Electrical Distribution Capital Plan (EDCP) 2012 – 2021

Toronto Hydro-Electric System Limited

Version 1.42
August 9, 2011

(this page is intentionally left blank)

Table of Contents

Table of Contents (Cont'd)

Table of Contents (Cont'd)

Executive Summary

The electrical distribution system owned and operated by THESL is comprised of several components, including an overhead distribution system, underground distribution system, secondary network system and stations; each of which possess different features and characteristics that impact system performance and reliability in different ways.

When examining the system as a whole, it is clear that system reliability is gradually worsening over time due to the large quantity of aging and deteriorating infrastructure, and legacy and obsolete assets. There are a number of issues concerning the electrical distribution system as a whole, including lack of operational flexibility, lack of available capacity to meet future load growth, security of supply, and potential safety risks. The "worst performing" feeders on the system continue to experience an unacceptably high number of sustained outages within a 12-month time period. While there have been some successes with respect to underground system reliability due to the ongoing replacement of direct buried cable infrastructure, underground system reliability has not significantly improved over the past ten years. Overall, system reliability is up to three times worse when compared to the average of other world-class cities.

THESL also faces other challenges, such as cresting retirements, externally-driven plant relocation pressures, and day-to-day challenges associated with connecting new customers and restoring customers following outages. In order to improve system reliability over a ten-year period, two like-for-like intervention approaches were examined. One approach involved keeping the quantity of assets approaching end-of-life criteria at a constant level by replacing these assets with their standardized equivalent over a ten-year period. The second approach involved a balancing of system performance through the application of a risk-based optimization methodology in order to produce the optimal replacement schedule for each evaluated asset class. Execution of either approach results in high capital spending over the ten-year period with minimal improvement in system reliability.

To achieve reliability improvements, like-for-like replacement must be combined with a modernization effort. This effort is intended to address operational constraints and poorly performing legacy assets, mitigate potential safety risks, and install and enable new technologies across the system that will allow for better monitoring of assets and shorter outages to customers. The combined approach ultimately requires the same amount of capital spending as the either of the like-for-like intervention approaches, but produces significantly greater reliability benefits. The proposed ten-year capital investment plan, which reflects the combined approach, is expected to improve SAIFI (System Average Interruption Frequency Index) by 40% and SAIDI (System Average Interruption Duration Index) by 44%.

The Electrical Distribution Capital Plan ("EDCP") that follows presents the total capital investment program to be implemented over the next ten years (2012-2021). In addition to the aforementioned like-for-like replacement and modernization approaches, this plan also contains programs to mitigate the risks from critical issues associated with load growth and security of supply concerns, safety risks associated with non-standard equipment, externally-driven asset replacements and renewal, worst performing feeders and deteriorating stations infrastructure. This plan also manages the challenges associated with a retiring technical workforce, externally-driven plant relocation activities, connection of new customers to the system and the restoration of service to customers following outages.

Ultimately, execution of the EDCP ensures that THESL will make the optimal investment decisions to mitigate risks and improve system reliability, which will enable Toronto's electrical distribution system to achieve the reliability levels found in other world-class cities.

1 Introduction

1.1 Purpose

The purpose of the Electrical Distribution Capital Plan ("EDCP") is to present the capital investment programs to be executed by THESL, along with the associated spending for each program over the next ten-year period, starting in 2012 and continuing until 2021. Each capital investment program is linked to a specific issue or series of issues that are being mitigated as a result of the program execution. The key issues and challenges[1] that the THESL electrical distribution system is exposed to are further summarized within this document.

This document explains how these issues and challenges will be remedied, through the execution of various programs and initiatives. These programs and initiatives will remedy issues at the Grid Systems level, as well as issues of a more critical nature and other challenges that the THESL electrical distribution system is exposed to. Ultimately, the key benefits of each program for the electrical distribution system are provided.

1.2 Scope

The EDCP focuses on capital investment programs to be executed over the next ten-year period, but does not provide details on specific projects to be executed within this time period. That is, the EDCP captures the *total* investments relating to the operational electrical and civil assets within the electrical distribution system operated by THESL. The information presented here does not cover investments relating to the GEA, corporate investments, or investments relating to IT, facilities, fleet, metering or street lighting services.

1.3 Background & Objectives

This edition of the EDCP supersedes Revision 1.0 of the 2011-2020 Electrical Distribution Capital Plan (EB-2010-0142, Exhibit D1, Tab 8, Schedule 10) that was filed in August of 2010.

THESL's electrical distribution system contains assets operating at 4.16kV, 13.8kV and 27.6kV respectively. Customers within the downtown region are predominantly supplied by assets operating at 4.16kV and 13.8kV, while customers to the east, west and north of the downtown region – areas collectively referred to as the "horseshoe" region – are supplied by assets operating at 4.16kV and 27.6kV.

THESL's electrical distribution system contains various deficiencies and risks (issues) that are contributing to an overall degradation of system reliability. These consist of Grid System Issues, Critical Issues, System-Wide Issues and Other Challenges.

This document presents different approaches on how these key issues and challenges can be mitigated. THESL also performed a study to weigh the potential benefits of each approach against the costs of execution. From the conclusions of this study, an optimal execution approach was selected and various programs and initiatives were derived. The approaches and overall study conclusions are defined in Chapter 2.

