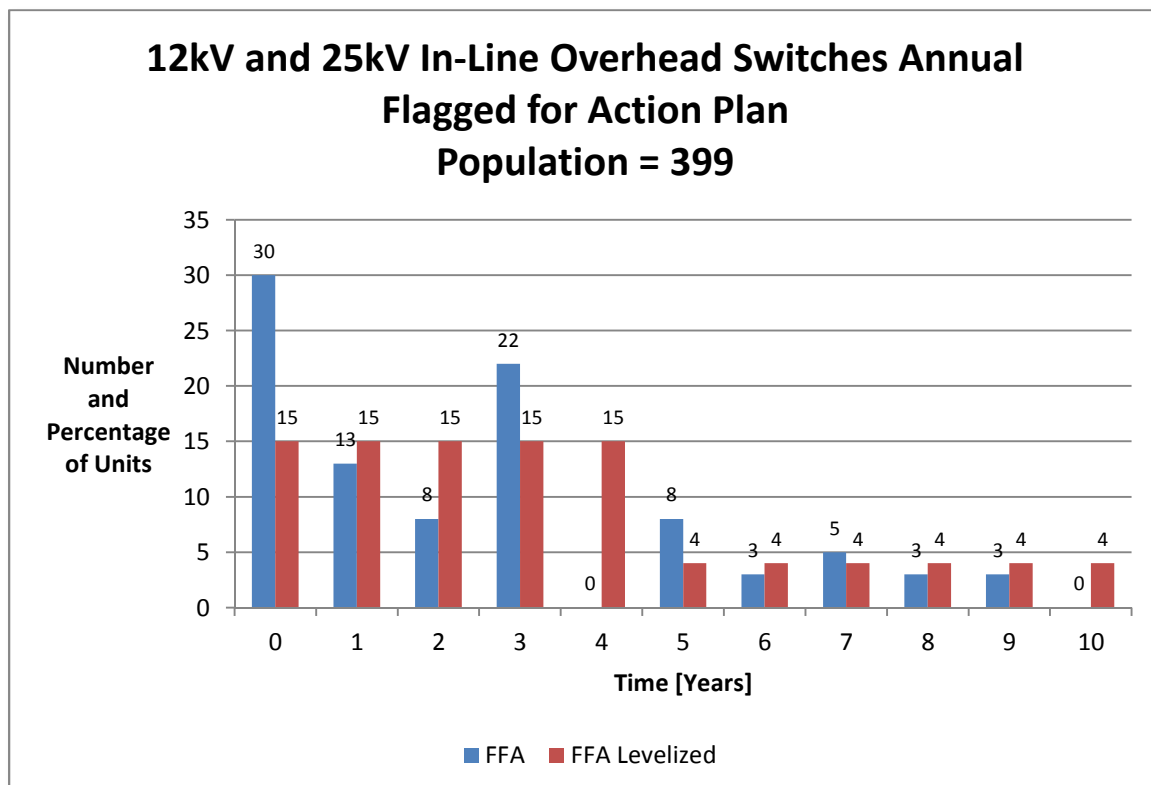


Figure 7-16 12 and 25kV In-Line Overhead Switches Flagged for Action Plan

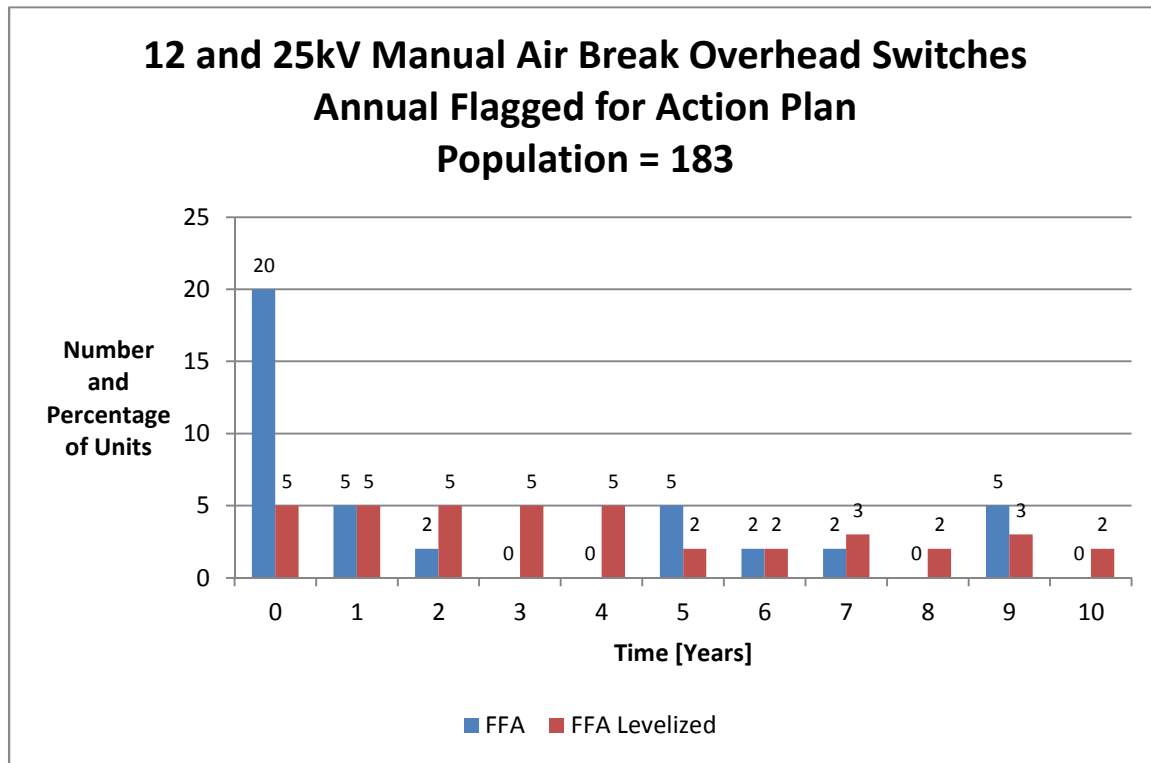


Figure 7-17 12 and 25kV Manual Air Break Overhead Switches Flagged for Action Plan

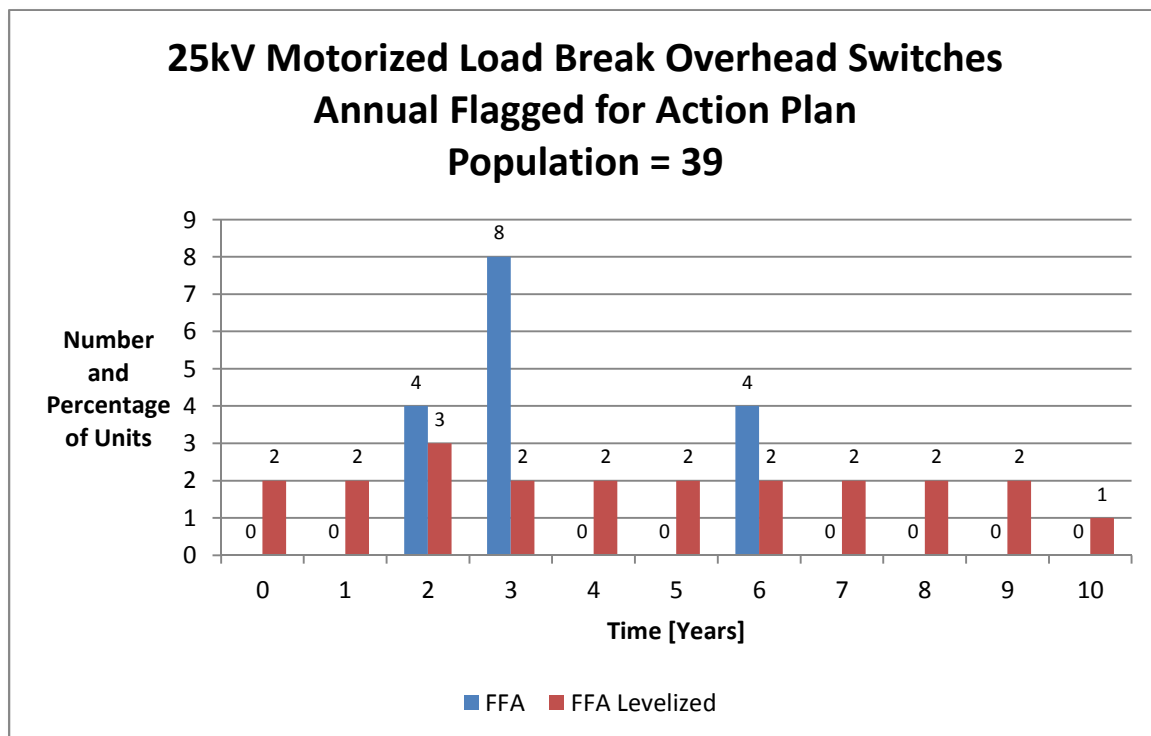


Figure 7-18 12 and 25kV Motorized Load Break Overhead Switches Flagged for Action Plan

7.5 Data Analysis

Age was the only information available for overhead and underground switches. Further, as can be seen from the low DAIs of these asset categories, fewer than half of the switches had age information. Age should be collected for the remainder of the population.

Sub-Category	DAI
ALL	42%
4kV In-Line	46%
4kV Manual Air Break	29%
12 and 25kV In-Line	37%
12 and 25kV Manual Air Break	40%
25kV Motorized Load Break	26%

Operations records and inspection/corrective maintenance records should be collected (e.g. condition related to switch, operating mechanism, insulation, arc extinguishing mechanism). Such information would provide insight to actual condition.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Motor/Manual Operation	Operation Mechanism	☆☆☆	Switch Operating system	Mechanical part and linkage issue	On-site manual inspection/ Corrective Maintenance Records
Mechanical Support		☆	Switch support	Loose installation	
Arc Horn	Arc Extinction	☆	Switch operation	Arc horn surface worn- out	
Arc Interrupter		☆☆	Switch arc extinction	Arc extinction part surface worn-out	
Insulator	Insulation	☆	Support insulator	Crack	
Switch Condition	Service Record	☆☆☆	Blade	Blade condition	

8 25kV Underground Load Break Switches

8.1 Health Index Formula

See Section 7.1.

8.2 Age Distribution

The average age of this asset group is 31 years.

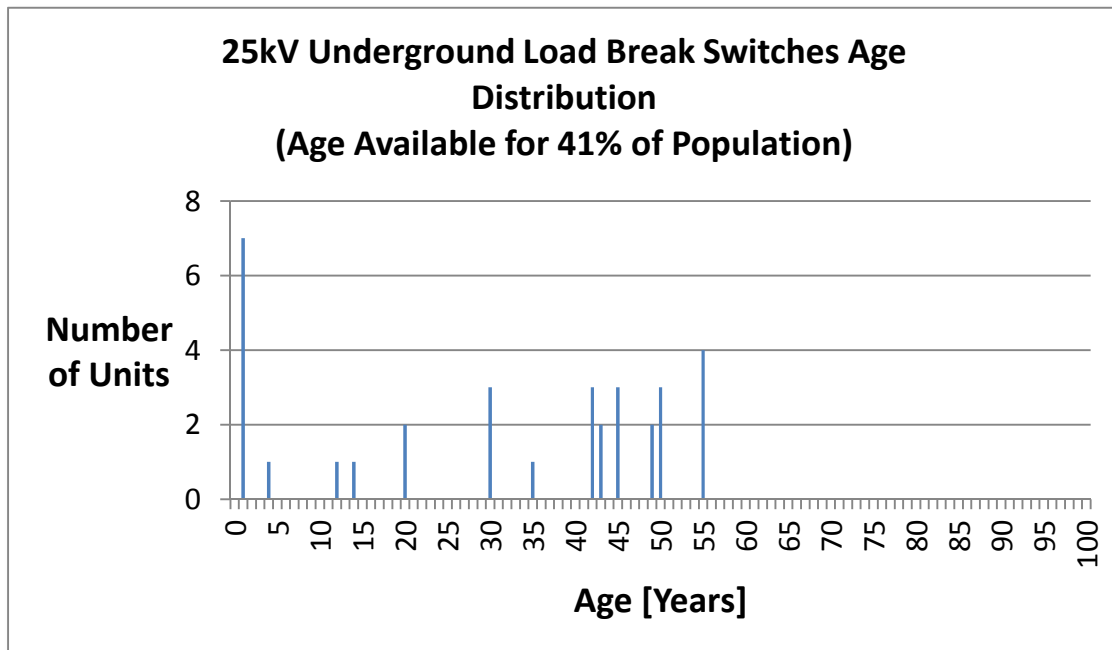


Figure 8-1 ALL 25kV Underground Load Break Switches Age Distribution

8.3 Health Index Results

There are 80 Overhead Switches at TBH. Of these, only 30 units had sufficient data for Health Indexing. The average Health Index for this asset group was 81%. Approximately 13% were in “poor” condition.

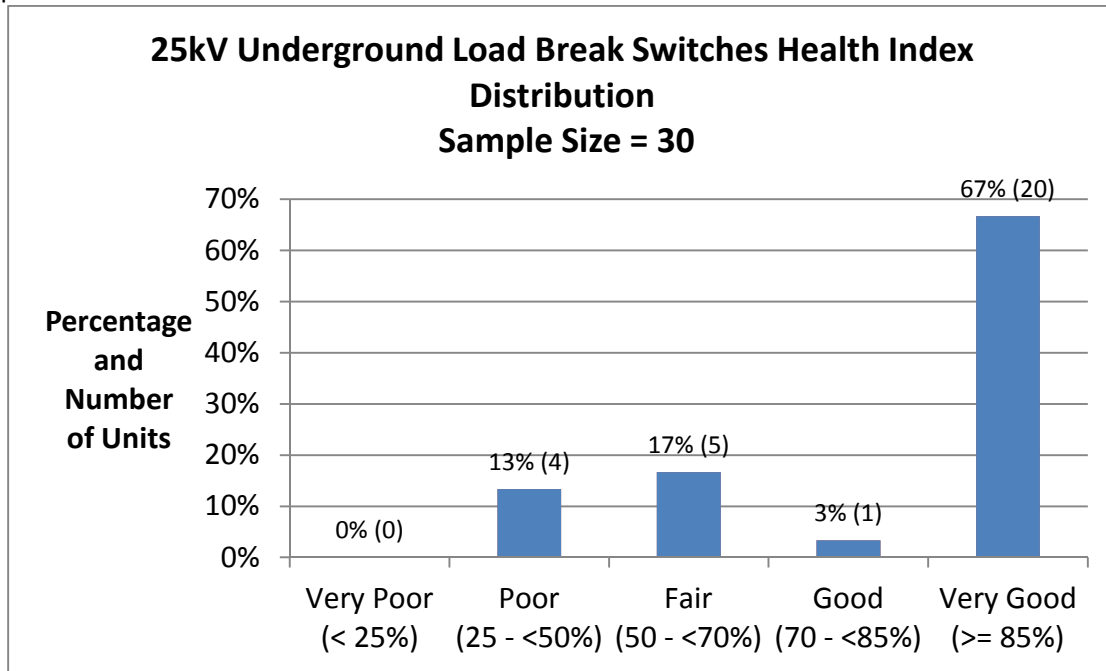


Figure 8-2 ALL 25kV Underground Load Break Switches Health Index Distribution

8.4 Flagged for Action Plan

As it is assumed that 25kV Underground Load Break Switches were reactively replaced, the flagged for action plan was based on the asset failure rate.

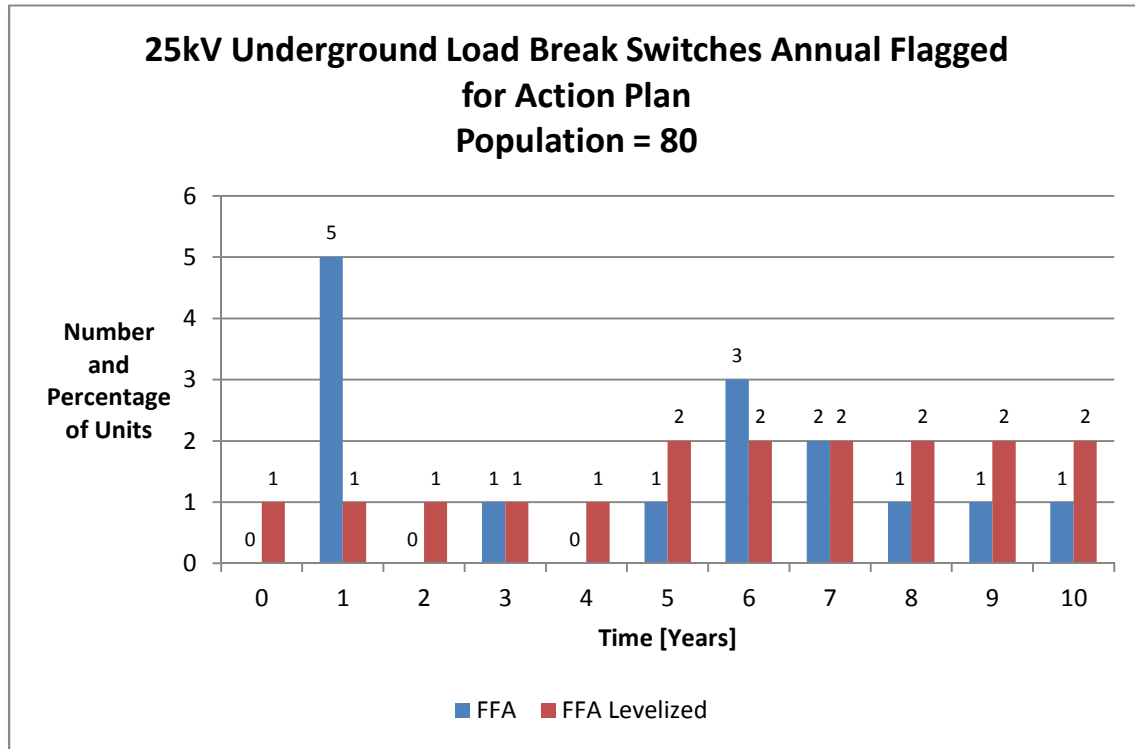


Figure 8-3 25kV 25kV Underground Load Break Switches Flagged for Action Plan

8.5 Data Analysis

Only age was available for this asset. At 38%, the DAI was low. Age information should therefore be collected for the remainder of the population. See Section 8.5 for data gaps.

9 Underground Cables

9.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

9.1.1 Condition and Sub-Condition Parameters

Table 9-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	Description	Weight	De-Rating Multiplier	m	Descriptio n	Weight	De-Rating Multiplier	SCP Criteria
		(WCP)	(DR_CP)			(WSCP)	(DR_SCP)	
1	Cable Tests	0*	1	1	Cable Test Results	0*	1	Test Dependent
2	Service Record	1	1	1	Age	1	1	Figure 9-1 Figure 9-2
Overall HI De-Rating Multiplier (DR)				Number of Failures in last 5 Years*				-
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

9.1.2 Condition Criteria

Age

Assume that the failure rate Underground Cables exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
 t = time
 α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
 P_f = cumulative probability of failure

All the underground cables in this study are of XLPE type. There are three sub categories of such cables based on different installation timelines:

1. non-tree retardant (Non-TR)
2. tree retardant (TR)
3. tree retardant (TR), in-duct

For non-TR cables, assuming that at the ages of 35 and 55 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve. For TR in-duct cables and direct buried, the ages of 40 and 60 were used.

The following curves show the survival curves for each cable type. Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. $4 \times \text{Survival Curve}$). The Score vs. Age is also shown in the figures.

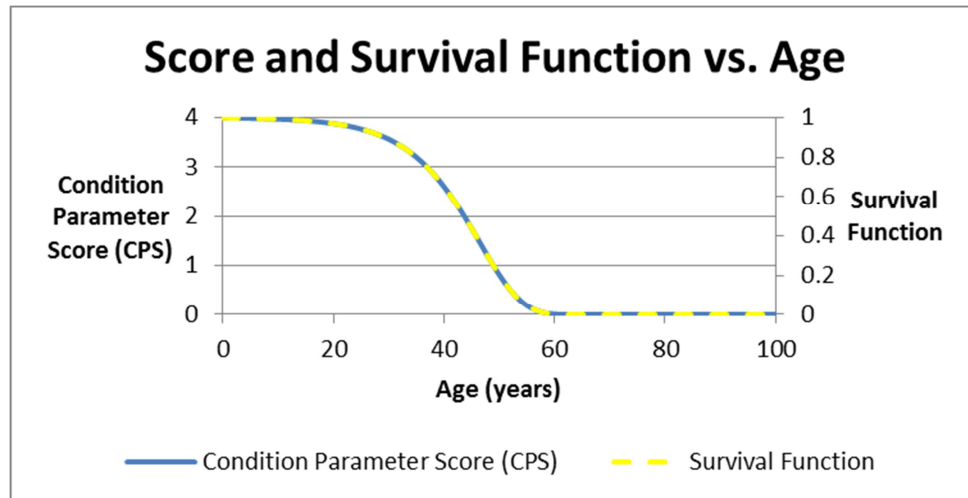


Figure 9-1 Underground Cables Age Criteria – Non-TR

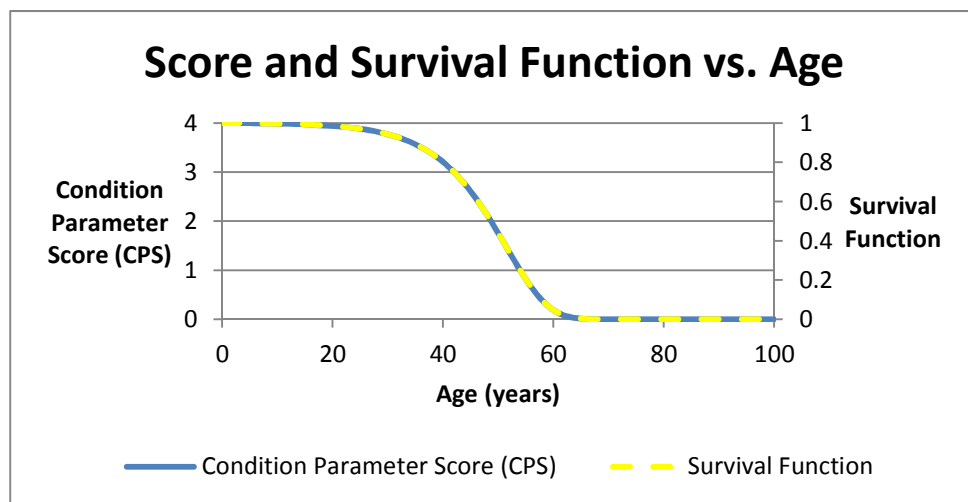


Figure 9-2 Underground Cables Age Criteria – TR (Direct Buried and In Duct)

9.2 Age Distribution

The average age of all cables is 29 years.

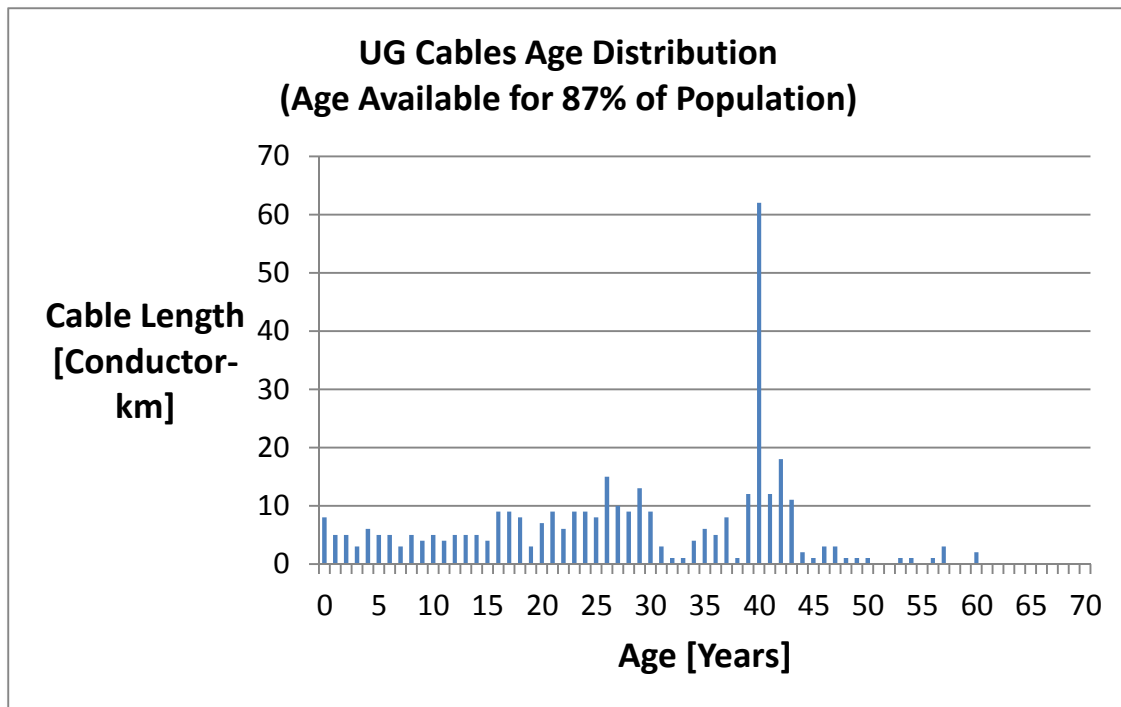


Figure 9-3 ALL Underground Cables Age Distribution

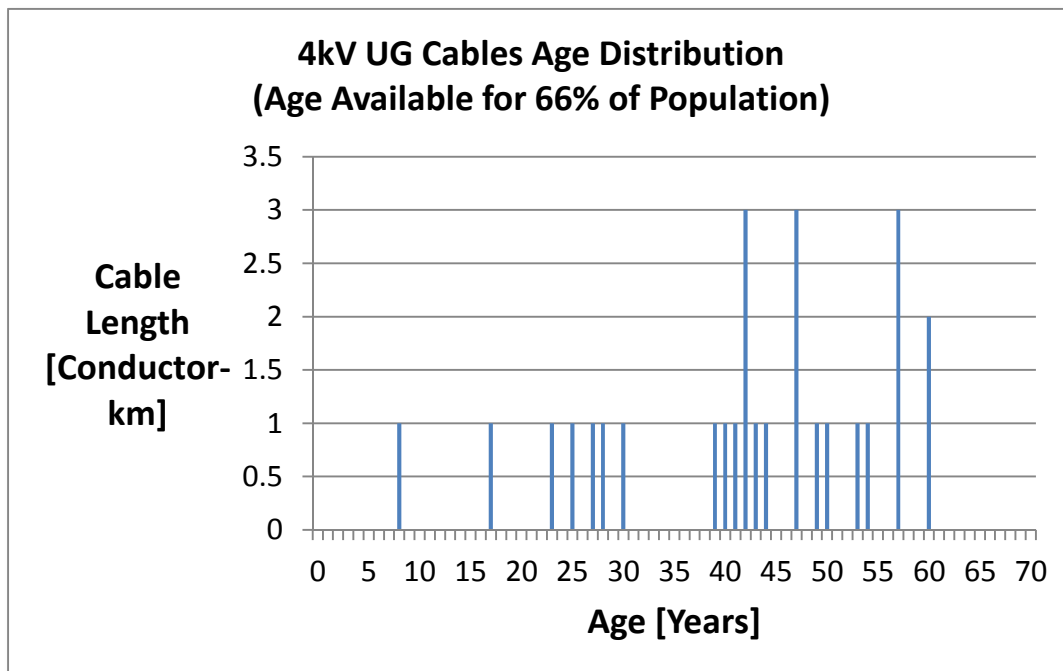


Figure 9-4 4kV Underground Cables Age Distribution

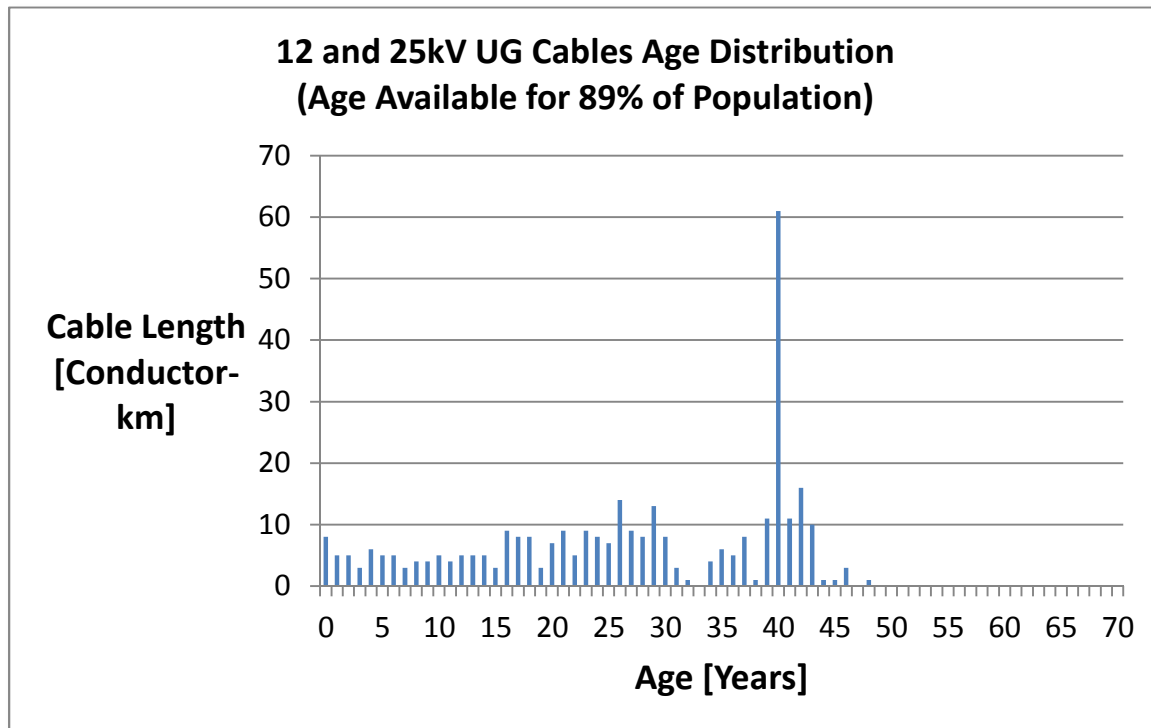


Figure 9-5 12 and 25kV Underground Cables Age Distribution

9.3 Health Index Results

Out of a total of 432 conductor-km of cables, 374 conductor-km of had sufficient data for Health Indexing. The average Health Index for this asset group was 80%. Approximately 6% of population was in “poor” or “very poor” condition.

Sub-Category	Population	Sample Size	Average HI	% in Poor/Very Poor
ALL	432	374	80%	6%
4kV	44	29	71%	48%
12 and 25kV	387	344	70%	2%

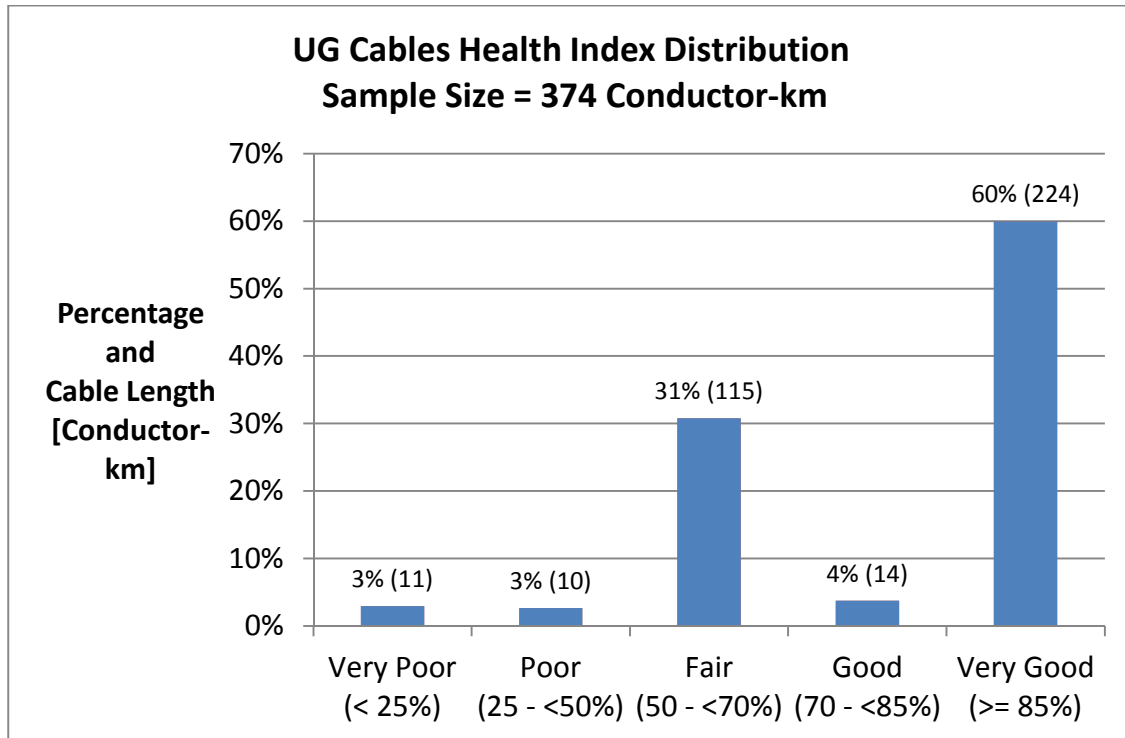


Figure 9-6 ALL Underground Cables Health Index Distribution

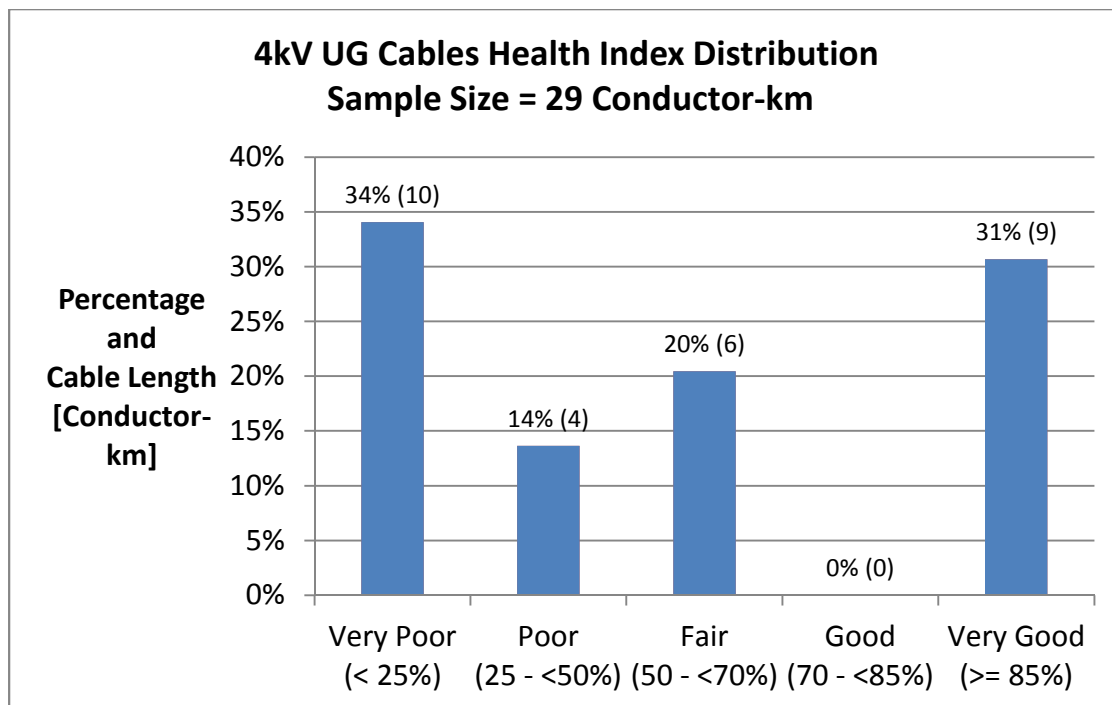


Figure 9-7 4kV Underground Cables Health Index Distribution

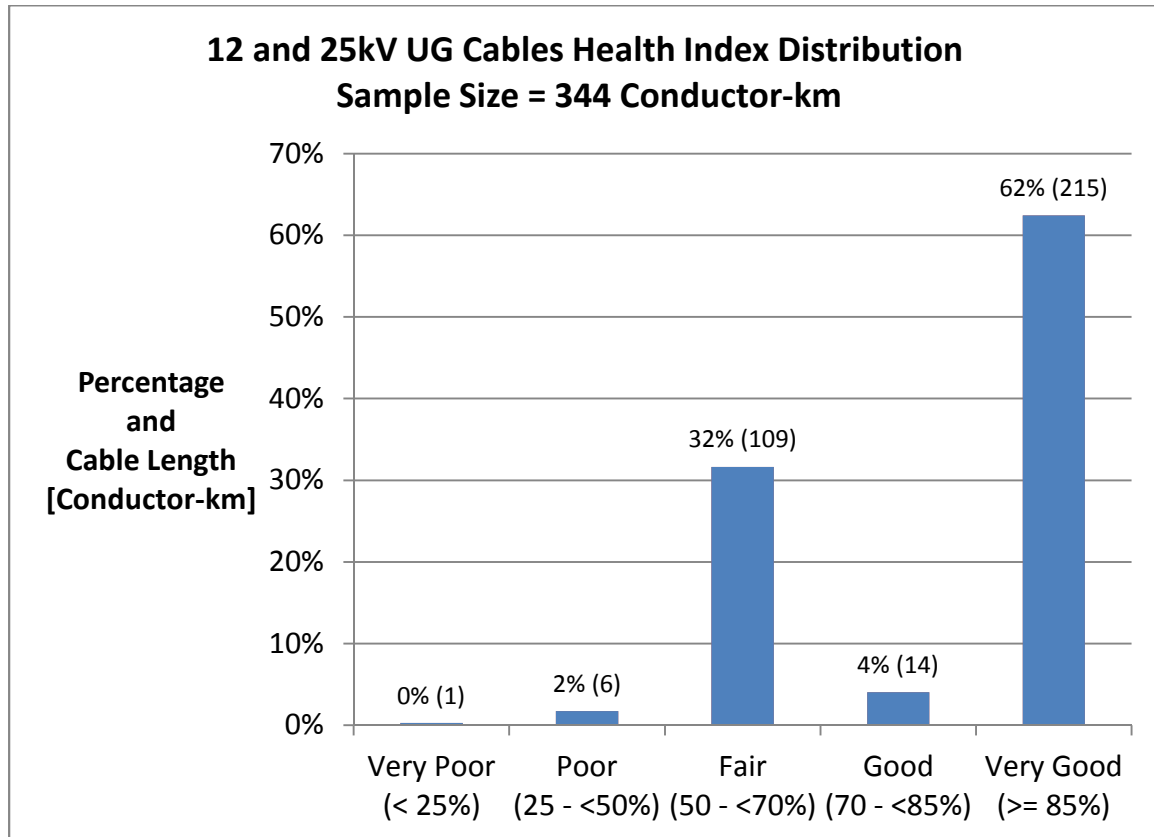


Figure 9-8 12 and 25kV Underground Cables Health Index Distribution

9.4 Flagged for Action Plan

As it is assumed that Underground Cables were reactively replaced, the flagged for action plan was based on the asset failure rate.

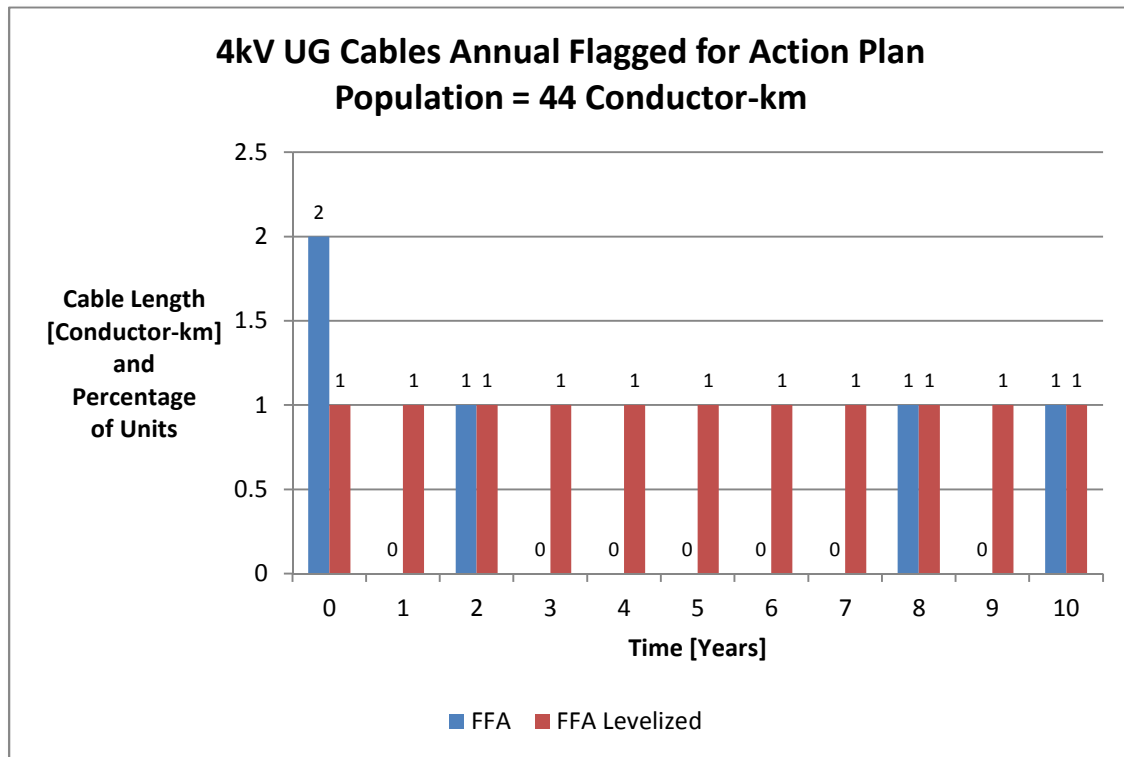


Figure 9-9 4kV Underground Cables Flagged for Action Plan

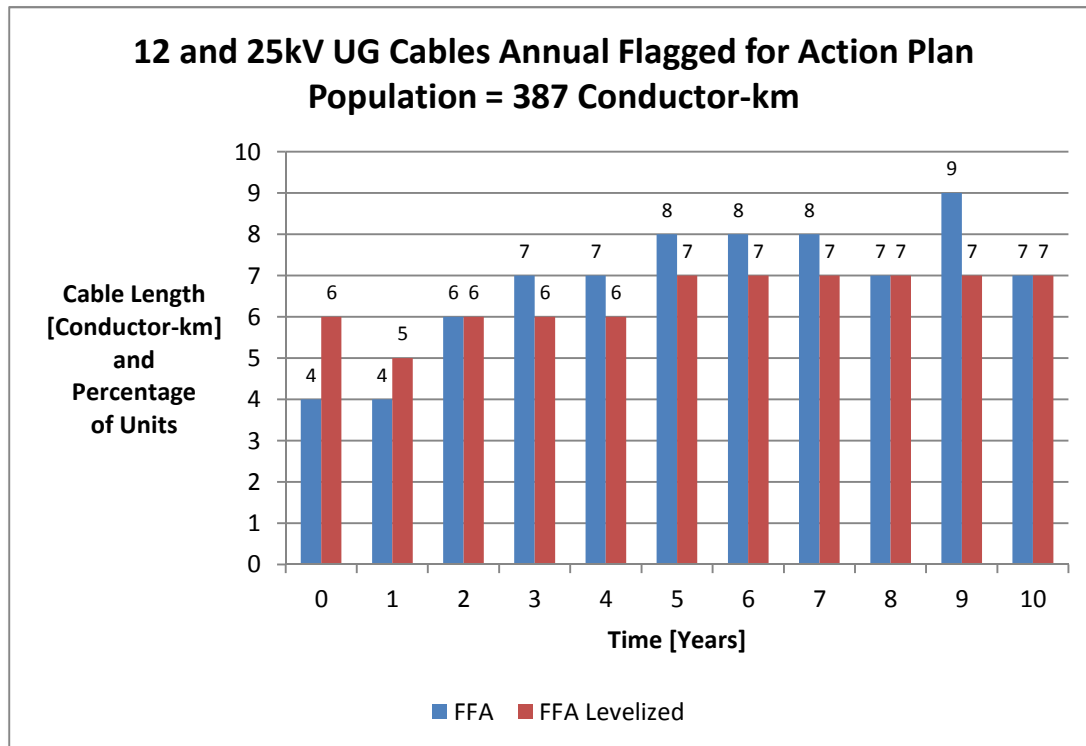


Figure 9-10 12 and 25kV Underground Cables Flagged for Action Plan

9.5 Data Analysis

Age was the only information available for underground cables. Further, as can be seen from the low DAIs of these asset categories, fewer than half of the switches had age information. Age should be collected for the remainder of the population.