[1] "System Challenges" schedule (Exhibit D1, Tab 7, Schedule 5)

Following the selection of the optimal approach, a series of investment programs was established in order to meet the following objectives over the next ten-year period:

- Targeting key unreliable and high risk assets to be replaced with standardized assets
- Re-configuring existing circuit designs to reduce the impact of asset failure
- Inclusion of new technologies to improve monitoring and restoration
- Establishing new sources of supply to properly service increasing loads
- Installing new assets and infrastructure to mitigate operational constraints
- Removal of assets that present safety risks to the public
- Relocation, replacement and/or construction of assets in response to externally-initiated programs
- Continued replacement of failed distribution assets and restoration of the impacted customers
- Connection of new customers and electric vehicles (EV) to system
- Ensuring the transfer of critical technical knowledge from retiring staff

The corresponding investment programs are further discussed in Chapters 3, 4 and 5 respectively. Chapter 3 concentrates on those programs targeting each Grid System, including the overhead, underground, secondary network and stations systems. Chapter 4 focuses on critical issues impacting the electrical distribution system as a whole. Finally, Chapter 5 focuses on investment programs that will target other challenges that THESL is currently facing.

In addition, this plan also contains the ten-year maintenance activities to be executed, in order to optimally maintain assets and prolong asset life cycles. This is further detailed in Chapter 6.

1.4 Overall Investments

Each of the objectives described in Section 1.3 have been broken down into three categories within the EDCP Grid Systems, Critical Issues and Other Distribution Investments.

Grid Systems pertains to those investments targeted to mitigate issues concerning each of the four system classifications within THESL's electrical distribution system: the underground distribution system, the overhead distribution system, the secondary network system and stations. Investment programs within this category will target issues such as unreliable and high risk assets, re-configuration of existing circuit designs and inclusion of new technologies to improve monitoring and restoration. A total of $3.57 billion in investments has been allocated to the Grid Systems category.

Critical Issues pertains to those investments targeted to mitigate serious challenges within the electrical distribution system as a whole, including load growth, security of supply, operational constraints, safety-related risks, degradation of infrastructure and externally-initiated expansion activities. A total of $892 million in investments has been allocated to the Critical Issues category.

Other Distribution Investments pertains to those investments targeted to mitigate day-to-day operational challenges associated with engineering and planning activities, externally-initiated plant relocations, connections of new customers to the electrical distribution system and the immediate replacement of failed assets and customer restoration during an outage. A total of $1.04 billion in investments has been allocated to the Other Distribution Investments category.

Total investments as described within the EDCP are $5.51 billion over the ten-year period. Each of these investments is shown in their respective categories in Figure 1.

#	Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
GRID SYSTEMS ($M)											
1	UNDERGROUND SYSTEM	$133.2	$143.8	$173.0	$194.7	$191.6	$192.3	$190.8	$191.7	$194.6	$202.3
2	OVERHEAD SYSTEM	$93.0	$99.3	$112.2	$110.8	$109.9	$93.3	$83.9	$84.7	$86.3	$88.3
3	NETWORK SYSTEM	$20.2	$46.4	$63.9	$63.4	$63.4	$63.0	$59.8	$63.4	$57.1	$58.4
4	STATIONS	$24.5	$24.1	$24.0	$24.3	$24.6	$25.0	$25.1	$25.2	$25.2	$25.4
	GRID SYSTEMS TOTAL	$270.9	$313.6	$373.1	$393.2	$389.4	$373.6	$359.6	$365.0	$363.2	$374.4
CRITICAL ISSUES ($M)											
#	Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
5	STATIONS ENHANCEMENTS	$89.6	$49.4	$13.0	$55.0	$48.0	$51.0	$27.0	$28.5	$31.0	$31.0
6	SECONDARY UPGRADES	$8.6	$12.2	$9.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
7	STANDARDIZATION	$9.0	$10.3	$6.1	$6.4	$6.4	$4.8	$4.8	$4.8	$4.8	$4.8
8	DOWNTOWN CONTINGENCY	$1.1	$9.3	$9.2	$9.2	$11.0	$20.4	$16.2	$16.0	$9.2	$9.2
9	WORST PERFORMING FEEDER	$11.0	$10.5	$10.5	$10.0	$9.0	$9.0	$8.0	$8.0	$7.5	$7.5
10	STATIONS INFRASTRUCTURE	$10.6	$15.2	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5
	CRITICAL ISSUES TOTAL	$129.9	$106.9	$67.1	$99.1	$92.9	$103.7	$74.5	$75.8	$71.0	$71.0
OTHER DISTRIBUTION INVESTMENTS ($M)											
#	Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
11	ENGINEERING CAPITAL	$30.6	$33.2	$35.2	$37.5	$36.8	$36.1	$32.9	$34.0	$34.1	$34.8
12	CUSTOMER CONNECTIONS	$26.6	$27.7	$28.7	$27.8	$29.7	$31.7	$33.0	$33.0	$33.0	$33.0
13	EXT. INIT. PLANT RELOCATION	$14.3	$9.5	$5.9	$8.4	$8.8	$9.7	$10.6	$11.8	$12.9	$14.2
14	REACTIVE CAPITAL	$27.3	$28.6	$30.1	$27.5	$28.0	$28.4	$28.8	$29.2	$29.7	$30.1
	OTHER DIST. INVESTMENTS TOTAL	$98.8	$99.0	$99.9	$101.2	$103.2	$105.9	$105.3	$108.0	$109.7	$112.2
	YEAR	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	TOTAL ($M)	$499.6	$519.5	$540.1	$593.6	$585.5	$583.2	$539.5	$548.8	$543.9	$557.6

Figure 1 – Electrical Distribution Capital Plan Ten-Year Investments ($ Millions)

Figure 2 replicates the ten-year expenditure categories in the table above graphically. As shown in the chart, the highest category of spending is associated with the underground distribution system. This is due to the significantly higher capital costs of replacing underground asset infrastructure when compared to other types of infrastructure.