Sub-Category	DAI
ALL	48%
4kV	65%
12 and 25 kV	47%

Underground cables had only age information. Further, fewer than half of the cable population had such information. TBH should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan Delta). Such information will provide good, objective condition data as input into the Health Index. Fault information should also be collected.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Splice & Termination	Physical Condition	★ ★	Cable splice	Under/over-compressed connector	On-site visual inspection
				Improper ground connection	
				Loose bolt	
			Cable termination	Sealing issue	
				Insulation erosion	
Overall		★ ★	Cable segment	Count of total corrective maintenance work orders issued on cable segment during a specific time window	Operation record
Cable Tests	Physical Condition	★ ★ ★	Cable Overall Condition	Gross/major defects; weak spots/bulk degradation in insulation; water treeing; localized defects in cable and accessories	Tests: insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan Delta

Appendix D: Grid Modernization Plan

2016

Thunder Bay Hydro
Electricity Distribution
Incorporated

[GRID MODERNIZATION PLAN]

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1.0 INTRODUCTION

The existing Thunder Bay Hydro distribution grid uses technologies and renewal strategies that are many decades old and include a limited use of digital communication and control technologies. Thunder Bay Hydro plans to address this aged infrastructure by creating a 'modernized' distribution grid that meets the changing needs of customers, industry and regulators. A modernized grid is one that facilitates the use of automated and self-healing devices to distribute electricity more effectively, economically and securely. Although Thunder Bay Hydro has been purposefully renewing its grid by converting voltages from 4kV to 25kV and installing telemetry based switching points for the last 5 years, a true modernization of the grid will allow for the deliberate incorporation of intelligent devices that will provide better visibility and operational flexibility to minimize outage impacts, and identify areas to achieve better grid performance. Over the next 5 years (2017-2021), Thunder Bay Hydro forecasts approximately \$1.29 million of capital spend in grid modernization projects. The projects are expected to benefit customers and the Thunder Bay Hydro with the functionality listed below.

- Detect and address emerging problems on the system before they affect service,
- Incorporate enhanced measurements, rapid communications, and feedback control that quickly return the system to a stable state after interruptions or disturbances,
- Re-route power flows, change load patterns, and take other corrective steps within seconds of detecting a problem,
- Provide system operators with advanced visualization tools to enhance their ability to oversee the system.

2.0 CURRENT REGULATORY AND GOVERNMENT INITIATIVES

In 2009, the Green Energy and Green Economy Act, 2009 ("GEA") established an additional objective for the OEB, namely, "to facilitate the implementation of a Smart Grid in Ontario". The Minister's Directive set out a number of objectives for the OEB to consider in providing guidance on Smart Grid implementation, namely: Customer control, Power system flexibility, and Adaptive infrastructure.

The Minister's Directive also set out a number of policy objectives to guide the OEB's development of criteria for evaluating LDC's plans. The Ontario Energy Board's Report of the

Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (the “RRFE Report”) was issued on October 18, 2012. The RRFE Report noted that Smart Grid investments are considered integral to all utility investment and that planning for Smart Grid development and implementation by electricity distributors and transmitters will be an essential part of the broader network investment planning exercise. The OEB has concluded that the objectives in the Minister’s Directive are aligned with the objectives of the renewed regulatory framework. The renewed regulatory framework set out by the OEB in the RRFE Report is a comprehensive performance-based approach to regulation. It is designed to encourage cost-effective planning and operation of the electricity distribution network so that it is efficient, reliable and sustainable, and provides value for customers. Therefore, the OEB will fulfill the Minister’s Directive by providing guidance on Smart Grid investments as part of implementing the performance-based framework set out in the RRFE Report.

In addition to being aligned with the above, Thunder Bay Hydro’s Grid Modernization plan is in support of Ontario’s Long Term Energy Plan issued in 2013 with a focus on the five principles to balance cost-effectiveness, reliability, clean energy, community engagement and an emphasis on conservation and demand management before building new generation.

3.0 MODERNIZATION ADVANTAGES AND BENEFITS

Thunder Bay Hydro has considered the cost of a ‘non-modernized grid strategy’. Embedded within this issue is the evaluation of the likely state of not pursuing grid automation and the impact that such decisions will have in future years. This assessment considers the true value proposition of the Grid Modernization versus a ‘Do Nothing’ Strategy. Rising costs for the utility that do not achieve grid efficiencies could have a more detrimental financial impact for customers than modernized grid capital requirements call for. Improving operational efficiencies through the investment in grid modernization will help fight rising costs and will offer future benefits to customers.

3.1 System/LDC Benefit

From a LDC point of view, several studies have been published offering benefit estimates for a group of major Smart Grid deliverables. Most notably the San Diego Smart Grid Study¹

¹ The Energy Policy Initiatives Center, University of San Diego School of Law, (2006) San Diego Smart Grid Study Final Report

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).

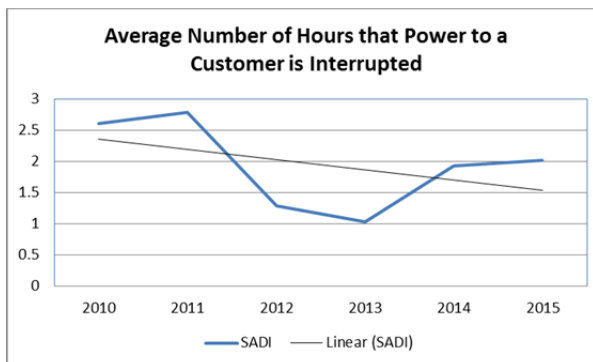


Figure 1- 2010-2015 Average Hours of Interruptions²

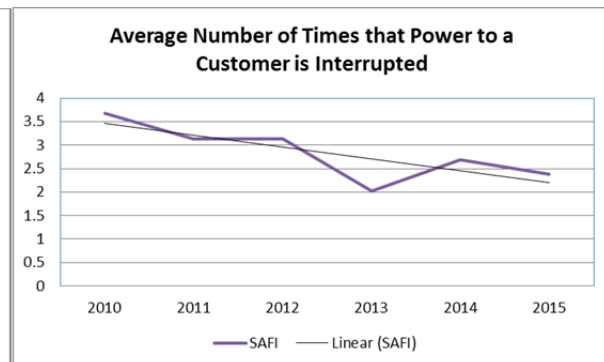


Figure 2- 2010-2015 Average Number of Interruptions

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>

detailed information about the status of the distribution system. This information will help Thunder Bay Hydro better manage the distribution assets by helping to identify imminent equipment failures or where equipment is operating above its designated ratings. The overall impact will be fewer outages due to equipment failure and a better ability to adapt to changing load conditions without over-stressing distribution assets. When outages occur they can be quickly localized and switching operations can be automatically performed where necessary to minimize the number of customers out of power at any one time. In some cases, all customers could be switched to an operating feeder resulting in a very minimal outage. In other cases, only a small subset of the affected customers may be left stranded on the un-energized feeder until permanent repairs are completed. The overall impact is that outages will be, on average, shorter and impact fewer customers.

With a modernized grid, the location of a fault can be quickly identified. This information will help Thunder Bay Hydro crews determine the necessary repair work and by extension provide staff with more detailed information about the cause and expected duration of an outage at a very early stage. This information can be disseminated to customers who, with more accurate information than is presently available, can better plan their affairs whether they are a business or a resident seeking information about how to plan their day (i.e. send employees home, re-schedule production, protect frozen food, heat house to protect plumbing, etc.)³. Aside from outage information, sensing data can inform customers, or customer owned equipment, about system conditions. These conditions could include signaling about critical periods that the system may be overstressed due to heat and loading conditions.

Not only will Thunder Bay Hydro personnel be better able and more quickly identify system faults and potential problems, but the enhanced instrumentation and detailed measurement throughout the system will enhance our ability to gauge the health of the system and more thoroughly manage utility assets. Through better Asset Management, Thunder Bay Hydro will operate more efficiently, benefiting customers by keeping operating and maintenance costs optimized.

³ W.-H. Liu, K. Liu, and D. Pearson, (2011). Consumer-centric Smart Grid, Innovative Smart Grid Technologies (ISGT), IEEE PES, January 2011, pp. 1–6.

4.0 THUNDER BAY HYDRO'S GRID MODERNIZATION STRATEGY

Thunder Bay Hydro has been purposefully modernizing its grid since 2012, at which time we submitted our first GEA plan. Thunder Bay Hydro understood the need to modernize its grid operations in order to maintain reliability to its customers, while connecting renewable generators. In order to continue to provide customers with the reliable service that they expect, Thunder Bay Hydro plans to install automated switches which will lead to automated feeder switching and a fully functioning outage management system. These intelligent back-office systems can replace human intervention in the fault locating and isolation process, as they automatically reconfigure the distribution system to isolate a problem to the fewest number of customers possible while balancing all the other competing priorities. It is envisioned that a human operators will remain an integral part of the system for some time, but the future path is apparent. Thunder Bay Hydro's research into distribution automation has determined that intelligent devices will allow the implementation of solutions that will automatically sectionalize and isolate faulted sections, allow faster restoration time and minimize the number of customers being impacted while reducing crew dispatching costs and restoration efforts.

4.1 Automated Switch Installations

Thunder Bay Hydro's Grid Modernization plan has been divided into segments to address modernization across the distribution system. The segments include; 4kV to 25kV conversions and Reliability Improvements which consist of Worst Feeder Analysis and 25kV Small Commercial and Large User Reliability Improvements.

Thunder Bay Hydro is in the midst of converting its 4kV distribution assets to 25kV, with the subsequent removal of 4kV substations. The benefits of conversion are plentiful; increase in protective reach, an increase in capacity, a reduction of substations and voltage drop, and fewer line losses. However the downside of voltage conversion is the removal of control and remote isolation capabilities of the substation, as well as the mesh redundancy properties of the 4kV network. Therefore in order to maintain customer reliability consistent with historical values, Thunder Bay Hydro has established a standardized calculation of protective zones. Through the strategic placement of devices, we have ensured the necessary protection speed, remote operability and ability to isolate as was previously achieved with substation breakers. Replacing existing substation protections with new automated switching in the distribution system during the conversion project has capitalized on resource availability to efficiently deploy smart

protections. Although the installed devices contribute to the modernization of the grid, the expenditures are incorporated into the 4kV to 25kV conversion projects and are not captured in the 'Grid Modernization' expenditures listed in Section 5.0.

On an annual basis Thunder Bay Hydro completes a 'Worst Performing Feeder' analysis and depending on the cause of the outage statistics, the installation of automated switching solutions can improve a feeder's outage instances and durations. The annual reliability statistics will continue to be analyzed and where appropriate, the installation of smart protective devices will be deployed.

Additionally, a significant portion of Thunder Bay Hydro's small commercial and large users are connected to the 25kV system. Customer Surveys regarding Distribution System Planning were performed in 2016 and provided insight into preferences and priorities for all customer classes. When asked what Thunder Bay Hydro should focus on for the next 5 years, small commercial and large users top priorities were "Infrastructure Upkeep" and "Maintaining Reliability", as compared to 'Lower Cost/Fewer Increases', 'Green energy Initiatives', "Outage Preparedness" and "Loss of Industry due to High Costs". As a result, the Asset Management and Engineering department undertook an analysis on feeders with high penetration of small users and large users and correlated these with the number of breaker operations and reliability statistics of these feeders over the past 5 years. Each feeder was subsequently scored based on the weighting of each of these factors a prioritized list of improvements was created. Thunder Bay Hydro is committed to maintaining high reliability standards and quality of service to all customer classes by systematically reviewing feeders on an annual basis and where required implementing solutions. It is our intention to improve reliability in the most needed areas of the distribution system with the installation of two automated switches each year from 2017 to 2021, as detailed in Section 5.0 Expenditures.

4.2 Automated Feeder Switching

Thunder Bay Hydro has designed its distribution feeders with switches so that portions of the feeder can be disconnected to isolate faults. In most cases, these switches are manually operated, and require a line worker to travel to the switch location, coordinate switching orders with a dispatcher, and then physically operate the switch. In contrast, Automatic Feeder Switching makes it possible to operate distribution switches autonomously in response to local events, or remotely in response to operator commands or a central control system. Automatic Feeder Switching does not prevent outages; it simply reduces the scope of outage impacts in

the longer term. This function is accomplished through the automatic isolation and reconfiguration of faulted segments of distribution feeders. Automatic Feeder Switching can reduce or eliminate the need for a human operator or field crew for operating switches. This saves time, reduces labor cost, and eliminates “truck rolls”. In order to implement automated feeder switching, a real time automation controller (RTAC) needs to be strategically placed and programmed to allow selected automated switches the ability to operate. These RTAC units will be procured and installed once the selected feeder switches and communication components are in place. Thunder Bay Hydro anticipates purchasing four of these units in the next 5 years, in order to create two potential ‘smart feeder’ zones. (See Section 5.0 for details on expenditures)

4.3 Outage Management System Improvements

In addition to the above device deployments on the distribution grid, Thunder Bay Hydro also plans to work towards the implementation of an Outage Management System. Thunder Bay Hydro replaced an unsupported VMS based SCADA system to a Windows based SCADA system in 2016 and entered into discussions with the vendor (Survalent) to ensure that the capabilities for future installation of an Outage Management System (OMS) are available. An OMS would greatly improve Thunder Bay Hydro’s capability to provide the highest quality of service and would allow for rapid and reliable communication on planned and unplanned outages to our customers. In order to realize the full benefits of an OMS, integration with Geographic Information System (GIS), Advanced Meter Infrastructure (AMI) and Customer Information Systems (CIS) systems needs to be completed. This integration of software packages will be staged over several years in order to allow challenges to be resolved prior to a full implementation. An OMS will not only help Thunder Bay Hydro proactively provide more frequent and timelier updates to our customers during an outage, but will also reduce the duration, frequency and impact of interruptions to our customers. The year over year expected OMS project expenditures are included in Section 5.0.

5.0 GRID MODERNIZATION EXPENDITURES 2017-2021

Grid Modernization Plan 2017				
Recloser (25kV Reliability)	\$ 90,000	1	\$ 90,000	
Recloser (Worst Performing Feeder)	\$ 90,000	1	\$ 90,000	
Distributed Automation (SEL 3530)	\$ 50,000	0	\$ -	
Programming + Engineering+Mods	\$ 20,000	0	\$ -	
OMS - GIS Integration	\$ 50,000	1	\$ 50,000	
Total Expenditure 2017			\$ 230,000	
Grid Modernization Plan 2018				
Recloser (25kV Reliability)	\$ 90,000	2	\$ 180,000	
Recloser (Worst Performing Feeder)	\$ 90,000	0	\$ -	
Distributed Automation (SEL 3530)	\$ 50,000	1	\$ 50,000	
Programming + Engineering+Mods	\$ 20,000	1	\$ 20,000	
OMS - AMI Integration	\$ 50,000	1	\$ 50,000	
Total Expenditure 2018			\$ 300,000	
Grid Modernization Plan 2019				
Recloser (25kV Reliability)	\$ 90,000	1	\$ 90,000	
Recloser (Worst Performing Feeder)	\$ 90,000	1	\$ 90,000	
Distributed Automation (SEL 3530)	\$ 50,000	1	\$ 50,000	
Programming + Engineering+Mods	\$ 20,000	0	\$ -	
OMS - CIS Integration	\$ 50,000	1	\$ 50,000	
Total Expenditure 2019			\$ 280,000	
Grid Modernization Plan 2020				
Recloser (25kV Reliability)	\$ 90,000	1	\$ 90,000	
Recloser (Worst Performing Feeder)	\$ 90,000	1	\$ 90,000	
Distributed Automation (SEL 3530)	\$ 50,000	1	\$ 50,000	
Programming + Engineering+Mods	\$ 20,000	0	\$ -	
OMS -SCADA Module Installment 1	\$ 50,000	1	\$ 50,000	
Total Expenditure 2020			\$ 280,000	
Grid Modernization Plan 2021				
Recloser (25kV Reliability)	\$ 90,000	2	\$ 180,000	
Recloser (Worst Performing Feeder)	\$ 90,000	0	\$ -	
Distributed Automation (SEL 3530)	\$ 50,000	1	\$ 50,000	
Programming + Engineering+Mods	\$ 20,000	1	\$ 20,000	
OMS -SCADA Module Installment 2	\$ 50,000	1	\$ 50,000	
Total Expenditure 2021			\$ 300,000	

Appendix E: Fleet Plan



THUNDER BAY HYDRO'S

VEHICLE AND EQUIPMENT

RESOURCE JUSTIFICATION PLAN

2016

May 30, 2016

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1) Introduction

Thunder Bay Hydro Electricity Distribution Inc.'s (TBHEDI) mandate is to ensure that any customer outage event(s) and or system maintenance is managed in the safest and most timely fashion possible. TBHEDI's Vehicle and Equipment Resource Justification Plan provides rational as to why specific vehicle types are required, the current number of vehicles/ equipment in service, information on which vehicles/ equipment should be replaced, and when that replacement is proposed based on the criteria detailed within. Furthermore, it also includes vehicle rental options if applicable and opportunities to reduce the number of assets within the fleet.

2) Specialty Line Vehicle Quota Rational

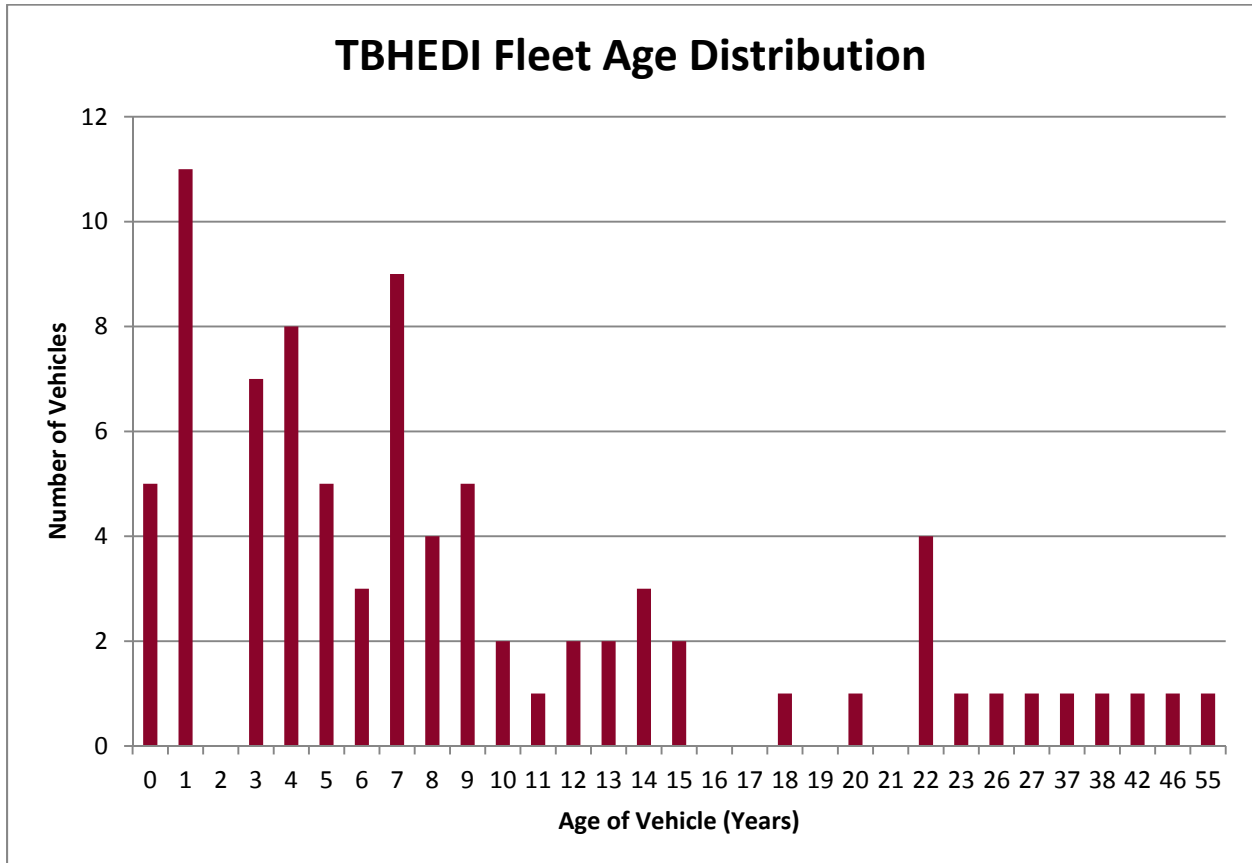
The vehicle types that currently make up TBHEDI's fleet (83 vehicles/ equipment) have specific functions or limitations, and are required to fulfill and or enhance worker safety, ergonomics, and operational activities. As with many other items within the corporation, the daily use of every specialty vehicle may or may not occur; however the fleet size is currently matched with our field staff compliment and utilized by numerous work groups within Power Systems. Unfortunately, due to the unpredictability of system disturbances, equipment failures, and maintenance/ construction activities determining when the exact need for a particular vehicle type or the number of similar vehicles required to manage the situation is not possible.

Not all planned/ unplanned system work activities such as construction, maintenance, and metering take place in the same location at the same time:

- o Construction activities are defined prior to work and require all vehicle/ equipment types in the completion of the power line construction tasks, the issue being that the construction plan at times scatters the crews throughout the city making vehicle sharing opportunities less efficient
- o Power line maintenance activities are so varied that one task may require a single truck while another task may require numerous trucks and or support vehicles/ equipment
- o Metering, Protection & Control (P&C) and Stations use of the specialty line vehicles varies in order to facilitate the needs of other departments such as:
 - Billing – smart meter collector maintenance/repairs
 - System control – switching device maintenance/repairs
 - Engineering – communication/ protection & control system installation/ maintenance
 - Operations – building security cameras, station maintenance structures

3) Vehicle Replacement Criteria

TBHEDI anticipates a useful service life for light vehicles of typically twelve (12) years, and a useful service life of heavy vehicles for typically fifteen (15) years. As displayed by the chart below, there are a large number of vehicles expected to reach their end of service life within the next few years.



However, in order to enhance vehicular reliability and work crew productivity, some older vehicles may be rotated from their current daily use duty into a seasonal or less critical type role. The intent is not to increase the overall fleet vehicle count; so any vehicle(s) displaced from the seasonal or less critical type role may be included as trade-in vehicles during the purchase process or may be surplused/scrapped. Mileages of 10 – 15,000km per vehicle can be anticipated as a yearly average, while certain assets may require replacement sooner depending upon the overall mileage accumulated and the physical condition of the vehicle (exterior body panel or chassis/ structural component deterioration).

- o It is important to note that this plan does not take into account or predict a vehicle/ equipment's projected repair history, reliability (uptime percentage), and or the vehicle/ equipment's operating costs due to repetitive breakdowns which may mandate the early replacement of that vehicle/ equipment

TBHEDI's speciality items which can be rented locally (ie. easement machine, etc.) will be monitored for increasing annual safety inspection costs and to limit any large repair expenditures on a case by case basis to a reasonable amount. If the cost of annual maintenance and or an individual repair

becomes excessive, the equipment will be removed from service and disposed of. Future needs for a similar equipment type will be sourced via rental options.

4) Current Vehicle and Equipment Justification (as of May 2016)

The following list provides a detailed explanation of both the vehicles and equipment owned by TBHEDI and their users. Furthermore, it provides an understanding for the use of each vehicle within the corporation.

1. Double Buckets (7): utilized by Lines, P&C and Stations staff.
 - a. They are 0 to 65 foot insulated work platforms with material handling capabilities and provisions for the storage of tools, material, and equipment which are utilized for overhead power line construction/ maintenance, radio communication testing/ confirmation, and substation maintenance work
2. Single Buckets (6): utilized by Lines, Metering, P&C and Stations staff.
 - a. They are 0 to 47 foot insulated work platforms with provisions for the storage of tools, material, and equipment which are utilized for overhead line construction/ maintenance, substation maintenance, smart metering collection, and miscellaneous building lighting/ camera work
3. Radial Boom Derricks (6): utilized by Lines and Stations staff.
 - a. They are 0 to 47 foot 16,000 pound material handling/ hoisting/ towing platforms with provisions for the storage of tools, material, and equipment which are utilized for overhead line construction, maintenance, station cabling/ structure, and trailer towing work
4. Light Trucks, SUV and Mini Vans (31): utilized by the Lines and Engineering & Operations Departments personnel for all of their associated duties.
5. Dump Truck (1): utilized by Lines and Stations for trailer/ equipment towing, and aggregate movement/ placement work (rear dumping only)
 - a. TBHEDI can utilize local equipment and operator service providers to back-fill any dump truck short falls
6. Mini Dump Trucks (3): utilized by Lines and Stations for trailer towing and aggregate movement/ placement work (rear and side dumping capable).
7. Super Cab Flat Deck (with lift gate) (1): utilized by Stations and Lines for transportation, material hauling, and for yard/ work area sanding purposes.
8. Cube Vans (2): utilized by Stations and Lines (underground crew) for transportation and material hauling purposes.
9. Backhoes (2): utilized by Lines for trenching, LHD of aggregate material, snow removal, rock breaker, and forklift/ material handling work.
 - a. TBHEDI can utilize a local equipment and operator service supply contract to back-fill any backhoe loader short falls

10. Stringing Trailer/ Machines/ Puller Tensioners (9): utilized by Lines for power distribution construction and maintenance activities.
 - a. As of this report, TBHEDI does not rent this type of equipment due to the uniqueness of the assembly, associated components, and the need to train the user's prior to utilizing this equipment
11. Reel Trailer (3): utilized by Lines for power distribution construction and maintenance activities.
 - a. As of this report, TBHEDI does not rent this type of equipment due to the uniqueness of the assembly, associated components, and the need to train the user's prior to utilizing this equipment
12. Pole Trailers (2): utilized by Lines to move hydro poles for power distribution construction and maintenance activities.
 - a. TBHEDI can utilize an equipment and operator service supply contract to back-fill any pole trailer short falls
13. Easement Machine and Trailer (2): utilized by Lines for power distribution construction and maintenance activities.
 - a. TBHEDI can utilize a local equipment and operator service supply contract to back-fill any easement machine short falls
14. Compressor Trailer (1): utilized by Lines for emergency power distribution activities.
15. Equipment Float Trailers (2): utilized by Lines/ equipment operators to transport the backhoe, large transformers and or material.
16. Rear Dump Trailers (2): utilized by Lines to place aggregate or to transport transformers or material.
17. Three Way Dump Trailer (2): utilized by Lines to place aggregate or to transport transformers or material.
18. Forklift (1): utilized by Lines, Stations, and Stores to place, transport, and or move transformers or material.

5) Recommendations and Equipment Renting

As most of the speciality line vehicles in Thunder Bay are not available for rent, it is recommended that in an effort to ensure our business continuity and commitment to customer satisfaction, TBHEDI maintains their current vehicle fleet quota based on the following variables:

1. The geographic location of Thunder Bay is by nature a detriment as it does not allow for a timely response for acquiring rental vehicles if they were required for either daily work objectives or outage management scenarios
 - o Based on immediate availability from a rental company, internal purchasing approvals, establishing insurance, providing an "in service" vehicle orientation etc.; TBHEDI could expect at best a 3-4 week lead time or
 - o If the required vehicle is not immediately available, a 2-6 month delay in acquiring the requested vehicle(s) is possible

2. Costs associated with acquiring specialty power line vehicles (RBDs, bucket trucks) includes delivery/ pick up fees, monthly fees, any associated damage and minimum rental term obligation.
 - o RBD rental is \$6,100 monthly, delivery fee is \$3,500, and the pick-up fee is \$3,500 with a minimum rental term of 1 month
 - o Double Bucket rental is \$6,100 monthly, delivery fee is \$3,500, and the pick-up fee is \$3,500 with a minimum rental term of 1 month
 - o Single Bucket rental is \$3,800 monthly, delivery fee is \$2,500, and the pick-up fee is \$2,500 with a minimum rental term of 1 month

6) New Vehicle Costs

New specialty line vehicle purchase costs that have been used for budgeting purposes (as of 2014) are as follows;

- o RBD = \$355,000
- o Double Bucket = \$425,000
- o Single Bucket = \$290,000

7) Vehicle and Equipment Acquisition Plan and Expenditures 2015-2027

The following charts provide an explanation (per year) on the number of vehicles projected to be purchased, and which vehicles they will be replacing within the corporation. Additionally, the charts outline the projected (and where applicable), actual costs of the new vehicle or equipment.

Description	2015			Additional Information
	Projected Cost	Purchase Approved	Actual Cost	
RBD to replace #4 (2000)	\$100,000	yes	\$100,250 +HST	Order was placed in 2015 -- \$100,250 to be spent in 2015 on the cab and chassis and \$254,880 to be spent in 2016 on the boom/ body
Single Bucket to replace #57 (1998)	\$75,000	yes	\$98,800 +HST	Order was placed in 2015 -- \$98,800 to be spent in 2015 on the cab and chassis and \$190,016 to be spent in 2016 on the boom/ body
Mini Single Bucket to replace #7 (1999)	\$138,522	yes	\$138,522 +HST	Order was placed in 2014 -- \$43,330 was spent in 2014 on the cab and chassis and \$138,522 was to be spent in 2015 on the boom/ body but was not delivered until March 2016 (paint/ body/ seat issues still existed until June 2016)
Mini Dump Truck to replace #8 (1997)	\$80,000	yes	\$63,867 +HST	Order was placed in 2015 -- \$42,367 for the cab and chassis and \$21,500 for the box
Stations Vehicle to replace #49 (2002)	\$140,000	yes	\$43,919 +HST	Order was placed in 2015 -- \$43,919 to be spent in 2015 for the cab and chassis and \$88,430 for the van/ enclosure to be spent in 2016 (total vehicle costs is \$132,349)

- Due to the +25% exchange rate as of March 2015, vehicle costs will increase

2016				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
RBD to replace #4 (2000)	\$254,880	yes	N/A	Remaining amount from the 2015 order -- \$254,880 – see above -- (total vehicle costs is \$355,130)
Single Bucket to replace #57 (1998)	\$190,016	yes	N/A	Remaining amount from the 2015 order -- \$190,016 – see above -- (total vehicle costs is \$288,816)
Stations Vehicle to replace #49 (2002)	\$88,430	yes	\$88,430 +HST	Remaining amount from the 2015 order -- \$88,430 – see above -- (total vehicle costs is \$132,349)
Double Bucket to replace #5 (2002)	\$125,000	Yes	\$125,000	Order to be placed in 2016 (\$125,000 for the cab and chassis portion) – projecting \$325,000 to be spent in 2017 on the boom/ body
Line Tech Vehicles	\$80,000	Yes	\$31,771	Only one of the approved 2 vehicles was purchased
Vehicle to replace #21 (2004)	\$45,000	Yes	\$41,985	See below
Vehicle to replace #23 (2004)	\$45,000	Yes	\$41,985	See below
Locates Vehicles (New)	\$80,000	Yes	\$63,542	2 vehicles for the new Tbaytel locate contract (Charged as expense in Utility Services)

- o Trucks 21 and 23 (used for seasonal labourers) will be traded-in, surplusd or scrapped
 - The 2 newly acquired crew cab vehicles are to go into lines
 - Truck 25 will be re-purposed as a seasonal labourer unit
 - Truck 50 will be re-purposed into stations to replace truck 20
- o Truck 20 will be re-purposed as a winter sand truck for the winter months
- o Truck 1 was removed from service in 2015 due to the cost to replace the transmission – this vehicle will not be replaced
- o Truck 6 was removed from service in early 2015 due to safety inspection costs – this vehicle will not be replaced
- o Truck 17 (2001) will be used as either a trade-in, surplusd, or scrapped to offset the cost of the two line distribution technician vehicles – this vehicle will not be replaced
- o Once trucks 17, 21 and 23 are gone, the TBHEDI fleet will have no “unassigned” vehicles available for long term break downs or special projects (ie. risk assessments, ESRW etc.) – if a need arises TBHEDI will rent vehicles

2017				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
Double Bucket to replace #5 (2002)	\$325,000	Not yet	N/A	Remaining purchase amount from the 2016 order
Double Bucket to replace #3 (2001)	\$125,000	Not yet	N/A	Order to be placed in 2017 (\$125,000 for the cab and chassis portion) – projecting \$325,000 to be spent in 2018 on the boom/ body
Flat Deck – Cable Reel Trailer	\$15,000	Not yet	N/A	
Line Tech Vehicle	\$40,000	Not Yet	N/A	
Crew Cab Vehicle to replace #45 (2006)	\$45,000	Not Yet	N/A	1 ton trucks for lines
Crew Cab Vehicle to replace #50 (2007)	\$45,000	Not Yet	N/A	1 ton trucks for lines

- One of the ¾ ton crew cab vehicles replaced for lines may be re-purposed and given to metering to replace mini-van #38 (2002)

2018				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
Double Bucket to replace #5 (2002)	\$325,000	Not yet	N/A	Remaining purchase amount from the 2017 order
RBD to replace #12 (2003)	\$125,000	Not yet	N/A	Order to be placed in 2018 (\$125,000 for the cab and chassis portion) – projecting \$300,000 to be spent in 2019 on the boom/ body
Vehicle to replace #45 (2006)	\$45,000	Not yet	N/A	
Forklift truck to replace CAT 918 (1998)	\$85,000	Not yet	N/A	

2019				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
RBD to replace #12 (2003)	\$300,000	Not yet	N/A	Remaining purchase amount from the 2018 order
Vehicle to replace #50 (2007)	\$45,000	Not yet	N/A	
Vehicle to replace #25 (2007)	\$45,000	Not yet	N/A	

2020				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
Underground vehicle to replace #76 (2008)	\$140,000	Not yet	N/A	
Mini-Single Bucket to replace #78 (2008)	\$200,000	Not yet	N/A	

2021				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
Single Bucket to replace #37 (2006)	\$325,000	Not yet	N/A	
Vehicle to replace #55 (2009)	\$75,000	Not yet	N/A	Replacement of this unit may be deferred – TBH by Operations Superintendent
Vehicle to replace #56 (2009)	\$45,000	Not yet	N/A	
Vehicle to replace #58 (2009)	\$45,000	Not yet	N/A	
Vehicle to replace #59 (2009)	\$45,000	Not yet	N/A	

2022				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
RBD to replace #42 (2007)	\$400,000	Not yet	N/A	
Double Bucket to replace #53 (2007)	\$400,000	Not yet	N/A	
Mini-Single Bucket to replace #97 (2012)	\$200,000	Not yet	N/A	

2023				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
Single Bucket to replace #77 (2008)	\$325,000	Not yet	N/A	
Vehicle to replace #62 (2011)	\$45,000	Not yet	N/A	
Vehicle to replace #63 (2011)	\$45,000	Not yet	N/A	
Vehicle to replace #64 (2011)	\$45,000	Not yet	N/A	

2024				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
RBD to replace #54 (2009)	\$400,000	Not yet	N/A	
Single Bucket to replace #87 (2009)	\$325,000	Not yet	N/A	
Mini-Single Bucket to replace #71 (2012)	\$200,000	Not yet	N/A	
Mini-Dump Truck to replace #70 (2012)	\$85,000	Not yet	N/A	
Vehicle to replace #65 (2012)	\$45,000	Not yet	N/A	
Vehicle to replace #66 (2012)	\$45,000	Not yet	N/A	
Vehicle to replace #68 (2012)	\$45,000	Not yet	N/A	
Vehicle to replace #69 (2012)	\$45,000	Not yet	N/A	
Vehicle to replace #84 (2012)	\$45,000	Not yet	N/A	

2025				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
Double Bucket to replace #60 (2010)	\$400,000	Not yet	N/A	
Mini Dump Truck to replace #89 (2013)	\$85,000	Not yet	N/A	
Vehicle to replace #86 (2013)	\$45,000	Not yet	N/A	
Vehicle to replace #91 (2013)	\$45,000	Not yet	N/A	
Vehicle to replace #92 (2013)	\$45,000	Not yet	N/A	

2026				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
Double Bucket to replace #61 (2011)	\$400,000	Not yet	N/A	

2027				
Description	Projected Cost	Purchase Approved	Actual Cost	Additional Information
Vehicle to replace #93 (2015)	\$45,000	Not yet	N/A	
Vehicle to replace #94 (2015)	\$45,000	Not yet	N/A	
Vehicle to replace #96 (2015)	\$45,000	Not yet	N/A	
Vehicle to replace #98 (2015)	\$45,000	Not yet	N/A	

Appendix F: Smart Metering Plan



THUNDER BAY HYDRO

SMART METER SAMPLING PLAN

Prepared By:
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Operations Superintendent
April 27, 2016

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THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. SMART METER SAMPLING PLAN

1.0 General Information:

As part of a legislated requirement, Thunder Bay Hydro Electricity Distribution Inc. (TBHEDI) replaced approximately 50,000 electro-mechanical type revenue meters with electronic smart meters in 2009.

The new electronic smart meters selected by TBHEDI for use were manufactured by Elster and had 10 year seal life and will expire in 2019. As per Measurement Canada requirements a meter with an expired seal cannot be left in service for revenue / billing purposes.

Measurement Canada's (MC) Statistical Method Specification (S-S-06) replaced the previous 1986 mechanical meter reverification standard LMB-EG-04; and defines how an electronic smart meter owner can utilize meter sampling for the purposes of extending the reverification period of an in-service lot of meters. Differing from the LMB-EG-04 Standard where the meter testing agency would be responsible for meter sampling data; the S-S-06 specification now places this and additional clerical data management and meter tracking responsibilities on the utility.

2.0 Purpose:

This plan will detail all of the activities necessary for TBHEDI to establish a smart meter pre-sampling and final compliance sampling program which aligns with the requirements detailed within Measurement Canada's (MC) Statistical Method Specification (S-S-06) so the utility can extend their smart meter's in-service life and ultimately maximize the return on investment (ROI).

It will also detail a meter re-verification strategy which will be utilized for any meters which do not qualify for pre/final sampling or that have substantial meter seal date extension limitations.

3.0 Responsibilities:

The Billing work group and the AMI Coordinator will provide the historical metering information and develop / close all meter replacement work orders as required. The AMI Coordinator will oversee the information provided via the Work Force Management Solution.

The Metering work group will execute all of the "complex" meter removal / installations, any required instrument transformer replacements and all associated verification activities associated with the smart meter sampling / reverification program(s), they will also forward all relevant meter information to the AMV and or the TBHEDI Clerk 2 for processing.

The meter installation contractor will execute the residential and or other meter removal / installation activities associated with TBHEDI's smart meter sampling / reverification needs. [ie. RS(2S), R2S(12S) and R2SD(2S) meter types). They will also forward all relevant meter information to the TBHEDI Clerk 2 for processing.

TBHEDI's Clerk 2 will assist the metering group and the field meter service provider(s) with any of their data entry requirements to ensure old/new meter records are accurate.

The Accredited Meter Verification (AMV) Shop will advise TBHEDI which meters are to be included within a specific meter sampling effort, oversee the meter "scrambling" and selection process, advise TBHEDI which exact meters are to be removed from service for sampling, complete all pre-test / final test or meter re-verification needs, provide program management and or report generation activities to satisfy any Measurement Canada audits associated with the smart meter sampling program(s).

The Lines group will respond to any damage or questionable meter installation complaints and make the appropriate call in the field on a case by case basis for repairs / disconnection as per their established process

The Stores work group will oversee all shipping / receiving / inventory efforts associated with the meter sampling program.

4.0 Measurement Canada Specification S-S-06:

Following the criteria within MC S-S-06;

- TBHEDI has created 10 smart meter “lots” from which 45,761 of their 46,188 “2009 vintage in service” meter inventory would be captured (*a meter lot is restricted to the following – all meters need to be the same manufacturer / model, same seal year, same configuration [volts, amps and elements] and a minimum of 70% “time-on-test (TT) / in-service time*)
- TBHEDI has determined which of their 46,188 meters meet the 70% TT criteria as only those meters can have a seal date extension applied (the meters which do not meet the 70% TT criteria cannot be tested and need to be removed from service once their seal date is expired)
- TBHEDI needs to determine the “target level” LQ (1 – 4) for testing their meters (ie. *selecting level 1 would allow a 8 year seal extension vs selecting level 4 would allow only a 2 year seal extension*)
- TBHEDI is required to provide the meter tag information for all the meters within a “lot or group” -- MC runs those tag numbers through a “scrambler” to determine which meters have to be provided for testing
- Each of these “lots” would require a small percentage of the meters be removed from service and sent away for testing at an Measurement Canada accredited facility (ie. *a 6,850 meter lot size would require 250 meters be removed for sampling activities*)
- If the “final” testing / verification is successful all of the remaining meters associated with that specific “lot” would have their seal dates extended
- If the “final” testing / verification is not successful all of the remaining meters associated with that specific “lot” would need to be removed from service and replaced with new smart meters

5.0 Smart Meter Sampling Plan Rational and Schedule:

The proposed “pre-sampling” effort is not mandatory but is purposeful and will assist TBHEDI in numerous determinations and will justify decisions made for the implementation and or execution of the smart meter sampling plan.

“Pre-sampling” will provide TBHEDI;

- the relevant information necessary to best determine the most appropriate LQ “target level” (1 – 4) for their seal extension periods (*ie. if the our pre-sampled smart meters are only meeting level 2 accuracy levels, there is no use in asking to have any “final” meter testing efforts occur with a level 1 target level request*)
- insight / confidence as to how large to make a final sample lot, realizing that a lot failure would result in the entire number of meters within that lot having to be replaced

- due diligence documentation on defending any meter lot or group failures (ie. MC can impose a fine up to \$1,000 for each meter within a lot or group that fails under Bill C-41--Fairness at the Pumps Act)

The smart meter “pre-sampling” field replacement effort is proposed to start in 2016 and continue through 2017 / 2018. Final sampling is planned to occur in 2018 / 2019. The combined activities will include the removal and testing on 4,136 meters (2,068 meters during pre-sampling and 2,068 meters for final sampling)

The justification detailed below is for only the residential RS (2S) meters; which make up the largest component of the proposed smart meter sampling plan (ie 41,097 meters vs 46,188 meters in service) and will involve the use of a meter installation contractor to complete.

For only the RS (2S) meters:

For the residential RS (2S) type meters, TBHEDI compared three different meter pre/final lot sizing options and costs.

Based on the Corporation’s tolerance for managing a large final sample group failure if one should occur, TBHEDI has selected a pre/final sample testing strategy as per Option 2 with an individual meter lot size of approximately 6,850 meters; totaling 41,097 meters for the bulk of their smart meter sampling efforts.

Descriptions for Years 2016 to 2019	Option 1	Option 2	Option 3
RS (2S) Meter Count	41,097	41,097	41,097
Number of RS (2S) Meter Lots	2	6	12
Approximate Number of RS (2S) Meters per Lot	20,548	6,850	3,424
Number of RS (2S) Meters to be Removed for Pre and Final Sampling	1,512	3,000	3,600
AMV Cost to Pre and Final Sample Test all RS (2S) Meters	\$12,434	\$24,675	\$29,610
*Contractor Cost to Replace all Pre and Final Test RS (2S) Meters	\$31,752	\$63,000	\$75,600
Return Shipping Costs	\$8,977	\$17,812	\$21,375
Totals	\$53,163	\$105,487	\$126,585

- **Option 1:** Two meter lots, sized at 20,548 meters each, equaling the 41,097 RS (2S) count; would require 1,512 meters to be removed from service for pre/final sample testing efforts and would cost \$53,163 which is \$52,324 less than TBHEDI’s selected plan.
 - The anticipated cost to purchase new replacement meters for this option should a single meter lot fail final testing is \$2,198,636 (20,548 meters x \$107)
- **Option 2:** Six meter lots, sized at approximately 6,850 meters each, equaling the 41,097 RS (2S) meter count; would require 3, 000 meters to be removed from service for pre/final sample testing efforts and would cost \$105,487.
 - The anticipated cost to purchase new replacement meters for this option should a single meter lot fail final testing is \$732,950 (6,850 meters x \$107)
- **Option 3:** Twelve meter lots, sized at 3,424 meters each, equaling the 41,097 RS (2S) meter count; would require 3,600 meters to be removed from service for pre/final sample testing efforts and would cost \$126,585 which is \$21,098 more than TBHEDI’s selected plan.
 - The anticipated cost to purchase new replacement meters for this option should a single meter lot fail final testing is \$366,368 (3,424 meters x \$107)

The anticipated meter sampling/reverification plan's activities are detailed within the chart below;

Activity	2016	2017	2018	2019
**RS (2S) Residential Meters for Sampling Campaign by Others	Order 750 new meters for inventory – received in Q2			
Acquire Accredited Meter Verification (AMV) Services	Awarded in April			
Acquire Meter Installation Services	By Q3			
**RS (2S) Pre-Sampling Campaign By Others	Remove from inventory and pre-test ~500 meters and return to inventory by/in Q4	Remove from inventory and pre-test ~1000 meters and return to inventory in Q2-4		
**R2S (12S) 200 Amp Network Meters for Sampling Campaign by Others		Order 156 new meters for inventory in Q4	Remove from inventory and pre-test 156 meters and return to inventory in Q2	
**R2SD (2S) Disconnect Type Meters for Sampling Campaign by Others		Order 156 new meters for inventory in Q4	Remove from inventory and pre-test 156 meters and return to inventory in Q2	
A3TL (3S) Meters for Sampling Campaign by TBH		Order 45 new meters for inventory in Q4	Remove from inventory and pre-test 100 meters and return to inventory in Q2	
A3TL (16S) Meters for Sampling Campaign by TBH		Order 149 new meters for inventory in Q4	Remove from inventory and pre-test 156 meters and return to inventory in Q2	
A3TL (3S) Meters for Sampling Campaign by TBH		Re-verify 55 meters in stores inventory in Q4		
A3TL (16S) Meters for Sampling Campaign by TBH		Re-verify 7 meters in stores inventory in Q4		
**RS (2S) Final Sampling Campaign by Others			Remove from inventory and final test ~1000 meters and return to inventory in Q3-4	Remove from inventory and final test ~500 meters and return to inventory in Q2-3
**R2S (12S) 200 Amp Network Meters for Sampling Campaign by Others				Remove from inventory and final-test 156 meters and return to inventory in Q2
**R2SD (2S) Disconnect Type Meters for Sampling Campaign by Others				Remove from inventory and final-test 156 meters and return to inventory in Q2
A3TL (3S) Meters for Sampling Campaign by TBH				Remove from inventory and final-test 100 meters and return to inventory in Q2
A3TL (16S) Meters for Sampling Campaign by TBH				Remove from inventory and final-test 156 meters and return to inventory in Q2
A3RL (16S) 3 Phase Bi-directional Meters with 2017 seal expiry by TBH	Re-verify 22 meters in stores inventory in Q2			
A3RL (16S) 3 Phase Bi-directional Meters with 2017 seal expiry by TBH (count = 20)	Replace 20 meters by/in Q4			
Small Lot Quantity Meters with 2019 Seal Expiry		Re-verify the 268 meters in stores inventory in Q1		
Small Lot Quantity Meters with 2019 Seal Expiry (count = 90)		Order 90 new meters for inventory in Q1		
Small Lot Quantity Meters with 2019 Seal Expiry (count = 338)		Remove from inventory and replace 150 meters and return to inventory in Q3-4	Remove from inventory and replace 188 meters and return to inventory in Q2-3	
Very Small Lot Quantity Meters with 2019 Seal Expiry				Re-verify 92 meters in stores inventory in Q1
Very Small Lot Quantity Meters with 2019 Seal Expiry				Order 15 new meters for inventory in Q1
Very Small Lot Quantity Meters with 2019 Seal Expiry (count 89)				Remove from inventory and replace 89 meters and return to inventory in Q2-4
Pre/Final Sampling and Reverification Plan Execution Cost for 2016 to 2019 will be \$304,511	\$10,500 (others installing 500**) \$1,200 (TBH installing 20) \$3,099 (shipping 522 meters) \$4,000 (WFM Solution – 2 mths) \$3,925 (pre-testing 500) \$880 (reverifications 22 meters) \$1,500 (doc. Man.) \$25,104 \$ 2,510(contingency) \$27,614	\$21,000 (others installing 1000**) \$9,000 (TBH installing 150) \$7,896 (shipping 1330 meters) \$10,000 (WFM Solution – 5 mths) \$8,100 (pre-testing 1000) \$10,816(reverification 330meters) \$1,500 (doc. Man.) \$68,312 \$ 6,831(contingency) \$75,143	\$27,552 (others installing 1312**) \$26,640 (TBH installing 444) \$9,310 (shipping 1568 meters) \$12,000 (WFM Solution – 6 mths) \$24,460 (pre/final testing 1568) \$0 (reverification 0 meters) \$1,500 (doc. Man.) \$101,462 \$ 10,146 (contingency) \$111,608	\$17,052 (others installing 812**) \$20,700 (TBH installing 345) \$6,887 (shipping 1160 meters) \$12,000 (WFM Solution – 6 mths) \$20,911 (final testing 1068) \$2,901 (reverification 92 meters) \$1,500 (doc. Man.) \$81,951 \$ 8,195(contingency) \$90,146

Structuring the pre/final sampling campaign with defined meter quotas per year are for logistical purposes as all other day-to-day metering work is still required in addition to the smart meter sampling program activities.

TBHEDI currently has 428 meters that fall within the small and very small lots criteria which have 2019 seal expiry dates. These meters either do not qualify for or have special seal expiry date limitations (ie. 50% reduction in seal extension period) as per the pre/final sampling as per Measurement Canada S-S-06 minimum meter lot size criteria. As discussed previously, TBHEDI has chosen to manage these meters via an alternative process (meter re-verification), whereby TBHEDI will need to remove those meters from service and replace them with new and or re-verified meters.

In 2016, 2017, 2018 and 2019 meter installation contractor services will be required to execute the majority pre/final meter sampling plan. See ** items detailed above for activities completed by “Others” (ie. meter installation contractor)

Although meter testing / reverification services will be required for perpetuity; it is unknown at this time if there will be a requirement for meter installation contractor services beyond 2019 as the meters with expiring seals will be substantially less.

6.0 Smart Meter Final Sampling:

For the majority of the “qualifying” installed meter inventory, TBHEDI could if they decided to and selected a final sampling LQ “target level” starting at 1 (ie. 8 year meter seal extension) and had a continued successful meter seal reverification program whereby in 8 years TBHEDI ran another meter sampling program and then selected LQ 2 (6 year seal extension) and so on until the meter seal was no longer extendable; a meter theoretically could remain in service for a maximum of 30 years before it would need to be replaced.

7.0 Smart Meter Sampling Plan Costing:

The cost of acquiring the MC S-S-06 accredited meter testing / reverification / compliancy documentation services, meter installation contractor services and executing the pre-sampling and final sampling efforts as per the chart above will be approximately \$304,511 over the next 4 years (2016 – 2019).

The \$304,511 total 2016 to 2019 plan cost includes a 10% contingency to manage unpredictable or unknown costs such as labour increases, USD/CAD exchange rates, CPI and other inflationary costs (ie. fuel/gasoline prices etc.)

The 2016 – 2019 smart meter sampling plan execution costs are based on prices taken for TBHEDI's inventory data base, TBHEDI's 2016 labour costing / overhead spreadsheet and actual prices from the contracted accredited meter verification shop (AMV), meter installation contractor and a shipping company.

From 2016 – 2019, there is a meter “re-verification” component which will cover the costs of having 444 meters re-verified with a new seal expiry date so they can be utilized to offset the cost of purchasing additional new meters of the same type (these meters either currently reside in TBHEDI's stores inventory or are installed in the field). The 444 meter reverification count differs from what is captured in Appendix's A, B and C (2019 seal expiries) as there are 22 meters that have a 2017 seal date expiries and the need to have a small quantity of tested meters available for immediate deployment.

In addition, there will be an ongoing and continuous annual component to the pre/final sampling program(s) as these “replaced” meters will have different seal expiry dates and will need to be managed via a “smaller scale” pre/final sampling program(s) or a meter replacement and reverification program.

Not included within this plan are the costs associated with:

1. Any meters which fail final testing. A meter lot failure which would mandate TBHEDI to replace all of the meters within that particular meter lot. As the majority of the 2019 final testing meter lots have approximately 6,850 meters in them, the cost to finance a 6,850 meter purchase would be approximately \$732,950.
2. Any of the 700-800 meters which are replaced annually due to unplanned failures.
3. Any of the OEB defined “Metering Inside the Settlement Timeframe” (MIST) GS >50 kW interval type meters which have a August 21, 2020 replacement deadline.
4. Any new customer meter requirements, which are projected at approximately 200 residential meters and 30 general service type meters annually.

At a new smart meter purchase cost of approximately \$5,000,000 (does not include installation); TBHEDI could avoid the smart meter sampling / seal reverification program by replacing 46,000 of their smart meters by/in 2019. However, this expense would be a reoccurring activity every 10 years where for a fraction of the total smart meter replacement cost TBHEDI could leverage the meter seal extension process and save millions of dollars.

8.0 Smart Meter Sampling Plan Conclusion / Recommendation:

In addition to implementing a compliance sampling meter seal extension program, TBHEDI has established a multi-year service agreement with an accredited meter verification (AMV) provider and will be incorporating a “pre-sampling” strategy into their meter seal extension program so they can establish with confidence what LQ target level / lot size is appropriate and to have due diligence documentation supporting that they did what was reasonable to avoid unknowingly leaving inaccurate meters in their system in the event that a final meter sample fails.

Appendix A details meter lots with 2019 seal expiry dates which qualify for “pre/final” sampling as per the Measurement Canada SS-06 criteria.

Appendix B and C details the “small” and “very small” meter lots with 2019 seal expiry dates and which meters will require re-verification and or purchase of new meters so they can be replaced prior to their 2019 seal expiry.

To mitigate unnecessary plan execution costs, existing meter inventory quantities will be re-verified and utilized accordingly in lieu of purchasing a new meter(s). This strategy, however will take longer to complete as TBHEDI will have to wait for the removed “in service” meters to be returned after testing before they can continue to replace all the other applicable meters within the targeted meter group.

The meter count discrepancy between the original smart meter installation number of approximately 50,000 meters in 2009 and the 46,188 smart meters detailed throughout this plan is due to the number of random meter failures TBHEDI has experienced annually since the initial smart meter rollout.

Smart meters that have failed since their inception and or any new customer meter installations since 2009 will be targeted for seal extension or re-verification activities in the years’ following 2019.

APPENDIX A

Meter Sample Groups For 2019 Appendix A	Number of Meters in Service	Sample Group Size as per Measurement Canada Criteria	Accredited Meter Verification Shop Recommended Sample Group Size to Replace any Meters Damaged in Shipment (+25%)	Purchase or Reverif. Plan
Elster RS(2S) 200A 240V Single Phase				
Test group 1002- 7011 meters	7011	200	250	buy 750
Test group 1003- 7034 meters	7034	200	250	
Test group 1015- 6911 meters	6911	200	250	
Test group 1026- 6960 meters	6960	200	250	
Test group 1030- 6334 meters	6334	200	250	
Test group 1035- 6847 meters	6847	200	250	
Elster R2S(12S) 200A 120V Network				
Test Group 1021- 2702 meters	2702	125	156	buy 156
Elster R2SD(2S)Internal disconnect single phase				
Test group 1020- 1151 meters	1151	125	156	buy 156
Elster A3TL (3S)				
Test group 1008- 357 meters 302 in service	302	80	100	buy 45 reverif. 55
Elster A3TL(16S)				
Test group 1009- 516 meters 509 in service	509	125	156	buy 149 reverif. 7
Ten separate sample groups totalling 2068 meters			2068	
Number of meters in service in this section -- 45761				
			Appendix A: # of New Meters to Bu	1256
			Appendix A: # of Reverif. Meters	62

Appendix B

Reverification Meters by 2019 Small Meter Lot Appendix B	Number of Meters in Service	Minimum Meter Sample Group Size as per Measurement Canada Criteria	Comments -- seal extension for all of these meters would be subject to a 50% reduction (ie. 8yrs down to 4 yrs)	Purchase or Reverif. Plan
Elster A3TL(35S)				
Test group 1004- 127 meters 81 in service	81	44	TBH has chosen to exclude these meters from the sampling program and do a meter re-verification	Buy 0 -- Re-verif. 86
Elster A3RL (9S) 3 phase transformer rated				
Test group 1005- 69 meters	69	44	TBH has chosen to exclude these meters from the sampling program and do a meter re-verification	Buy 25 -- Re-verif. 49
Elster R2SD(12S) W/Int disconnect				
Test group 1022 - 110 meters	110	44	TBH has chosen to exclude these meters from the sampling program and do a meter re-verification	Buy 40 -- Re-verif. 75
Elster A3RL(9S)				
Test group 1028 - 78 meters	78	44	TBH has chosen to exclude these meters from the sampling program and do a meter re-verification	Buy 25 -- Re-verif. 58
Potentially 4 separate sample groups (338 meters) a "small lot size" has to be utilized				
allowable seal extension is			Appendix B: # of New Meters to Buy	90
however subject to a 50% reduction (ie. 8yrs down to 4 yrs)			Appendix B: # of Reverif. Meters	268
reverif. More meters that what are deployed is for immediate availability / deployment purposes only				

Appendix C

Reverification Meters by 2019 Very Small Meter Lot Appendix C				Number of Meters in Service	Sample Group Size as per Measurement Canada Criteria	Comments	Purchase or Reverif. Plan
Elster A3TL(12S) 200A 120V Network							
Test group 1006- 34 meters 25 in service				25	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 0 -- Re-verif. 30
Elster A3RL (35S) 3 phase							
Test group 1007 -14 meters 6 in service				6	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 0 -- Re-verif. 7
Elster A3RL (35S) 3 phase 2.5 element							
Test group 1012- 4 meters				4	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 2 -- Re-verif. 3
Elster A3TL(16S) Ext Antennae							
Test group 1016 - 50 meters 5 in service				5	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 0 -- Re-verif. 6
Elster A3RL(16S)							
Test group 1010- 4 meters				4	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 2 -- Re-verif. 3
reverif. More meters that what are deployed is for immediate availability / deployment purposes only							

Appendix C

Reverification Meters by 2019 Very Small Meter Lot Appendix C				Number of Meters in Service	Sample Group Size as per Measurement Canada Criteria	Comments	Purchase or Reverif. Plan
Elster A3RL (3S)							
Test group 1011-9 meters				9	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 3 -- Re-verif. 7
Elster A3TL(3S) Ext Antennae							
Test group 1017 - 25 meters 0 in service				0	30	not compliant for sampling program due to the time on test and or meter quantity requirements	0 used no action required
Elster A3TL(9S) Ext Antennae							
Test group 1018 - 70 meters 4 in service				4	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 0 -- Re-verif. 5
Elster R2S(1S)100A 120V							
Test group 1023 - 24 meters 10 in service				10	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 0 -- Re-verif. 12
Elster A3RL(9S) Ext Antennae							
Test group 1024 - 7 meters 2 in service				2	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 0 -- Re-verif. 3
reverif. More meters that what are deployed is for immediate availability / deployment purposes only							

Appendix C

Reverification Meters by 2019 Very Small Meter Lot Appendix C					Number of Meters in Service	Sample Group Size as per Measurement Canada Criteria	Comments	Purchase or Reverif. Plan
Elster A3TL (35S) Ext Antennae								
Test group 1025 - 10 meters 0 in service					0	30	not compliant for sampling program due to the time on test and or meter quantity requirements	0 used no action required
Elster RSS(2S) 200A 240V Bi-Directional								
Test group 1031 - 12 meters					12	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 4 -- Re-verif. 10
Elster R2S(12S) Bi-Directional								
Test group 1032 - 4 meters					4	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 2 -- Re-verif. 3
Elster R2S(1S)100A 120V Bi-Directional								
Test group 1034 - 4 meters					4	30	not compliant for sampling program due to the time on test and or meter quantity requirements	Buy 2 -- Re-verif. 3
					89			
Meters impacted by the 2019 seal expiry date					46188		Appendix C: # of New Meters to Bu	15
							Appendix C: # of Reverif. Meters	92
reverif. More meters that what are deployed is for immediate availability / deployment purposes only								

Appendix G: Tbaytel Fibre Media Release



MEDIA RELEASE

Tuesday, October 13th, 2015
For Immediate Release

Tbaytel, City of Thunder Bay and Thunder Bay Hydro Partnering to Make Smart City Infrastructure Investments

Thunder Bay, Ont. (Oct. 13, 2015) – Tbaytel is committed to investing over \$40.5 million in the expansion of its state of the art fibre optic network by the end of 2020. The company has invested close to \$9.5 million to date and with a partnership between the City of Thunder Bay and Thunder Bay Hydro, Tbaytel will accelerate the deployment of fibre to more neighbourhoods throughout the city with an additional investment of \$31 million.

Tbaytel Fibre runs a system of next generation fibre optic cables throughout a neighbourhood with a dedicated fibre optic connection right to a customer's home or business. Fibre networks provide an extremely reliable connection to deliver virtually unlimited bandwidth, allowing for faster upload and download speeds than is possible with the use of traditional copper technology.

"Creating a smarter, more efficient and more connected city is a top priority for Tbaytel as well as for the City of Thunder Bay and Thunder Bay Hydro," says Tbaytel president and CEO Dan Topatigh. "By working co-operatively using a co-ordinated approach to capital planning, Tbaytel is now able to enter new neighbourhoods to install Tbaytel Fibre while Thunder Bay Hydro is working to replace aging infrastructure in the same areas."

Like Tbaytel, Thunder Bay Hydro is also placing a priority on meeting the future demand of its customers with the installation of more sophisticated technology as portions of the electricity system are rebuilt.

"Our company has been pursuing an accelerated infrastructure investment program to rebuild portions of our distribution system that have reached end of life," says Robert Mace, president and CEO of Thunder Bay Hydro. "The expected result of increased annual spending in our infrastructure is a robust, reliable and safe electrical system, which is a vital foundation for the support of smart city technologies."

The creation of a smart city with multi-year capital investment projects like public Wi-Fi and broadband connectivity upgrades was originally identified as a priority for the City of Thunder Bay in 2009 through the city's strategic infrastructure plan *Renew Thunder Bay*.

"Investment in the creation of a smart city through the use of emerging communication and telecommunication technologies is hugely beneficial for the people of Thunder Bay," says Mayor Keith Hobbs. "By having a more reliable, more efficient source of electricity and modern broadband solutions in

place to advance our community forward, Thunder Bay is in a better position than ever to meet the growing needs of our citizens and position itself globally.”

On Sept. 28, 2015, the City of Thunder Bay announced that it will continue to focus on investments made to contribute to smart city initiatives when it released the implementation plan for the approved 2015-2018 Corporate Strategic Plan *Becoming our Best*.

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About Tbaytel:

Tbaytel is dedicated to delivering telecom solutions that ensure people, businesses and communities in northern Ontario have multiple points of access to the global communications highway. Tbaytel offers 4G LTE, the region’s largest 4G HSPA digital cellular coverage area and extensive products and services in many neighbourhoods that include data, voice, wireless, internet, security and digital TV. With over a century of contributing to the quality of life, infrastructure and economic health of the north, Tbaytel’s understanding and commitment to northern Ontario is unparalleled.

About Thunder Bay:

Thunder Bay is a vibrant, multicultural community and is home to regional government, commercial, medical, and educational facilities. The largest municipality in Northwestern Ontario and the largest city on Lake Superior, Thunder Bay has the best of both knowledge and nature. With an increasingly diversified economy and newly developed waterfront, the City has demonstrated its ability to capitalize on opportunities and resources. The city is building a reputation for technical leadership and world renowned medical research, and is home to the newest Law and Medical schools in North America.

With a population of 110,000, Thunder Bay is rich in people and resources. We value our high quality of life and promote a clean, green, beautiful community that provides economic opportunity, respects diversity and provides affordable and safe neighbourhoods that are accessible to all. From parks and recreation to transportation, clean drinking water or waste management, Thunder Bay is always working to live up to our motto, Superior By Nature.

About Thunder Bay Hydro:

Thunder Bay Hydro Electricity Distribution Inc. is responsible for the power line system within the city limits of Thunder Bay. The company is the local, front-line customer service face of the province's electrical industry providing for the reading of customer meters, billing, and offering energy conservation advice and programs. Locally, we build, plan & maintain the city's power line system and provide 24-hour emergency response to outages.

For more information, please contact:

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Appendix H: PCB Management Plan



THUNDER BAY HYDRO'S PCB MANAGEMENT PLAN

**Originally Prepared by : Guy Gasgoine
Revised by: Duane Szyszka**

April 22,2016

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1.0 Introduction:

Polychlorinated biphenyls (PCBs) are a mixture of up to 209 individual chlorinated compounds, are colorless to light yellow, have no known smell or taste, and do not naturally occur.

PCBs have been used as coolants and lubricants in transformers, capacitors, and other electrical equipment because they do not burn easily and are good insulators.

In 1977, PCB production was stopped when evidence showed that they built up in the environment and exposure was linked to causing acne-like skin conditions in adults, and neurobehavioral and immunological changes in children. It is for these reasons that the Canadian Environmental Protection Act now includes regulations and proposals in place that ensure PCB elimination.

2.0 General PCB Information:

Below is a list of general PCB facts that relate directly to the content of this document.

- One part per million (ppm) is the equivalent to one mg/kg
- Based upon a network analysis, Thunder Bay Hydro decided to remove 23 >50ppm PCB transformers per year
- Thunder Bay Hydro has currently identified 292 >50ppm PCB transformers
- A high PCB contamination level is >7,000 ppm
- A medium PCB contamination level is 500 – 7,000 ppm
- A low PCB contamination level is 50 – 500 ppm
- As of 2011, contaminated oil > 2 ppm PCB can no longer be picked up by a local waste management company and subsequently will be picked up, shipped, and processed appropriately via Thunder Bay Hydro's approved PCB destruction company
- As of 2014, Thunder Bay Hydro can no longer allow local scrap metal recyclers to purchase >2 to <50 ppm PCB equipment due to the lack of control in managing the final destination country where this waste stream ultimately ends up. This waste will be picked up, shipped and processed appropriately via Thunder Bay Hydro's approved PCB destruction company
- Sensitive areas are areas within 100 meters of a school, food processing facility or water treatment plant, hospital and child care facilities
- Thunder Bay Hydro is a licensed generator of PCB waste ONO171700
- Thunder Bay Hydro Site Identification Number for 37 Front Street is 601 86 A 009

3.0 PCB Strategic Plan

To comply with legislative requirements, Thunder Bay Hydro established a detailed action plan to systematically remove and destroy all identified PCB transformers and other pieces of PCB equipment within the utilities network. Thunder Bay Hydro will (under the projected completion horizon of the PCB Management Plan) be requesting approximately 1.8 million dollars to fulfill all present legislated PCB use and destruction requirements. The chart below provides a summary of the work done from 2009, to the future PCB removal plans for 2017.

PCB Plan Year	>500ppm PCB	>50ppm PCB	PCB Substation Transformers	PCB Reclosers	Total
2009	38	12			50
2010		26			26
2011		25			25
2012		29	2		31
2013		28		2	30
2014		28	1	4	33
2015		20			20
2016		23			23
2017		13			13

*2016-2017 are future PCB removal plan estimates

4.0 Legal Requirements

The current legislation for PCB removal is broken into three parts which include: deadlines, storage requirements, and labeling and reporting. However, the key element of the current regulations is the prescribed end of use deadlines for liquids containing PCBs and PCB contaminated equipment that is still in use or temporarily out of service.

4.1 Part 1- PCB End of Use Deadline:

Part one sets out the deadlines for phasing out the use of PCBs and PCB products. Removal of this equipment by the dates indicated is required in order to comply with legislation.

- For equipment containing PCBs in a concentration of 500 ppm or more:
 - December 31, 2009
- For equipment containing PCBs in a concentration of at least 50 ppm but less than 500 ppm:
 - December 31, 2009 (when located in sensitive locations)

- December 31, 2014 (for padmounted equipment)
- December 31, 2025 (at all other locations)

4.2 PCB End of Storage Deadline

Part two sets out the storage requirements for PCBs and products containing PCBs that are no longer in use. The legislated end of storage dates and storage time periods for PCBs and products containing PCBs with a concentration of 50 ppm or more are as follows:

- A storage period of one year is allowed for PCBs and PCB contaminated products once the equipment has been removed from service at the following locations:
 - At the owner's PCB storage site
 - At the PCB storage site of an authorized facility for decontamination
 - At the PCB storage location of an authorized transfer site
 - At the PCB storage site of an authorized destruction facility
 - Within 100 m of a sensitive location

4.3 PCB Reporting and Identification Requirements

Part three sets out the end of use labeling and reporting requirements for PCBs and products containing PCBs that may continue to be used or that are stored for specific periods. The regulations also prescribe the analytical methods and standards to be used to determine the concentration of PCBs for the purpose of determining compliance with the proposed regulations. A written report for PCBs in use and in storage is to be submitted to the Ministry of Environment and Energy (MOEE) annually and is to include the following:

- An inventory of PCB oil, PCB contaminated equipment in use, and our plan to progress towards the end of use deadlines including time lines and destruction dates
- An annual written report summarizing the quantities of PCB oil or PCB contaminated products that were manufactured, imported, exported, sold, offered for sale, used or processed at a laboratory or research facility
- Notification and a written report to an Environment Canada enforcement officer or a person identified in the proposed regulations for a >1 gram PCB solids release into the environment or the likelihood of a release. This report shall include such details as the estimated quantity of PCBs released in grams, the environment affected by the release, and other information as required in the regulations

- Accurate and detailed inventory information on any PCBs in storage

4.4 Identification Requirements

PCB equipment and containers must be properly labelled (until they have been eliminated), regardless if they are out of service or in storage. On equipment, containers, or products containing >50 ppm PCBs, the identification shall indicate the owner's name and date the products were put in storage. For electrical transformers that have been decontaminated to a PCB concentration of <50 ppm, the identification shall indicate the owner's name and that the transformer is decontaminated.

Finally, at PCB storage sites, a notice indicating a PCB contamination level of >50 ppm in any of the equipment, containers, or products, stored at that site and the storage site must display the owner's name. There are some exceptions or alternatives to the labelling requirements based on practical considerations for in-use equipment already labelled, as well as cables and pipelines.

5.0 PCB Testing History

Thunder Bay Hydro has approximately 7,100 distribution transformers, power transformers, primary metering units, circuit breakers and oil circuit reclosers presently in service. In 1987, approximately 500 units were field tested. The testing then continued in 2004 and 2007, where 2,000 and 2,338 units were field tested respectively. Additionally, all substation transformer oil has been tested and was found to contain <50ppm PCBs.

Number of transformers tested to date	PCB content less than 50 ppm	PCB content between 50 and 500 ppm	PCB content between 500 and 10,000 ppm	PCB content > 10,000 ppm
4838	4546	254	35	3
Number of transformers removed from service and decommissioned as of January 20, 2016		218	35	3
Total Remaining	4546	36	0	0

Table 1 - Thunder Bay Hydro PCB Testing and Replacement History
(as of January 20, 2016)

- In a continuing effort to eliminate PCB transformers, so far this year (January-June), Thunder Bay Hydro has removed 26 transformers that were known to contain PCBs

6.0 Budgeting

For each future year of this program, Thunder Bay Hydro Power Systems will request funding to replace and dispose of all targeted PCB equipment and or waste. Consequently, there are budgeting considerations put in place by Thunder Bay Hydro which include:

- Advertising larger scale interruptions should they be required
- Lines personnel will work with the Utility Work Protection Code (UWPC) as it relates to isolation and de-energization to ensure personnel safety and to the most efficient use of interruptions where transformers are to be removed
- Ensure all Thunder Bay Hydro personnel (lines, stores, engineering, stations etc.) working times directed to this project are entered on timesheets to track the true cost of this project

To assist in timely equipment procurement, the Operations Group will provide a detailed list to engineering for all the >50 ppm PCB transformers that will be replaced in the preceding year. This list will detail each of the targeted transformer's voltage, KVA, sub group, serial number, Thunder Bay Hydro number, address, PCB content etc.

7.0 PCB Oil and Solid Waste removal and Destruction

In order for the PCB Management Plan to be successful, multiple departments within Thunder Bay Hydro (Engineering, Lines, Operations, and Substations) will be responsible for carrying out different aspects of the plan which include:

- Asset Management & Engineering:
 - Oversee the specification / requisition entry process for all transformers required to fulfill this plan
- Lines Department:
 - Oversee the replacement of all targeted transformers
- Operations Department:
 - Acquire the services of an approved PCB Transportation and Destruction Contractor for the duration of the program
 - Review emergency plans regarding fires and spill response
 - Update this plan no less than annually and or as required throughout a calendar year
- Substations Group:
 - Assist in the safe processing, storage and loading of all PCB contaminated material, in preparation for transportation by the PCB Transportation and Destruction Contractor

- Maintain accurate record keeping of material types and PCB concentrations removed from Thunder Bay Hydro property for inclusion onto the transportation manifests
- Maintain accurate records and update 'HTE'
- Maintain accurate record keeping of all PCB material movement for year-end reporting as per regulations of Canadian Environmental Protection Act
- Maintain and archive all certificates of destruction as they are awarded and maintain the security of Thunder Bay Hydro PCB storage facilities

8.0 Actual and Anticipated Cost of PCB Management Plan Compliance

Grey shaded area denotes actual expenditures for PCB activities completed for the applicable years

Year	Actual and Anticipated Number of U/G Transformers Replaced	Actual and Anticipated Number of O/H Transformers Replaced	Actual and Anticipated Transformer Replacement OM&A Cost (labour, trucking, materials overheads etc.) (2009 – 2012 CGAP was used OMA costs were extracted)	Actual and Anticipated Transformer Replacement Capital Cost (2009 – 2012 CGAP was used OMA costs were extracted 2013+ -- IFRS was used and all assoc. transf. costs were Capitalized)	Substations OM&A Cost (labour, trucking, materials overheads for underground and overhead PCB waste management and processing etc.)	Combined OM&A and Capital Transformer Replacement Cost (\$6,000 per transformer) – as of 2013 the Substations labour was also included	Actual and Anticipated >2 ppm PCB Oil Destruction Costs for (2011-2017) (2008-2010 TBH only destroyed >50 ppm PCB oil)	Actual and Anticipated Destruction Costs of >50 ppm PCB Solid Waste Material (2014-2017 >2 ppm PCB Solid Waste is included in this cost)	Actual and Anticipated Transport Costs (2014-2017 >2 ppm PCB Waste is included in this cost)	Actual and Anticipated Cost Totalled
2009	6	44	\$162,206.12	\$101,412.28	Not tracked	\$263,618.40	\$17,913.02	\$9,684.59	\$8,770.00	\$299,986.01
2010	3	23	\$121,296.48	\$41,908.65	Not tracked	\$163,205.13	\$6,378.75	\$1,248.45	\$3,500.00	\$174,332.33
2011	12	13	\$97,882.08	\$59,605.70	Not tracked	\$157,487.78	\$25,107.75	\$1,568.90	\$6,241.04	\$190,405.47
2012	18	11	\$206,502.95	\$127,557.07	Not tracked	\$334,060.02	\$16,412.49	\$6639.81	\$8,750.00	\$365,862.32
2013	5	25		\$122,913.43	\$36,068.10	\$158,981.53	\$15,787.98	\$2,520.66	\$7,000.00	\$184,290.17
2014	4	24		\$114,165.64	\$30,215.63	\$144,380.97	\$11,866.85	\$23,674.90	\$7,000.00	\$186,922.72
2015	0	20		\$100,383.59	\$23,591.06	\$123,974.65	\$3,878.42	\$8,464.45	\$10,500.00	146,817.52
2016	0	23		\$110,000	\$25,000	\$135,000	\$5,000	\$10,000	\$7,600	\$157,600
2017	0	13		\$60,000	\$15,000	\$75,000	\$5,000	\$10,000	\$7,600	\$97,600
TOTAL										\$1,803,816.54

The current plan total incorporates overall program cost actuals for 2009 – 2014 and includes a revised average transformer replacement cost of ~\$5,200 vs the original plan amount of \$10,000 (based on 2009 – 2011 actual costs)

In 2011, 1 substation transformer was de-tankled with the oil causing an increased 2011 oil destruction cost

In 2012, 18 u/g transformers were replaced with a OM&A cost of \$157,980.52, in contrast replacing the 11 o/h transformers cost OM&A \$48,522.43, in addition 2 substation transformers (1T1 / 7T2) were disposed of causing an increase in the 2012 solid waste and oil destruction costs (11,224 Kg @ \$0.15/kg + unknown litres of oil) – station OM&A costs were captured under the station decommissioning / retirement WFOs J/O 11

In 2013, 2 transformers (late removals), 2 reclosers from Chippewa and 4 underground feeder cables were removed from Brock substation (these items have not been captured within the 2013 pickup, transportation and disposal costs as they came into storage after the September PCB waste pick-ups)

In 2014, additional costs will be incurred to transport and dispose of >2 ppm to <50 ppm PCB solid waste – as the contaminated equipment within the 2 to 50 ppm range does not have any legislated removal criteria, only substations processing, the pick-up, transportation and destruction component will be tracked and included within future revision of this plan – it is anticipated to increase the historical solid waste destruction and double the transportation costs

In 2015, the Balsam substation 4Kv breakers need to be managed as PCB waste as it is planned for retirement

In 2016, additional costs will be incurred to transport and dispose of >2 ppm to <50 ppm PCB solid waste as our new contract pricing has some increases over previous years and the Balsam 18T1 transformer (146 ppm carcass) and the Mapleward 36Spare transformer (9.3 ppm carcass) will be managed as PCB waste

In 2017 the Grenville substation transformer (37 ppm carcass) needs to be managed as PCB waste as it is planned for retirement

PCB costs were tracked via the following work orders:

2008 – 2011 WFO329417 (O/H) and WFO 329418 (U/G) – J/O's 001/002/004/005/009 for OM&A – J/O 008 for Capital

2012 -- WFO424737 (O/H) and WFO424738 (U/G) -- J/O's 001/002/004/005/006/009 for OM&A – J/O 008 for Capital – transformer counts were taken from the applicable Part A Project #A21

2013 -- Substation's staff OM&A will be tracked using WFO450902 J/O 15 (O/H) and WFO450903 J/O 09 (U/G) -- for Capital / Lines – costing and transformer counts were taken from the applicable Part A Project #A1301

2014 -- Substation's staff OM&A will be tracked using WFO450902 J/O 15 (O/H) and WFO450903 J/O 09 (U/G) -- for Capital / Lines – costing and transformer counts were taken from the applicable Part A Project #A1401

2015 -- Substation's staff OM&A will be tracked using WFO450902 J/O 15 (O/H) and WFO450903 J/O 09 (U/G) -- for Capital / Lines – costing and transformer counts were taken from the applicable Part A Project #A1501

2016 -- Substation's staff OM&A will be tracked using WFO450902 J/O 15 (O/H) and WFO450903 J/O 09 (U/G) -- for Capital / Lines – costing and transformer counts were taken from the applicable Part A Project #A1601

2017 -- Substation's staff OM&A will be tracked using WFO450902 J/O 15 (O/H) and WFO450903 J/O 09 (U/G) -- for Capital / Lines – costing and transformer counts were taken from the applicable Part A Project #A1701

9.0 Other Cost Factors to Consider

The pricing shown in the preceding chart makes various assumptions for the purpose of estimation. Listed below are some factors that have the potential to affect the accuracy of these estimates.

9.1 Potential Additional Costs

- Due to local contractors NOT being able to pick up 2 – 50 ppm oil because of regulatory constraints in 2011, Thunder Bay Hydro may be forced to include this lower level PCB oil waste in with the volume of waste oil provided to the destruction company. Thunder Bay Hydro will manage the storage of this oil within the East/ West tanks accordingly so there is a reduced cost for the oil picked up, shipped, and processed
- Transportation costs through 2012 have been increased to \$7000 to reflect additional waste pick up requests based on the extra oil waste accumulating as per the above statement. Additionally, transportation costs in 2016 have been increased to \$3,800 per trip as per the rate change indicated within the new contract
- As of January 2014, due to approximately three additional >50 ppm PCB transformers being removed from service annually (capital construction activities, equipment failures, motor vehicle accidents etc.) the PCB management plan has progressed ahead of schedule as only 86 of the original 292 >50 ppm PCB transformers remain in service, the plan was updated from the original version which had a 2020 completion year to 2017 to reflect a continued commitment to replace 23 transformers annually
- Replacement of the contaminated substation transformers and substation breakers is not detailed as an annual activity. The transformers and breakers are part of Thunder Bay Hydro's 4 kV to 25 kV system wide voltage conversion commitments and due to construction variables may or may not occur when projected
- Decontamination and destruction prices for PCB oil and PCB waste has the potential to increase, as seen in 2007/2008 when there was a 12% PCB material increase cost
- Changes to the Canadian Environmental Protection Act could shorten the timeframes that must be complied to by changing the deadlines, or changing the levels of PCB contamination that must be removed and destroyed
- Labeling previously tested equipment from 2007 and earlier years (more than 2,000 transformers) that remain in service is a requirement of the regulations and represents a substantial investment in Thunder Bay Hydro staff involvement which was not originally budgeted for
- The cost of inflation for services and material was not taken into account for the purpose of estimating the cost of the sampling campaign
- As of 2014, Thunder Bay Hydro was no longer able to sell their transformers which are contaminated at > 2 ppm to <50 ppm PCB to local scrap metal recyclers. These

items will be managed, processed, picked-up, transported and destroyed by Thunder Bay Hydro's approved contractor (these costs are estimated in the 2014/2017 calculations)

- Although this PCB Management Plan is primarily based on the current >50 ppm PCB legislation and is anticipated to conclude in 2017; Thunder Bay Hydro will need to budget funds to appropriately manage the transportation and destruction costs of its >2 ppm PCB oil, contaminated substation transformer shells, >2 ppm PCB ancillary equipment and its >2 <50 ppm PCB distribution transformer waste until all of those >2 ppm PCB assets have been removed from service

9.2 Cost Savings

Previously scheduled capital work will also limit the need to schedule the removal of identified PCB transformers as these units will be replaced under the capital funding programs instead of operating accounts.

10.0 Summary

By implementing this PCB Management Plan, Thunder Bay Hydro will have initiated a mechanism to track progress, costs associated with this endeavor, and comply with the Canadian Environmental Protection Act of 1999, and the latest proposals regulating the continued use, storage and destruction of PCBs. This plan identifies the decommissioning, labeling, and record keeping required to properly manage PCB contaminated equipment in service and in storage. Furthermore, it outlines a systematic and scheduled approach to removing this equipment from service, eliminating it from storage and the budget requirements necessary to ensure it happens.

As revised in January 2016, there are 36 known >50 ppm PCB distribution type transformers remaining in service. As of this report, it is projected that Thunder Bay Hydro will have to spend approximately \$255,000 dollars over the next two years to manage the >50 ppm PCB waste and to remain in compliance with the present PCB legislation. This figure does not take into account any annual cost of transportation or destruction service increases, nor does it project costing for managing any >2 < 50 ppm PCB waste after 2017.

In conclusion, the cost of compliance will be expensive, but not as expensive as the potential risks to the environment should PCB's be allowed to remain in service. It is with this mindset that Thunder Bay Hydro will assert all necessary resources to achieve this goal.

As revised in April 2016:

Clarifications and changes to the indicated costing spreadsheet completed. 2009 – 2012 CGAP was in place which required OMA costs be extracted from the Capital transformer replacement costs.

Appendix I: IS and IT Strategy

Thunder Bay Hydro Electricity Distribution Inc.

I.S. and I.T. Assessment

Overview of Information Systems and Technology strategy and capital projects.

Contents:

- Summary
- IS/IT Strategy
- Hardware
- Software
- Resources

Summary

This document outlines capital requirements for IS/IT initiatives in support of TBHEDI business requirements. Hardware, software and supporting resources will be detailed. Capital expenditures for IS/IT initiatives are projected out 5 years and are specific to business requirements, protections and efficiencies utilizing information technologies and processes.

IT technology presents an inherently short life cycle requiring annual equipment replacements and technological upgrades staggered annually. Capital forecasts reflect standard equipment replacement as well as new initiatives and requirements in support of corporate business and operational goals. Network integrity, data security and business efficiencies are primary concerns, as reflected in overall capital expenditures.

IS/IT Strategy

Information systems within TBHEDI require a complex technology infrastructure to support corporate business goals, operational processes and regulatory requirements. Ongoing expenditures ensure that critical requirements are effectively addressed and the infrastructure and data processes are both resilient and secure. IT expenditures are reflected in a wide range of critical components including; cabling (both copper and optical), switches, servers, storage area networks, firewalls, tape libraries, cellular and internet communication nodes, end user devices (desktops, laptops, tablets, thin clients), multifunction printers and scanners, as well as backup power protections. Ensuring that technology is both current and adaptive has been an ongoing strategy with TBHEDI, this focus has provided a stable, reliable and secure environment. Initiatives specific to business continuity, disaster recovery and data protections are a direct result of a defined and explicit technology design plan.