The graph in Figure 3 shows spending over the next ten-year period at a summary expenditure level. As shown in this figure, the highest spending is associated with the Grid Systems category relative to the Critical Issues and Other Distribution Challenges categories.

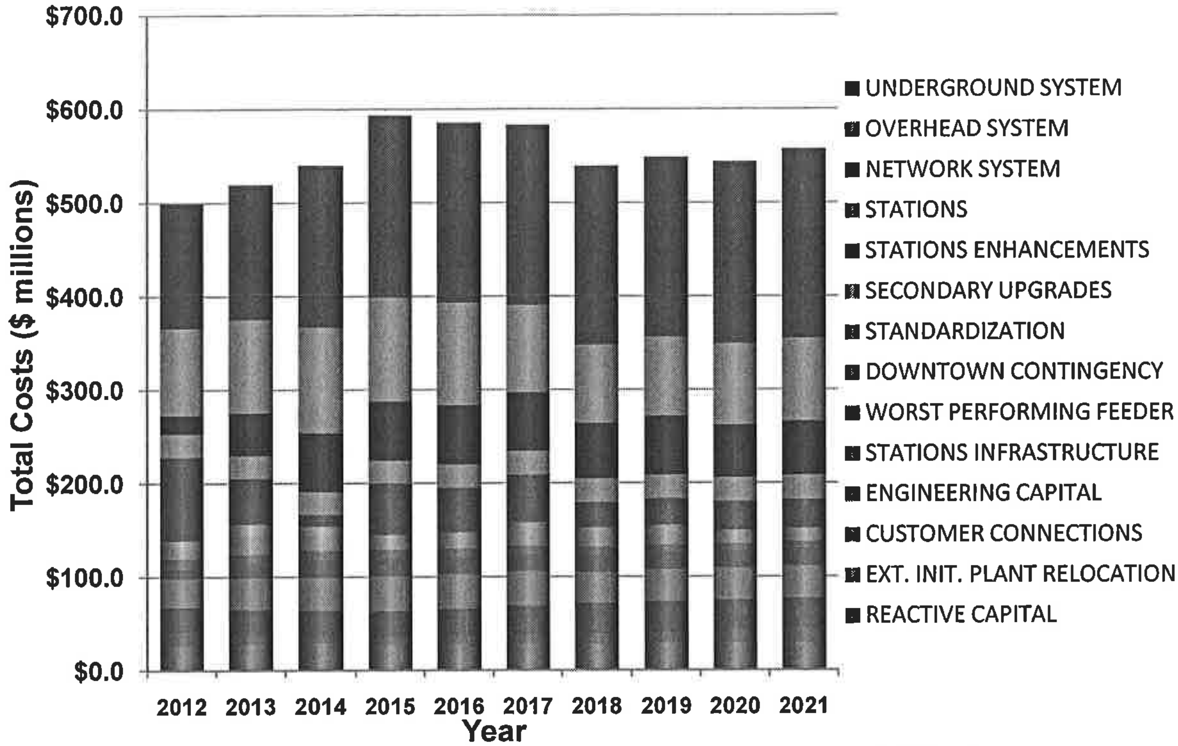


Figure 2 – Electrical Distribution Capital Plan Ten-Year Investments ($ Millions)