Overall planning and capital expenditure for hardware, software and resources has provided the requirements for critical goals to be met;

- Effective and efficient business processes
- Integrated, reliable enterprise solutions
- Regulatory and third party secure data interchanges
- Business continuity and disaster recovery processes
- Best practices for a secure and managed network infrastructure

Hardware

Hardware acquisitions have been driven by multiple requirements including ongoing business requirements, supporting evolving and new software applications, network and data security, as well as an emphasis on risk management through business continuity and disaster recovery strategies. Ensuring critical IT infrastructure security, availability and integrity requires appropriate monitoring and control mechanisms as well as resiliency and redundancy by design. Core business systems are subject to continuous evaluation and technology review to ensure IT investments are appropriate and support Thunder Bay Hydro Electric Distribution Inc. business objectives.

Key hardware components within TBHEDI's infrastructure include;

- 22 physical servers hosting 53 virtual application servers
- 2 iSeries power system computers hosting ERP and CIS/billing environments for TBHEDI and four district utilities
 - Primary computer hosts both production and development partitioned environments
 - Secondary computer hosts replicated ERP and CIS environments for business continuity/disaster recovery
- 7 firewall appliances (6 used in 3 HA clusters)
- 26 network switches
- 2 high capacity storage area network (SAN) appliances

- o Dual SAN environments provide data replication function for business continuity/disaster recovery
- 3 tape libraries
 - o Media backups are segregated for network, production ERP/CIS, DR ERP/CIS
- 109 user workstations including desktop, laptop and tablet devices
- 26 network available printers

Hardware components are maintained with current maintenance agreements and are managed as part of TBHEDI's cyclical end of life (EOL) replacement program. Current equipment replacement cycles are;

- Six year EOL equipment include;
 - o network switches
 - o network stations (thin) clients
 - o non corporate firewalls
- Five year EOL equipment include;
 - o host servers
 - o ERP/CIS host (replaced unit is moved to business continuity/DR role)
 - o storage area networks (SAN)
 - o tape libraries
- Four year EOL equipment;
 - o user laptops (warrantied at 3 years but budget for 5% final year failure rate as contingency)
- Three year EOL equipment includes;
 - o corporate firewall appliances (HA clusters)
 - o desktop computers

Some items including computer monitors, wireless access points, tablets, Ethernet cabling, I.T. physical plant (A/C, UPS, Racks, security) are replaced as required.

Category Hardware	2017	2018	2019	2020	2021	Total
PC's, Laptops	41,600	38,200	53,000	61,800	40,000	234,600
GIS Mobility	25,000	0	0	0	0	25,000
Network Switches	10,000	0	20,000	0	0	30,000
Printers and Photocopiers	38,500	9,000	4,000	9,000	4,000	64,500
Servers	30,000	0	50,000	20,000	30,000	130,000
IBM iSeries Servers	0	170,000	0	0	0	170,000
SAN Storage	0	35,000	35,000	0	0	70,000
Firewall security systems	0	20,000	10,000	5,000	10,000	45,000
Network cabling	6,500	0	0	0	0	6,500
Wireless Access Points	5,000	0	0	0	0	5,000
I.T. Physical Plant	0	20,000	0	0	0	20,000
Professional services	0	15,000	0	0	0	15,000
Miscellaneous	12,400	0	0	0	0	12,400
Total	169,000	307,200	172,000	95,800	84,000	828,000

Software

TBHEDI continues to pursue effective automation of corporate business systems as well as operational efficiencies utilizing relevant application software. A number of projects are defined to promote stated goals;

- Transition of old and unsupported SCADA operating system code to a standardized Microsoft Windows server environment.
- Introduction of a mobile work management system to provide direct field access to critical ERP/CIS data in a timely and secure manner.
- Development of an outage management system (OMS) that is spatially oriented and will support work management initiatives as well provide effective customer information interactions.
- Enhanced data interaction between spatial systems (GIS) and the corporate ERP for data control and work management initiatives.

- Continue on the initiative to replace the legacy on premise email environment. The legacy system supported application development that hosted critical corporate applications that require redevelopment on a new programming platform.
- TBHEDI document management system continues to absorb and support varied corporate document handling and workflow requirements. The DMS will be used as the core application for an electronic forms control system transitioning internal paper forms to an electronic format and subsequently provide electronic forms to customers for an enhanced self-serve experience. Electronic forms will provide data in a format to be used for application integration and analytics/business intelligence initiatives.
- Replacement of the existing ERP/CIS 'green screen' interface with a windows look and feel presentation to provide both a consistent, multi system, experience as well as presenting efficiencies through reengineering screen data presentations.
- Upgrading the current Microsoft Office suite from the existing Office 2010 to cloud based MS Office 365 to provide enhanced functionality, secure and universal 24/7 access as well as reducing management overheads and internal storage requirements.
- Development of an enhanced web based customer resource management system (CRM) to improve customer experience and interaction with TBHEDI as well as provide the ability to harvest correct and current information, both demographic and service oriented, for the CIS environment.

Category Software	2017	2018	2019	2020	2021	Total
ERP/CIS enhancement	20,000	0	0		0	20,000
DMS Electronic Forms	12,500	0	0	5,000	0	17,500
MS Office 360	0	44,000	0	0	0	44,000
Interface customization	0	30,000	0	0	0	30,000
Custom Application Creation	0	20,000	20,000	0	0	40,000
WEB Portal Development	0	0	35,000	0	0	35,000
Mobile Work Management	0	15,000	0	0	0	15,000
CRM	0	0	0	40,000	0	40,000
Professional services	9,500	10,000	0	20,000	0	39,500
Network security software	0	0	0	0	50,000	50,000
Total	42,000	119,000	55,000	65,000	50,000	331,000

Resources

TBHEDI continues to be challenged in providing appropriate, timely and technically advanced solutions in an increasingly complex I.T. environment. New third party interactions, advanced processes to protect both I.T. business assets and data integrity, reliance on data based business intelligence and complex business processes all aggregate to challenge existing resources. To ensure that TBHEDI has the resources necessary to address the many challenges it is necessary to make significant investment in technology expertise provided by outside consulting. Expertise is required to not only validate technology planning and implementation but to also provide the critical resources to ensure data and process flows, from multiple systems, are effective, consistent and secure. Future I.T. based business functionality and adaptability will require the efficiencies and controls provided with multiple system cohesion, a complex process.

Conclusion

Thunder Bay Hydro Electric Distribution Inc. is committed to providing cost effective, secure and technically advanced processes and services to both our internal and external customers. Technology deployments and solutions continue to be closely aligned with business objectives and regulatory requirements. A focus on the ability to react effectively to shifts in either the business or technology paradigm is critical to the I.T. environment.

Hardware/Software Totals	2017	2018	2019	2020	2021	Total
Hardware	169,000	292,200	172,000	95,800	84,000	739,000
Software	42,000	119,000	55,000	65,000	50,000	331,000
Total	211,000	411,200	227,000	160,800	134,000	1,070,000

Appendix J: Material Capital Expenditures



2017 Capital Project Summary

A. General Information

Project Name	PCB Transformer Replacements	
Project Number	A1701	
Investment Category	System Access	
Capital Investment(s)		
	PCB Transformer Replacements A1701	2017
	Capital Cost (5.4.5.2 A.1)	\$118,655
	Capital contribution	\$0
	Net Cost	\$118,655
	O&M Cost (5.4.5.2 A.2)	\$46,600
	Thunder Bay Hydro expects there to be \$46,600 in costs due to the management, processing, transportation and destruction of PCB waste.	

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 90-195 customers
 Load: Between 72-155 kWh

Start Date (5.4.5.2 A.3)	01-01-17	In-Service Date (5.4.5.2 A.3)	01-10-17

Expenditure Timing for the Test Year

2017 Q1	2017 Q2	2017 Q3	2017 Q4
\$29,080	\$29,080	\$29,080	\$29,080

Project Summary

This project is comprised of the removal of PCB transformers and replacement with PCB free transformers in the Thunder Bay Hydro distribution system as per the Canadian Environmental Protection Act. Expenditures in 2017 include the cost to remove and replace 13 pole mounted distribution transformers that have been identified as greater than 50 ppm PCB content as per the Thunder Bay Hydro PCB Management Plan. The labour, trucking, and small miscellaneous material costs to remove and replace the device(s) are tracked in this project, the management, processing, transportation and destruction of PCB waste is not. The 13 transformers targeted for removal in 2017 are the final transformers to be removed from the Thunder Bay Hydro distribution system with greater than 50 ppm PCB. This project will be considered complete beyond 2017, with 244 transformers greater than 50ppm having been removed from 2009-2017. This project will not see expenditures until such time that government regulations mandate the removal of transformers between 2 ppm and 50 ppm.

Risk Identification & Mitigation (5.4.5.2 A.4)

PCB Regulations require the removal from service and destruction of all greater than 50 ppm PCB equipment by December 31, 2025. Thunder Bay Hydro has a plan in place to remove all identified greater than 50 ppm PCB equipment by 2018. The continued removal of these units ensures that Thunder Bay Hydro remains in regulatory compliance, but also reduces the risk of any potential spill or environmental contamination issues, and demonstrates Thunder Bay Hydro's stewardship in the environmental community.

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

Comparable investments are indicated above and vary based on the number of PCB transformers targeted in a given year.

None

See Appendix H – PCB Management Plan

The main driver for this project is the compliance with government regulations. Thunder Bay Hydro seeks to prioritize projects based on the successful completion of regulatory and/or legal obligations.

The secondary drivers are risk mitigation to the Environment and Health and Safety. Thunder Bay Hydro seeks to minimize impact to the environment through consideration of the risk for the potential contaminants released during asset failure and proximity to sensitive environmental areas. Thunder Bay Hydro is obligated to ensure that the manner in which it operates its system does not negatively impact the health and safety of the general public, customers or Thunder Bay Hydro's employees.

Thunder Bay Hydro's PCB Management Plan targets the end of 2017 for the removal of all transformers with a greater than 50 ppm concentration. The investment in 2017 includes 13 pole mount transformer replacements.

Asset data and Nameplate data from transformers, as well as additional oil testing completed subsequent to purchase (not available on all units) was used to plan the removal of PCB identified transformers.

PCB Transformer Investments are ranked P3 – High Priority, as this work or project is non-discretionary in nature and are essential to meet project deadlines or legislative/regulatory compliance. This project has been completed in order to meet compliance deadlines and has been ranked as 8 out of 21 projects for the test year.

With this program in place, customers can be assured that there will not be an environmental or health impact due to a PCB transformer. The installation of new transformers that meet current standards (e.g. current limiting fuses) will allow for the operation of equipment in a more efficient manner due to safer working conditions.

- a. A reduction of environmental consequences in the event of a failure of a PCB identified transformer
- b. A reduction in the outage time for the remediation of an environmental impact where a PCB transformer has failed and released oil to the environment.
- c. The removal of the requirement for speciality environmental services to manage the costly remediation efforts to ensure environmental compliancy.

Effect of the investment on system reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)

The replacement of transformers in this project will provide more cost effective options to limit outage areas and restore outage areas, providing improved reliability while eliminating a safety hazard to the public.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)
The alternative to removing and replacing the transformer is the following; a) Do nothing – this option results in non-compliance with regulations and may result in fines for the corporation which is not considered appropriate b) Leave transformers in service and replace only at the end of the deadline – this option results in a large amount of expenditure and resources required in one time period, and results in a greater burden to the corporation and rate payers, as such a levelled and strategic approach is considered more appropriate c) Replace the oil – this option is more costly than removing the transformer from service and replacing with a new PCB free transformer, for this reason this is not considered appropriate
Safety (5.4.5.2 B.2)
Although not technically a designated substance polychlorinated biphenyl's (PCB) are hazardous and can have adverse health effects associated with exposure.
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)
Transformer removals in this program do not impact the co-ordination with utilities, and any other regional planning activities. As with every project any customers related to a replacement are coordinated with.
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)
Where not currently installed, the new pole mounted transformers will be equipped with animal protection to enhance reliability and reduce outages from animal contacts.
Economic Development (where applicable) (5.4.5.2 B.5)
Not applicable
Environmental Benefits (where applicable) (5.4.5.2 B.6)
This project has a potential impact on the environment as oil containing high concentrations of PCB's will have environmental consequences upon release and avoiding this is a benefit to all.
C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA – C1)
There are 13 distribution transformers targeted to be replaced in 2017, after such time this project will be considered complete.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA – C2)
This project replaces transformers in a like-for-like manner, however if during the notification process customers have a preference for the location this is taken into consideration.
Factors Affecting the Final Cost (5.4.5.2 SA – C3)
Transformer replacement costs are based on historical metrics, factors that could affect the final cost include the difficulty of removal, as well as commercial customer outage requirements (overtime).
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA – C4)
In order to manage the costs associated with larger and more difficult transformer removals, a PCB management plan has been created to levelize the costs and resource requirements associated with the transformer removal and replacement.
Other Planning Objectives (where applicable) (5.4.5.2 SA – C5)

Other planning objectives such as ensuring the Health and Safety of the Public and Thunder Bay Hydro's employees are considered when executing this project. For example, PCB transportation, handling and disposal guidelines are strictly adhered to when managing the replacement of a PCB transformer.

Technically feasible project design and/or implementation options exist (5.4.5.2 SA – C6)

Thunder Bay Hydro makes all connections in accordance with the Conditions of Service posted on our website; this document has been created to minimize overall costs and impacts on the customer. There are other technically feasible options available, (see the Project Alternatives above) however as a like-for-like replacement of the transformers is the most cost effective option to remove existing transformers with PCB content.

Summary of results analysis (5.4.5.2 SA – C7)

The least cost and most cost efficient method is to replace these transformers like for like, where this is not the case, alternatives are reviewed.

Results of a final economic evaluation (where applicable) (5.4.5.2 SA – C8)

Not Applicable

Nature and Magnitude of System Impacts, Costs and Cost Recovery (5.4.5.2 SA – C9)

The PCB Transformer Replacement in 2017 is expected to have a low impact on the system, and is not considered a recoverable cost according to the Distribution System Code.



2017 Capital Project Summary

A. General Information

Project Name	Customer Recoverable System Modifications		
Project Number	A1702		
Investment Category	System Access		
Capital Investment(s)			
	Customer Recoverable System Modifications A1702	2017	
	Capital Cost (5.4.5.2 A.1)	\$281,092	
	Capital contribution	\$219,248	
	Net Cost	\$61,844	
	O&M Cost (5.4.5.2 A.2)	\$0	
	There is not expected to be anv O&M costs associated with this capital investment.		

There is not expected to be any O&M costs associated with this capital investment.

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: between 10-1000 customers
 Load: 11-1687 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
\$70,273	\$70,273	\$70,273	\$70,273

Project Summary

This project is comprised of customer driven work for additions or changes the Thunder Bay Hydro distribution system.

Examples of the work expected in this project include

- Accident repairs, such as motor vehicle accidents where Thunder Bay Hydro plant has been damaged,
- Make ready work for third party attachments
- Customer requests for relocation of services

Risk Identification & Mitigation (5.4.5.2 A.4)

This work is covered by well-established processes both from design and construction perspectives which mitigate issues around scheduling related risk. Customer connections are very important to Thunder Bay Hydro and timelines are strictly monitored and enforced to ensure obligations set forth in the Distribution System Code are met and that customer satisfaction is maintained

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

Customer Recoverable System Modifications A1702	2012	2013	2014	2015	2016	2017
Capital Cost	\$0	\$221,636	\$509,842	\$859,513	\$235,458	\$281,092

Comparable investments are indicated above and are dependent on the number customer requests in a given year.

2013 was the first year that Thunder Bay Hydro began tracking these investments in this account. Prior to that date, work of this nature was tracked elsewhere.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

None

Attach Other project reference material i.e. Images, Drawings and or reference material
These projects are typically requested and completed in the same fiscal year, and as such reference material is not available at this time.
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 driver for this project is Customer Driven Work. Thunder Bay Hydro is committed to executing customer work in a timely manner and must repair damages incurred from motor vehicle accidents as soon as possible and reduce the outage time seen by customers. Thunder Bay Hydro must grant access to third parties with agreements with Thunder Bay Hydro and make ready work due to a third party attachment request.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)
The secondary driver is the Health and Safety of Third Parties with attachments on Thunder Bay Hydro owned poles. The integrity of Thunder Bay Hydro assets ensures a safe workplace for those requiring to work on and around those assets.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)
The objectives for performing the work are to minimize the effect of an accident to our customers, and as such the objective for repairs is as soon as possible. The performance targets for the replacement of poles due to third party are based on a mutually agreed timeline created with each Joint Use Permit Party.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1a)
Requests for Third Party work are routed through the mandated Regulation 22/04 permit process and are reviewed by the Engineering department. Thunder Bay Hydro is in regular contact with all Third Party users to obtain their capital plans for subsequent years. Accident work and customer requests for relocation are variable and based on 2012-2015 historical numbers.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1a)
Recoverable investments are overall as ranked P3 – High Priority, as this project work is required to be compliant with CSA regulations. A small percentage of these investments are rated as P1 – Emergency as they are the executed as a result of loss of service (for example in the case of a pole being struck by a vehicle). System Access Projects are ranked above System Renewal, System Service and General Plant projects. This project has been ranked as 10 out of 21 projects for the test year.
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency, cost-effectiveness (5.4.5.2 B.1c)
Newly installed assets will be designed and constructed in the most cost-effective manner, and where possible, repairs are completed to restore power, and additional tasks are completed during regular time to ensure cost-effectiveness. For example, an accident pole may be braced in the middle of the night and then replaced the following day.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)
This project ensures that customers receive a reliable electrical supply from Thunder Bay Hydro's distribution system.
Effect of the investment on system on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)
Accident work can have an effect on the reliability performance (duration) as reported by Thunder Bay Hydro. As such the repairs are treated as emergency work, and when required to restore service are completed at all hours.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)
The alternative to completing the work is the following; a) Do nothing – this option results in potential safety hazards to the public, or delay in servicing our third parties, neither of which are acceptable
Safety (5.4.5.2 B.2)
These projects address immediate safety concerns posed by the results of car accidents. There is no safety concern addressed with respect to the projects completing make-ready work for third parties to attach, however additional guying requires a permit approval by the Engineering department, which will ensure no new safety concerns are created because of the new attachments.

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 meets regularly with Third Parties to exchange capital plans, this co-ordination has led to better capital expenditure planning. This process has become increasingly important as a local telecommunications company has increased their installation of fibre throughout the City. In order to coordinate efforts and to minimize effects of construction on customers, Third Parties have started to follow the practice of following the Thunder Bay Hydro capital program and are requesting new attachments primarily in areas where new poles have been installed, thus negating the need for potential work to be completed.
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)
Through the enabling of Third Party fibre attachments, Thunder Bay Hydro's investment in this project supports the potential use of fibre for future communication protocols on the distribution system.
Economic Development (where applicable) (5.4.5.2 B.5)
The City of Thunder Bay has prioritized investments in the creation of a 'smart city' with multi-year capital investment projects like public Wi-Fi and broadband connectivity upgrades. This was originally identified in the 2009 strategic infrastructure plan Renew Thunder Bay. The mayor has publicly stated that "By having a more reliable, more efficient source of electricity and modern broadband solutions in place to advance our community forward, Thunder Bay is in a better position than ever to meet the growing needs of our citizens and position itself globally." Through the enabling and coordination with Third Party attachers Thunder Bay Hydro's investment in this project supports the economic development goals of the City to position itself globally. (See Appendix G – for the details of this co-ordination)
Environmental Benefits (where applicable) (5.4.5.2 B.6)
Not Applicable.
C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA – C1)
The timing of individual projects is based on what is required by the customer. Projects in the System Access category take priority over System Renewal and System Service projects and if there are an abundance of requests in these categories, then System Access projects will take precedence.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA – C2)
These projects are initiated by Third Parties or by motor vehicle accidents and are designed to meet the needs of the customer.
Factors Affecting the Final Cost (5.4.5.2 SA – C3)
Main factors that affect final costs are amount of make ready work required as well as the amount of repair required after a motor vehicle accident. Final costs of individual projects cannot be determined until the scope of the project is finalized. Charges to the customer are based on fixed and variable costs that are updated annually.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA – C4)
The design and completion of make ready work is standardized and therefore costs are controlled through established processes and the use of standardized materials.
Other Planning Objectives (where applicable) (5.4.5.2 SA – C5)
Not applicable
Technically feasible project design and/or implementation options exist (5.4.5.2 SA – C6)

Third Parties have the option to reroute potential attachments, however, feasible options must be reviewed on a project by project basis, which cannot start until each project is initiated.

Summary of results analysis (5.4.5.2 SA – C7)

The cost efficient methodologies are controlled through adhering to Thunder Bay Hydro's Conditions of Service and through the use of standardized designs ensuring that calculations are performed uniformly and consistently for all projects. This process has been established to ensure customers benefit from Thunder Bay Hydro's experience in completing these types of projects. However, where options exist customers can select an alternative suited to their project.

Results of a final economic evaluation (where applicable) (5.4.5.2 SA – C8)

Thunder Bay Hydro does not conduct a life-cycle cost analysis for these types of projects as costs are controlled through the process identified in the summary above.

Nature and Magnitude of System Impacts, Costs and Cost Recovery (5.4.5.2 SA – C9)

Due to recent aggressive investment by a local telecommunications company (as discussed in section 5.2.2.3) to provide fibre to the home, investments in this category have increased in the last 5 years. Pole replacements that were not in the planning horizon by Thunder Bay Hydro have required completion due to request for attachment. In these cases the costs are recovered from the third party.

There are some cases (hit and run, drunk driver) where Thunder Bay Hydro is unable to charge the customer for the repairs and as such the cost is borne by Thunder Bay Hydro.



2017 Capital Project Summary

A. General Information

Project Name	Customer Driven System Expansions		
Project Number	A1711		
Investment Category	System Access		
Capital Investment(s)			
	Customer Driven Expansions A1711	2017	
	Capital Cost (5.4.5.2 A.1)	\$209,034	
	Capital contribution	\$158,863	
	Net Cost	\$50,171	
	O&M Cost (5.4.5.2 A.2)	\$0	
	There are no anticipated O&M Costs for this Capital Project, due to the work being solely new capital additions to the system.		

Customer Attachments and Load (5.4.5.2 A.2)

The number of customer attachments and load is different for each specific request within this project. A detailed listing of individual projects is not available at this time, as these projects are typically requested and constructed in the same fiscal year. In a typical year, Thunder Bay Hydro will construct approximately 2 large modifications to the distribution system;
 Customer Attachments: between 1-100
 Load: Up to 148kWh

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
\$52,259	\$52,259	\$52,259	\$52,259

Timing of expenditures is expected to be distributed throughout the year.

Project Summary

This project accounts for all requests for distribution system upgrades or expansions to facilitate customer upgrades or connect new customers. Examples of the work expected in this project include

- Line Extension
- Converting Single phase Service to Three phase Service
- Replacing a transformer to increase the kVA size
- Converting a distribution line to operate at a higher voltage
- Rebuilding a distribution line with a larger size conductor to service the customer

Risk Identification & Mitigation (5.4.5.2 A.4)

These projects are driven by customer service requests, and thus there is very limited control over the scope and timing of these projects. Thunder Bay hydro works with developers to manage timing of these projects such that customer expectations are met.

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

Customer Driven Expansions A1711	2012	2013	2014	2015	2016	2017
Capital Cost	\$87,797	\$197,649	\$83,133	\$181,267	\$175,506	\$209,034

Comparable investments are indicated above and are dependent on the number customer requests in a given year.

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
These projects are typically requested and completed in the same fiscal year, thus drawings are not yet available for 2017 work.
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 driver for this project is customer driven requests. Thunder Bay Hydro is committed to executing customer work in a timely manner.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)
The secondary driver is mandated service obligations. Meeting customer obligations requires an understanding of our customers' needs and expectations and a commitment to delivering a high level of service.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)
The objective of this program is to ensure proper allocation of investments to fulfill service obligations; the performance target is to meet the needs set out by the customer.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1a)
This project was planned incorporating elements of discussions with the City of Thunder Bay to assist in forecasting commercial and industrial developments over the planning cycle.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1a)
Customer driven expansions are ranked as P3 – High priority, since they are non-discretionary in nature and are essential to meet customer project deadlines. These projects are completed in order of receipt or paced to meet compliance deadlines. This project is ranked as 5 of 21 projects.
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency, cost-effectiveness (5.4.5.2 B.1c)
Newly installed assets will be designed and constructed in the most cost-effective manner and where possible with added flexibility in system operations.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)
This project provides access for customers to connect and receive their required electrical supply from Thunder Bay Hydro's distribution system.
Effect of the investment on system on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)
This program is not intended for reliability improvements, and as such it is not expected to have an impact on system reliability performance. New facilities will be designed to the most recent standards that at a minimum maintain the overall reliability of Thunder Bay Hydro's distribution system. Constructions is coordinated and performed with minimum interruptions to existing customers.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)
The alternative to completing the work is the following; a) Do nothing – this option results in neglecting mandated service obligations and could result in disciplinary action from the regulating body (OEB) It also results in negatively impacting the relationship and satisfaction of our customers which is not acceptable b) Design alternatives are possible and are determined based on the scope of the submitted requests as they are received, and cannot be addressed until such time. Where options are available, the most effective overall alternative is selected.
Safety (5.4.5.2 B.2)
These projects are not intended to address any existing safety concerns, but all new facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.
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)
Customer connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with our customers is an integral part of each project. Where applicable Thunder Bay Hydro coordinates with the Electrical Safety Authority prior to connection and this is completed through an established process.
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)
Where applicable, new distribution lines are designed to the latest standards and technologies to meet future operational requirements.
Economic Development (where applicable) (5.4.5.2 B.5)
Though not directly related to economic development, through the enabling of customer requested line extensions and upgrades, Thunder Bay Hydro's investment in this project contributes to the economic development within the city.
Environmental Benefits (where applicable) (5.4.5.2 B.6)
Not Applicable
C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA – C1)
The timing of individual projects is based on what is required by the customer, as well as the number of requests received in a given year. Thunder Bay Hydro prioritizes requests based on expectations of service connections, and has been able to meet customer demands.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA – C2)
These projects are initiated by the Customer and the Thunder Bay Hydro Engineering department works with the customer to provide options to meet the needs of the customer, within the required standards and Conditions of Service constraints.
Factors Affecting the Final Cost (5.4.5.2 SA – C3)
Main factors that affect final costs are the scope and amount of additional infrastructure required as well as the labour to install such. This type of work is contestable and can be performed by the customer. Final costs of individual projects cannot be determined until the scope of the project is finalized, charges to the customer are based on fixed and variable costs that are updated annually.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA – C4)
The design and completion of expansions is completed according the Thunder Bay Hydro and USF approved standards and therefore costs are controlled through established processes and the use of standardized materials.
Other Planning Objectives (where applicable) (5.4.5.2 SA – C5)
Where appropriate, Thunder Bay Hydro reviews and implements other planning objectives such as Asset Retirement and Operational Efficiency (As detailed in Section 5.3) in coordination with the design of projects requested in this category.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA – C6)
Technically feasible options will not exist, however, if an option is requested by the customer, specialized requests are evaluated on a case by case basis, which cannot start until each project is initiated.
Summary of results analysis (5.4.5.2 SA – C7)
The cost efficient methodologies are controlled through adhering to Thunder Bay Hydro's Conditions of Service and through the use of standardized designs ensuring that calculations are performed uniformly and consistently for all projects. This process has been established to ensure customers benefit from Thunder Bay Hydro's experience in completing these types of projects. However, where options exist customers can select an alternative suited to their project.
Results of a final economic evaluation (where applicable) (5.4.5.2 SA – C8)

Thunder Bay Hydro does not conduct a life-cycle cost analysis for these types of projects as costs are controlled through the process identified in the summary above.

Nature and Magnitude of System Impacts, Costs and Cost Recovery (5.4.5.2 SA – C9)

Distribution System Expansions generally have a low impact on the system unless the developments are very large. Individual connections and small developments are below the materiality threshold and are funded through customer contributions based on fixed and variable fees.



2017 Capital Project Summary

A. General Information

Project Name	Residential Service Connections											
Project Number	A1712											
Investment Category	System Access											
Capital Investment(s)	<table><tr><td>Residential Service Connections A1712</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$445,213</td></tr><tr><td>Capital contribution</td><td>\$155,250</td></tr><tr><td>Net Cost</td><td>\$289,963</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> Thunder Bay Hydro does not expect to see any O&M costs associated with this project, as any additions to the system would be capitalized.		Residential Service Connections A1712	2017	Capital Cost (5.4.5.2 A.1)	\$445,213	Capital contribution	\$155,250	Net Cost	\$289,963	O&M Cost (5.4.5.2 A.2)	\$0
Residential Service Connections A1712	2017											
Capital Cost (5.4.5.2 A.1)	\$445,213											
Capital contribution	\$155,250											
Net Cost	\$289,963											
O&M Cost (5.4.5.2 A.2)	\$0											

Customer Attachments and Load (5.4.5.2 A.2)

The number of customer attachments and load is different for each specific project within the program. A detailed listing of individual projects is not available at this time. Thunder Bay Hydro has budgeted for the connection approximately 200 customers in 2017, with having connected 242 customers in 2014 and 193 customer connections in 2015.
 Customer attachments: budgeted approximately 200 customers
 Load: 159kWh

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
\$ 22,261	\$ 89,043	\$ 133,564	\$ 200,346

The timing of investment in customer connections coincides with the freeze up period imposed on underground service installation which typically occurs November 15th to May 1st.

Project Summary

This project accounts for all requests for residential customers connections 200-amp and below. Examples of the work expected in this project includes the cost of the transformers and material and labour and can be of any of the following type;

- Installation of 200-amp residential underground services in subdivisions,
- Installation of 100-amp and 200-amp underground services not in subdivisions,
- Installation of 100-amp and 200-amp overhead services
- Rural primary lines on customer owned lines
- microFIT connections

None of the individual connections are expected to exceed the materiality threshold.

Risk Identification & Mitigation (5.4.5.2 A.4)

Typical risks associated with this program include variances between forecasted and actual connection requests that may prevent Thunder Bay Hydro from connecting customers in a timely manner. To mitigate these risks Thunder Bay Hydro has retained a contractor to complete the work in the case that internal resources are not available.

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

Comparable investments are indicated above and are dependent on the number customer requests in a given year.

Not Applicable

These projects are typically requested and completed in the same fiscal year; therefore there are no reference drawings available. All connections will be in accordance with Thunder Bay Hydro's Conditions of Service, and applicable USF, ESA and CSA standards.

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

The secondary driver is mandated service obligations. Meeting customer obligations requires an understanding of our customers' needs and expectations and a commitment to delivering a high level of service.

The objective of this program is to ensure proper allocation of investments to fulfill service obligations.

This project was planned incorporating elements of discussions with the City of Thunder Bay as well as historical trending to assist in forecasting residential connections in the test year.

These projects are ranked as P3 – High Priority, since they are required to be compliant with service obligations and are essential to meet the timeframe agreed upon with the customer. These projects are completed in order of receipt or paced to meet customer deadlines. This project is ranked 6 of 21 projects in the test year.

New facilities will be designed to the most recent standards that at a minimum maintain the overall reliability of Thunder Bay Hydro's distribution system. Newly installed assets will be designed and constructed in the most cost-effective manner and where possible with added flexibility in system operations.

Connections are planned and charged in accordance with Conditions of Service, and where options are available, the most effective overall alternative is selected.

This program is not intended for reliability improvements, and as such it is not expected to have an impact on system reliability performance. Construction is coordinated and performed with minimum interruptions to existing customers.

Alternatives are determined based on the scope of the submitted requests, and cannot be addressed until such time. A Do nothing or deferral approach is not considered as it results in poor customer satisfaction and a non-compliance with the DSC, neither of which are acceptable.

Safety (5.4.5.2 B.2)

These projects are not intended to address any existing safety concerns, but all new facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.
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)
Customer connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with our customers is an integral part of each project. Thunder Bay Hydro coordinates with the Electrical Safety Authority prior to connection, and this is completed through an established process.
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)
Not Applicable
Economic Development (where applicable) (5.4.5.2 B.5)
Though not directly related to economic development, these projects often connect new small commercial customers (under 200A) that contribute to the economic development of the city.
Environmental Benefits (where applicable) (5.4.5.2 B.6)
Not Applicable
C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA – C1)
The timing of individual projects is based on what is required by the customer, as well as the number of requests received in a given year. Thunder Bay Hydro prioritizes requests based on expectations of service connections, and has been able to meet customer demands.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA – C2)
These projects are initiated by the Customer and then Thunder Bay Hydro staff work with the customer to provide options to meet the needs of the customer, all within the required standards and Conditions of Service constraints. Where a customer preference cannot be accommodated within the constraints, the standards and Conditions of Service shall prevail.
Factors Affecting the Final Cost (5.4.5.2 SA – C3)
The main factors that affect final costs are the scope of the project, as well as the labour to install such. Final costs of individual projects cannot be determined until the scope of the project is finalized, charges to the customer are based on fixed and variable costs that are updated annually, and final costs are based on actual costs to complete the work.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA – C4)
The installation of new connections is completed according the Thunder Bay Hydro and USF approved standards and therefore costs are controlled through established processes and the use of standardized materials.
Other Planning Objectives (where applicable) (5.4.5.2 SA – C5)
Where appropriate, Thunder Bay Hydro reviews and implements other planning objectives such as Operational Efficiency (As detailed in Section 5.3) in coordination with the design of new connections requested in this category.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA – C6)
Technically feasible options may not exist, however, if an option is requested by the customer, specialized requests are evaluated on a case by case basis, which cannot start until each project is initiated.
Summary of results analysis (5.4.5.2 SA – C7)

The cost efficient methodologies are controlled through adhering to Thunder Bay Hydro's Conditions of Service and through the use of standardized designs ensuring that calculations are performed uniformly and consistently for all projects. This process has been established to ensure customers benefit from Thunder Bay Hydro's experience in completing these types of projects. However, where options exist customers can select an alternative suited to their project.

Results of a final economic evaluation (where applicable) (5.4.5.2 SA – C8)

Thunder Bay Hydro does not conduct a life-cycle cost analysis for these types of projects as costs are controlled through the process identified in the summary above.

Nature and Magnitude of System Impacts, Costs and Cost Recovery (5.4.5.2 SA – C9)

Customer Connections under 200 amps generally have a low impact on the system, all of the individual connections and are below the materiality threshold and have an expected customer contribution of \$760 per service.



2017 Capital Project Summary

A. General Information

Project Name	General Service Connections											
Project Number	A1713											
Investment Category	System Access											
Capital Investment(s)	<table><tr><td>General Service Connections A1713</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$926,898</td></tr><tr><td>Capital contribution</td><td>\$722,400</td></tr><tr><td>Net Cost</td><td>\$204,498</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> Thunder Bay Hydro does not expect to see any O&M costs associated with this project, as any additions to the system would be capitalized.		General Service Connections A1713	2017	Capital Cost (5.4.5.2 A.1)	\$926,898	Capital contribution	\$722,400	Net Cost	\$204,498	O&M Cost (5.4.5.2 A.2)	\$0
General Service Connections A1713	2017											
Capital Cost (5.4.5.2 A.1)	\$926,898											
Capital contribution	\$722,400											
Net Cost	\$204,498											
O&M Cost (5.4.5.2 A.2)	\$0											

Customer Attachments and Load (5.4.5.2 A.2)

The number of customer attachments and load is different for each specific general service request within the program. A detailed listing of individual projects is not available at this time. Thunder Bay Hydro has budgeted for the connection approximately 30 new general service customers.

Customer attachments: approximately 30 customers

Load: 44 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
\$ 46,345	\$ 185,380	\$ 278,069	\$ 417,104

The timing of investment in general services coincides with the freeze up period imposed on underground service installation which typically occurs November 15th to May 1st.

Project Summary

This project accounts for all of Thunder Bay Hydro's costs to connect customer requested general services over 200-amp. Work associated with the connection of a general service may include the following;

- Installation of new or upgrade of existing transformation
- Installation of new or upgrade of existing metering
- Installation of new or upgrade of existing underground or overhead lines
- Upgrades and metering required for the connection of FIT applications

Individual projects within this program range between \$10,000 and \$60,000 and an average connection is approximately \$30,000.

Risk Identification & Mitigation (5.4.5.2 A.4)

Typical risks associated with this program include variances between forecasted and actual requests that may impact Thunder Bay Hydro's ability to meet customer deadlines. In addition general service work needs to be coordinated with the customer as well as the engineering, lines and metering departments at Thunder Bay Hydro. Projects are generally completed on a first come first serve basis depending on customer requested deadlines. To mitigate the risks of project delays, Thunder Bay Hydro works very closely with the customer and depending on availability of resources, and the requirements of the customer, has the ability to offer afterhours work at a premium cost.

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

General Service Connections A1713	2012	2013	2014	2015	2016	2017
Capital Cost	\$950,922	\$969,802	\$580,813	\$461,209	\$907,343	\$926,898

Comparable investments in general services are indicated above and are dependent on the number of requests and the size of the connection requested, e.g. pole mounted, and three phase transformer bank with an overhead service vs 1000 kVA transformer with underground service.

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

These projects are typically requested and completed in the same fiscal year; therefore there are no reference drawings available. All connections must be in accordance with Thunder Bay Hydro's Conditions of Service, and applicable USF, ESA and CSA standards.

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

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

The main driver for this project is customer driven requests. Thunder Bay Hydro is committed to executing customer work in a timely manner.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)

The secondary driver is mandated service obligations. Meeting customer obligations requires an understanding of our customers' needs and expectations and a commitment to delivering a high level of service.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)

The objective of this program is to ensure proper allocation of investments to fulfill service obligations.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1a)

This project was planned incorporating elements of discussions with the City of Thunder Bay as well as historical trending to assist in forecasting general connections in the test year.

Analysis of Project & Alternatives -Effect of the investment on system operation efficiency, cost-effectiveness (5.4.5.2 B.1c)

New facilities will be designed to the most recent standards that at a minimum maintain the overall reliability of Thunder Bay Hydro's distribution system. Newly installed assets will be designed and constructed in the most cost-effective manner and where possible with added flexibility in system operations.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1a)

These projects are ranked as P3 – High Priority, since they are required to be compliant with service obligations and are essential to meet the timeframe agreed upon with the customer. These projects are completed in order of receipt or paced to meet customer deadlines. This project is ranked 7 of 21 projects for the test year.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Connection of new general services are planned and charged in accordance with Conditions of Service, and where options are available, the most cost effective overall alternative is selected.

Effect of the investment on system on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)

This program is not intended for reliability improvements, and as such it is not expected to have an impact on system reliability performance. New facilities will be designed to the most recent standards that at a minimum maintain the overall reliability of Thunder Bay Hydro's distribution system. Construction is coordinated and performed with a minimum of interruptions to existing customers.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)

Alternatives are determined based on the scope of the submitted requests, and cannot be addressed until such time. A Do nothing or deferral approach is not considered as it results in poor customer satisfaction and a non-compliance with the DSC, neither of which are acceptable.

Safety (5.4.5.2 B.2)
These projects are not intended to address any existing safety concerns, but all new facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.
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)
Customer connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with our customers is an integral part of each project. Thunder Bay Hydro coordinates with the Electrical Safety Authority prior to connection, and this is completed through an established process.
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)
Not Applicable
Economic Development (where applicable) (5.4.5.2 B.5)
Though not directly related to economic development, these projects often connect commercial and industrial customers that contribute to the economic development of the city.
Environmental Benefits (where applicable) (5.4.5.2 B.6)
Not Applicable
C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA – C1)
The timing of individual projects is based on what is required by the customer, as well as the number of requests received in a given year. Thunder Bay Hydro prioritizes requests based on expectations of service connections, and has been able to meet customer demands.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA – C2)
These projects are initiated by the Customer and then Thunder Bay Hydro Engineering staff work with the customer to provide options to meet the needs of the customer, all within the required standards and Conditions of Service constraints. Where a customer preference cannot be accommodated within the constraints, the standards and Conditions of Service shall prevail.
Factors Affecting the Final Cost (5.4.5.2 SA – C3)
The main factors that affect final costs are the scope of the project, as well as the labour to install such. Final costs of individual projects cannot be determined until the scope of the project is finalized, charges to the customer are based on fixed and variable costs that are updated annually, and final costs are based on actual costs to complete the work.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA – C4)
The installation of new connections is completed according Thunder Bay Hydro and USF approved standards and therefore costs are controlled through established processes and the use of standardized materials.
Other Planning Objectives (where applicable) (5.4.5.2 SA – C5)
Where appropriate, Thunder Bay Hydro reviews and implements other planning objectives such as Operational Efficiency (As detailed in Section 5.3) in coordination with the design of new connections requested in this category.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA – C6)
Technically feasible options may not exist, however, if an option is requested by the customer, specialized requests are evaluated on a case by case basis, which cannot start until each project is initiated.
Summary of results analysis (5.4.5.2 SA – C7)

The cost efficient methodologies are controlled through adhering to Thunder Bay Hydro's Conditions of Service and through the use of standardized designs ensuring that calculations are performed uniformly and consistently for all projects. This process has been established to ensure customers benefit from Thunder Bay Hydro's experience in completing these types of projects. However, where options exist customers can select an alternative suited to their project.

Results of a final economic evaluation (where applicable) (5.4.5.2 SA – C8)

Thunder Bay Hydro does not conduct a life-cycle cost analysis for these types of projects as costs are controlled through the process identified in the summary above.

Nature and Magnitude of System Impacts, Costs and Cost Recovery (5.4.5.2 SA – C9)

Customer preferences may impact the final design and implementation of the projects, however General Service Connections have a low impact on the system, and are evaluated by the Engineering department prior to approving design. The individual connections are below the materiality threshold and have an expected customer contribution of \$24,000 per service. Where a customer requests a more costly alternative (ie. pole mounted, and three phase transformer bank with an overhead service vs 1000 kVA transformer with underground service) it is at the expense to the customer.



2017 Capital Project Summary

A. General Information

Project Name	Expansions for Residential Subdivisions										
Project Number	A1714										
Investment Category	System Access										
Capital Investment(s)	<table border="1"> <tr> <td>Expansions for Residential Subdivisions A1714</td><td>2017</td></tr> <tr> <td>Capital Cost (5.4.5.2 A.1)</td><td>\$230,530</td></tr> <tr> <td>Capital contribution</td><td>\$0</td></tr> <tr> <td>Net Cost</td><td>\$230,530</td></tr> <tr> <td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr> </table> Thunder Bay Hydro does not expect to see any O&M costs associated with this project, as any additions to the system would be capitalized.	Expansions for Residential Subdivisions A1714	2017	Capital Cost (5.4.5.2 A.1)	\$230,530	Capital contribution	\$0	Net Cost	\$230,530	O&M Cost (5.4.5.2 A.2)	\$0
Expansions for Residential Subdivisions A1714	2017										
Capital Cost (5.4.5.2 A.1)	\$230,530										
Capital contribution	\$0										
Net Cost	\$230,530										
O&M Cost (5.4.5.2 A.2)	\$0										

Customer Attachments and Load (5.4.5.2 A.2)

The number of customer attachments and load is different for each specific residential development within the program. A detailed listing of individual projects is not available at this time. Thunder Bay Hydro has budgeted for the connection approximately 3 new subdivisions as well as the completion / ongoing work in 2-3 subdivisions.