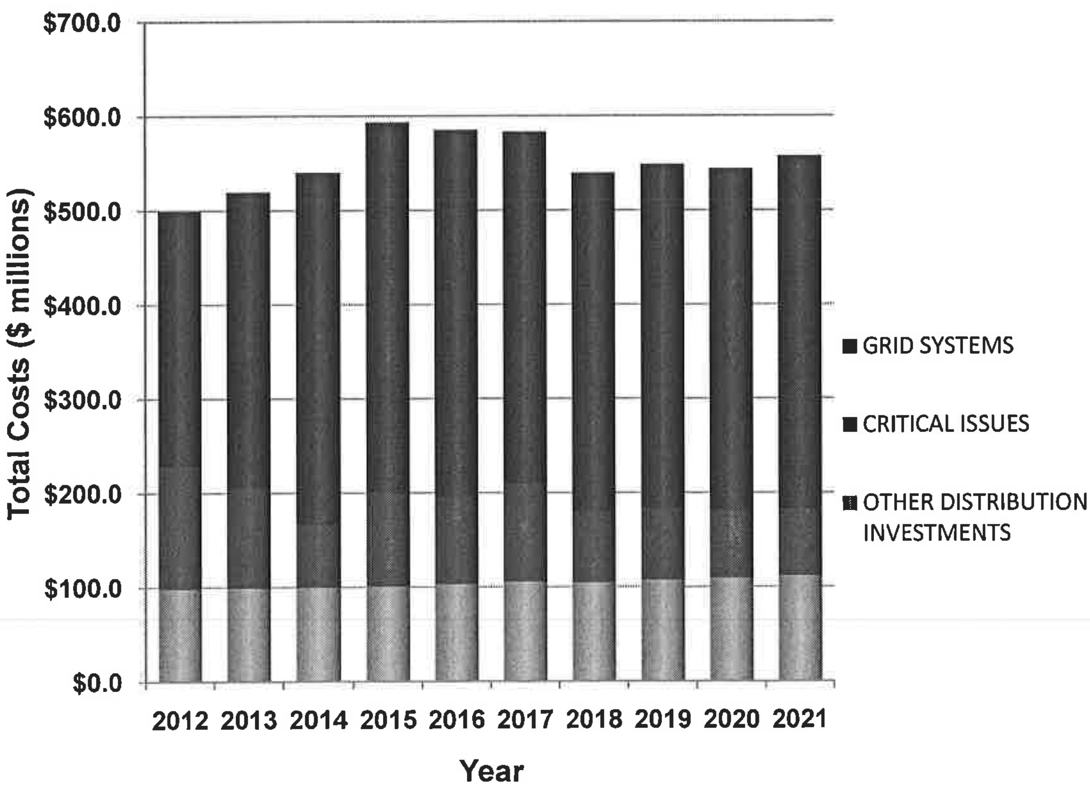


Figure 3 – Electrical Distribution Capital Plan Ten-Year Investments by Program ($ Millions)

II Approaches to Address System Challenges

THESL's distribution system reliability has been gradually worsening due to a large number of aging and deteriorating infrastructure, legacy and obsolete assets and accessories. There are a number of serious risks that THESL is facing should these assets be allowed to fail within the distribution system. There are also more critical system-level challenges, such as continued load growth with limited capacity, contingency issues concerning the radial downtown system and overall security of supply and safety-related issues, both to crew workers and the general public.

For these reasons, THESL examined two approaches in order to address System Challenges

(a) Sustaining system performance by keeping the quantity of assets approaching end-of-life at a constant level
(b) Balancing system performance by applying risk-based optimization methodology

Sustaining system performance by keeping the quantity of assets which are approaching their end-of-life at a constant level involves the replacement of existing assets with their standardized equivalent over the next ten-year period in order to sustain the current level of system performance.

Balancing system performance by applying a risk-based optimization methodology involves the implementation of a risk-based approach that is rooted in value-based reliability planning, so as to produce the optimal intervention timing for each evaluated asset. Like the sustained system performance approach, assets that are deemed to be at an optimal stage for intervention will be replaced with their standardized equivalent. Under this program, system performance is balanced between the costs of the increasing risk of asset failure against the benefit of extending asset service life for as long as possible.

Both of these approaches revealed that a large amount of capital investments must be made in order to either sustain or balance system performance. However, THESL believes that both approaches would result in rate increases to customers, without offering significant improvements to system reliability.

The risk-based optimization approach applied to distribution transformers, switches, poles, underground cables and network units reveals that a total investment of $1.61 billion would be required over the next ten-year period, compared to $1.57 billion in spending for the same asset classes as a result of the sustained system performance approach. With civil infrastructure and station assets also included, the sustained system performance approach increases the total required investment to $3.46 billion over a ten-year period.

Both of these approaches possess certain limitations. Certain assets installed in specific configuration types, such as rear lot and box construction, cannot be replaced on a like-for-like basis. Therefore, their replacement costs are not reflected within these approaches. In addition, these approaches do not account for modernization improvements, such as modifications to the existing distribution circuits and installation of new technologies that will support improvements, critical issues such as standardization, load growth, worst performing feeders and downtown contingency, or other distribution investments such as connecting new customers, externally initiated investments, engineering and reactive capital expenditures. By including these elements into the study, total costs for the sustained system performance approach increase to approximately $5.61 billion across a ten-year period.

Based upon these conclusions, THESL opted for a modernization approach that will complement both like-for-like asset replacement approaches with strategic system enhancements such as design re-configuration and self-healing system technologies that can be implemented across the electrical distribution system. Ultimately, the combination of modernization with like-for-like replacement results in a comparable required investment amount, but adds significant benefits to the electrical distribution system as opposed to only executing either like-for-like asset replacement approaches on its own.

By executing the combined approach, THESL will not only address system needs but will also enable significant system performance improvements for customers. These benefits will ultimately outweigh the required rate increases.

Each of these approaches is described in further detail below.

2.1 Sustained System Performance

Sustained system performance represents a basic intervention program where the quantity of assets approaching end-of-life are held to a constant level. To do this, a certain quantity of assets is replaced in each year with their standardized equivalent assets, and the forecast of the required capital investments to execute this approach flows from the expected cost of the standardized equivalent assets.

THESL employed the use of Hazard Rate Distribution Functions (HDF) in order to forecast the quantity of assets approaching their end-of-life and associated costs over the next ten-year period, from 2012 to 2021. The Hazard Rate methodology presents the conditional probability of asset failure from the remaining population of assets that have survived up to a certain point in time. These functions were either directly validated, or developed via the assistance of asset life studies from third-party consultants.[2]

Where asset performance was found to be deteriorating for a particular asset class, the total investment required to sustain performance to current levels was determined on an annual basis, such that the quantity of end-of-life assets would be held constant over the entire ten-year period.