Customer attachments: approximately 75-150 customers

Load: 60-120 kWh

Start Date (5.4.5.2 A.3)	01-04-17	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
\$ 11,545	\$ 46,180	\$ 69,270	\$ 103,905

The timing of investment in subdivisions in most cases coincides with the freeze up period imposed on underground service installations; however, some developers have been known to continue working well into the winter months of December and January, requiring inspections from Thunder Bay Hydro during that period.

Project Summary

This project accounts for Thunder Bay Hydro's costs to establish electrical service connections to residential subdivision developments. Work expected in this project includes the cost of approving, inspecting & connecting new expansions and connection assets required to service a new subdivision. The majority of the installation of subdivision expansion and connection assets is contestable work and is typically completed by the Developer. Therefore the total cost of construction of per subdivision (approximately \$350k) is not reflected in this project for the test year, as Thunder Bay Hydro only incurs the costs to establish the connection. Potential Subdivisions which are in various approval stages with the City of Thunder Bay include the following;

- Gemstone Estates Stage 4
- Parkdale Stage 6
- Wenscott Developments
- Hutton Park Estates Stage 4
- Maplewood Estates Stage 2

Individual subdivision stages have historically been below the \$119,000 materiality threshold, with an average total cost per subdivision of \$50,000. Once all work is completed in a subdivision, Thunder Bay Hydro performs an economic evaluation on the total cost of the subdivision as per the DSC economic model to determine the transfer price of the subdivision.

Risk Identification & Mitigation (5.4.5.2 A.4)

Typical risks associated with this program include variances between forecasted and actual subdivision requests that may impact Thunder Bay Hydro's ability to meet customer deadlines. In addition, subdivision work is driven by the developer thus Thunder Bay Hydro has very little control over the scope and timing of projects. To mitigate these risks Thunder Bay Hydro works very closely with the City of Thunder Bay, and the developer involved with individual projects, to ensure customer expectations are met.

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

Subdivisions A1714	2012	2013	2014	2015	2016	2017
Capital Cost	\$88,787	\$44,981	\$335,496	\$118,498	\$232,955	\$230,530

Comparable investments in subdivision connections are indicated above and are dependent on the number of requests and the size of the subdivision being developed request in a given year, ie. 25 lots vs 78 lots.

The above costs in 2012-2015 include Thunder Bay Hydro's cost to establish a subdivision as well as the transfer price of completed subdivisions.

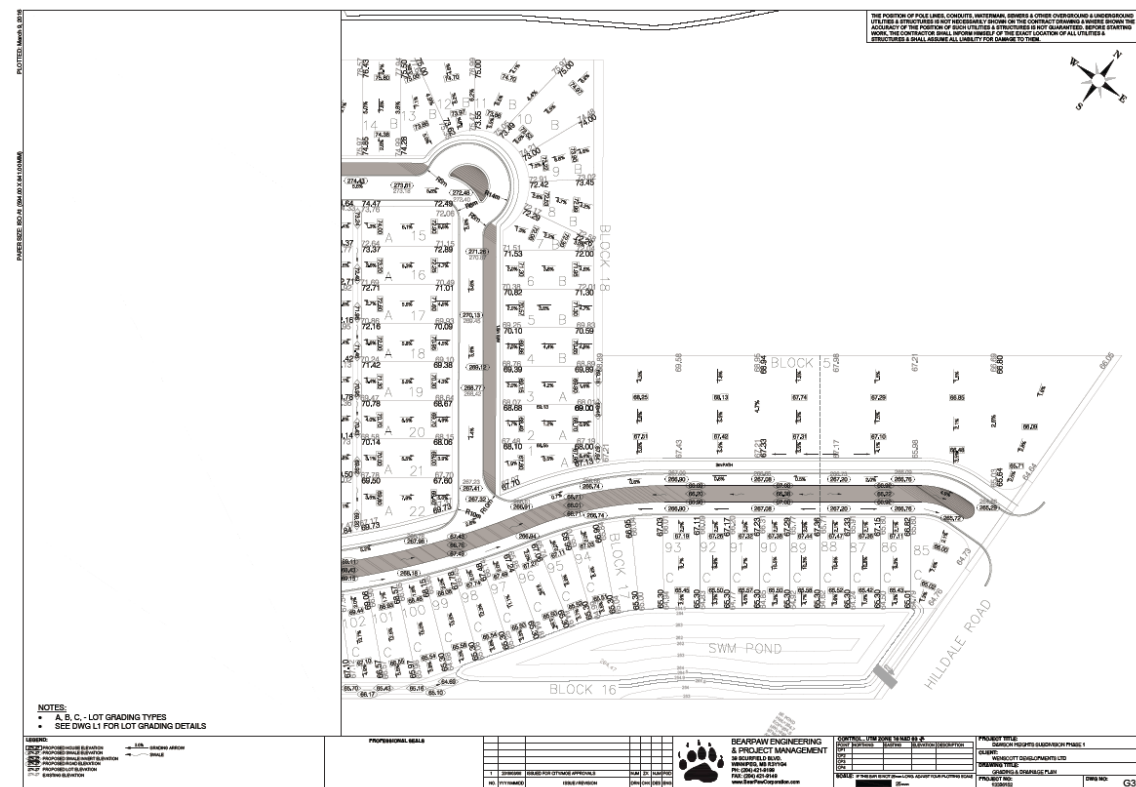
REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

Not Applicable

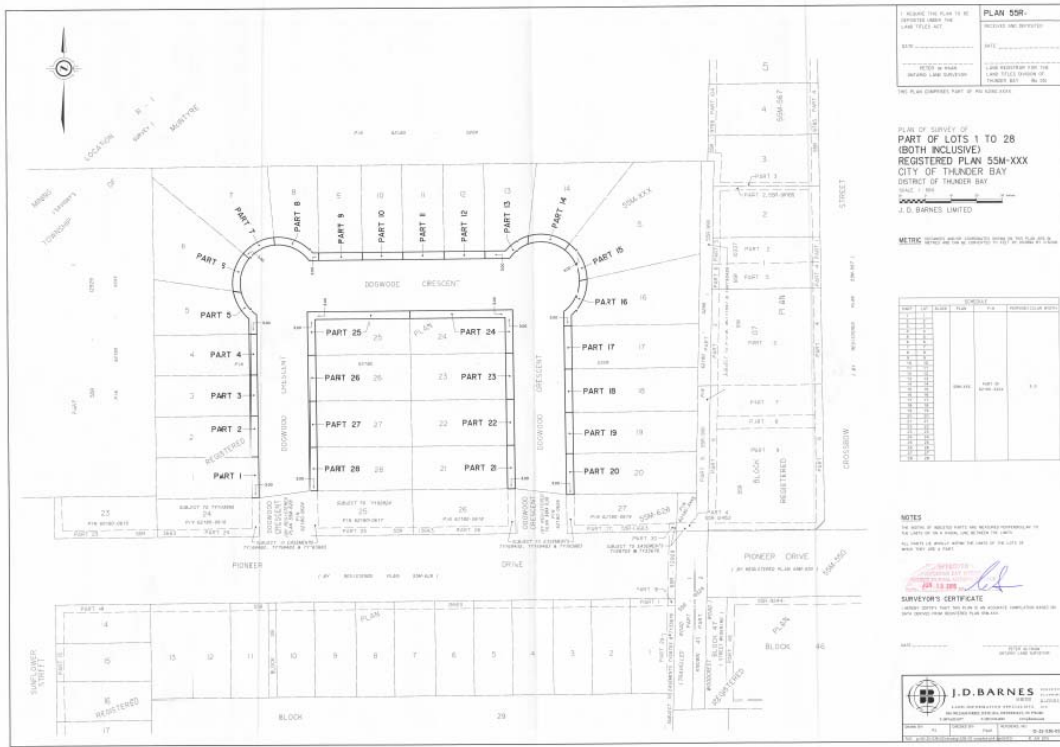
Attach Other project reference material i.e. Images, Drawings and or reference material

Preliminary approved layout drawings are included for reference for Wenscott Developments, Hutton Park Estates Stage 4 and Maplewood Estates Stage 2. Gemstone Estates Stage 4 and Parkdale Stage 6 are still in the approval stages with the City of Thunder Bay.

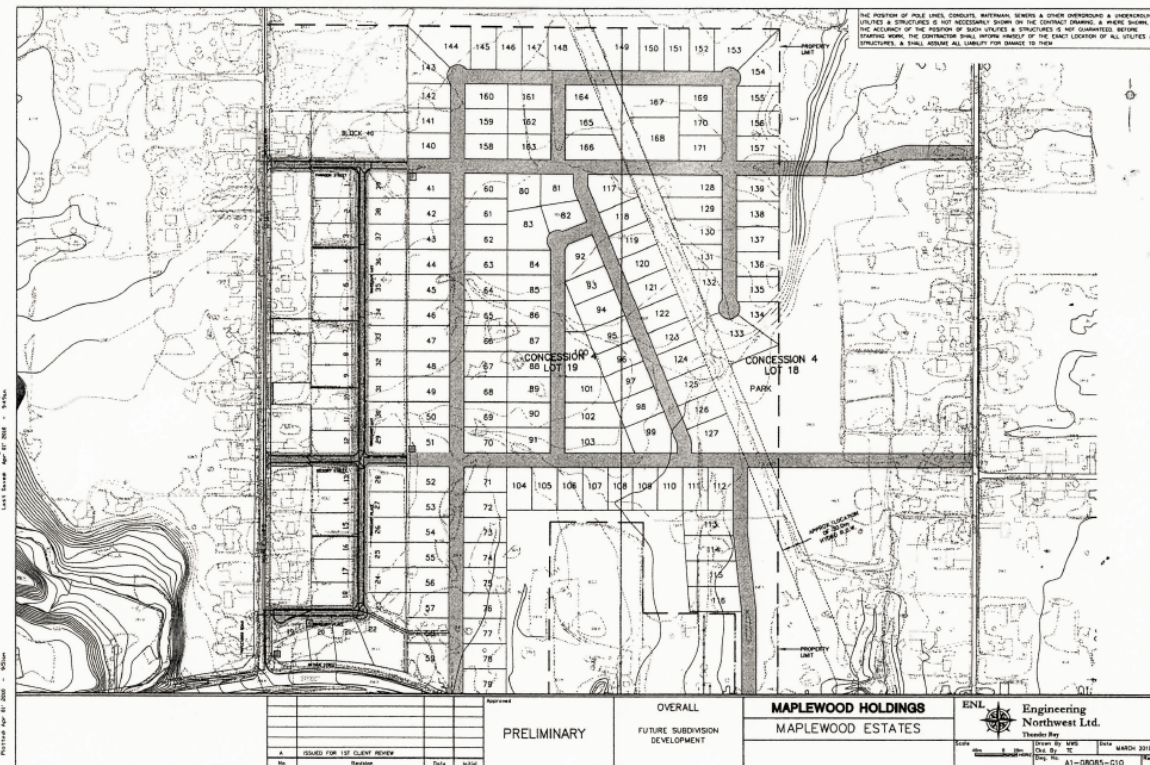
Wenscott Developments



Hutton Park Estates Stage 4



Maplewood Estates Stage 2



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

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

The main driver for this project is customer driven requests. Thunder Bay Hydro is committed to executing customer work in a timely manner.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)

The secondary driver is mandated service obligations. Meeting the developer's and our /their customer obligations requires an understanding of needs and expectations and a commitment to delivering a high level of service.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)

The objective of this program is to ensure proper allocation of investments to fulfill service obligations in an economical & reliable way.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1a)

A Plan of Subdivision Application is required when a developer wishes to extend municipal services for the purposes of subdividing property, and this process requires the approval of the City of Thunder Bay. Thunder Bay Hydro receives all correspondence regarding subdivision approvals from the City of Thunder Bay, thus is informed of upcoming developments. In addition, Thunder Bay Hydro also sits on the Subdivision Development and Coordinating subcommittee, which meets annually to discuss approved plans and upcoming potential developments within the city.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1a)

These projects are ranked P3 – High Priority, since they are required to be compliant with service obligations and must be completed within the mandated timeframe agreed upon with the developer. These projects are completed in order of receipt or paced to meet compliance deadlines. This project is ranked 4 of 21 projects for the test year.

Analysis of Project & Alternatives -Effect of the investment on system operation efficiency, cost-effectiveness (5.4.5.2 B.1c)

New facilities will be designed to the most recent standards that at a minimum maintain the overall reliability of Thunder Bay Hydro's distribution system. Newly installed assets will be designed and constructed in the most cost-effective manner and where possible with added flexibility in system operations.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

This project provides access for residential customers to receive their electrical supply from Thunder Bay Hydro's distribution system.

Effect of the investment on system on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)

This program is not intended for reliability improvements, and as such it is not expected to have an impact on system reliability performance. New facilities will be designed to the most recent standards that at a minimum maintain the overall reliability of Thunder Bay Hydro's distribution system. Constructions are coordinated and performed with minimum interruptions to existing customers.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)

The alternative to completing the work is the following;

- a) Do nothing – this option results in neglecting mandated service obligations and could result in disciplinary action from the regulating body (OEB) It also results in negatively impacting the relationship and satisfaction of our customers which is not acceptable
- b) Design alternatives are possible and are determined based on the scope of the submitted requests as they are received, and cannot be addressed until such time. Where options are available, the most effective overall alternative is selected.

Safety (5.4.5.2 B.2)

These projects are not intended to address any existing safety concerns, but all new facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.

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)
Customer connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with our customers is an integral part of each project. Where applicable Thunder Bay Hydro requires coordination with the Electrical Safety Authority prior to connection, this is completed through an established process.
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)
Where applicable, new distribution connections and lines are designed to the latest standards and technologies to meet future operational requirements.
Economic Development (where applicable) (5.4.5.2 B.5)
Though not directly related to economic development, through the connection of new subdivisions, Thunder Bay Hydro's investment in this project contributes to the economic development within the city.
Environmental Benefits (where applicable) (5.4.5.2 B.6)
Not Applicable
C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA – C1)
The timing of individual projects is dependent on developer requested timelines, as well as the number of requests received in a given year. Thunder Bay Hydro prioritizes requests based on customer expectations, and has been able to meet customer demands.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA – C2)
For new subdivision developments, a certain amount of Thunder Bay Hydro's plant must be located on the customer's property in utility easements. This can include but not be limited to primary and secondary cables as well as pad mount transformers. The Conditions of Service document outline the requirements for different types of services and has been developed to account for various customer preferences.
Factors Affecting the Final Cost (5.4.5.2 SA – C3)
The main factors that affect final costs are the scope of the development (number of lots, length of services, subsurface conditions, existing infrastructure). Final costs of this project may deviate from the estimate provided in the DSP, and cannot be determined until the scope of each subdivision stage is finalized.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA – C4)
The installation of new subdivision developments is completed according to Thunder Bay Hydro approved processes which are provided to the Developer at the time of signing a connection agreement with Thunder Bay Hydro. This minimized controllable costs through the use of an established process, installation standards and the use of standardized materials.
Other Planning Objectives (where applicable) (5.4.5.2 SA – C5)
Where appropriate, Thunder Bay Hydro reviews and implements other planning objectives such as Asset Retirement and Operational Efficiency (As detailed in Section 5.3) in coordination with the design of projects requested in this category.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA – C6)
Technically feasible options may not exist, however, if an option is requested by the customer, specialized requests are evaluated on a case by case basis, which cannot start until each project is initiated.
Summary of results analysis (5.4.5.2 SA – C7)
The cost efficient methodologies are controlled through adhering to Thunder Bay Hydro's Conditions of Service and through the use of standardized designs ensuring that calculations are performed uniformly and consistently for all projects. This process has been established to ensure customers benefit from Thunder Bay Hydro's experience in completing these types of projects. However, where options exist customers can select an alternative suited to their project
Results of a final economic evaluation (where applicable) (5.4.5.2 SA – C8)

Each subdivision requires a Final Economic Analysis as described in the DSC based on the total actual costs to install the subdivision and the developer's connection horizon. The internal procedure to complete the analysis outlines the processes required by the Finance department to support customer driven system expansions to Thunder Bay Hydro while complying with regulatory requirements set forth in the Distribution System Code and Thunder Bay Hydro Conditions of Service. The final economic evaluation is determined on a case-by-case basis.

Nature and Magnitude of System Impacts, Costs and Cost Recovery (5.4.5.2 SA – C9)

Subdivisions connections generally have low impact on the system unless the developments are very large or on the end of a radial feeder. Each submission is evaluated by the Engineering department prior to approving the location of connection. During the development of a new subdivision there is minimal impact to customers as it is typically constructed in greenfield locations without interruptions to customers.

The costs associated with this project budget in 2017 are not recoverable, as they are solely costs to establish electrical service connections to residential subdivision developments. If in the future the developer were to request Thunder Bay Hydro complete contestable work, this would be recovered at full cost to the customer.

A. General Information

Project Name	System Relocations												
Project Number	A1715												
Investment Category	System Access												
Capital Investment(s)	<table><tr><td>System Relocations A1715</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$164,881</td></tr><tr><td>Capital contribution</td><td>\$65,940</td></tr><tr><td>Net Cost</td><td>\$98,941</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> Thunder Bay Hydro does not expect to see any O&M costs associated with this project, as any relocation to the system would be capitalized.			System Relocations A1715	2017	Capital Cost (5.4.5.2 A.1)	\$164,881	Capital contribution	\$65,940	Net Cost	\$98,941	O&M Cost (5.4.5.2 A.2)	\$0
System Relocations A1715	2017												
Capital Cost (5.4.5.2 A.1)	\$164,881												
Capital contribution	\$65,940												
Net Cost	\$98,941												
O&M Cost (5.4.5.2 A.2)	\$0												

Customer Attachments and Load (5.4.5.2 A.2)

The number of customer attachments and load is different for each relocation project within the program. Thunder Bay Hydro has budgeted for the relocation for two known projects, Golf Links Road Stage 3 and Balmoral Street Reconstruction. These road widening projects by the City of Thunder Bay are not expected to impact customer attachments or loading.
Customer attachments: approximately 20-100 customers
Load: up to 87 kWh

Start Date (5.4.5.2 A.3)	01-06-17	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	\$0	\$82,441	\$82,441

The timing of investment in relocations coincides with approval of the budget by the City of Thunder Bay.

Project Summary

This project accounts for all of Thunder Bay Hydro's costs to relocate assets based on customer requests. When the work is requested by the City of Thunder Bay or the Ministry of Transportation Ontario, the charges are in accordance with the Public Service Works on Highways Act. This act requires a contribution from the requestor (City, MTO) for labour and trucking costs related to road widening activities.

The two individual projects expected to be completed in 2017 are subject to approval by City Council are the following:

- a) Golf Links Road –Stage 3 (Up to 21 poles relocated due to a road widening)
- b) Balmoral Street Road Widening – Stage 2 (Up to 40 poles relocated depending on change in grade and routing of road)

Thunder Bay Hydro also expects to see the movement of approximately 10 poles from other customer driven relocation work.

Risk Identification & Mitigation (5.4.5.2 A.4)

Typical risks associated with this program include last minute changes to the City of Thunder Bay budget as well as project scope. Historically these changes have required a reprioritization of work (within the year) in order to meet customer deadlines. In these instances System Access projects are prioritized in comparison to System Renewal, System Service projects, and design and construction on these projects are completed first.

To mitigate these risks Thunder Bay Hydro works very closely with the City of Thunder Bay, and the various contractors and consultants involved with individual projects, to ensure co-ordination and understanding of timelines. Thunder Bay Hydro maintains an Engineering Services contract to allow the flexibility for internal resources to focus on customer driven work, while maintaining internally driven asset renewal schedules.

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

System Relocations A1715	2012	2013	2014	2015	2016	2017
Capital Cost	\$447,447	\$44,981	\$713,472	\$176,094	\$162,858	\$164,881

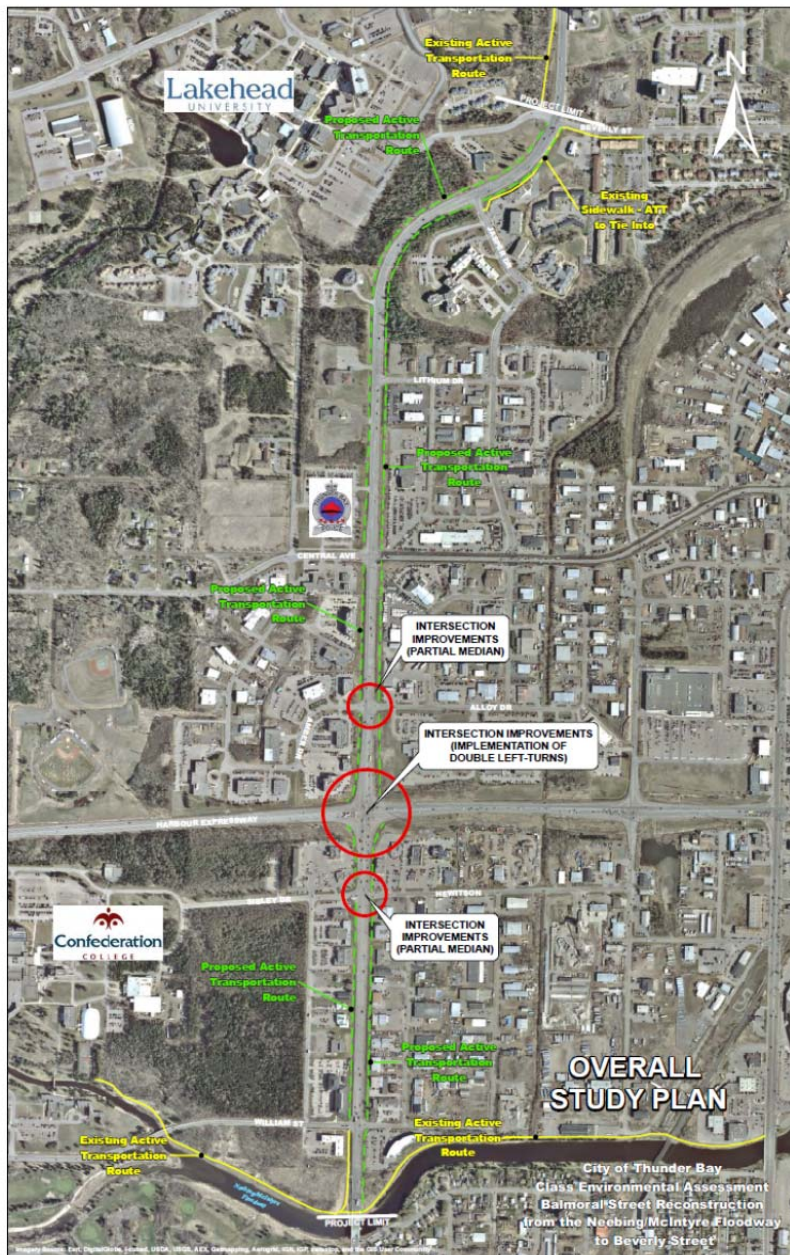
Comparable investments in relocations are indicated above and are dependent on the number of requests and the size of the request in a given year, ie. 100 poles vs 10 pole relocation.

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

An image of the Balmoral Street Reconstruction received from the City of Thunder Bay is attached. Other projects are released by the City of Thunder Bay once the budget has been approved by council.



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 driver for this project is Customer Driven Work. Thunder Bay Hydro is committed to executing customer work in a timely manner and must repair damages incurred from motor vehicle accidents as soon as possible and reduce the outage time seen by customers.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)

The secondary driver is mandated service obligations. Meeting customer obligations requires an understanding of our customers' needs and expectations and a commitment to delivering a high level of service.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)

The objective of this program is to ensure proper allocation of investments to fulfill requests. The performance target is to meet the needs set out by the customer.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1a)

This program is based largely on government funding and priorities, as well as budget constraints from the City of Thunder Bay, and MTO. Discussions with the City of Thunder Bay occur throughout the year for planning purposes.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1a)

Customer driven expansions are ranked as P3 – High priority, since they are non-discretionary in nature and are essential to meet customer project deadlines. These projects are completed in order of receipt or paced to meet compliance deadlines. This project is ranked 9 of 21 projects in the test year.

Analysis of Project & Alternatives -Effect of the investment on system operation efficiency, cost-effectiveness (5.4.5.2 B.1c)

New facilities will be designed to the most recent standards that at a minimum maintain the overall reliability of Thunder Bay Hydro's distribution system. Newly installed assets will be designed and constructed in the most cost-effective manner and where possible with added flexibility in system operations.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1a)

This project provides benefits customers by enabling the improvements to city owned infrastructure, such as road widening.

Effect of the investment on system reliability performance including frequency and duration of outages (5.4.5.2 B.1a)

This program is not intended for reliability improvements, and as such it is not expected to have an impact on system reliability performance. New facilities will be designed to the most recent standards that at a minimum maintain the overall reliability of Thunder Bay Hydro's distribution system. Constructions are coordinated and performed with minimum interruptions to existing customers.

Analysis of Project & Alternatives (5.4.5.2 B.1a)

Alternatives are determined based on the scope of the submitted requests, and cannot be addressed until such time. Relocation projects are designed according to approved Thunder Bay Hydro and USF standards, where options are available; the most cost effective overall alternative is selected.

Safety (5.4.5.2 B.2)

These projects are not intended to address any existing safety concerns, but all new facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.

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)

Connections at this level do not impact inter-utility coordination or regional planning activities. Coordination with our customers is an integral part of each project. Where applicable Thunder Bay Hydro coordinates with the Electrical Safety Authority prior to connection and this is completed through an established process.

Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)
Where applicable, relocation may allow the installation of new distribution assets which are designed 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 Access
Factors Affecting Timing/Priority (5.4.5.2 SA – C1)
The timing of individual projects is dependent on requested timelines. Thunder Bay Hydro prioritizes customer requests based on expectations, and has consistently been able to meet customer demands.
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA – C2)
These projects are initiated by the customer and where there is a preference for improved appearance in the road allowance; reliability and cost are factored into the final design.
Factors Affecting the Final Cost (5.4.5.2 SA – C3)
The main factors that affect final costs are the scope of the relocation, as well as the labour required to install such. Final costs of individual projects cannot be determined until the scope of the project is finalized, charges to the customer are based on fixed and variable costs that are updated annually, and final costs are based on actual costs to complete the work.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA – C4)
The design and completion of expansions is completed according to Thunder Bay Hydro and USF approved standards and therefore costs are controlled through established processes and the use of standardized materials.
Other Planning Objectives (where applicable) (5.4.5.2 SA – C5)
Where appropriate, Thunder Bay Hydro reviews and implements other planning objectives such as Asset Retirement and Operational Efficiency (As detailed in Section 5.3) in coordination with the design of projects requested in this category.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA – C6)
Technically feasible options may not exist, however, if an option is requested by the customer, specialized requests are evaluated on a case by case basis, which cannot start until each project is initiated.
Summary of results analysis (5.4.5.2 SA – C7)
The cost efficient methodologies are controlled through adhering to Thunder Bay Hydro's Conditions of Service and through the use of standardized designs ensuring that calculations are performed uniformly and consistently for all projects. This process has been established to ensure customers benefit from Thunder Bay Hydro's experience in completing these types of projects. However, where options exist customers can select an alternative suited to their project.
Results of a final economic evaluation (where applicable) (5.4.5.2 SA – C8)
Thunder Bay Hydro does not conduct a life-cycle cost analysis for these types of projects as costs are controlled through the process identified in the summary above.
Nature and Magnitude of System Impacts, Costs and Cost Recovery (5.4.5.2 SA – C8)
System Relocations do not have an impact on the system as they do not add any additional load or connections. System Relocations that are classified as road widening projects driven by the City of Thunder Bay or MTO are subject to a 50% contribution of labour and trucking costs as per the Highway Act. Thunder Bay Hydro contributes remaining portion of the labour and trucking as well as 100% of the material required for the project. Thunder Bay Hydro is currently in negotiations with the City of Thunder Bay regarding a cost sharing agreement. This agreement would clarify cost responsibilities for different classifications work undertaken by the City of Thunder Bay.



2017 Capital Project Summary

A. General Information

Project Name	Meter Installations											
Project Number	A1721											
Investment Category	System Access											
Capital Investment(s)	<table><tr><td>Meter Installations A1721</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$286,129</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$286,129</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$30,245</td></tr></table> There anticipated O&M Costs associated with this Capital Project which includes shipping and reverification of meters.		Meter Installations A1721	2017	Capital Cost (5.4.5.2 A.1)	\$286,129	Capital contribution	\$0	Net Cost	\$286,129	O&M Cost (5.4.5.2 A.2)	\$30,245
Meter Installations A1721	2017											
Capital Cost (5.4.5.2 A.1)	\$286,129											
Capital contribution	\$0											
Net Cost	\$286,129											
O&M Cost (5.4.5.2 A.2)	\$30,245											

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 2,050 customers
 Load: Not Applicable

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
\$71,532	\$71,532	\$71,532	\$71,532

The meter replacement and meter compliance pre-sampling program(s) are expected to run throughout the year.

Project Summary

This project accounts for all of Thunder Bay Hydro's costs to remain in compliance with Measurement Canada (MC) standards and the Distribution System Code (DSC). It includes the inspection and replacement of defective meters, procurement, testing, and installation of meters for existing residential and commercial services.

In 2017 Thunder Bay Hydro expects to replace 800 residential smart meters and 96 >50 kW General Service Meters. Thunder Bay Hydro is also implementing of a meter compliance pre- sampling and reverification program, within which 1,150 smart meters will be replaced. The existing in-service electronic smart meters selected by Thunder Bay Hydro were manufactured by Elster and have a 10 year seal life that will expire in 2019. As per Measurement Canada requirements a meter with an expired seal cannot be left in service for revenue/billing purposes. Utilizing the S-S-06 Specification Measurement Canada has defined how an electronic smart meter owner can utilize meter compliance sampling for the purposes of extending the seal expiry period of an in-service lot of meters. The project expenditures within this account encompasses the capitalized activities necessary for Thunder Bay Hydro to establish a smart meter pre-sampling and final compliance sampling program which aligns with the requirements detailed within Measurement Canada's Specification (S-S-06) so the utility can extend their smart meter's in-service life and ultimately maximize the return on investment (ROI). There will also be expenditures to acquire new / re-verify existing meters which do not qualify for pre/final sampling or that have substantial meter seal date extension limitations.

Risk Identification & Mitigation (5.4.5.2 A.4)

Typical risks associated with this program include issues with the ensuring accurate implementation, tracking and management of any replacement meter information for billing purposes (respecting existing/future “black-out periods”), the logistics around shipping and handling numerous meters (keeping them separate) and or with the approved meter sampling / verification vendor in providing test results as well as completing the field replacements in a timely manner. In order to mitigate these risks, Thunder Bay Hydro is working closely with the accredited meter verification shop and the meter removal service provider to ensure timelines are adhered to. (See Appendix F –Smart Meter Sampling Plan for additional details)

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

Meter Installations A1721	2012	2013	2014	2015	2016	2017
Capital Cost	\$3,374	\$189,544	\$175,260	\$192,854	\$396,177	\$286,129

In addition to the annual meter failure replacement program and the MIST meter replacements, Thunder Bay Hydro has initiated the smart meter sampling and re-verification program in 2016.

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

See Appendix F: Smart Meter Sampling Plan

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 driver for this project is our mandated service and billing obligations to the customer. Thunder Bay Hydro seeks to prioritize projects based on the successful completion of regulatory and/or legal obligations.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)

The secondary driver for this project is asset lifecycle optimization. Thunder Bay Hydro seeks to extend meters seal expiry dates for meter asset fiscal accountability and to maintain compliancy with the applicable entities.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)

The objective of this program is to ensure proper allocation of investments to fulfill service obligations.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1a)

This meter sample seal extension program is based on providing additional value to customers and the utility by extending the meter seal expiry date at minimal cost versus replacing the meters. Thunder Bay Hydro’s plan also utilizes a meter re-verification component whereby meters that are not permitted for compliance sampling (due to the smaller number of meters) will be re-verified and or partially replaced versus a 100% meter replacement strategy. Where meter inventory numbers do not allow; then the acquisition of some new meters is required so Thunder Bay Hydro can replace or re-verify legacy meters.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1a)

These projects are ranked P3 – High Priority, as this project work is required to be compliant with Industry Canada regulations. This project is ranked as 11 of 21 projects planned for the test year.

Analysis of Project & Alternatives -Effect of the investment on system operation efficiency, cost-effectiveness (5.4.5.2 B.1c)

New facilities will be designed to the most recent standards that at a minimum maintain the overall reliability of Thunder Bay Hydro’s distribution system. Newly installed assets will be designed and constructed in the most cost-effective manner and where possible with added flexibility in system operations.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.cii)

The net benefit to customers is to continue to have an accurate meter installed at thier facility to ensure accurate and timely billing. In the future, it is possible that the interval metering data will become available to the customer to facilitate customer awareness of electricity consumption and will aid in managing energy to reduce or shift demand to off-peak periods.

Effect of the investment on system reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)

This program is not intended for reliability improvements, and as such it is not expected to have an impact on system reliability performance or efficiencies. Smart metering infrastructure or remote communication enabled interval meters are now the standard installation for Thunder Bay Hydro, and will facilitate the elimination of manual meter reading and appointments to read difficult to access meters.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)
Metering asset management is governed by Measurement Canada (MC) and or the OEB for distributor requirements as such these projects are mandatory with established deadlines and do not have alternatives. Alternative approaches to meet MC standards are discussed in Appendix F: Smart Meter Sampling Plan.
Safety (5.4.5.2 B.2)
These projects are not intended to address any existing safety concerns, but all new facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety protection and performance.
Cyber-Security, privacy (where applicable) (5.4.5.2 B.3)
Thunder Bay Hydro's Smart Meter and related AMI network have been procured through Elster. This system supports a multi-layered security approach including: access control, authorization, authentication and data integrity protocols.
Co-Ordination, Interoperability Recognized Standards, Co-ordination with utilities, regional Planning, and/or 3rd party providers (where applicable) (5.4.5.2 B.4ii)
Metering Installations at this level do not impact inter-utility coordination or regional planning activities. Coordination with our customers is an integral part of each project.
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)
Not Applicable
Economic Development (where applicable) (5.4.5.2 B.5)
Not Applicable
Environmental Benefits (where applicable) (5.4.5.2 B.5)
Smart Meters are aligned with the province's conservation culture, and these projects have a positive environmental benefit due to eliminated manual meter reading and the associated transportation / vehicle emissions.
C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA – C1)
Due to the number of meters that have a requirement for replacement prior to 2019 and for additional final-sampling decision making justification, the completion of the meter pre-sampling campaign needs to occur before the final meter-sampling effort. The information acquired on the accuracy of the tested meters will be utilized by Thunder Bay Hydro to "more confidently" determine what duration of seal extension to request, it will also assist Thunder Bay Hydro in proving due diligence if a final-sampling meter lot failure were to occur as MC (Bill C-14) could levy a \$1,000 per meter fine against Thunder Bay Hydro for having an inaccurate meter left in the field. The meter compliance program will be in addition to the Metering work group's daily activities so staging the effort over multiple years and utilizing contractor's to assist with certain meter types is required to maintain our current customer commitments
Factors Related to Customer/Third-Party Preferences (5.4.5.2 SA – C2)
Replacement meters are designed to meet the previously specified customer requirements.
Factors Affecting the Final Cost (5.4.5.2 SA – C3)
The main factors that affect final costs will be the cost of labour and the meter type (single phase, three phase, interval etc.). Budgeted values are based on inventory costs, negotiated labour rates and standard metrics / time frames to replace smart meters.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA – C4)
The installation of meters is a standardized practice and, therefore, costs are controlled through well-established processes, the use of standard material, and the efficiencies from experience in executing such tasks.

Other Planning Objectives (where applicable) (5.4.5.2 SA – C5)
The change-over of revenue meters to smart meters for general service customers is expected to improve operating efficiency and enable hourly pricing for customers as the transition is completed. The conversion period is aligned with the Ontario Energy Board's amendments as set out in EB-2013-0311, which establishes a completion date of 2020 for all >50 KW General Service type installations.
Whether technically feasible project design and/or implementation options exist
Thunder Bay Hydro operates an Elster AMI system and has standardized on the procurement of meters from Elster, therefore minimal technically feasible options exist.
Results of a final economic evaluation (where applicable)
Not Applicable
Nature and Magnitude of System Impacts, Costs and Cost Recovery
Not Applicable



2017 Capital Project Summary

A. General Information

Project Name	Small Pole Replacements												
Project Number	A1716												
Investment Category	System Renewal												
Capital Investment(s)	<table><tr><td>Small Pole Replacements A1716</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$342,512</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$342,512</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> There are no expected O&M costs associated with this project, as all assets installed will be capitalized.			Small Pole Replacements A1716	2017	Capital Cost (5.4.5.2 A.1)	\$342,512	Capital contribution	\$0	Net Cost	\$342,512	O&M Cost (5.4.5.2 A.2)	\$0
Small Pole Replacements A1716	2017												
Capital Cost (5.4.5.2 A.1)	\$342,512												
Capital contribution	\$0												
Net Cost	\$342,512												
O&M Cost (5.4.5.2 A.2)	\$0												

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 50-100 customers
 Load: 40-80 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
\$85,628	\$85,628	\$85,628	\$85,628

This project is expected to run throughout the year.

Project Summary

This project category is comprised of replacement of wood poles determined to be in poor condition that pose a potential risk to public safety and/or customer reliability. The selected poles are either at the end of their useful life or have prematurely degraded beyond what could be expected of poles of similar age. The poles replaced in this project are identified through field inspections and lines safety reports submitted from customers and internal staff, and are scheduled for replacement within the test year. These projects are typically larger in scope than 5 poles and use work instructions or engineered drawings to conform to O. Reg. 22/04. It is expected that Thunder Bay Hydro will replace up to 40 poles in the Small Pole Replacement program, across the 4kV / 25kV / 12kV voltages.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is not flexible as the poles identified pose a risk to either safety or reliability. This project will be completed within the test year, and projects with a lower level of prioritization in the System Renewal category are deferred if increases are poles identified for replacement. As discussed in 5.3.1.3, as part of its continuous improvement Thunder Bay Hydro is looking to include pole testing as part of an improved inspection practice to better plan pole replacements.

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

This program has the potential to positively impact system reliability, as proactive replacement will greatly reduce the risk of outages and their duration to customers.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)
Alternatives for pole replacement are considered, and are captured below a) Do nothing approach – this results in increased risk and reactive replacement of poles which would result in potential long outages for those customers affected, and potentially off business hours, resulting in a higher cost for replacement, for these reasons this alternative is not considered b) Use of concrete, composite or alternative material poles – this alternative is would result in a higher initial cost which would not necessarily provide more value to the utility or the customer c) Removing line and placing overhead section of line underground which would result in improved reliability but according to Thunder Bay Hydro metrics, underground construction results in significant cost increases compared to overhead. For this reason this alternative is not considered d) Like-for-like replacement- provides the least impact to the customer, the land and the utility. It is also the most cost-effective and efficient option, and for those reasons is the best alternative.
Safety (5.4.5.2 B.2)
This investment will maintain Thunder Bay Hydro's safety to the public, as well as worker safety by replacing existing poles and their associated framing with newer standards of framing with 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. This program does not impact any other regional planning activities. As with every project, customers and third party attachers related to a replacement are notified and coordinated with.
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 replace the suggested quantities of wood poles by Kinectrics by 2019. (See Appendix C) New poles 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 and minimizing the risk of lengthy unplanned outages from failed poles. This project also supports safety targets by the elimination of poles nearing failure which pose a potential risk to public and worker 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)

The assets involved with these projects are replaced because they are near failure, and therefore, in line with lifecycle optimization policies and practices (Section 5.3.3.1). Asset condition of poles relative to typical life varies based on several factors, for example soil conditions that may cause premature deterioration regardless of the age of the pole.
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 100-350. Additionally all customers on the same feeder would be affected for a short duration until the appropriate field disconnect device can be opened to isolate the work area.
Quantitative customer impacts (5.4.5.2 SR – C1.4)
Outage events related to defective equipment account for approximately 24% (by duration) of all outages (See Figure 5.2.3 5 Outage Causes by Duration 2012-2015). The replacement of the identified poles in this project will contribute to improving Thunder Bay Hydro's outage statistics attributed to this cause.
Qualitative customer impacts (5.4.5.2 SR – C1.5)
The replacement of these poles will aid in reducing that the number and duration of outages attributed to the defective equipment and 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 medium on a system level. Depending on the location of the failure, an outage impact and duration will vary depending on several factors including: the location of the downstream disconnecting/isolating device; and quantity of circuits/customers serviced by the equipment. 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)
The timing of these projects is affected by the urgency of resolving the potential risk of failure, if an asset is identified as more urgent, it will be prioritized, rather than completing replacements based on the timing of their identification. This project has been prioritized as 3 of 21 projects for the test year.
Consequences for system O&M costs (5.4.5.2 SR – C3)
Replacement of these poles in a proactive way will reduce the cost of future unplanned failures. Poles can be scheduled to be replaced relative to best option for the customers in the area. This results in reduced O&M costs to the utility due to the replaced poles not needing detailed inspection immediately, reducing pole inspections costs.
Impact on Reliability performance and or Safety (5.4.5.2 SR – C4)
Replacement of these poles 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 tree contacts 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, impacting reliability d) A reduction in risk by increasing asset health (through replacement) and therefore reducing the probability of failure
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 using the process described in 5.3.3.1. 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. The poles identified in this project pose an imminent risk of failure and safety concern to the public and are identified as urgent meaning they are required to be attended to in a timely fashion. In addition to this Thunder Bay Hydro also evaluates how asset replacement may affect public safety, employee safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction. The timing of the project also considers the benefits and costs described in this project summary. Costs of the project may be affected by increases in the requirements for contractors and increases in material prices. While there is some uncertainty in the cost and timing of the project, the project cannot be delayed beyond 2017 due to its risk of failure to increasing dramatically and will reduce the project benefits.
Like for Like Renewal Analysis, Alternative Comparison (5.4.5.2 SR – C6)
This project will be completed in a like for like manner, as noted in Section B: Analysis of Alternatives.



A. General Information

Project Name	Lines Safety Reports											
Project Number	A1717											
Investment Category	System Renewal											
Capital Investment(s)	<table><tr><td>Lines Safety Reports A1717</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$761,834</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$761,834</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> There are no expected O&M costs associated with this project, as all assets installed will be capitalized.		Lines Safety Reports A1717	2017	Capital Cost (5.4.5.2 A.1)	\$761,834	Capital contribution	\$0	Net Cost	\$761,834	O&M Cost (5.4.5.2 A.2)	\$0
Lines Safety Reports A1717	2017											
Capital Cost (5.4.5.2 A.1)	\$761,834											
Capital contribution	\$0											
Net Cost	\$761,834											
O&M Cost (5.4.5.2 A.2)	\$0											

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 50-300 customers
Load: 100-250 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
\$190,458	\$190,458	\$190,459	\$190,459

The replacement of poles is expected to run throughout the year.

Project Summary

This project category is comprised of replacement of wood poles, overhead conductor, porcelain insulators wood cross arms, or wood pins that are identified to be in poor condition and that pose a potential risk to public safety and/or customer reliability. The selected assets are either at the end of their useful life or have prematurely degraded beyond what could be expected of assets of similar age. The assets replaced in this project are identified through field inspections and lines safety reports submitted from customers and internal staff, and are scheduled for replacement within the test year. These projects are below 5 poles in scope and use USF standards for like-for-like construction with installation framed to conform to O. Reg. 22/04. It is expected that Thunder Bay Hydro will replace approximately 90 poles and associated infrastructure in the Lines Safety Reports project, primarily across 25kV / 12kV voltages.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is not flexible as the poles identified pose a risk to either safety or reliability. This project will be completed within the test year, and projects with a lower level of prioritization in the System Renewal category are deferred if increases are poles identified for replacement. As discussed in 5.3.1.3, as part of its continuous improvement Thunder Bay Hydro is looking to include pole testing as part of an improved inspection practice to better plan pole replacements.