Figure 4 shows the total capital investments required to execute this approach from the current year through to 2021. Were this approach to be executed, $669 million will need to be spent in the first year, and a total of $3.46 billion will be required to be spent over the next ten-years. This expenditure will account for all major electrical and civil assets, including distribution transformers, switches, poles, wires, network units and civil infrastructure.

[2] "Planning Process / Asset Management Approach" schedule (Exhibit D1, Tab 7, Schedule 1)

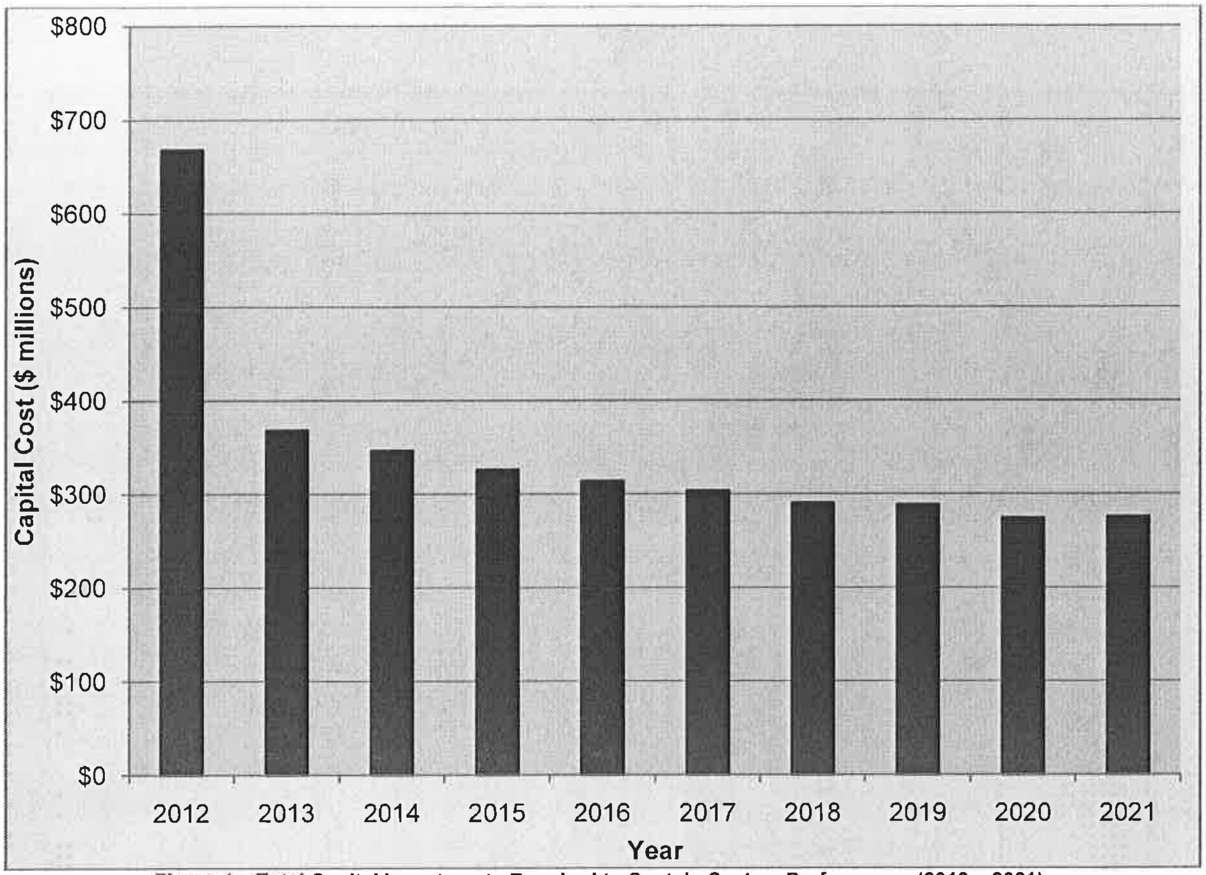


Figure 4 – Total Capital Investments Required to Sustain System Performance (2012 – 2021)

The results presented in Figure 4 illustrate that many investments will need to be made in order to sustain system performance across the ten-year period. It is noteworthy that system performance will only be sustained to current-state levels as per this approach, as opposed to being improved.

One of the key limitations of the like-for-like replacement approach is that assets are replaced in the same configuration and circuit design as before. There are no enhancements to the circuit design or configurations included in this program, nor are any investments considered to improve outage restoration time and operating flexibility. There are certain assets that simply cannot be re-installed as per their current configuration and circuit design, such as rear-lot infrastructure and box construction. Other issues which are not resolved by this spending program would include critical issues such as load growth, downtown contingency, standardization and worst performing feeders, along with other distribution system investments such as connecting new customers, engineering capital, reactive capital and externally initiated plant relocation activities. Should these elements be accounted for within this program, total spending would rise to approximately $5.61 billion over the ten-year period.

Implementation of this like-for-like replacement approach on its own would not improve THESL's reliability levels which are up to forty times worse when compared to other world class cities. Furthermore, this approach to capital spending does not apply to all assets, and does not remedy numerous critical issues that THESL's distribution system is currently facing.

2.2 Balancing System Performance via Risk-Based Optimization

A second approach to resolve key issues within THESL's electrical distribution system would be to execute a risk-based approach which is rooted in value-based reliability planning, so as to produce the optimal intervention timing for each distribution system asset which in turn is based on balancing economic risks and capital costs.

Economic risks within this approach reflect various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions; the costs of emergency repairs and replacement; and the indirect costs associated with a potentially catastrophic failure of assets.

Assets with an optimal intervention timing value of zero years can be described as being beyond their economic end-of-life criteria. Once these assets have reached their economic end-of-life criteria, they will be replaced with their standardized equivalents, as contemplated under the Sustained System Performance approach. Ultimately, this approach allows for the balancing of system performance to ensure the most valuable cost-benefit result for customers.

This approach has advantages over the sustained system performance approach, in that both the probability and the impact of failure are considered within the risk evaluation. The execution of this program will ultimately result in a balance between the costs of the increasing risk of failure against the benefit of extending asset service life for as long as possible.

THESL's Feeder Investment Model ("FIM"), which incorporates this risk-based approach, was used to perform an evaluation on major distribution assets, including overhead & underground distribution transformers, overhead & underground switches, poles, underground primary cables and network units.

The following subsections provide further results as per this Balancing System Performance approach for each aforementioned asset class.

2.2.1 Balancing System Performance: Underground Distribution Transformer Results

Submersible, pad-mounted and building vault transformers were evaluated by the FIM to produce total spending results as illustrated in Figure 5. The results reveal a backlog of 3,905 underground transformers that are at their economic end-of-life criteria. Risk contributors to this significant backlog include aging transformers nearing their end-of-life criteria. As per this program, a total of 10,797 underground transformers will be replaced over a ten-year period at a cost of $269 million.

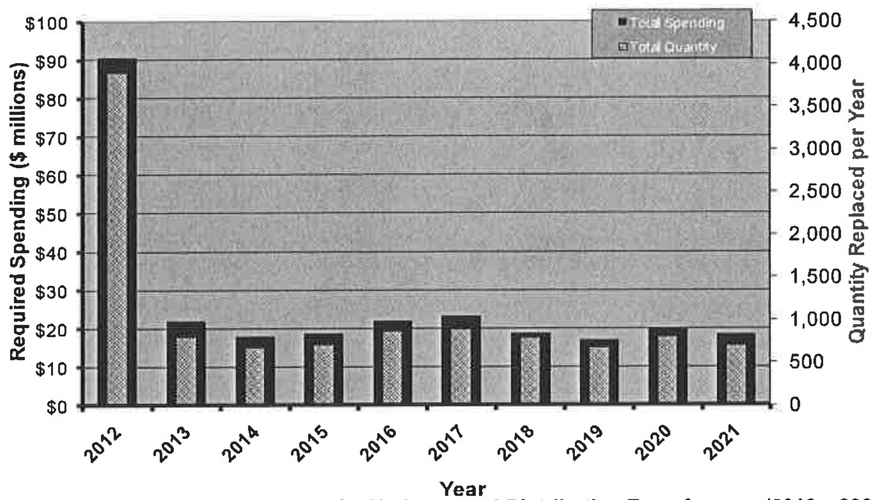


Figure 5 – Risk Optimization Results for Underground Distribution Transformers (2012 – 2021)

2.2.2 Balancing System Performance: Underground Switch Results

Air-insulated pad-mounted, minirupter and SF6 underground switches were evaluated by the FIM to produce the total spending results as illustrated in Figure 6. The results reveal a backlog of 6,321 underground switches that are at their economic end-of-life criteria. Contributors to this significant backlog include poor performing air-insulated pad-mounted switches. The results of the FIM indicate that a total of 8,381 underground switches will need to be replaced over a ten-year period at a total cost of $252 million.

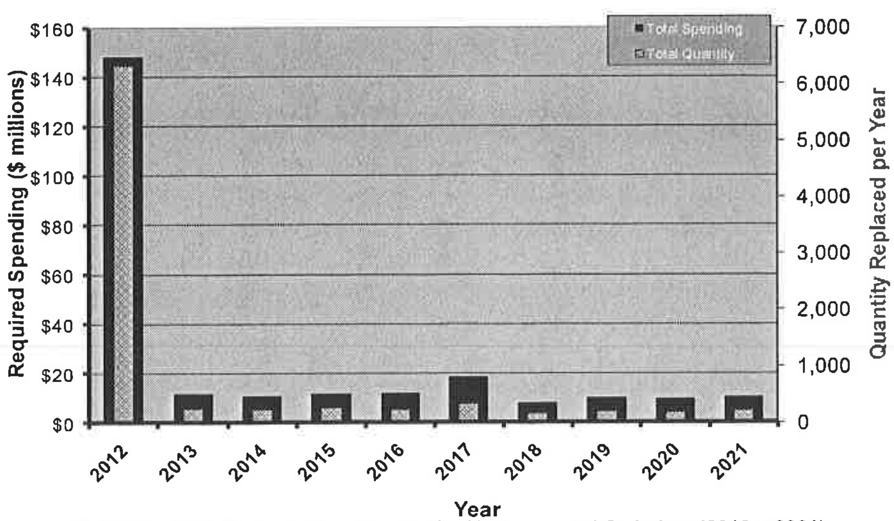


Figure 6 – Risk Optimization Results for Underground Switches (2012 – 2021)