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

Alternatives for pole replacement are considered, and are captured below a) Do nothing approach – this results in increased risk and reactive replacement of poles which would result in potential long outages for those customers affected, and potentially off business hours, resulting in a higher cost for replacement, for these reasons this alternative is not considered b) Use of concrete, composite or alternative material poles – this alternative is would result in a higher initial cost which would not necessarily provide more value to the utility or the customer c) Removing line and placing overhead section of line underground which would result in improved reliability but according to Thunder Bay Hydro metrics, underground construction results in significant cost increases compared to overhead. For this reason this alternative is not considered d) Like-for-like replacement- provides the least impact to the customer, the land and the utility. It is also the most cost-effective and efficient option, and for those reasons is the best alternative.
Safety (5.4.5.2 B.2) This investment will maintain Thunder Bay Hydro’s safety to the public, as well as worker safety by replacing existing poles and their associated framing with newer standards of framing with allow for improved safe work practices. In areas of these projects where porcelain insulators are discovered these will be replaced with polymer insulators additionally eliminating a potential safety hazard to the public.
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. This program does not impact any other regional planning activities. As with every project, customers and third party attachers related to a replacement are notified and coordinated with.
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 replace the suggested quantities of wood poles by Kinectrics by 2019. (See Appendix C) New poles 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
Relationship between the characteristics of assets and the consequences of asset performance (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 and minimizing the risk of lengthy unplanned outages from failed poles. This project also supports safety targets by the elimination of poles nearing failure which pose a potential risk to public and worker 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) The assets involved with these projects are replaced because they are close to failure, and therefore, in line with lifecycle optimization policies and practices (Section 5.3.3.1). Asset condition of poles relative to typical life varies based on several factors, for example soil conditions that may cause premature deterioration regardless of the age of the pole.
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 50-300. Additionally all customers on the same feeder would be affected for a short duration until the appropriate field disconnect device can be opened to isolate the work area.
Quantitative customer impacts (5.4.5.2 SR – C1.4)
Outage events related to defective equipment account for approximately 24% (by duration) of all outages (See Figure 5.2.3 5 Outage Causes by Duration 2012-2015). The replacement of the identified poles in this project will contribute to improving Thunder Bay Hydro's outage statistics attributed to this cause.
Qualitative customer impacts (5.4.5.2 SR – C1.5)
The replacement of these assets will ensure that the number and duration of outages attributed to the defective equipment cause are reduced and 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 medium on a system level. Depending on the location of the 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)
The timing of these projects is affected by the urgency of resolving the potential risk of failure, if an asset is identified as more urgent, it will be prioritized, rather than completing replacements based on the timing of their identification.
Consequences for system O&M costs (5.4.5.2 SR – C3)
Replacement of these poles in a proactive way will reduce the cost of future unplanned failures. Poles can be scheduled to be replaced relative to best option for the customers in the area. This results in reduced O&M costs to the utility due to the replaced poles not needing detailed inspection immediately, reducing pole inspections costs.
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 tree contacts b) Installation of new standards and framing 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) A reduction in risk by increasing asset health (through replacement) and therefore reducing the probability of failure
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 using the process described in 5.3.3.1. 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. The poles identified in this project pose an imminent risk of failure and safety concern to the public and are identified as urgent meaning they are required to be attended to in a timely fashion. In addition to this Thunder Bay Hydro also evaluates how asset replacement may affect public safety, employee safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction. The timing of the project also considers the benefits and costs described in this project summary. Costs of the project may be affected by increases in the requirements for contractors and increases in material prices. While there is some uncertainty in the cost and timing of the project, the project cannot be delayed beyond 2017 due to its risk of failure to increasing dramatically and will reduce the project benefits.
Like for Like Renewal Analysis, Alternative Comparison (5.4.5.2 SR – C6)
This project will be completed in a like for like manner, as noted in Section B: Analysis of Alternatives.



2017 Capital Project Summary

A. General Information

Project Name	Transformers and Switch Replacements											
Project Number	A1718											
Investment Category	System Renewal											
Capital Investment(s)	<table><tr><td>Transformers and Switch Replacements A1718</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$756,484</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$756,484</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> There are no expected O&M costs associated with this project, as all assets installed will be capitalized.		Transformers and Switch Replacements A1718	2017	Capital Cost (5.4.5.2 A.1)	\$756,484	Capital contribution	\$0	Net Cost	\$756,484	O&M Cost (5.4.5.2 A.2)	\$0
Transformers and Switch Replacements A1718	2017											
Capital Cost (5.4.5.2 A.1)	\$756,484											
Capital contribution	\$0											
Net Cost	\$756,484											
O&M Cost (5.4.5.2 A.2)	\$0											

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 350-1000 customers
 Load: 290-815 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
\$ 37,824	\$ 264,769	\$ 264,769	\$ 189,121

Transformer replacements are coincident with the risk assessment process which begins in at the end of Q1, as this process identifies defective transformers.

Project Summary

This project category is comprised of reactive replacement of transformers, switches and switchgear. Risk assessments and field inspections are completed on 1/3 of the system each year and include visual and detailed assessments. These assessments result in the discovery of equipment that is in very poor condition, or present a safety or environmental hazard. The expected assets replaced in this project are as follows;

- a) 40 pole mount transformers
- b) 25 pad mount transformers
- c) 3 load break switches
- d) 7 in-line switches

Risk Identification & Mitigation (5.4.5.2 A.4)

These quantities of replacements are dependent on the field inspections and risk assessments. As inspections can be subjective by nature it is important to establish sufficient criteria to ensure the data collected is valid. For this reason, the Engineering department has worked closely with the Lines department to create a standardized testing and inspection procedure, to ensure that imminent replacement quantities are justifiable. In addition there is a risk that required replacements will exceed the expected quantities and planned expenditures. For this reason, all replacements are reviewed by the Maintenance Lines Supervisor and the expenditures in this account are tracked by the Project Engineer and reported on a bi-monthly basis. This project is not flexible as the assets identified pose a risk to either safety or reliability. This project will be completed within the test year, and projects with a lower level of prioritization in the System Renewal category are deferred if increases are poles identified for replacement.

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

Transformers/Switch/Switchgear A1718	2012	2013	2014	2015	2016	2017
Capital Cost	\$123,691	\$345,416	\$544,471	\$932,264	\$816,936	\$756,484

The comparative information regarding this project varies dependent on the level of defective transformers discovered through the risk assessment process.

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

Not Applicable, as equipment is identified during the risk assessment process and scheduled for completion in the test year.

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 for this project are health and safety. Thunder Bay Hydro is obligated to ensure that the manner in which it operates its system does not negatively impact the health and safety of the general public, customers or Thunder Bay Hydro's employees. Replacing end of life assets that are not scheduled for replacement, but due to their present condition must be replaced immediately to ensure reliability and safety are not compromised. The assets identified in this program for replacement have a high probability of failure which is a result of the age and the condition of the assets.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)

The secondary drivers for this project are Asset Retirement. Thunder Bay Hydro seeks to prioritize project selection based on assets that are at or beyond their useful life as determined through Thunder Bay Hydro's safety reporting process.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)

The objective of this program is to reduce asset failure risk. By removing these assets, Thunder Bay Hydro plans to maintain its high level of performance with regards to safety as reported in Figure 5.1.5-1 2015 Scorecard. Thunder Bay Hydro recorded 0 serious electrical incidents from 2011-2015.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1a)

The ACA provided by Kinectrics (See Appendix C) was used in conjunction with inspection data to inform the planning process in determining the amount of pole mount and pad mount transformers as well as overhead switches considered in poor condition and needing an action plan. Thunder Bay Hydro determines which repair/replace/remove strategy is appropriate through the use of its Asset Management Strategy as described in 5.3.1.3.

Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments

This project is ranked overall as P2 – Urgent, as replacement work is required for continued operation; and should be completed to ensure continuous operation and restore health of the system. Not an emergency however a respond upon completion of current work but within a specified period (such as same day or same week). There are cases, such as a failed transformer in which the project is ranked P1 – Emergency and replacement is executed as a result of loss of service.

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 transformers and switches as executed in this project area will 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.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1cii)	

The net benefit to customers is to reduce the potential risk associated with untimely failure and to ensure that any safety hazards are reduced and reliability is maintained.
Effect of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)
The replacement of defective equipment ensures that Thunder Bay Hydro maintains current reliability performance and has the ability to operate overhead switches when needed to isolate or redirect power to customers during an outage. Replacing assets with as suspected imminent failure is more cost-effective than doing so reactively.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)
Alternatives for transformer/switch/switchgear replacement are considered, and are captured below; a) Do nothing approach – this results in reactive replacement of these assets which would result in potential long outages for those customers affected, and potentially off business hours, resulting in a higher cost for replacement, for these reasons this alternative is not considered b) Removal of the asset – this option is considered for overhead switches based on functionality and operational effectiveness, but is not an option for transformers which provide service to customers c) Relocation of the asset - this alternative could result in a higher cost, but it is considered in cases where there are access issues or where this results in a more cost effective option which provides value to the utility or the customer d) Decreased or increased sizing for transformers is considered based on an analysis of the loading e) Like-for-like replacement with updated standards (such as transformers of the same size but with current limiting fuses) is the typical replacement strategy as it provides the least impact to the customer, the land and the utility. It is also typically the most cost-effective and efficient option
Safety (5.4.5.2 B.2)
This investment will maintain Thunder Bay Hydro's safety to the public, as well as worker safety by replacing defective assets and their associated newer standards to 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. This program does not impact any other regional planning activities. As with every project, customers and third party attachers related to a replacement are notified and coordinated with.
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 replace the suggested quantities of pole mount and pad mount transformers and overhead switches. (See Appendix C) New assets are 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)
Avoidance of potential transformer oil spills, according to Environment Canada and Ontario O.Reg 675/98 Regulations.
C. Category-Specific Requirements - System Renewal
Relationship between the characteristics of assets and the consequences of asset performance (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 assets. This project also supports safety targets by the elimination of assets 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) The assets involved with these projects are replaced because they are close to failure, and therefore, in line with lifecycle optimization policies and practices (Section 5.3.3.1). Asset condition relative to typical life varies based on several factors, for example proximity to the sidewalk that may cause premature deterioration due to salt, regardless of the age of the transformer.
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 varies greatly from 1 through to several hundred depending on the type of equipment and customers serviced downstream of it. Additionally all customers on the same feeder would be affected for a short duration until the appropriate field disconnect device can be opened to isolate the work area.
Quantitative customer impacts (5.4.5.2 SR – C1.4) Outage events related to defective equipment account for approximately 24% (by duration) of all outages (See Figure 5.2.3 5 Outage Causes by Duration 2012-2015). The replacement of the identified poles in this project will contribute to improving Thunder Bay Hydro's outage statistics attributed to this cause.
Qualitative customer impacts (5.4.5.2 SR – C1.5) The replacement of these assets will positively impact the number and duration of outages attributed to the defective equipment cause are reduced and 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 medium on a system level. Depending on the location of the 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) Replacement of some of these assets is completed at failure and as a result the work is completed immediately. The timing of these projects is affected by the urgency of resolving the potential risk of failure, if an asset is identified as more urgent, it will be prioritized, rather than completing replacements based on the timing of their identification. This project has been prioritized within the System Renewal category and takes seasonal and resource availability into account. The project has been ranked 2 out of 21 projects for the test year.
Consequences for system O&M costs (5.4.5.2 SR – C3) Proactive replacement of assets identified in this project will ensure that the devices are operable when required to do so to either restore or isolate sections of the distribution system. This will ensure the system continues to operate efficiently and effectively.
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) Installation of new standards will enhance working clearances providing for safer working conditions for both Thunder Bay Hydro and Third party employees b) Installation of new standards includes animal protection on transformers which will reduce the number of animal contact related outage, improving reliability c) Improved reliability by reducing potential failures prior to failure and greatly decreasing restoration times d) Significant improvement in safety by removing defective equipment from the system as soon as possible
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 using the process described in 5.3.3.1. 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. The poles identified in this project pose an imminent risk of failure and safety concern to the public and are identified as urgent meaning they are required to be attended to in a timely fashion. In addition to this Thunder Bay Hydro also evaluates how asset replacement may affect public safety, employee safety, environmental impacts, reliability and power quality, operational efficiency and customer satisfaction. The timing of the project also considers the benefits and costs described in this project summary. Costs of the project may be affected by increases in the requirements for contractors and increases in material prices. While there is some uncertainty in the cost and timing of the project, the project cannot be delayed beyond 2017 due to its risk of failure to increasing dramatically and will reduce the project benefits.

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, the alternative discussed in **Analysis of Project & Alternatives** shall be considered.



2017 Capital Project Summary

A. General Information

Project Name	25kV Planned Pole Replacements											
Project Number	B11140											
Investment Category	System Renewal											
Capital Investment(s)	<table><tr><td>25kV Pole Replacements B11140</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$584,384</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$584,384</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> There are no expected O&M costs associated with this project, as all assets and the work associated with it will be capitalized.		25kV Pole Replacements B11140	2017	Capital Cost (5.4.5.2 A.1)	\$584,384	Capital contribution	\$0	Net Cost	\$584,384	O&M Cost (5.4.5.2 A.2)	\$0
25kV Pole Replacements B11140	2017											
Capital Cost (5.4.5.2 A.1)	\$584,384											
Capital contribution	\$0											
Net Cost	\$584,384											
O&M Cost (5.4.5.2 A.2)	\$0											

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 45 customers
 Load: 50 kWh

Start Date (5.4.5.2 A.3)	01-07-17	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	\$0	\$292,192	\$292,192

This project is expected to start in Q3 and be completed at the end of the year.

Project Summary

This project category is comprised of the replacement of wood poles in the McDougall Court, Hodder Ave and Montreal Street areas. These poles are in poor condition and past their typical useful life (TUL). The selected poles are all at end of useful life or have prematurely degraded beyond what could be expected of poles of similar age. Selection of poles as part of this project category is a multi-step process consisting of an internal GIS model which selects poles of the oldest vintage with the highest criticality and worst risk assessment. Following this selection, field inspections are completed to verify the condition assumptions. This process results in selecting only the replacement of assets which have a high risk and probability of failure. Each project scope includes design, construction and installation of new poles framed to conform to O. Reg. 22/04 compliant standards. In certain cases where overhead conductor or porcelain insulators are identified as end of life, within these projects, replacement will also occur. (See the reference material) Through this project, Thunder Bay Hydro plans to improve the level of safety and reliability associated with newer standards and materials. It is expected that Thunder Bay Hydro will replace 60 poles in the 25kV Planned Pole Replacement program on 25kV / 12kV voltages.

Risk Identification & Mitigation (5.4.5.2 A.4)

Scheduling Risk: This project is subject to scheduling risks with respect to other system renewal projects which are prioritized ahead of it. All planned capital projects are scheduled for completion in the test year; however there is a risk that projects of higher prioritization such as Small Pole Replacements, Lines Safety Reports and Transformer/Switch/Switchgear identifying additional assets for replacement. The mitigation plan for these risks are weekly internal project updates from the Project Manager to review progress and identify action plans to discuss project scopes and schedules. This project is less flexible than other projects that do not contain pole setting as this task is most effectively completed during the months that the ground is thawed. If the project goes into the frost season, the possibility of cost increases will likely result due to the difficulty in auguring

/ hydro vac activities in the frost. This risk is minimized by scheduling the work to begin in the summer.

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

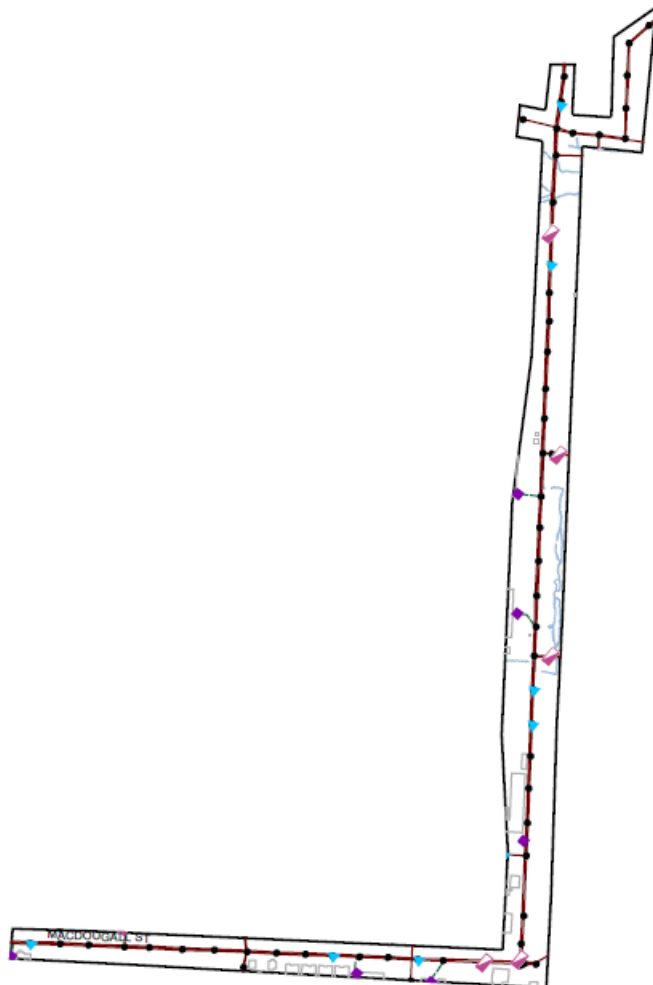
Thunder Bay Hydro historically completed 25kV pole replacements in the reactive Lines Safety Reports and Small Unplanned Capital accounts. In future years, Thunder Bay Hydro intends to incorporate pole replacements in a planned manner through the 25kV pole replacements and Voltage conversion projects.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

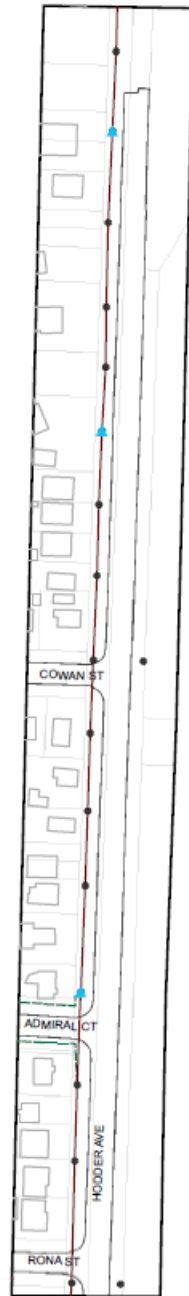
Not Applicable

Attach Other project reference material i.e. Images, Drawings and or reference material

MacDougall- Court Pole Line Rebuild



Hodder Ave Pole Line Rebuild

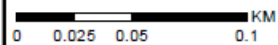


- Poles
- Primary Overhead
- Primary Underground
- ▲ Pole Mount Transformer



Date: July 21, 2016
Projected Coordinate System:
NAD_1983_UTM_ZONE_18N

15 poles to be replaced



Montreal St Pole Line Rebuild



- Poles
- Primary Overhead
- Primary Underground
- ▲ Pole Mount Transformer



Date: July 21, 2016
Projected Coordinate System:
NAD_1983_UTM_ZONE_16N

7 poles to be replaced

0 0.025 0.05 0.1 KM

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 for this project are Asset Retirement and Health and Safety. Thunder Bay Hydro seeks to prioritize project selection based on assets that are at or beyond their useful life, and Thunder Bay Hydro is obligated to ensure that the manner in which it executes its initiatives does not negatively impact the health and safety of the general public, customers or Thunder Bay Hydro's employees. The assets identified in this project have a high probability of failure which is a result of the age and or the condition of the assets.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)

The secondary driver is Reliability. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability and customer satisfaction.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)
The objective of this program is asset retirement. Thunder Bay Hydro seeks to prioritize project selection based on assets that are at or beyond their useful life as determined through Thunder Bay Hydro's ACA process. The performance objectives of this project is 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.1.a)
Kinectrics provided Thunder Bay Hydro with an Asset Condition Assessment, which indicated the aging and identifies the quantities for 4kV substation transformer, breaker, transformer and wood pole replacement. (See Appendix C) The information contained in this report assists in identifying the areas for replacement of 25kV infrastructure.
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.
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 25kV poles as planned in the project areas will greatly decrease the probability of a failure in these areas. The installation of poles 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)
The net benefit to customers is to reduce the potential for a risk in failure and to ensure that any safety hazards are eliminated while maintaining reliability.
Analysis of Project & Alternatives - Effect of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)
This program has the potential to positively impact system reliability, as proactive replacement will greatly reduce the risk of outages and their duration to customers.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)
Alternatives for pole replacement are considered, and are captured below a) Do nothing approach – this results in reactive replacement of poles which would result in potential long outages for those customers affected, and potentially off business hours, resulting in a higher cost for replacement, for these reasons this alternative is not considered b) Use of concrete, composite or alternative material poles – this alternative is would result in a higher initial cost which would not necessarily provide more value to the utility or the customer c) Removing line and placing overhead section of line underground which would result in improved reliability but according to Thunder Bay Hydro metrics, underground construction results in significant cost increases compared to overhead. For this reason this alternative is not considered d) Like-for-like replacement- provides the least impact to the customer, the land and the utility. It is also the most cost-effective and efficient option, and for those reasons is the best alternative.
Safety (5.4.5.2 B.2)
This investment will maintain Thunder Bay Hydro's safety to the public, as well as worker safety by replacing existing poles and their associated framing with newer standards of framing with allow for improved safe work practices. In areas of these projects where porcelain insulators are discovered these will be replaced with polymer insulators thereby greatly reducing the risk of failure and eliminating a safety hazard to the public.
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. This program does not impact any other regional planning activities. As with every project, customers and third party attachers related to a replacement are notified and coordinated with.																				
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 replace the suggested quantities of wood poles by Kinectrics by 2019. (See Appendix C) New poles 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)																				
The assets involved with these projects are replaced because they are close to failure, and therefore, in line with lifecycle optimization policies and practices (Section 5.3.3.1). Asset condition of poles relative to typical life varies based on several factors, for example soil conditions that may cause premature deterioration regardless of the age of the pole.																				
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 45.																				
<table><tr><td>Project</td><td>Residential/ Other</td><td>General Users</td><td>Large Users</td><td>Total</td></tr><tr><td>Hodder Ave</td><td>24</td><td>0</td><td>0</td><td>24</td></tr><tr><td>Macdougall 25 kV</td><td>18</td><td>8</td><td>0</td><td>18</td></tr><tr><td>Montreal St</td><td>0</td><td>3</td><td>0</td><td>3</td></tr></table>	Project	Residential/ Other	General Users	Large Users	Total	Hodder Ave	24	0	0	24	Macdougall 25 kV	18	8	0	18	Montreal St	0	3	0	3
Project	Residential/ Other	General Users	Large Users	Total																
Hodder Ave	24	0	0	24																
Macdougall 25 kV	18	8	0	18																
Montreal St	0	3	0	3																
Additionally all customers on the same feeder would be affected for a short duration until the appropriate field disconnect device can be opened to isolate the outage area.																				
Quantitative customer impacts (5.4.5.2 SR – C1.4)																				
Outage events related to customers in this area are indicated below; the replacement of the identified poles in this project will contribute to improving Thunder Bay Hydro’s outage statistics on the identified feeders.																				
<table><tr><td>Feeder</td><td>Total Customers in Project area on specified feeder</td><td>Hours of Interruptions</td><td>Number of Interruptions</td></tr><tr><td>2M5</td><td>88</td><td>801</td><td>1382</td></tr><tr><td>10M8</td><td>146</td><td>2719</td><td>30518</td></tr><tr><td>2M2</td><td>18</td><td>805</td><td>10246</td></tr></table>	Feeder	Total Customers in Project area on specified feeder	Hours of Interruptions	Number of Interruptions	2M5	88	801	1382	10M8	146	2719	30518	2M2	18	805	10246				
Feeder	Total Customers in Project area on specified feeder	Hours of Interruptions	Number of Interruptions																	
2M5	88	801	1382																	
10M8	146	2719	30518																	
2M2	18	805	10246																	
Qualitative customer impacts (5.4.5.2 SR – C1.5)																				
The replacement of these poles will aid in reducing the number and duration of outages attributed to defective equipment and tree contacts and existing levels of reliability are maintained or improved, 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 medium 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 an 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 12 out of 21 projects in the test year.
Consequences for system O&M costs (5.4.5.2 SR – C3)
Replacement of these poles in a proactive way will reduce the cost of future unplanned failures. Poles can be scheduled to be replaced relative to best option for the customers in the area. This results in reduced O&M costs to the utility due to the replaced poles not needing detailed inspection immediately, reducing pole inspections costs.
Impact on Reliability performance and or Safety (5.4.5.2 SR – C4)
Replacement of these poles 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 tree contacts 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 using the process described in 5.3.3.1. 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 also considers the benefits and costs described in this project summary. Costs of the project may be affected by increases in the requirements for contractors and increases in material prices. While there is some uncertainty in the cost and timing of the project, the project cannot be delayed beyond 2017 due to its risk of failure to increasing dramatically and will reduce the project benefits.
Like for Like Renewal Analysis, Alternative Comparison (5.4.5.2 SR – C6)
This project will be completed in a like for like manner, as noted in Section B: Analysis of Alternatives.



2017 Capital Project Summary

A. General Information

Project Name	Black-Bay Dewe Voltage Conversion												
Project Number	B12111												
Investment Category	System Renewal												
Capital Investment(s)	<table><tr><td>Black Bay-Dewe B12111</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$1,174,110</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$1,174,110</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> There are no expected O&M costs associated with this project, as all assets and the work associated with it will be capitalized.			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
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												

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

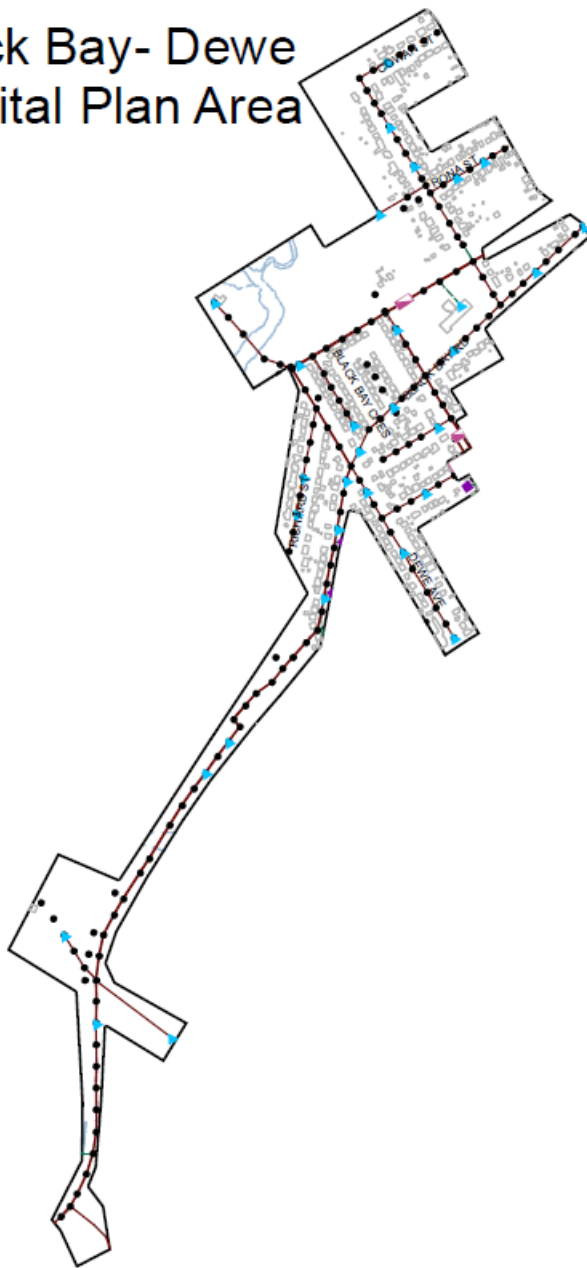
This project is the completion of a voltage conversion project where pole setting occurred in 2016 and 2017 includes the replacement of end of life 4kV distribution assets and substations that are targeted for replacement with modern 25kV distribution, which will allow for increased system reliability 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)

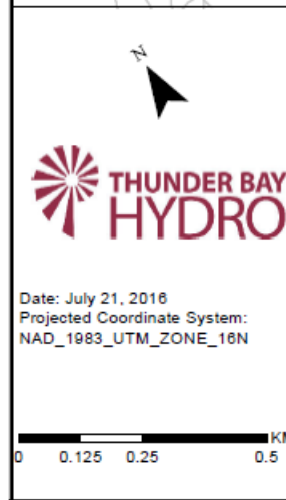
Scheduling Risk: The projects in this program are subject to scheduling risks with respect to other major projects. All planned capital projects are scheduled for completion in 2017. The mitigation plan for these risks are weekly internal project updates from the Project Manager to review progress and 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.

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

Black Bay- Dewe Capital Plan Area



- Poles
- Primary Overhead
- Primary Underground
- Padmount Transformer
- ▲ Pole Mount Transformer
- ▭ Load Break Switch



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

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 upgrading 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; a) Eliminate older, end of life 4kV distribution assets 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 c) Standardize construction practices across the different systems, which helps to control construction and operating costs d) Reduce system losses through the elimination of substations e) Allow for the connection of larger loads and generators without major system rebuilds. f) Conform to the standard voltage across the Province making it easier to source material and expertise. g) Eliminate the use of outdated, hard to replace and maintain equipment. 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. Alternatives for voltage conversion are considered, and are captured below; 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. 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. 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. 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) 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. 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.



2017 Capital Project Summary

A. General Information

Project Name	Dewe-Rita Voltage Conversion		
Project Number	B12112		
Investment Category	System Renewal		
Capital Investment(s)			
	Dewe-Rita B12112	2017	
	Capital Cost (5.4.5.2 A.1)	\$1,489,302	
	Capital contribution	\$0	
	Net Cost	\$1,489,302	
	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 522 customers as broken down by customer class below.

Project	Residential/ Other	General Users	Large Users	Total
Dewe- Rita	513	8	1	522

Load: 854 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
\$ 372,326	\$ 446,791	\$ 446,791	\$ 223,395

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

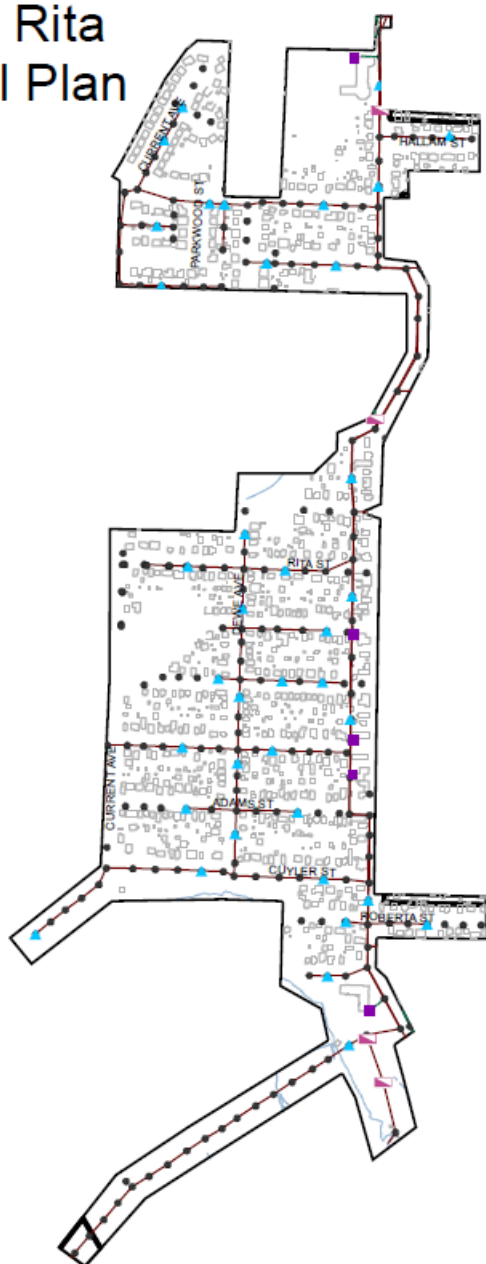
This project is the completion of a voltage conversion project where pole setting occurred in 2016 and 2017 includes the replacement of end of life 4kV distribution assets and substations that are targeted for replacement with modern 25kV distribution, which will allow for increased system reliability 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 176 poles; reframe of 28 poles, 35 pole mount transformers and 1 pad mount transformer. The project also targets to replace 11165 m of overhead conductor and 570 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.

Comparative information on expenditures for equivalent projects/activities (if any) (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 Dewe-Rita project's proposed construction cost is in-line with the historic per-unit costs considering this project includes the replacement of 176 poles, the reframe of 28 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

Dewe- Rita Capital Plan Area



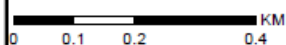
- Poles
- Primary Overhead
- Primary Underground
- Padmount Transformer
- ▲ Pole Mount Transformer
- ▭ Load Break Switch



N



Date: July 21, 2016
Projected Coordinate System:
NAD_1983_UTM_ZONE_16N



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 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 upgrading 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 substation transformer, breaker, transformer and wood pole replacements. (See Appendix C) These 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. The project has been ranked 15 of 21 projects planned for 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 substation 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; a) Eliminate older, end of life 4kV distribution assets 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 c) Standardize construction practices across the different systems, which helps to control construction and operating costs d) Reduce system losses through the elimination of substations e) Allow for the connection of larger loads and generators without major system rebuilds. f) Conform to the standard voltage across the Province making it easier to source material and expertise. g) Eliminate the use of outdated, hard to replace and maintain equipment. 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 while eliminating a safety hazard to the public.
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. Alternatives for voltage conversion are considered, and are captured below; 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. 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 load to 25kV as they reach end of life. 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. d) Install several step-down transformer banks to feed the area 25kV 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. (See Appendix C) 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 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 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 522.

Project	Residential/ Other	General Users	Large Users	Total
Dewe- Rita	513	8	1	522

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 outage area.

Quantitative customer impacts

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	Hours of Interruptions	Number of Interruptions
02M4	522	11194	21744

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 an 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 15 of 21 projects planned for 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;

- Tree trimming due to replacement will improve reliability by reducing the amount of tree contacts
- Installation of new standards will enhance clearance providing for safer working conditions for both Thunder Bay Hydro and Third party employees
- Installation of new standards includes animal protection which will reduce the number of animal contact related outage, improving reliability
- 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.

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

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.

A. General Information

Project Name	Cumming-Brodie Voltage Conversion												
Project Number	B1270												
Investment Category	System Renewal												
Capital Investment(s)	<table><tr><td>Cumming-Brodie B1270</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$580,677</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$580,677</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> There are no expected O&M costs associated with this project, as all assets and the work associated with it will be capitalized.			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
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												

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)

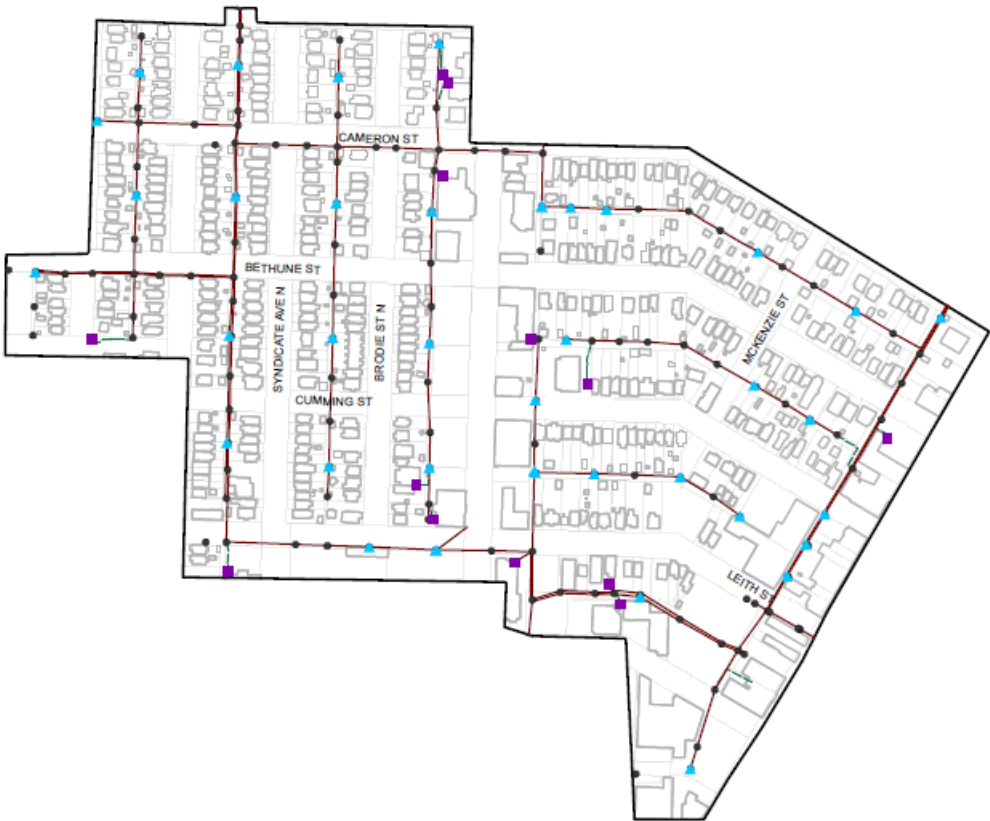
Thunder Bay Hydro has completed a number of similar projects over the past five years. Most recently, projects have been completed in Durban-Brodie pole setting project. This pole setting project also involved the replacement of poles which are primarily located in back lanes. The approximate average cost of construction of this project on a per pole basis was \$4,700. Based on this information, the Cumming-Brodie project's proposed construction cost is in-line with the historic per-unit costs considering this project includes the replacement of 123 poles.

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

Cumming- Brodie Capital Plan Area



Date: July 21, 2016
Projected Coordinate System:
NAD_1983_UTM_ZONE_18N

- Poles
- Primary Overhead
- Primary Underground
- Padmount Transformer
- ▲ Pole Mount Transformer

0 0.05 0.1 0.2 KM



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 driver for this project is Asset Retirement. Thunder Bay Hydro seeks to prioritize project selection based on assets that are at or beyond their useful life. The assets identified in this program for replacement are being fed by Hardisty substation transformers and breakers which are at end of life and have a high probability of failure which is a result of the age and the condition of the assets.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)

The secondary 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 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 from 4kV to 25kV eliminates the need to operate, maintain, and upgrade stations required for providing electrical connectivity between the 25kV and the 4kV systems. The Cumming-Brodie and Finlayson-Brodie projects contribute directly to Thunder Bay Hydro's ability to retire Hardisty by the end of 2018. 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 load and/or generation customers.

Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)

The objective of this program is Asset Retirement. Thunder Bay Hydro seeks to prioritize project selection based on assets that are at or beyond their useful life as determined through Thunder Bay Hydro's ACA process and to reduce asset failure risk, and to update the distribution system to a 25kV system with all of the advantages it provides. (See Net benefits accruing to customers) 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 substation transformer, breaker, transformer and wood pole replacements. (See Appendix C) These projects accounts 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. The project has been ranked 16 of 21 projects planned for 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 substation 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.1.ci)

With the conversion from 4kV to 25kV construction Thunder Bay Hydro expects the following benefits to customers;

- a) Eliminate older, end of life 4kV distribution assets
- 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
- c) Standardize construction practices across the different systems, which helps to control construction and operating costs
- d) Reduce system losses through the elimination of substations
- e) Allow for the connection of larger loads and generators without major system rebuilds.
- f) Conform to the standard voltage across the Province making it easier to source material and expertise.
- g) Eliminate the use of outdated, hard to replace and maintain equipment.
- 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 while eliminating a safety hazard to the public.
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. Alternatives for voltage conversion are considered, and are captured below; 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. 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 load to 25kV as they reach end of life. 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. d) Install several step-down transformer banks as a contingency for the failure of Hardisty and to feed the area 25kV 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 substation transformers by Kinectrics. (See Appendix C) 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 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 while removing Hardisty substation. The uprating 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 421.

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

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 outage 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
10M1	18	2335	42924
10M3	403	2731	31242

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 an 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 16 of 21 projects planned for 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.

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.



2017 Capital Project Summary

A. General Information

Project Name	Donald-Mountdale Voltage Conversion												
Project Number	B1277												
Investment Category	System Renewal												
Capital Investment(s)	<table><tr><td>Donald-Mountdale B1277</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$310,256</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$310,256</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> There are no expected O&M costs associated with this project, as all assets and the work associated with it will be capitalized.			Donald-Mountdale B1277	2017	Capital Cost (5.4.5.2 A.1)	\$310,256	Capital contribution	\$0	Net Cost	\$310,256	O&M Cost (5.4.5.2 A.2)	\$0
Donald-Mountdale B1277	2017												
Capital Cost (5.4.5.2 A.1)	\$310,256												
Capital contribution	\$0												
Net Cost	\$310,256												
O&M Cost (5.4.5.2 A.2)	\$0												

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 128 customers as broken down by customer class below.