2.2.3 Balancing System Performance: Underground Cable Results

Cross-Linked Polyethylene (XLPE), Tree-Retardant Cross-Linked Polyethylene (TR-XLPE) and Paper-Insulated Lead-Covered (PILC) cables were evaluated by the FIM to produce total spending results as illustrated in Figure 7. Note that polymeric cables (XLPE, TR-XLPE) are further broken down based upon whether they are jacketed or unjacketed, as well as their construction type (direct buried, direct buried conduit or concrete-encased conduit). The results reveal a backlog total of 332 km of underground cables that are at their economic end-of-life criteria. Contributors to this significant backlog include poor-performing direct buried XLPE cable. As per this program, a total of 804 km of cable will be replaced over a ten-year period at a cost of $392 million.

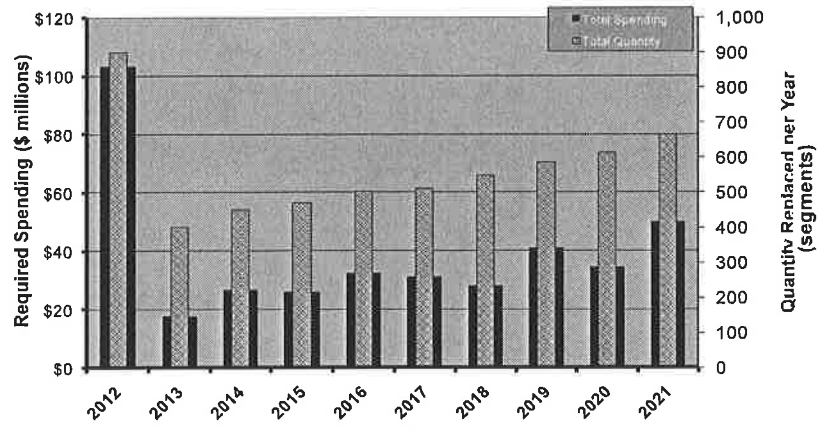


Figure 7 – Risk Optimization Results for Underground Cables (2012 – 2021)

2.2.4 Balancing System Performance: Network Units Results

Fibertop, semi-dust type and submersible network units were evaluated by the FIM to produce total spending results as illustrated in Figure 8. The results reveal a backlog total of 313 network units that are at their economic end-of-life criteria. The primary contributor to this significant backlog is high-risk fibertop network units. As per this program, a total of 505 network units will be replaced over a ten-year period at a cost of $62 million.

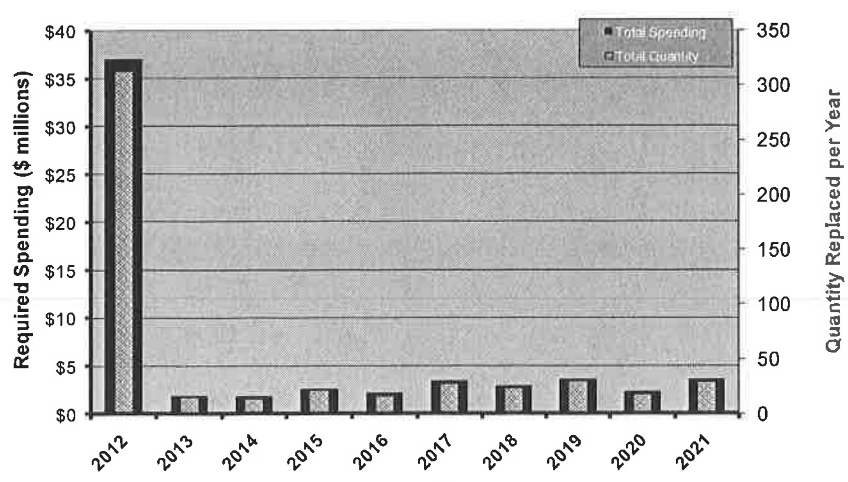


Figure 8 – Risk Optimization Results for Network Units (2012 – 2021)

2.2.5 Balancing System Performance: Pole Results

Distribution poles were evaluated by the FIM to produce total spending results as illustrated in Figure 9. The results reveal a backlog total of 13,877 poles that are at their economic end-of-life criteria. Risk contributors to this significant backlog include aging poles nearing their end-of-life criteria. As per this program, a total of 27,021 poles will be replaced over a ten-year period at a cost of $371 million – this includes the cost of insulators and re-conductoring.