Project	Residential/ Other	General Users	Large Users	Total
Donald-Mountdale	99	29	0	128

Load: 122 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	\$ 62,051	\$ 248,205	\$0

The Donald-Mountdale 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. The project has been prioritized due to being the final in-service project area prior to the removal of Mountdale Substation which has one transformer that has been identified as having a low interconnectivity and no back up transformation should the substation transformer fail. Expenditures in 2017 include the installation of 62 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)

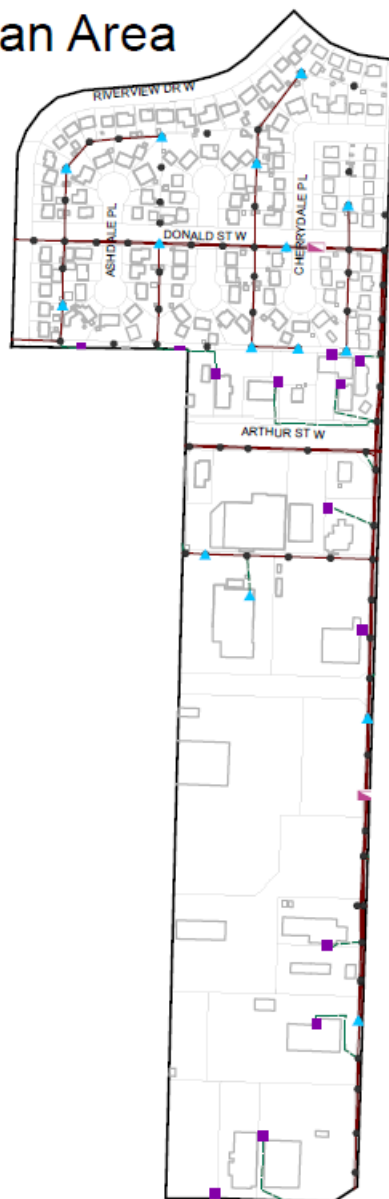
Thunder Bay Hydro has completed a number of similar projects over the past five years. Most recently, projects have been completed in Victoria-James pole setting project. This pole setting project also involved the replacement of poles which are primarily located in easement areas in the back of residential properties. The approximate average cost of construction of this project on a per pole basis was \$4,900. Based on this information, the Cumming-Brodie project's proposed construction cost is in-line with the historic per-unit costs considering this project includes the replacement of 65 poles.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

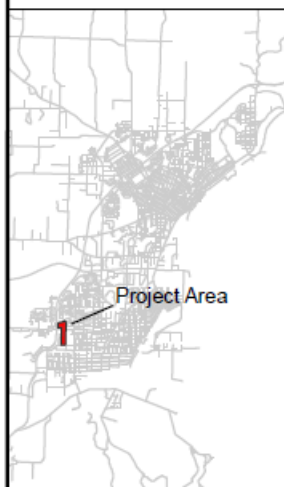
Not Applicable

Attach Other project reference material i.e. Images, Drawings and or reference material

Donald- Mountdale Capital Plan Area



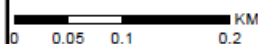
- Poles
- Primary Overhead
- Primary Underground
- Padmount Transformer
- ▲ Pole Mount Transformer
- ▭ Load Break Switch



N



Date: July 21, 2016
Projected Coordinate System:
NAD_1983_UTM_ZONE_18N



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 Donald-Mountdale project is the final project connected to the Mountdale substation and contributes directly to Thunder Bay Hydro's ability to retire Mountdale 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 load and/or generation customers.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (If applicable)

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 substation transformer, breaker, transformer and wood pole replacements. (See Appendix C) These projects accounts 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. The project has been ranked 13 of 21 projects planned for 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 substation 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

With the conversion from 4kV to 25kV construction Thunder Bay Hydro expects the following benefits to customers;

- a) Eliminate older, end of life 4kV distribution assets
- 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
- c) Standardize construction practices across the different systems, which helps to control construction and operating costs
- d) Reduce system losses through the elimination of substations
- e) Allow for the connection of larger loads and generators without major system rebuilds.
- f) Conform to the standard voltage across the Province making it easier to source material and expertise.
- g) Eliminate the use of outdated, hard to replace and maintain equipment.
- 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.

Alternatives for voltage conversion are considered, and are captured below;

- 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.
- 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 load to 25kV as they reach end of life.
- 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.
- d) Install several step-down transformer banks to feed the area 25kV 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 substation transformers by Kinectrics. (See Appendix C) 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 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 128.

Project	Residential/ Other	General Users	Large Users	Total
Donald-Mountdale	99	29	0	128

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 outage area.

Quantitative customer impacts

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
10M4	86	1374	24324
10M10	21	3351	15721
10M4	6	1374	24324
10M9	15	9837	50190

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 an overall system renewal program for 2017. The assets being replaced fall within the planned leveled 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 13 of 21 projects planned for 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.

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.



2017 Capital Project Summary

A. General Information

Project Name	MacDougall-Court Voltage Conversion		
Project Number	B1298		
Investment Category	System Renewal		
Capital Investment(s)			
	MacDougall-Court B1298	2017	
	Capital Cost (5.4.5.2 A.1)	\$789,716	
	Capital contribution	\$0	
	Net Cost	\$789,716	
	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 185 customers as broken down by customer class below.

Project	Residential/ Other	General Users	Large Users	Total
Donald-Mountdale	163	23	0	185

Load: 164 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	\$236,915	\$552,801	\$0

The Macdougall-Court project consists of setting poles in 2017, as well as additional framing. The completion of framing, stringing, services and transformers are to be completed in 2018.

Project Summary

This project is a voltage conversion project that will be completed over a 2 year period. Expenditures on pole setting will occur in 2017 and 2018 will include the replacement of end of life 4kV distribution assets with 25kV distribution assets. The project has been prioritized due to it being related to the removal of Algoma Substation which has one transformer that is 57 years of age and has been identified as having a low interconnectivity and no back up transformation should the substation transformer fail. Expenditures in 2017 include the installation of 155 poles, and the framing of 35 poles.

Risk Identification & Mitigation

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.

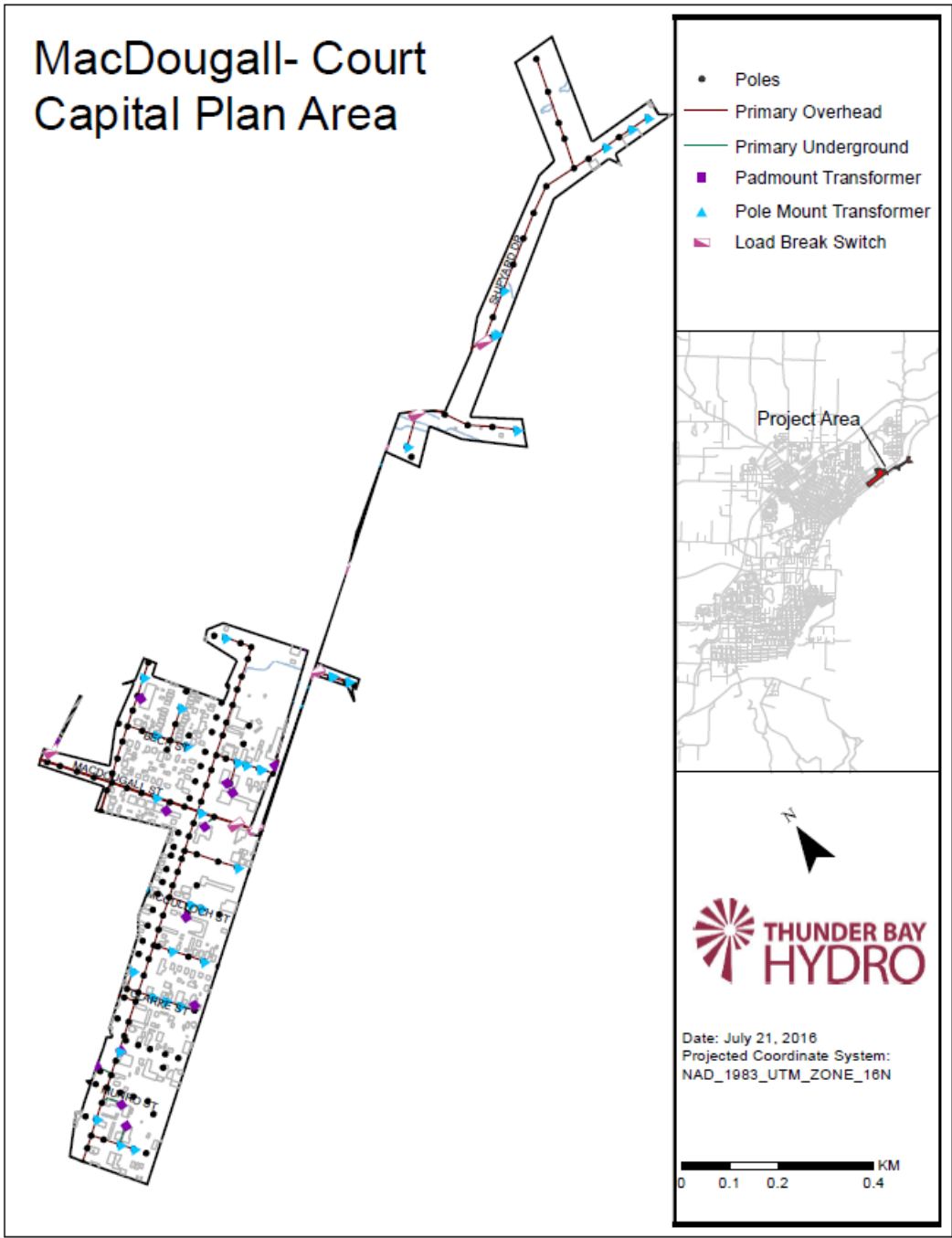
Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Thunder Bay Hydro has completed a number of similar projects over the past five years. Most recently, projects have been completed in Huron-Otto pole setting project. This pole setting project also involved the replacement of poles which are primarily located in busy street front areas. The approximate average cost of pole setting of this project on a per pole basis was \$4,500, and \$7,400 for framing. Based on this information, the MacDougall-Court project's proposed construction cost is in-line with the historic per-unit costs considering this project includes the replacement of 155 poles, and the framing of 35 poles.

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 Macdougall-Court project contributes directly to Thunder Bay Hydro's ability to retire Algoma substation. 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 improve line losses as well as ability to accept more load and/or generation customers.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)

The secondary drivers for this project are Effective Asset Management and Relationships. 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. The City of Thunder Bay approached Thunder Bay Hydro regarding their completion of a beautification of Cumberland Street which is located in this project area. A co-ordination of design to removing poles from this area has affected the design for customer esthetics.

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 substation transformer, breaker, transformer and wood pole replacements. (See Appendix C) These projects accounts 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. The project has been ranked 19 of 21 projects planned for 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 substation 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

With the conversion from 4kV to 25kV construction Thunder Bay Hydro expects the following benefits to customers;

- a) Eliminate older, end of life 4kV distribution assets
- 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
- c) Standardize construction practices across the different systems, which helps to control construction and operating costs
- d) Reduce system losses through the elimination of substations
- e) Allow for the connection of larger loads and generators without major system rebuilds.
- f) Conform to the standard voltage across the Province making it easier to source material and expertise.
- g) Eliminate the use of outdated, hard to replace and maintain equipment.
- 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 while eliminating a safety hazard to the public.
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. Alternatives for voltage conversion are considered, and are captured below; 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. 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 load to 25kV as they reach end of life. 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. d) Install several step-down transformer banks to feed the area 25kV 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 substation transformers by Kinectrics. (See Appendix C) 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 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 185.				
Project	Residential/ Other	General Users	Large Users	Total
Donald-Mountdale	163	23	0	185
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 outage area.				
Quantitative customer impacts				
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	Hours of Interruptions	Number of Interruptions	
02M2	82	805	10246	
02M3	104	105	1689	
Qualitative customer impacts				
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 an 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 19 of 21 projects planned for 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.

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.



2017 Capital Project Summary

A. General Information

Project Name	Finlayson-Brodie Voltage Conversion											
Project Number	B12135											
Investment Category	System Renewal											
Capital Investment(s)	<table><tr><td>Finlayson – Brodie B12135</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$893,725</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$893,725</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> There are no expected O&M costs associated with this project, as all assets and the work associated with it will be capitalized.		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
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											

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)

Thunder Bay Hydro has completed a number of similar projects over the past five years. Most recently, projects have been completed in Brunswick-Legion complete project. This voltage conversion project also involved the replacement of poles which were primarily located in back lanes and used the services of a lines sub-contractor. The approximate average cost of construction of this project on replacement per pole basis was \$12,400 and on a reframe was \$8,000. Based on this information, the Finlayson-Brodie project's proposed construction cost is in-line with the historic per-unit costs considering this project includes the replacement of 65 poles and the reframe of 10 poles.

REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.6)

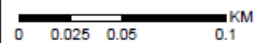
Not Applicable

Attach Other project reference material i.e. Images, Drawings and or reference material

Finlayson- Brodie
Capital Plan Area



Date: July 21, 2016
Projected Coordinate System:
NAD_1983_UTM_ZONE_16N



- Poles
- Primary Overhead
- Primary Underground
- Padmount Transformer
- ▲ Pole Mount Transformer



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 driver for this project is Asset Retirement. Thunder Bay Hydro seeks to prioritize project selection based on assets that are at or beyond their useful life. The assets identified in this program for replacement are being fed by Hardisty substation transformers and breakers which are at end of life and have a high probability of failure which is a result of the age and the condition of the assets.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (If applicable)

The secondary 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 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 from 4kV to 25kV eliminates the need to operate, maintain, and upgrade stations required for providing electrical connectivity between the 25kV and the 4kV systems. The Cumming-Brodie and Finlayson-Brodie projects contribute directly to Thunder Bay Hydro's ability to retire Hardisty by the end of 2018. 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 load and/or generation customers.

Efficiency, Customer Value & Reliability – Investment objectives and/or performance targets (5.4.5.2 B.1a)

The objective of this program is Asset Retirement. Thunder Bay Hydro seeks to prioritize project selection based on assets that are at or beyond their useful life as determined through Thunder Bay Hydro's ACA process and to reduce asset failure risk, and to update the distribution system to a 25kV system with all of the advantages it provides. (See Net benefits accruing to customers) 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 substation transformer, breaker, transformer and wood pole replacements. (See Appendix C) These projects accounts 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. The project has been ranked 17 of 21 projects planned for 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 substation 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

With the conversion from 4kV to 25kV construction Thunder Bay Hydro expects the following benefits to customers;

- a) Eliminate older, end of life 4kV distribution assets
- 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
- c) Standardize construction practices across the different systems, which helps to control construction and operating costs
- d) Reduce system losses through the elimination of substations
- e) Allow for the connection of larger loads and generators without major system rebuilds.
- f) Conform to the standard voltage across the Province making it easier to source material and expertise.
- g) Eliminate the use of outdated, hard to replace and maintain equipment.
- 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 while eliminating a safety hazard to the public.

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.

Alternatives for voltage conversion are considered, and are captured below;

- 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.
- 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 load to 25kV as they reach end of life.
- 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.
- d) Install several step-down transformer banks as a contingency for the failure of Hardisty and to feed the area 25kV 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 substation transformers by Kinectrics. (See Appendix C) 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 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 while removing Hardisty substation. The uprating 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 234.

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

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 outage 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
10M1	146	2335	42924
10M3	88	2731	31242

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 an 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 17 of 21 projects planned for 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 TBHEDI'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.

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.

A. General Information

Project Name	Underground Replacements		
Project Number	B14129		
Investment Category	System Renewal		
Capital Investment(s)			
	FWTS Exit Feeder Cables - 10M9 & 10M10 B14129	2017	
	Capital Cost (5.4.5.2 A.1)	\$376,868	
	Capital contribution	\$0	
	Net Cost	\$376,868	
	O&M Cost (5.4.5.2 A.2)	\$0	
	There will not be any O&M cost related to this project, as all of the installed assets will be capitalized including the labour to install such.		

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 4,350 customers as broken down by customer class below.

Feeder	Residential	General Service	Large Users	Other	Total
10M9	3, 417	91	0	12	3, 520
10M10	757	35	0	5	797

Load: 3528 kWh

Start Date (5.4.5.2 A.3)	01-07-17	In-Service Date (5.4.5.2 A.3)	31-09-17

Expenditure Timing for the Test Year

2017 Q1	2017 Q2	2017 Q3	2017 Q4
\$0	\$0	\$376,868	\$0

The timing of this project is planned in the summer months when the ground is thawed, and work is most efficient and cost effective.

Project Summary

This project is comprised of the replacement of direct buried and conduit installed underground primary feeder cables 10M9 and 10M10 from Fort William Transformer Station (FWTS) underground to the first primary dip pole. These primary cables are in poor condition and past their typical useful life (TUL). These cables were originally installed in the early 1970's and are reaching their end of life and pose a significant risk in failure. Emergency repairs on similar feeders exiting FWTS have indicated that complete replacement of the assets is required due to their age and condition. FWTS is one of three TS's in the Thunder Bay Hydro distribution system and in 2015 serviced 43% of the entire gross load. As such, the feeders are highly critical, and a failure would have a high customer impact. The FWTS Exit Feeder Cable replacement project scope includes design, construction and installation of new high voltage underground feeder cables (10M9 and 10M10) into existing duct, resulting in reduced failure risk. Since most of the cables from FWTS are of the same vintage and since rates of failure are expected to increase as the cables age, Thunder Bay Hydro has prepared a plan to replace all of the high voltage cables in the next 3 years.

Risk Identification & Mitigation (5.4.5.2 A.4)

Thunder Bay Hydro has investigated the project conditions and has used as-built drawings from the original installation to prepare a replacement plan. In 2011 Thunder Bay Hydro undertook cable testing with an experienced contractor and the final report provided Thunder Bay Hydro with information that indicated that the FWTS exit cables were at end of life. Further inspection is cost prohibitive and redundant as it has been confirmed that these cables require replacement. Additionally there is also a risk that the concrete underground structures that encompass the cables have collapsed, are clogged or do not run the extent of the cables (From station to dip pole). In these cases, Thunder Bay Hydro would be required to either extend the duct or to directionally bore new conduit in which to install the cables. A direct boring contractor will be retained on a blanket purchase order if this situation was realized and would be available to complete this task.

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

Underground Renewal	2012	2013	2014	2015	2016	2017
Capital Cost	\$0	\$0	\$173,026	\$672,379	\$0	\$376,304

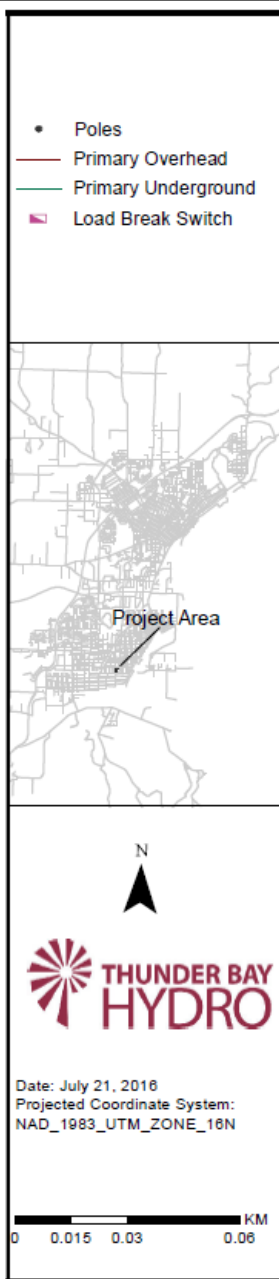
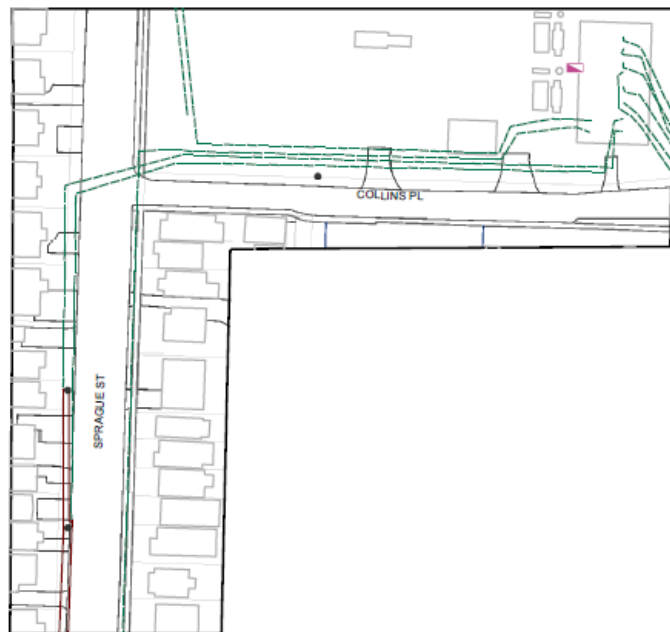
These are the comparative costs that Thunder Bay Hydro has spent on underground projects. (Some of these include pad mount transformers and switches, and are not directly attributable to underground line renewal. In 2015 the expenditure of \$672,379 accounts for the total expenditure which included the renewal of 20 poles, and associated hardware.

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

10M9/ 10M10 Capital Plan Area



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 for this project are Asset Retirement and Reliability. Thunder Bay Hydro seeks to prioritize project selection based on assets that are at or beyond their useful life. The assets identified in this project have a high probability of failure which is a result of the age and/or the condition of the assets. Thunder Bay Hydro is committed to providing highly reliable electricity supply to its customers as is evidenced in Section **Error! Reference source not found.** We regularly analyze our reliability statistics to determine opportunities for improvement and use this data to assess the extent to which certain projects will impact reliability and how best to effectively implement these opportunities.

Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)

The secondary driver is Customer Service Focus. At its core, Thunder Bay Hydro exists to provide safe, reliable electricity supply to its customers. Meeting this obligation requires an understanding of our customers' needs and expectations and a commitment to delivering a high level of service. Thunder Bay Hydro continuously monitors its performance in the form of OEB and corporate metrics targeted towards providing timely service and effective communication to our customers.
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)
The objective of this program is to continue to meet the system reliability targets of SAIDI and SAIFI. The performance target is to meet the quantities of replacement as suggested by the ACA proposed by Kinectrics of 6km per year by 2019. Thunder Bay Hydro plans to slowly increase its quantities of underground replacements, starting in 2017; and this project contributes 1500m to the total target of 3500m.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment ((5.4.5.2 B.1a)
The ACA provided by Kinectrics (See Appendix C) was used in conjunction with cable testing data to inform the planning process in determining the amount of underground cable considered in poor condition and needing an action plan. Thunder Bay Hydro determines which repair/replace/remove strategy is appropriate through the use of its Asset Management Strategy as described in 5.3.1.3. These projects account for the majority of underground cable replacements; however there are also replacements of poor condition cables incorporated into Voltage Conversion projects.
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 18 of 21 projects planned 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 critical underground cables that have reached their end of life will greatly decrease the probability of a failure in this project area. Because the cables are not a stock item, (1250kcmil) purchasing a replacement is a very time consuming and costly process. Due to the above potential for a large duration outage in the event of a failure and the timing of receiving new cables, the completion of replacing these cables on a planned basis is the safest, most efficient and cost effective option.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1cii)
The renewal of this infrastructure will have the following benefits: reduction of the potential risk of failure and number and duration of outages, avoidance of an emergency repair resulting in a potential loss of functionality.
Analysis of Project & Alternatives - Effect of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)
All underground cable sections under this project have been identified as being at the end of their useful life and in need of replacement. The following were considered as alternatives: a) Do Nothing - this option will result in the perpetuation of operational issues, increased risk of failure, and further deterioration resulting in decrease in reliability, and is therefore not considered appropriate. b) Rejuvenate the cable – this option was considered and found that it was not a good fit for these feeder cables due to the advanced deterioration of the cable which would considerably drive up rejuvenation and restoration costs. c) Replace the underground feeder a cable with an overhead line – this option was considered however, as the location is in a residential area, the use of an overhead system is not conducive to the design and aesthetics of the existing site. A prior feeder replacement was designed for overhead (10M8) and due to public pressures, the project was redesigned to an underground project. For this reason, a like for like replacement was considered most effective. d) Defer replacement until a later date – this project has been prioritized against other proposed projects, and to delay the replacement to a later date puts Thunder Bay Hydro and customers on these feeders at too great a risk of failure for delay. e) Replace the cable in a like-for-like fashion – this alternative is the most cost effective where possible cable will be pulled in existing concrete and PVC duct structures, with a minimal impact to land.

Safety (5.4.5.2 B.2)					
These projects are not intended to address any existing safety concerns, but all new facilities will be designed and constructed to current safety standards. This program will have no adverse impact on health and safety, or protection and performance.					
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. This program does not impact any other regional planning activities or third party attachers. As with every project, customers related to a replacement are notified and coordinated with.					
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 replace the suggested quantities of underground cable. (See Appendix C) New assets are 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 underground cables. 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)					
The original feeder cables in the project area were purchased and installed in 1976 on average (two feeder cables have already been replaced). The cable is 40 years old which falls above the maximum useful life (30 years) of primary non-TR XLPE cables in duct as per the Kinectrics Asset Depreciation Study for the Ontario Energy Board. The cable has performed as required, but due to the failure of one of the cables during cable testing, and exceeding the typical useful life, the probability of failure continues to increase, resulting in a requirement for replacement.					
The number of customers in each class potentially affected by the failure of the assets (5.4.5.2 SR – C1.3)					
Feeder	Residential	General Service	Large Users	Other	Total
10M9	3, 417	91	0	12	3, 520
10M10	757	35	0	5	797
Quantitative customer impacts (5.4.5.2 SR – C1.4)					
Outage events related to Feeder 10M9 and 10M9 are as follows;					
Feeder	Customer hours of interrupts	% of Annual Total	Customer interrupts	% of Annual Total	
10M9	9837	8.7%	50190	11.8%	
10M10	3351	3.0%	15721	3.7%	
The replacement of the identified cable in this project will ensure that a large outage does not impact customers on these feeders					

and contribute to Thunder Bay Hydro's overall outage statistics.
Qualitative customer impacts (5.4.5.2 SR – C1.5)
The replacement of these assets will aid in reducing the impact of the number and duration of outages attributed to the defective equipment cause and 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 high on a system level, as these cables represent approximately 10% of Thunder Bay Hydro customers. In the event that both feeders failed catastrophically at the same time depending on system conditions at the time it would be a serious impact to the system. Even though these feeders are predominately residential there are still 120 general service customers and a large spread outage would pose impacts on economic productivity of these customers. Asset failures on underground cable are very often difficult to repair and cannot be repaired quickly (require excavation, emergency locates, etc.) and therefore, lead to prolonged outages.
Timing & Priority of Project (5.4.5.2 SR – C2)
This project is part of an overall system renewal program for 2017. The assets being replaced fall within the planned leveled 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. This project has been ranked 18 of 21 projects planned in the test year.
Consequences for system O&M costs (5.4.5.2 SR – C3)
Replacement of these cables in a proactive way will reduce the cost of future unplanned failures. Cables can be scheduled to be replaced relative to the best option for the customers in the area. This results in reduced O&M costs due to reduction in cost of future repairs from cable faults. Cable can be removed and replaced in the duct and time intensive fault locating and costly excavating and splicing work will be avoided.
Impact on Reliability performance and or Safety (5.4.5.2 SR – C4)
Replacement of this cable with one continuous run will improve reliability by reducing potential weaknesses. Where duct is not discovered, new duct will be installed which will improve reliability by greatly decreasing restoration times to pull new cable.
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 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. This particular project has been ranked against other material system renewal projects planned for completion in 2017. The timing of the project also considers the benefits and costs described in this project summary. Costs of the project may be affected by increases in the 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.
Like for Like Renewal Analysis, Alternative Comparison (5.4.5.2 SR – C6)
This project will be completed in a like for like manner, as noted in Section B: Analysis of Alternatives.



2017 Capital Project Summary

A. General Information

Project Name	Grid Modernization												
Project Number	A1735												
Investment Category	System Service												
Capital Investment(s)	<table><tr><td>Grid Modernization A1735</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$230,375</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$230,375</td></tr><tr><td>O&M Cost (approximate) (5.4.5.2 A.2)</td><td>\$10,000</td></tr></table> There may be minimal O&M costs related to this project, as Engineering labour associated with the research into implementation of distributed automation will be completed ahead of the project and only the design and installation of the devices and associated labour will be capitalized and charged to this project.			Grid Modernization A1735	2017	Capital Cost (5.4.5.2 A.1)	\$230,375	Capital contribution	\$0	Net Cost	\$230,375	O&M Cost (approximate) (5.4.5.2 A.2)	\$10,000
Grid Modernization A1735	2017												
Capital Cost (5.4.5.2 A.1)	\$230,375												
Capital contribution	\$0												
Net Cost	\$230,375												
O&M Cost (approximate) (5.4.5.2 A.2)	\$10,000												

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 400-1,000
Load: 1220-1730 kWh

Start Date (5.4.5.2 A.3)	01-01-17	In-Service Date (5.4.5.2 A.3)	01-10-17

Expenditure Timing for the Test Year

2017 Q1	2017 Q2	2017 Q3	2017 Q4
\$57,594	\$57,594	\$57,594	\$57,594

The installation of grid modernization components is expected to begin in the first quarter and be completed in the fourth quarter; with several activities running concurrently (e.g. design of second location will be occurring at the same time as the communications path study of the first location).

Project Summary

Thunder Bay Hydro covers a large service territory and has only a handful of remotely monitored or controlled devices in its system. Grid modernization enhancements are aimed at reducing outages and providing improved service to customers when an outage does occur (e.g. information, and reduction in duration). Details of the benefits to the customer and the LDC are further explained in the Grid Modernization Plan in Appendix D.

This project category consists of design, installation, and commissioning of remotely controlled reclosers and distributed automation enhancements to the SCADA system. This is a five year program with a plan for 10 remotely monitored and controlled devices, 4 distribution automation modules and continued enhancements of the SCADA system being deployed in the next 5 years. In 2017 the expenditures include costs to install two reclosers with all the associated hardware, telemetry and labour. The recloser locations are chosen based on the worst performing feeder analysis from 2015 as well as the 25 kV reliability analyses.

Thunder Bay Hydro is also working towards the implementation of a fully functional Outage Management System (OMS). Understanding that this is an extensive undertaking and a burden, both financially and on internal resources required for implementation, Thunder Bay Hydro plans to appropriately pace SCADA integration with several operational pieces: Geographic Information System (GIS); Advanced Meter Infrastructure (AMI); and Customer Information Systems (AMI) over the next 5 years. In 2017, expenditures will focus on the integration of the GIS system with the SCADA system.

Risk Identification & Mitigation (5.4.5.2 A.4)

The first mid-feeder reclosers in the Thunder Bay Hydro distribution system were installed as a result of the connection of a large solar farm, and since then improvements have been made in the design and installation coordination between Engineering, Lines and Stations groups. A standardized design has been created for both vertical and horizontal three phase installations. The reclosers as well as all of the associated hardware are stock items that are kept at a minimum level due to their long lead times. Familiarity with the product and its installation is becoming common among the lines staff and as the program matures, installation practices and metrics will become increasingly standardized. Thunder Bay Hydro has had a recent negative experience with its selected vendor of remotely controlled vacuum reclosers and has needed to return all of its stock due to multiple defects found while in operation. Thunder Bay Hydro is working closely with the vendor in order to remedy these situations and ensure the adequacy of the product in the harsh northern environment. Several other vendors also offer similar equipment.
Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5) This is the first year that Thunder Bay Hydro is requesting funds in specifically this category. Previous installations were performed as enhancements to the distribution system for RESOP and FIT generators. As such there is no comparative information for equivalent projects.
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 See Appendix D: Grid Modernization Plan.
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 driver is Customer Service Focus. At its core, Thunder Bay Hydro exists to provide safe, reliable electricity supply to its customers. Meeting this obligation requires an understanding of our customers' needs and expectations and a commitment to delivering a high level of service. Thunder Bay Hydro continuously monitors its performance in the form of OEB and corporate metrics and customer satisfaction surveys. The main objective for this project is to decrease the time required to restore power during an outage, and to improve reliability statistics.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a) The secondary driver is Operational Efficiency. 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 installation of automatic reclosing devices helps to improve equipment protection, and reduce arc-flash energy (i.e. improve worker safety).
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a) The objective of this program is to continue to improve the system reliability targets of SAIDI and SAIFI, specifically feeders with the largest concentration of small commercial and large users. Thunder Bay Hydro's commitment to continuous improvement seeks to positively impact these metrics through these enhancements to its system. The performance target is to see these measures decrease as a result of this project.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1a) Thunder Bay Hydro performed a customer survey with regards to the objectives of its Distribution System Plan and one of the categories that small commercial and large users indicated should be a priority was "Infrastructure Upkeep" and "Maintaining Reliability". This Grid Modernization initiative was incorporated into the DSP as a result of this feedback. This project will specifically address reliability for this class of customers and the associated feeders where breaker operations and outage durations are impacting small commercial and large users most and install devices to improve reliability.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1b) Grid Modernization investments are ranked P5 – Low Priority, since there is a net benefit to reliability measures, but there is no regulatory or mandatory requirements and these investments do not directly improve the long term health of the system. This project has been ranked 21 of 21 projects planned for 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 effect of these investments is an improvement in operation efficiency and cost-effectiveness in the following ways; a) Eliminates manual switching, therefore improves resource allocations, and operational efficiency b) Provides a more cost-effective option of dealing with outages, automated vs truck rolls c) Provides improved information flow to system controllers allowing them to resolve issues quickly
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1cii) The addition of these devices have numerous benefits to both the customer and the LDC, all are listed in Appendix D, the Grid Modernization Plan, below is a synopsis. a) Enhanced visibility and more timely information related to outages b) More accurate information regarding outages including anticipated restoration time c) Reduced outage duration d) Improved planning for commercial and residential customers regarding energy usage and outage response
Analysis of Project & Alternatives - Effect of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii) The effect of these investments is an expected improvement in reliability performance. a) Reduces restoration time for outages, automated vs manual patrolling and switching b) Reduces duration of outages by providing improved information flow to system controllers allowing them to isolate or transfer power to areas experiencing an outage.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii) The projects identified under system service category have been initiated as a result of customer preferences and feedback and the continued improvements required operating a distribution system in a cost effective manner. To address these issues, Thunder Bay Hydro considered the following alternatives: a) Do Nothing - this option results in degradation in service quality as well as significant (and potentially very public) customer dissatisfaction. Over time, with risk of increased frequency of failures due to aging infrastructure and associated outages for a large number of customers, results in notable deterioration of reliability indices at a system level. For these reasons, this option is not considered appropriate. b) Integrate more manual switching points into the system - this option is always considered as one of the alternatives for reliability enhancement. It has the characteristics of being quick and relatively inexpensive to implement. However it does not significantly improve the duration of outages. If additional switching points form the complete or part of the final solution, installing automated switches rather than manually operated ones is always considered as the increased upfront investment will have an enhanced long term return on system wide operational benefits. c) Installation of more line sensing and fault indicating devices. These will improve operations' ability to determine the fault location, and likely improve efficiency in isolation, but they cannot automatically transfer load, thus eliminating outages for many customers. In some situations, these devices may be utilized for information purposes, but a more robust system that provides all of the benefits of isolation and operability is preferred. d) Invest more heavily in renewal activities, to reduce the potential failure points. This option consists of a greater investment than is proposed in the system renewal justifications of pole, transformer and line replacements. These replacements may slightly improve system reliability; however the unpredictability of storms, lighting, and animals will continue to produce some level of outages regardless of the age of the system. e) Combination of Alternatives b) thru d) - it is very unusual that only one of the above alternatives will provide an adequate and complete technical solution to address reliability. Most often, the adequate technical solution requires the use of a combination of the above identified options, depending on the issues being experienced. It involves identifying various line sections where multiple trigger drivers or benefits can be realized and forming a solution comprised of various steps. This may result in minimizing overall and future costs, avoiding the possibility of renewing pole lines that are not approaching end of life, and minimizes the risk of stranded assets on a long term basis. The improvements to the SCADA system in preparation for a fully functional Outage management System (OMS) are in harmony with the above improvements in reliability and are customer-focused. To ensure functionality of an OMS and the information it provides to both the system operators and customer must be accurate and reliable. By reviewing the integration thoroughly, Thunder Bay Hydro is ensuring that when the purchase of an OMS is complete, the system will function as intended.
Safety (5.4.5.2 B.2)

Although this project is not primarily meant to address any particular safety issues, the Grid Modernization project has the added benefit of reducing manual switch operation, which reduces crew exposure to energized equipment and reduces associated safety risks, especially during major weather events where access to switches might not be optimal and operating a switch may cause energization of a faulted section. It also increases safety by faster isolation of faulted conductors where feeder segmentation has been implemented, including a significant reduction in the amount of arc-flash energy when working downstream of these devices
Cyber-Security, privacy (where applicable) (5.4.5.2 B.3)
Thunder Bay Hydro has taken reasonable precautions related to serial communications, and employs industry standard practice security measures with respect to IP based communications that connect into to the SCADA system.
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 meets regularly with City of Thunder Bay and sits on the Public Utilities Coordinating Committee. This forum allows utilities to exchange capital plans; however this project will have minimal interaction with the other utilities, as communication will likely be over our existing radio system.
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii)
This project is integral to enabling future technological functionality and to addressing future operational requirements in order to meet the changing needs of customers, industry and regulators. A modernized grid is one that facilitates the use of automated and self-healing devices to distribute electricity more effectively, economically and securely. Although Thunder Bay Hydro has been purposefully renewing its grid by converting voltages from 4kV to 25kV and installing telemetry based switching points for the last 5 years, a true modernization of the grid will allow for the deliberate incorporation of intelligent devices that will provide better visibility and operational flexibility to minimize outage impacts and identify areas to achieve better grid performance. There are two main approaches to distributed automation in the industry: centralized and localized. Both require intelligent devices and a communication system. In the localized mode, the intelligent devices communicate directly to their peers to determine where the system disturbance might be and how best to restore the power to as many people as possible. This system works very well in locations where feeder routes are fixed and not subject to reconfiguration. In the centralized mode, the intelligent devices communicate to a centralized location, and the centralized system determines origin of disturbance and follow up actions. As Thunder Bay Hydro's distribution system is subject to minimal change and reconfiguration, the localized mode will be the initial trail for the installation of distributed automation, with a look beyond 5 years to one day become a more centralized and automated system.
Economic Development (where applicable) (5.4.5.2 B.5)
Not Applicable
Environmental Benefits (where applicable) (5.4.5.2 B.6)
Albeit small, these projects will have a positive environmental benefit due to reduced vehicle emissions. This is because travel to operate manual switches is eliminated and area required for patrol is smaller once distribution automation is implemented on a feeder.
C. Category-Specific Requirements - System Service
Benefits to Customers vs. Cost Impact (5.4.5.2 SS-C1)
These options are discussed above in Part B: Net benefit to customers. The project is expected to begin in 2017 and over the next 5 years (2017-2021), Thunder Bay Hydro forecasts approximately \$1.29 million of capital spend in grid modernization projects. During this time the expenditures are between \$230,000 and \$300,000 per year.
Regional electricity infrastructure requirements (5.4.5.2 SS-C2)
Although not directly related to the Regional Planning process, both of the individual projects identified above support the concept of addressing system service issues with distribution level solutions.
Advanced technology (5.4.5.2 SS C3)

Integration of Advanced Technology is always considered when looking for solutions to system service issues. This level of analysis will be performed at the individual project level during detailed design. This project integrates the installation of new distributed automation modules into the Thunder Bay Hydro Distribution System, standards associated with cyber security and interoperability will be adhered to.

Reliability, efficiency, safety and coordination benefits (5.4.2 SS –C4)

The benefits as they pertain to Thunder Bay Hydro grid modernization initiatives are as follows:

- a) Improved reliability due to a reduction in forced outages/interruptions, and a reduction in restoration time
- b) Increased integration of distributed generation resources and higher capacity utilization
- c) Power quality, and system availability and capacity improvement due to improved power flow,
- d) Environmental benefits gained by increased asset utilization and coordination with the 4kV conversion schedule

Timing & Priority of Project (5.4.5.2 SS –C5)

The project is expected to begin in 2017 and over the next 5 years (2017-2021), Thunder Bay Hydro forecasts installation of approximately 2 devices and 1 distributed automation enhancement per year. This project has been ranked 21 of 21 projects planned for the test year.

Analysis of project benefits and costs i.e. ‘Do Nothing’ & ‘Technically feasible alternatives’ (5.4.2 SS –C6)

These options are discussed above in Part B: Project Alternatives.



2017 Capital Project Summary

A. General Information

Project Name	2016 Double Bucket											
Project Number	C											
Investment Category	General Plant											
Capital Investment(s)	<table><tr><td>Double Bucket Replacements</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$325,000</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$325,000</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$2,000</td></tr></table> There will be minimal O&M costs associated with this project, as the decals are installed in house upon arrival.		Double Bucket Replacements	2017	Capital Cost (5.4.5.2 A.1)	\$325,000	Capital contribution	\$0	Net Cost	\$325,000	O&M Cost (5.4.5.2 A.2)	\$2,000
Double Bucket Replacements	2017											
Capital Cost (5.4.5.2 A.1)	\$325,000											
Capital contribution	\$0											
Net Cost	\$325,000											
O&M Cost (5.4.5.2 A.2)	\$2,000											

Customer Attachments and Load (5.4.5.2 A.2)

Not Applicable

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	\$0	\$0	\$325,000

Project Summary

This project includes expenditures associated with the replacement of Double Bucket trucks, which are Thunder Bay Hydro's largest fiscal component and have the longest build time within its vehicle fleet. Double bucket trucks typically take 16-20 months to purchase and receive, and require payment of a portion upfront. Thus the expenses associated with these purchases are seen over a 2 year period. The expenditures in 2017 include;

- Completion of the purchase of a boom and body for a double bucket truck whose cab and chassis were expensed in 2016, as a replacement for truck #5, a 2002 double bucket

This vehicle is 54,000 lbs. rated, 6x4 tandem axles, 55 foot insulated, double bucket material handling trucks with a working height of 60 feet. They are required to allow work on energized apparatus at 25 kV voltages in the Thunder Bay Hydro distribution system.

Risk Identification & Mitigation (5.4.5.2 A.4)

Risks associated with not allowing for timely equipment replacement include an aging fleet with potentially increased downtime and or operating costs. If the acquisition of these specialty vehicles are postponed, eventually multiple pieces of equipment will require replacement at one time resulting in larger annual expenditures for fleet. Other risks associated with aging vehicles include employee safety and ergonomics, efficiency issues including increased response time to customer emergencies, and capital projects, increased fuel consumption and the potential that annual mechanical fitness testing and the repairs associated with keeping an aged vehicle road worthy will become non-economical. The geographic location of Thunder Bay is by virtue a detriment as it does not allow for a timely response for acquiring rental vehicles if they were required for either daily work objectives or outage management scenarios. To this end Thunder Bay Hydro initiates the process to replace a double bucket when it is approximately 15 years old knowing that receipt of the new replacement vehicle will be in 16 - 20 months.

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

Fleet	2012	2013	2014	2015	2016	2017
Capital Cost	\$437,900	\$760,604	\$569,595	\$485,438	\$992,128	\$610,000

Vehicle and Equipment expenditures are varied year over year depending on the end of life and replacement schedules; however a

Vehicle and Equipment Resource Justification Plan exists to prioritize and levelize needs as much as possible.
REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.G)
Not Applicable
Attach Other project reference material i.e. Images, Drawings and or reference material
See Appendix E: Thunder Bay Hydro Vehicle and Equipment Resource Justification Plan.
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 for the double bucket replacements are Asset Retirement Operational Efficiency. Thunder Bay Hydro seeks to maximize factors that positively affect operational efficiency through consideration of equipment types. The vehicle types that currently make up the fleet have specific functions and limitations and are required to fulfill or enhance worker safety, ergonomics and operational activities and the fleet size is currently matched with our field staff compliment. Thunder Bay Hydro's replacement policy maintains an average age of 15 years for heavy equipment. Truck #5 will be 15 years old in 2017.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)
Not Applicable
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)
The objective of this program is to ensure prudent Return on Investment (ROI) for any vehicle and equipment assets and to ensure customer commitments are not compromised or delayed because of vehicle or equipment gaps. The double bucket enable crews to work on energized powerline apparatus while meeting legislated and company safety requirements.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)
Repair costs and total km are among the factors considered when contemplating replacement, however it is primarily vehicle age determines when a replacement will be initiated.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1a)
These projects rank as Low Priority which is work or projects that are desired but not essential to protect, preserve or restore facilities or equipment; generally new work or equipment that is not tied to a specific goal or milestone, as they are discretionary in nature. Replacement of double buckets is in accordance with Thunder Bay Hydro's vehicle and equipment replacement philosophy and considers; a) Age of the vehicle; b) Annual vehicle test results, including structural/dielectric testing; and c) Crew/other department needs
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1c)
The reliability of bucket trucks impact any work on the 25kV system including voltage conversion, 25kV pole replacements and maintenance work. Equipment availability directly impacts construction schedules as well as emergency response times, crew efficiencies and productivity and or work effectiveness.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1cii)
Benefit to customers includes maintaining or improving response time to outages and system reliability statistics.
Analysis of Project & Alternatives - Effect of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)
This project maintains or improves response time to outages by ensuring equipment availability.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)

The alternatives for double bucket truck replacement are the following; a) Do Nothing (continue to use and repair as needed) – as the truck ages, the required maintenance and downtime will likely increase thus resulting in lost productivity by lines crews and increased operational costs. This is not a feasible option as it deviates from the Utility's commitment to customer satisfaction, is fiscally irresponsible and severely impacts the construction schedules and cost of other capital projects b) Replace with a lower specified vehicle – this would result in a loss of functionality for the truck, work activities on energized powerline apparatus would be limited / restricted as well as putting an increased demand on the remaining Double bucket trucks which would result in scheduling conflicts and a resulting loss in effectiveness and productivity. This is not a feasible option. c) Purchase Used – this alternative was not considered for this purchase, but has been selected in the past. The issues associated with a used purchase are that there is a considerable risk on the dependability of the vehicle. As well the option for competitive bidding and warranty are not available. In our experience with this alternative the longevity and price is not worth the sacrifice to purchase used.
Safety (5.4.5.2 B.2) Not Applicable
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) Not Applicable
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii) Not Applicable
Economic Development (where applicable) (5.4.5.2 B.5) Not Applicable
Environmental Benefits (where applicable) (5.4.5.2 B.6) Reduced emissions (carbon footprint impact) via OEM exhaust treatment solutions and improved mileage when compared to a legacy vehicles.
C. Category-Specific Requirements – General Plant
Results of quantitative and qualitative analysis, business case documenting the justifications for the expenditure (5.4.5.2 GP – C1) Thunder Bay Hydro prioritizes vehicle replacements primarily by age, with some consideration regarding vehicle condition, reliability knowledge from its mechanics and daily users. The targeted 2002 double bucket truck is nearing end of life condition and is at risk of incurring major future maintenance costs related to the truck's major components such as: engine, transmission, hydraulic system or chassis. Thunder Bay Hydro reviewed several alternatives for replacing this truck. The "Do Nothing" option was considered inappropriate because it is likely to result in an increased risk of equipment failure, maintenance costs, reduced staff safety and ergonomics and could impact our ability to respond to our customer's needs in a timely manner . The alternative of purchasing a replacement truck and sharing it with a neighboring LDC was considered impractical due to the substantial travel distances between the neighbouring northwest utilities. The alternative was not considered due to the loss in dependability, longevity and price is not worth the sacrifice. The alternatives considered for this purchase confirmed that replacing these double bucket trucks with new provided the greatest benefit to Thunder Bay Hydro, as the cost of maintenance is expected to be reduced going forward compared to costs associated with maintaining a 17 year old truck. This will help to lower Thunder Bay Hydro's total operating costs for fleet maintenance. The net benefit of the investment is to allow Thunder Bay Hydro to keep its fleet aligned with its staff compliment, keep its workers productive and safe, and ensure reliability of equipment needed to construct and maintain the electricity distribution system.
Assessment of project benefits and costs i.e. 'Do Nothing' & 'Financially feasible alternatives' (5.4.5.2 GP – C1)

Alternatives to purchasing these vehicles new include deferring the purchase and purchasing used vehicles. The Section “Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)” discussed why these are not feasible alternatives in this case. All purchases are made in accordance with purchasing policies.

Additional Business Case documentation (if applicable)

See Appendix E: Thunder Bay Hydro Fleet Resource and Equipment Justification Plan.



2017 Capital Project Summary

A. General Information

Project Name	2017 Double Bucket											
Project Number	C											
Investment Category	General Plant											
Capital Investment(s)	<table><tr><td>Double Bucket Replacements</td><td>2017</td></tr><tr><td>Capital Cost (5.4.5.2 A.1)</td><td>\$125,000</td></tr><tr><td>Capital contribution</td><td>\$0</td></tr><tr><td>Net Cost</td><td>\$125,000</td></tr><tr><td>O&M Cost (5.4.5.2 A.2)</td><td>\$0</td></tr></table> There will be no O&M cost incurred until 2018, as the decals are installed in house upon arrival.		Double Bucket Replacements	2017	Capital Cost (5.4.5.2 A.1)	\$125,000	Capital contribution	\$0	Net Cost	\$125,000	O&M Cost (5.4.5.2 A.2)	\$0
Double Bucket Replacements	2017											
Capital Cost (5.4.5.2 A.1)	\$125,000											
Capital contribution	\$0											
Net Cost	\$125,000											
O&M Cost (5.4.5.2 A.2)	\$0											

Customer Attachments and Load (5.4.5.2 A.2)

Not Applicable

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	\$0	\$125,000	\$0

Project Summary

This project includes expenditures associated with the replacement of Double Bucket truck which is Thunder Bay Hydro's largest fiscal component and has the longest build time within its vehicle fleet. Double bucket trucks typically take 16-20 months to purchase and receive, and require payment of a portion upfront. Thus the expenses associated with these purchases are seen over a 2 year period. The expenditures in this project for 2017 will include;

- a) Initial purchase of the cab and chassis portion of a replacement for truck #3, a 2001 double bucket. The boom and body will be expensed in 2018

This vehicle is 54,000 lbs. rated, 6x4 tandem axles, 55 foot insulated, double bucket material handling truck with a working height of 60 feet. They are required to allow work on energized apparatus at 25 kV voltages in the Thunder Bay Hydro distribution system.

Risk Identification & Mitigation (5.4.5.2 A.4)

Risks associated with not allowing for timely equipment replacement include an aging fleet with potentially increased downtime and or operating costs. If the acquisition of these specialty vehicles are postponed, eventually multiple pieces of equipment will require replacement at one time resulting in larger annual expenditures for fleet. Other risks associated with aging vehicles include employee safety and ergonomics, efficiency issues including increased response time to customer emergencies, and capital projects, increased fuel consumption and the potential that annual mechanical fitness testing and the repairs associated with keeping an aged vehicle road worthy will become non-economical. The geographic location of Thunder Bay is by virtue a detriment as it does not allow for a timely response for acquiring rental vehicles if they were required for either daily work objectives or outage management scenarios. To this end Thunder Bay Hydro initiates the process to replace a double bucket when it is approximately 15 years old knowing that receipt of the new replacement vehicle will be in 16 - 20 months.

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

Fleet	2012	2013	2014	2015	2016	2017
Capital Cost	\$437,900	\$760,604	\$569,595	\$485,438	\$992,128	\$610,000

Vehicle and Equipment expenditures are varied year over year depending on the end of life and replacement schedules; however a

Vehicle and Equipment Resource Justification Plan exists to prioritize and levelize needs as much as possible.
REG Investment Details including Capital and OM&A Costs (5.4.5.2 A.G)
Not Applicable
Attach Other project reference material i.e. Images, Drawings and or reference material
See Appendix E: Thunder Bay Hydro Vehicle and Equipment Resource Justification Plan.
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 for the double bucket replacements are Asset Retirement Operational Efficiency. Thunder Bay Hydro seeks to maximize factors that positively affect operational efficiency through consideration of equipment types. The vehicle types that currently make up the fleet have specific functions and limitations and are required to fulfill or enhance worker safety, ergonomics and operational activities and the fleet size is currently matched with our field staff compliment. Thunder Bay Hydro's replacement policy maintains an average age of 15 years for heavy equipment. Truck #3 will be 17 years old by the time the replacement is complete in 2018.
Efficiency, Customer Value & Reliability - Investment Secondary Drivers (5.4.5.2 B.1a)
Not Applicable
Efficiency, Customer Value & Reliability - Investment objectives and/or performance targets (5.4.5.2 B.1a)
The objective of this program is to ensure prudent Return on Investment (ROI) for any vehicle and equipment assets and to ensure customer commitments are not compromised or delayed because of vehicle or equipment gaps. The double bucket enable crews to work on energized powerline apparatus while meeting legislated and company safety requirements.
Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)
Repair costs and total km are among the factors considered when contemplating replacement, however it is primarily vehicle age determines when a replacement will be initiated.
Efficiency, Customer Value & Reliability - Priority Level / Project Prioritization and Reasoning, Priority Relative to Other Investments (5.4.5.2 B.1a)
These projects rank as Low Priority which is work or projects that are desired but not essential to protect, preserve or restore facilities or equipment; generally new work or equipment that is not tied to a specific goal or milestone, as they are discretionary in nature. Replacement of double buckets is in accordance with Thunder Bay Hydro's vehicle and equipment replacement philosophy and considers; a) Age of the vehicle; b) Annual vehicle test results, including structural/dielectric testing; and c) Crew/other department needs
Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost-effectiveness (5.4.5.2 B.1c)
The reliability of bucket trucks impact any work on the 25kV system including voltage conversion, 25kV pole replacements and maintenance work. Equipment availability directly impacts construction schedules as well as emergency response times, crew efficiencies and productivity and or work effectiveness.
Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1cii)
Benefit to customers includes maintaining or improving response time to outages and system reliability statistics.
Analysis of Project & Alternatives - Effect of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1cii)
This project maintains or improves response time to outages by ensuring equipment availability.
Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)

The alternatives for double bucket truck replacement are the following; a) Do Nothing (continue to use and repair as needed) – as the truck ages, the required maintenance and downtime will likely increase thus resulting in lost productivity by lines crews and increased operational costs. This is not a feasible option as it deviates from the Utility's commitment to customer satisfaction, is fiscally irresponsible and severely impacts the construction schedules and cost of other capital projects b) Replace with a lower specified vehicle – this would result in a loss of functionality for the truck, work activities on energized powerline apparatus would be limited / restricted as well as putting an increased demand on the remaining Double bucket trucks which would result in scheduling conflicts and a resulting loss in effectiveness and productivity. This is not a feasible option. c) Purchase Used – this alternative was not considered for this purchase, but has been selected in the past. The issues associated with a used purchase are that there is a considerable risk on the dependability of the vehicle. As well the option for competitive bidding and warranty are not available. In our experience with this alternative the longevity and price is not worth the sacrifice to purchase used.
Safety (5.4.5.2 B.2) Not Applicable
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) Not Applicable
Co-Ordination, Interoperability Future Technological functionality and/or future operational requirements (where applicable) (5.4.5.2 B.4ii) Not Applicable
Economic Development (where applicable) (5.4.5.2 B.5) Not Applicable
Environmental Benefits (where applicable) (5.4.5.2 B.6) Reduced emissions (carbon footprint impact) via OEM exhaust treatment solutions and improved mileage when compared to a legacy vehicles.
C. Category-Specific Requirements – General Plant
Results of quantitative and qualitative analysis, business case documenting the justifications for the expenditure (5.4.5.2 GP – C1) Thunder Bay Hydro prioritizes vehicle replacements primarily by age, with some consideration regarding vehicle condition, reliability knowledge from its mechanics and daily users. The targeted 2001 double bucket trucks are nearing end of life condition and is at risk of incurring major future maintenance costs related to the truck's major components such as: engine, transmission, hydraulic system or chassis. Thunder Bay Hydro reviewed several alternatives for replacing this truck. The "Do Nothing" option was considered inappropriate because it is likely to result in an increased risk of equipment failure, maintenance costs, reduced staff safety and ergonomics and could impact our ability to respond to our customer's needs in a timely manner . The alternative of purchasing a replacement truck and sharing it with a neighboring LDC was considered impractical due to the substantial travel distances between the neighbouring northwest utilities. The alternative was not considered due to the loss in dependability, longevity and price is not worth the sacrifice. The alternatives considered for this purchase confirmed that replacing these double bucket trucks with new provided the greatest benefit to Thunder Bay Hydro, as the cost of maintenance is expected to be reduced going forward compared to costs associated with maintaining a 17 year old truck. This will help to lower Thunder Bay Hydro's total operating costs for fleet maintenance. The net benefit of the investment is to allow Thunder Bay Hydro to keep its fleet aligned with its staff compliment, keep its workers productive and safe, and ensure reliability of equipment needed to construct and maintain the electricity distribution system.
Assessment of project benefits and costs i.e. 'Do Nothing' & 'Financially feasible alternatives' (5.4.5.2 GP – C1)

Alternatives to purchasing these vehicles new include deferring the purchase and purchasing used vehicles. The Section “Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1cii)” discussed why these are not feasible alternatives in this case. All purchases are made in accordance with purchasing policies.

Additional Business Case documentation (if applicable)

See Appendix E: Thunder Bay Hydro Fleet Resource and Equipment Justification Plan.

Appendix K: Thunder Bay Hydro Inspection and Maintenance Programs

Overhead Asset Classifications and Inspection Considerations

Due to the subjective nature of performing a visual inspection, it is important to provide a reasonably objective set of inspection points for the inspector to review. These inspection points alert the inspector to consider a common set of defects. Where no defect is discovered no report is required. However, where a defect has been discovered, a maintenance request is generated using a standardized template for the purposes of assigning the priority of the request when measured against the request population.

Initial Vehicular Inspection

For the purposes of efficiency and completing the annual inspection in a timely fashion, much of the overhead inspection is conducted from a vehicle. Where a noted defect warrants, a detailed inspection takes place. A detailed inspection also takes place intermittently on a sample of the population, selection of the detailed population sample inspection is discussed later.

The initial vehicular inspection reviews the following inspection points. Where a defect is found, the related follow up action takes place;

Inspection Point	Potential Findings	Indication	Follow Up Action
Base of pole	Pole perforations or treated butt is not visible above ground or is within 1' of ground level	-Pole is not set to ideal depth -grade may have changed since pole setting -Oversetting of poles may result in premature rotting of pole butt	Detailed inspection
	Pole tapers slightly at base	-Pole butt rot has begun to set in	Detailed inspection
	Fresh sawdust, hole, and/or cracking	-Pest infiltration, either carpenter ants, woodpecker, or both	Detailed inspection of associated pole and each adjacent pole
	Fibre depressions, split fibres, fibre void	-vehicle impact (passenger vehicle, snow plow) -vandalism	Detailed inspection
	Soil is soft or eroding near pole base	-soil erosion due to washout -improper backfilling/tamping	Detailed inspection
Pole length (butt to top)	Pole tapers non-uniformly or has mottled surface	-shell rot	Detailed inspection
	Hole(s)	-Woodpecker infiltration	Detailed inspection
	Substantially jagged pole top	-pole top rot/deterioration	Detailed inspection
	Pole is leaning, angle exceeds 10 degrees (1' out of vertical 6' above the ground)	-unstable soil conditions -broken pole butt -broken/loose/missing guy wire	Detailed inspection

Inspection Point	Potential Findings	Indication	Follow Up Action
Down Ground	Truncated down ground	-copper theft/vandalism	Submit maintenance request
	Exposed ground rod	-rod heaved to surface by frost action	Submit maintenance request
Terminations , Insulators, & Cutouts	Dark spots near contact point with live parts	-flashover	Submit maintenance request
	Primary conductor not resting uniformly on glass insulator or small gauge wire visibly dangling from insulator	-broken tie wire	Submit maintenance request
	Glass standoffs: 	-Glass standoffs are known to fail unexpectedly during routine maintenance or while performing work on the associated pole	Submit maintenance request
Lightning Arrestor	Dark marks on or separation of insulative material.	-Arrestor has failed during a temporary overvoltage condition	Submit maintenance request
Overhead Conductors	Distance between primary and secondary circuit is insufficient	-minimum clearances are violated	Contact Engineering for verification Submit maintenance request following verification
	Distance between circuit and neutral and/or guy wire is insufficient	-minimum clearances are violated	Contact Engineering for verification Submit maintenance request following verification
	Distance from lowest conductor/cable to grade is insufficient	-minimum clearances are violated	Contact Engineering for verification Submit maintenance request following verification
	Jumper to take-off is under high tension	-take-off is too tight, can result in hot spot and eventual failure	Detailed inspection
	Open wire secondary is not evenly spaced	-broken/missing mid-span bracket -service tension is excessive	Submit maintenance request
	System neutral is not in contact with insulator spool	-broken tie wire	Submit maintenance request
In-Line Switches	All in-line switches are subject to detailed inspection		Detailed Inspection
Guys & Anchoring	Guy wire is in/near contact with live parts	-insufficient tensioning -compromised anchor points	Submit maintenance request
	Guy wire not clearly marked	-missing guy guard	Submit maintenance request
	Guy wire is slack	-insufficient tensioning -compromised anchor points	Detailed inspection
	Discoloration of strain insulator	-insulator is making contact with live parts -insulator is breaking down due to UV exposure	Submit maintenance request
	Anchor Rod protrudes > 6" from finished grade	-compromised anchor point -unstable soil conditions	Detailed inspection
	Circuit, neutral, or third party	-construction incomplete or guy	Contact Engineering for

Inspection Point	Potential Findings	Indication	Follow Up Action
	attachment has no associated guy	is missing	verification Submit maintenance request upon verification
Distribution Transformer	Discoloration at transformer bushings, below lid, or at any point on can	-oil leak	Submit maintenance request
	Discolouration of bushings	-flashed insulators	Detailed inspection
	Significant tank rust	-missing paint -can produce oil leaks	Submit maintenance request
Framing & Hardware	Splintering or jagged ends on wooden crossarm	-rotten crossarm	Submit maintenance request
	Insulator in crossarm is leaning significantly or is sitting directly on crossarm with no clearance	-broken insulator pin (possibly wood pin) -rotted crossarm pin seats	Submit maintenance request
	Single phase insulator mount (in top of pole) is leaning	-pole top has rotted and insulator mount is pivoting	Submit maintenance request
	Hardware is loose or compromised		Submit maintenance request
Vegetation	Vegetation is encroaching on primary conductor	-may produce ground fault	Submit maintenance request
	Trees are resting on neutral, 3 rd party, or secondary	-mechanical straining of connections and cables	Submit maintenance request
Third Party Attachments	Numerous		Submit maintenance request

Detailed Inspection

In certain cases the inspector may suspect that a defect exists but cannot confirm that suspicion from the vehicle. In these cases a detailed inspection is required prior to submission of a maintenance request. Further, where a section of line shares common attributes (ie. voltage class, number of phases, number of circuits, vintage, etc.), a pole installation is designated randomly for a detailed inspection. The inspector is informed of the asset selected for detailed inspection by the presence of highlighting on the mapping interface. Note that all in-line switches require a detailed inspection.

The following table presents TBHs presently accepted methodology for performing a detailed inspection of a utility pole installation and/or in-line switch installation. In all cases, the inspector must collect photos of all inspection points. Where no maintenance request is generated, photos will provide a reference point in the event of future deterioration.

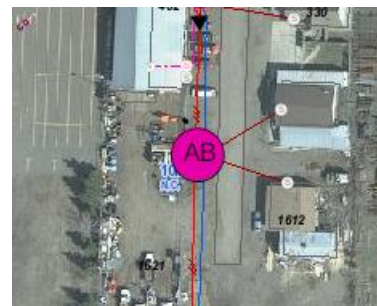
Inspection Point	Activity	Observations	Result Which Produces Maintenance Request
Pole	Sound pole from base to 7' above grade with hammer	Note the sound of the impact. A compromised pole (ie. significant heart rot) will produce a hollow sound	- Any two quadrants have less than 2" of sound wood - Any three quadrants have less than 3" of sound wood
	Pound screwdriver into pole butt at ground level (pound at 45 degrees to grade level) in 4 quadrants	Estimate thickness of healthy shell in each of the quadrants	
	Pound screwdriver into pole 5' above ground level (pound at 45 degrees to grade level) in 4 quadrants	Estimate thickness of healthy shell in each of the quadrants	
	Pound screwdriver into area(s) with significant shell rot	Estimate depth of shell rot	
	Visual Inspection	Estimate extent of pest, vandalism, or collision damage	Depth of depression or void exceeds 30% of pole's diameter
		Review extent of soil erosion	- Missing or depressed soil poses a public hazard - Significant erosion of soil directly opposite of conductor or guy tension at pole top
		Use binoculars to determine extent of pole top rot	Pole top rot has compromised a framing connection point
		Observe angle of pole	Measured pole angle exceeds 10° (1' out of vertical 6' above grade)
Overhead Conductors, Terminations, Insulators, connection points & Bushings	Visual Inspection (Binoculars)	Dark spots on insulator	- Clearly verified flash points on insulators - Obvious insulator soiling
		Insulator tie wires	Broken tie wires on neutral or circuit conductors
	Visual Inspection (Thermographic Camera)	Review all terminations, connection points, and insulators	The temperature of any energized component is 20°C hotter than adjacent components
In-line Switches	Visual Inspection (Binoculars)	Dark spots on insulator	- Clearly verified flash points on insulators - Obvious insulator soiling
		Switch operation mechanism is not parallel to ground	Switch is twisted to the point of being non-operational from ground level
	Visual Inspection (Thermographic Camera)	Review all terminations, connection points, switch blades and insulators	The temperature of any energized component is 20°C hotter than adjacent components

Inspection Point	Activity	Observations	Result Which Produces Maintenance Request
Guying and Anchoring	Review of anchor points (Binocular inspection of pole connection points and ground level inspection of ground penetrations)	Pole connection points are compromised by pole rot	Guy/strut attachment is clearly sinking into pole
		Ground anchor is receding from original set point	Top of anchor rod is >1' above grade
Distribution Transformer	Visual Inspection (Binoculars)	Presence of oil on exterior of transformer tank	- Oil pattern extends from point of leak to bottom of tank - Oil leak apparent from 2 or more bushings
		Significant rust on transformer surface	- Transformer tank is clearly compromised by rust - Surface rust covers >50% of exposed surface
	Visual Inspection (Thermographic Camera)	Transformer tank	Transformer temperature exceeds energized component temperature by 40°C
		Transformer connections	The temperature of any energized component is 20°C hotter than adjacent components

Distribution Switch Inspection and Risk Assessment

For the purposes of achieving the legislated inspection regime, TBH subdivides the switch population according to their feeder designation. The intention is to ensure that every switch is at least visually inspected every three years. Visual inspection of the in-line switch population is captured under the Overhead Inspection and Risk Assessment while the inspection of air-break, load-break, and recloser population is captured under this initiative. The list of switches targeted for inspection and maintenance are available on the corporate intranet GIS environment. This list is managed by Engineering and cycled through in January of each year. The switch inspection/maintenance module is a sub-module to the Maintenance Request Administration System (discussed later).

When a switch is targeted for the present year's inspection it appears on the web GIS interface as follows, with the various symbols representing the various switch types;



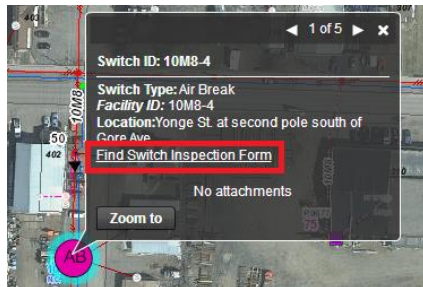
Load Break Switch Scheduled for Inspection

Air Break Switch Scheduled for Inspection

The exhaustive list of switches scheduled for inspection is also available within the reporting feature in the intranet environment;

10M5-1	Load Break	Kam Rd. at Thunder Bay Chemicals	Open GIS
10M6-2	Load Break	North side of Kam just north of 10M5 tower	Open GIS
10M6-6	Load Break	15th. Sideroad first pole north of Hwy 61.	Open GIS
10M6-7	Load Break	Hwy. 61 third pole east of Riverdale Rd.	Open GIS
10M6-4	Load Break	City Rd. east of James, 2 spans east of takeoff to McAshphalt.	Open GIS
10M6-8	Load Break	5th pole west of Mission Rd on Bernard-Moriseau Dr (100 Amp)	Open GIS
10M7-12	Load Break	Churchill Drive, 2nd pole west of Ford St	Open GIS
10M7-4	Load Break	Lane behind #5 Substation (west rear corner)	Open GIS
10M7-3	Load Break	Lane behind #5 Substation (between taps to 5T1 and 5T2)	Open GIS

Switch maintenance activities are conducted in parallel with switch inspection activities. When the Maintenance Supervisor deploys a crew to perform switch inspection duties, the crew is provided a switch detailed inspection form. The detailed inspection form is available to the Maintenance Supervisor through the intranet environment and is pre-populated with certain specifics regarding the associated switch;



TBHEDI SWITCH INSPECTION REPORT

Facility ID:	10M8-4	Switch Style:	Air Break
Location:	Yonge St. at second pole south of Gore Ave.		
Inspection Completed By:		Inspection Date:	
Maintenance Required (Yes/No):			
GENERAL INSPECTION POINTS:			
Switch Operated During Inspection (Yes/No):			
Activity Performed (Inspected/Maintained/Replaced):			
Switch Label Condition (New/Good/Poor/Missing/NA):			
Blade Contact (Good/Poor):			
Blade Alignment (Aligned/Misaligned):			
Hinge Condition (Good/Stiff/Seized):			
Line Connection Condition (Good/Poor):			
Blades Open to 90° (Yes/No):			
Switch Handle Operable (Yes/No/NA):			
Switch Insulators (Dirty/Cracked or Broken/Evidence of Flashing):			
Strain Insulators (Dirty/Cracked or Broken/Evidence of Flashing):			
Ground Contact (Good/Poor):			
LOAD BREAK SPECIFIC INSPECTION POINTS:			
Shunt Contact Condition (New/Good/Poor):	N/A		
Shunt Contact Clearance from Interrupter Housing (Ideally 5/8"):			
Shunt Contact Funct. (Full Contact Prior to Disengage/Insuff. Contact):	N/A		
Closing cam clearance from interrupter closing lever (Ideally 3/16"):			
Opening cam clearance from interrupter opening lever (Ideally 1/4"):			
AIR BREAK SPECIFIC INSPECTION POINTS:			
Arc Horn Condition (Good/Deteriorated/Misaligned):			
Arc Horn Function (Full contact through operation/Insuff. Contact):			
INSPECTION COMMENTS:			

Where the inspection determines that maintenance of the switch is required, the inspection crew may conduct the maintenance immediately and note this on the inspection form. Where the crew is unable to immediately perform the maintenance, a deficiency is noted on the inspection form.

The completed detailed inspection form is submitted to the Maintenance Supervisor. The details of the annual inspection are then logged into the intranet environment;

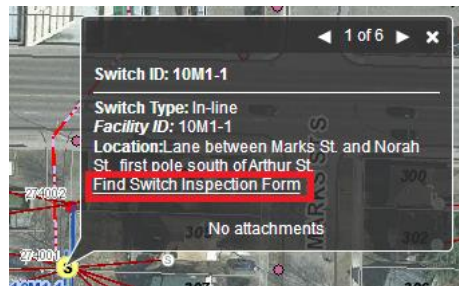
Once the annual inspection form has been submitted, the outstanding switch inspection/maintenance request becomes a 'completed' request and subsequently exits the 'outstanding' report and enters the 'completed' report;

Completed Switch Inspections

57 Maintenance Records

Switch Facility ID	Switch Type	Location	GIS Location
10M1-1	In-line	Lane between Marks St. and Norah St. first pole south of Arthur St.	Open GIS
10M1-10M3-2	Load Break	Archibald & Syndicate lane 2nd pole N. of Ridgeway. (SCADA - CONFIRM USING 3 PHASE AMP READINGS)	Open GIS
10M1-10M7-1	Load Break	Donald St. second pole east of Ford.	Open GIS
10M1-17M6-1	Load Break	Wellington St. 2nd pole south of Cameron St.	Open GIS
10M1-19	In-line	Collins Place first span east of Selkirk Street	Open GIS
10M1-29	In-line	Selkirk St. at Victoria Ave.	Open GIS
10M10-2	In-line	Arthur St, just E. of Mountdale. (road circuit)	Open GIS

Individual switch inspection results are also available by querying the ‘completed switch inspections’ layer;



TBHEDI SWITCH INSPECTION REPORT

Facility ID:	10M1-1	Switch Style:	In-line
Location:	Lane between Marks St. and Norah St. first pole south of Arthur St.		
Inspection Completed By:	OPERATIONS	Inspection Date:	01-JAN-13
Maintenance Required (Yes/No):	N		
GENERAL INSPECTION POINTS:			
Switch Operated During Inspection (Yes/No):	Y	Inspection Only	
Activity Performed (Inspected/Maintained/Replaced):			
Switch Label Condition (New/Good/Poor/Missing/NA):	Good		
Blade Contact (Good/Poor):	Good		
Blade Alignment (Aligned/Misaligned):	Aligned		
Hinge Condition (Good/Stiff/Seized):	Good		
Line Connection Condition (Good/Poor):	Good		
Blades Open to 90° (Yes/No):	Y		
Switch Handle Operable (Yes/No/NA):	N/A		
Switch Insulators (Dirty/Cracked or Broken/Evidence of Flashing):			
Strain Insulators (Dirty/Cracked or Broken/Evidence of Flashing):			
Ground Contact (Good/Poor):			
LOAD BREAK SPECIFIC INSPECTION POINTS:			
Shunt Contact Condition (New/Good/Poor):		N/A	
Shunt Contact Clearance from Interrupter Housing (Ideally 5/8"):			
Shunt Contact Funct. (Full Contact Prior to Disengage/Insuff. Contact):		N/A	
Closing cam clearance from interrupter closing lever (Ideally 3/16"):			
Opening cam clearance from interrupter opening lever (Ideally 1/4"):			
AIR BREAK SPECIFIC INSPECTION POINTS:			

If an inspection report indicates that ‘maintenance is required’ (a condition noted when the inspection crew is unable to perform the associated maintenance) a Maintenance Request is generated and prioritized against the existing maintenance request population. Maintenance will take place according to the request’s prioritization ranking.

Underground Asset Classifications and Inspection Considerations

Due to the subjective nature of performing a visual inspection, it is important to provide a reasonably objective set of inspection points for the inspector to review. These inspection points alert the inspector to consider a common set of defects. Where no defect is discovered no report is required. However, where a defect has been discovered, a maintenance request is generated using a standardized template for the purposes of assigning the priority of the request when measured against the request population.

High Level Inspection

For the purposes of efficiency and completing the annual inspection in a timely fashion, 66% of pad mounted distribution transformers contained within the inspection zone are subject to a high level inspection.

The high level inspection may take place from a vehicle where possible and by foot patrol where necessary. The high level inspection reviews the following inspection points. Where a defect is found, the related follow up action takes place;

Inspection Point	Potential Findings	Indication	Follow Up Action
Access	Blocked Access	-Vegetation built up around transformer -Customer equipment/materials on or around unit -Grade changes or significant lean make door unable to be opened	Submit maintenance request. Customer notifications will be generated by Engineering accordingly.
Tank	Dented	-Vandalism -Vehicle impact	Detailed inspection
	Paint condition & corrosion	-significant rust can produce oil leaks	Detailed inspection
	Dark pattern on tank exterior or pad	-Oil leak	Detailed inspection
Door	Nomenclature or warning signs missing	-Complicates switching/restoration procedures -signage necessary for public safety	-Verify nomenclature with Engineering and affix -Apply new signage
	Penta bolt and/or lock missing	-Represents a public safety concern	Detailed inspection
Foundation	Sinking foundation	-significant lean, to the degree where door cannot be opened or lean exceeds 15 degrees (6 inches in 2 feet)	Submit maintenance request
	Gap under foundation	-provides unauthorized access (public, animals, etc.) to transformer terminations	Submit maintenance request
	Ground wires/grid exposed	-change in grade, frost heave, or soil erosion has exposed grounding infrastructure	Submit maintenance request
Cooling Fins	Exposure of fins is restricted	-Vegetation growth in and around fins -Foreign materials blocking air flow around fins	- Clear blockage where possible - Submit maintenance request where follow up required. - Customer notifications will be generated by Engineering.

Detailed Inspection

In certain cases the inspector may suspect that a defect exists but cannot confirm that suspicion from the high level inspection. In these cases a detailed inspection is required prior to submission of a maintenance request. Further, every underground distribution transformer installation undergoes a detailed inspection once every 9 years. The inspector is informed of the asset selected for detailed inspection by the presence of highlighting on the mapping interface. Note that all outdoor pad-mounted switchgear requires a detailed inspection each 3 year cycle.

The following table presents TBHs presently accepted methodology for performing a detailed inspection of a pad mounted distribution transformer installation. **In all cases, the inspector must collect photos of all inspection points. Where no maintenance request is generated the photos will provide a reference point in the event of future deterioration. The detailed inspection is conducted with the transformer doors opened;**

Inspection Point	Activity	Observations	Result Which Produces Maintenance Request
Tank	Visual Inspection	Dent from impact	• Significant oil leakage
		Significant rust	
		Compromised seals	
Door	Visual/Operational Inspection	Penta bolt, lock , or other door fastening devices	• Missing • Seized
		Hinge function	• Door will not open sufficiently to allow for live operation
Termination Enclosure	Visual Inspection	Vegetation	• Growth is encroaching on live components
		Pest infiltration	• Nests or substantial soiling
		Hygiene	• Significant soiling of insulators
		Staining of concrete pad	• Significant oil leakage
		Condition of fiber board	• Significant sagging above live parts

Inspection Point	Activity	Observations	Result Which Produces Maintenance Request
Terminations	Visual Inspection	Condition of glass	• Cracked or broken
		Dark spots on cable terminations or transformer bushings	• Evidence of flashing
	Visual Inspection (Thermographic Camera)	Primary Terminations/Elbows	• The temperature of any energized component is 20°C hotter than adjacent components
		Secondary Terminations	
		Fuse clips	

The following table presents the manufacturer's recommended procedure for performing a detailed inspection of a pad mounted outdoor switchgear installation. Where maintenance activity cannot be performed at the time of inspection a maintenance request is to be generated. In all cases, the inspector must collect photos of all inspection points. Where no maintenance request is generated the photos will provide a reference point in the event of future deterioration.

Item	Inspection Procedure			Maintenance Activity		
Inspect Interior	- Visually inspect interior of each compartment for excess dirt, weeds, and pest intrusion - Inspect insulators, surge arrestors, terminators, etc. for electrical damage - Check that grouting around base of unit is in good condition - Verify that there has been no major water ingress - Scan live components with Thermographic Camera			- Wash dirty or contaminated surfaces with water and mild soap - If the temperature of any energized component is 20°C hotter than adjacent components, submit maintenance request		
Inspect Barriers and Minimum Air Clearances	- Inspect barriers for signs of tracking and corona discharge - Verify that interphase and end barriers hang vertically and that retaining hardware is secure. Verify that barriers are properly seated in support notches - Verify the clearance from the terminators and other energized parts to the barriers and electrical ground is maintained to prevent flashover (Minimum clearances below)			Surface deposits can be wiped off. If surface erosion is present, the barriers may need to be replaced		
			Minimum Air clearances (Inches)			
		Rating (kV)	Energized Parts to Barriers	Terminator Skirts to Barriers	Energized Parts to Elec. Ground	Phase-to-Phase
		14.4	1	½	6	6
		25	2 ¼	1 ¼	7 ½	7 ½

Item	Inspection Procedure	Maintenance Activity
Inspect & Exercise Switches	- Exercise the switches and check all blades for proper opening and closing. Be sure that barriers are not in open gap - Check blades for signs of galling and excessive arc interruption. - Check contacts and joints for signs of overheating, as evidenced by distorted or discoloured metal	- Clean & re-lubricate the switches - Burnish out minor surface imperfections - Apply a thin layer of lubricant to the blades if necessary - Lubricate hinge contacts if necessary
Inspect Fuses (As applicable)	- Open & close fuses to ensure proper latching - Inspect the fuse contact surfaces for signs of galling and overheating, as evidenced by distorted or discolored contacts	- Minor imperfections can be burnished out - Clean contacts and apply a thin layer of lubricant as necessary
Inspect Key Interlock and Door Latching Mechanisms	- Verify proper functioning of key interlocks, if furnished - Verify proper operation of door latching mechanisms	Lubricate and/or replace mechanisms as required

Vault Asset Classifications and Inspection Considerations

All vaults will be subjected to a detailed inspection every three years. In most cases these vaults form a part of the customer owned premises. Vaults may contain the following TBH owned assets;

- Distribution transformers;
- Primary conductors;
- Primary fusing, and;
- Primary switching and/or load centres.

Vaults may also contain the following assets which, although customer owned, can impact the performance of the TBH assets. As such, where a deficiency in one of the following customer owned assets is noted, TBH will notify the customer and request an action plan and timeline for the repair of the noted defect.

- Ventilation louvers and filters;
- Mechanical ventilation system;
- Lighting;
- Vault access doors;
- Drainage systems, and;
- The structure of the enclosure itself.

The following table presents TBHs presently accepted methodology for performing a detailed inspection of a vault containing TBH owned assets. In all cases, the inspector must collect photos of all inspection points. Where no maintenance request is generated, photos will provide a reference point in the event of future deterioration.

Category	Inspection Point	Points of verification
Vault Access	Accessibility to public	Public access is restricted
	Locks & Hinges	Locks and hinges function as intended and operate smoothly
	Accessibility to authorized workers	Entry to vault is unobstructed on interior and exterior
	Emergency egress	Where emergency egress exists, exits are clear and function as intended
Live Part Access	Warning rope and signage	Proximity to live parts is clearly indicated and access is sufficiently limited (ie. roped off)
Lighting	Light fixtures and points of operation	Lighting is sufficient to perform work safely
Structure	Roof/Ceiling	- Evidence of water ingress (ie. leaking roof) - In some cases parging may be crumbling from ceiling surface
	Foundation	Stability of foundation structure.
	Walls	- Evidence of water ingress - In some cases parging may be crumbling from wall surfaces - Integrity of walls, evidence of vandalism or vehicular impact
	Spill basin	Basin should not be holding standing water or oil
Drainage	Vault floor drain and equipment clearances from floor	- All live components are sufficiently protected from flooding - Search for any evidence of water damage or standing water - Floor drain is present and unobstructed
Ventilation	Mechanically Assisted Ventilation	If equipped, functions normally
	Ventilation filters	If equipped, are present and clean
	Ventilation louvers	In good condition and sufficiently limit public/wildlife access
	Bird screens	In place, clean, and sufficient
	Security bars	If equipped, are in place and sufficient
Signage	Exterior signage	In place and sufficient
	Interior signage	In place and sufficient

Category	Inspection Point	Points of verification
Housekeeping	Live parts	• Insulators are clean with no significant dust buildup • No foreign material in proximity to live parts
	General	• Evidence of pest infiltration (ie. nests, feces, etc.) • General cleanliness of vault including impediments to emergency evacuations
Transformer	Tank	• Oil leakage • Significant rusting • Nomenclature is affixed and legible
	Bushings	• Oil leakage • Clean & no evidence of tracking
Cable Tray	Floor, Ceiling, & Wall Connections	• Lag points appear sound and sufficient to carry associated load

Substation Maintenance Schedule

Stations Maintenance Schedule				
Month	Transformer Oil Testing	Station Maintenance	Additional Maintenance	Monthly Checks
January	.	__ Station Inspections All stations __ New Main St. Recloser Control Installation Station Risk Assessments: __ Algoma __ Donald __ Grenville __ Hardisty __ MacDonnel __ Mountdale __ Vickers	__ Stations. Smoke Detectors __ GFI Test __ Compressors __ Annual PPE Inspection __ PCB Quarterly Report O/H, Pad Mount Transformer Maintenance Record Number process (____) __ Ladder Inspections __ First Aid Kit in Trucks 49 & 20	__ Operations Center, Cameras, fans, UPS & UPS battery inspection __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection
February	Transformer Oil DGA Test __ All Stations __ Northwood Plaza	__ Battery Inspection/Maintenance All Stations __ Station Inspections All stations __ RTU 45 Controller Upgrade __ B.E.L.T.	O/H, Pad Mount Transformer Maintenance Record Number process (____)	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Locker Room Filter Change __ Monthly PCB Storage Inspection

Month	Transformer Oil Testing	Station Maintenance	Additional Maintenance	Monthly Checks
March	Transformer Oil DGA Test	Donald (5) Station __ Yard, building, structure inspections/repair __ Breakers & cubicles __ Relays __ Transducers __ Station Inspections All stations __ B.E.L.T __ RTU 33 controller upgrade	__ Water Filter __ Roof Bird Nest Patrol O/H, Pad Mount Transformer Maintenance Record Number process (____) __ Vault Cleaning/Check Waverly and Northwood __ Change air filter Lines locker room _	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection
April	Transformer Oil DGA Test	All Stations __ Battery Inspection/Maintenance __ inspect/repair transformer cooling fans __ transformer paint condition __ Fence conditions, signage __ Station Inspections All stations __ B.E.L.T Mountdale (9) Station __ Yard, building, structure inspections/repair __ Breakers __ Relays __ Transducers	__ Roof Bird Nest Patrol __ PCB Quarterly Report O/H, Pad Mount Transformer Maintenance Record Number process (____)	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection

Month	Transformer Oil Testing	Station Maintenance	Additional Maintenance	Monthly Checks
May	Transformer Oil DGA Test __ Northwood Plaza __ Camelot	__ Station Inspections All stations __ spray herbicide for weed control All stations __ B.E.L.T Broadway (19) Station: __ Recloser/controller upgrade Balsam (18) __ Pump down 4KV transformer __ Remove transformer	__ Roof Bird Nest Patrol O/H, Pad Mount Transformer Maintenance Record Number process (____) __ Install radio fleet garage.	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, generator transfer switch __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection
June	Transformer Oil DGA Test	__ Battery Inspection/Maintenance All Stations __ Station Inspections All stations Vickers (4) Station __ Yard, building, structure inspections/repair __ Breakers & cubicles __ Relays __ Transducers __ B.E.L.T	__ Compressors (M) __ Roof Bird Nest Patrol __ Water Filter (3M) O/H, Pad Mount Transformer Maintenance Record Number process (____)	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, generator transfer switch __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection

Month	Transformer Oil Testing	Station Maintenance	Additional Maintenance	Monthly Checks
July	Transformer Oil DGA Test	__ Station Inspections All stations __ B.E.L.T	__ PCB Quarterly Report O/H, Pad Mount Transformer Maintenance Record Number process (____)	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection
August	Transformer Oil DGA Test __ Northwood Plaza __ Camelot	__ Battery Inspection/Maintenance All Stations __ Kyles __ Station Inspections All stations __ B.E.L.T	__ First Aid Kit in Trucks 49 & 20 __ Change air filter Lines locker room O/H, Pad Mount Transformer Maintenance Record Number process (____)	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection
September	Transformer Oil DGA Test	__ Station Inspections All stations __ B.E.L.T __ Hardisty (3) Station	__ PCB Quarterly Report __ Water Filter (3M) O/H, Pad Mount Transformer Maintenance Record Number process (____)	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection

Month	Transformer Oil Testing	Station Maintenance	Additional Maintenance	Monthly Checks
October	Transformer Oil DGA Test	__ Battery Inspection/Maintenance All Stations	O/H, Pad Mount Transformer Maintenance Record Number process (____)	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection
November	Transformer Oil DGA Test __ Northwood Plaza __ Camelot	__ Station Inspections All stations	O/H, Pad Mount Transformer Maintenance Record Number process (____)	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection
December	Transformer Oil DGA Test	__ Battery Inspection/Maintenance All Stations __ Station Inspections All stations __ B.E.L.T	__ Water Filter (3M) O/H, Pad Mount Transformer Maintenance Record Number process (____)	__ Operations Center, Cameras, fans, UPS & UPS battery inspection, __ Gas Sensors __ fire extinguisher inspections __ AED Inspections __ Fire Alarm test __ Emergency Lights Inspection __ First Aid Station Inspection __ Eye Wash Stations Ops Center __ Monthly PCB Storage Inspection