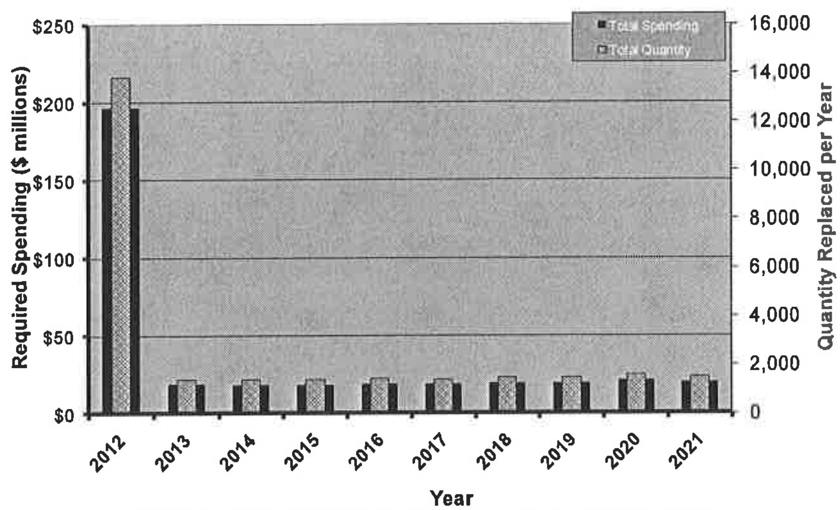


Figure 9 – Risk Optimization Results for Poles (2012 – 2021)

2.2.6 Balancing System Performance: Overhead Distribution Transformer Results

Overhead pole-top distribution transformers were evaluated by the FIM to produce total spending results as illustrated in Figure 10. The results reveal a backlog total of 9,132 transformers that are at their economic end-of-life criteria. Risk contributors to this significant backlog include aging overhead pole-top transformers nearing their end-of-life criteria. As per this program, a total of 14,901 overhead transformers will be replaced over a ten-year period at a cost of $159 million.

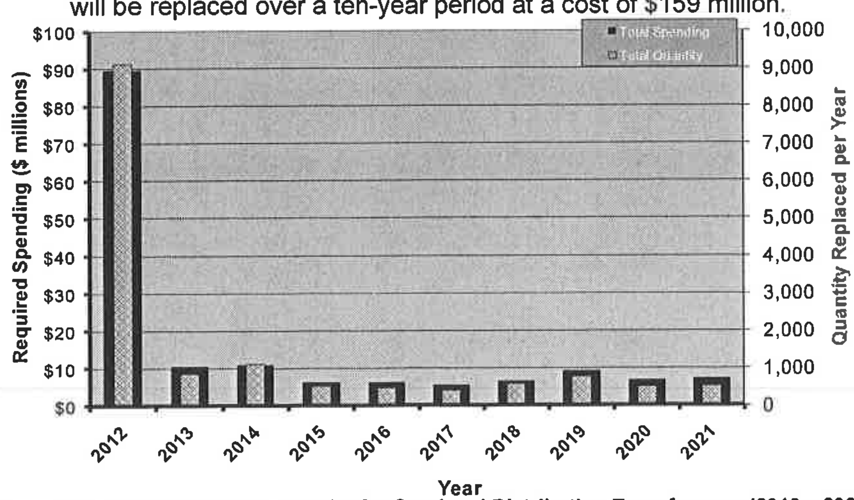


Figure 10 – Risk Optimization Results for Overhead Distribution Transformers (2012 – 2021)

2.2.7 Balancing System Performance: Overhead Switch Results

Overhead switches were evaluated by the FIM to produce total spending results as illustrated in Figure 11. The results reveal a backlog total of 4,523 overhead switches that are at their economic end-of-life criteria. Risk contributors to this significant backlog include aging gang-operated load break switches nearing their end-of-life criteria. As per this program, a total of 6,371 overhead switches will be replaced over a ten-year period at a cost of $103 million.

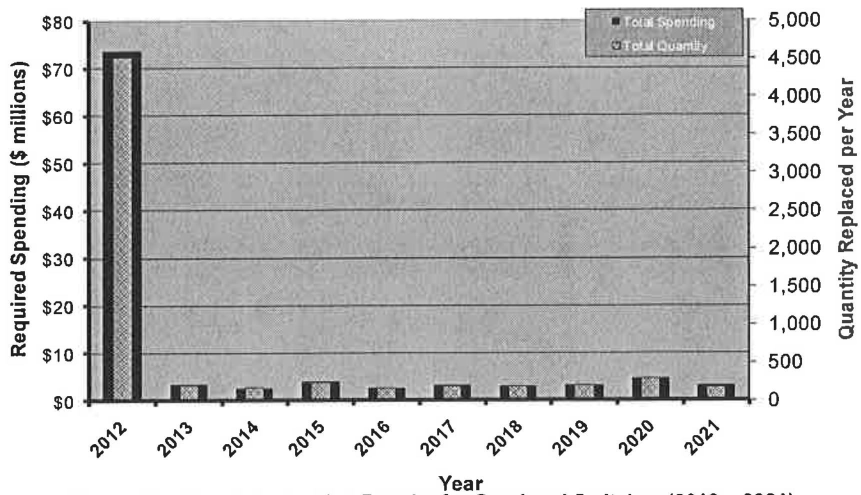


Figure 11 – Risk Optimization Results for Overhead Switches (2012 – 2021)

2.2.8 Balancing System Performance: Overall Conclusions

The results produced by the risk-based optimization approach illustrate that every major studied asset class contained a backlog of assets that must be addressed in the first year of the 19-year plan. These backlogs contain assets which are at or past their economic end-of-life criteria value, and contained within these backlogs are quantified risks to which THESL's distribution system is already exposed, including direct and indirect cost attributes associated with in-service asset failures.

Although this approach to capital investment is designed to produce optimal investment results in order to ensure the highest value cost-benefit balance for customers, a significant investment of $739 million is required in the first year, and a total capital spend of $1.61 billion will be required over the ten-year period to address assets that are past their economic end-of-life criteria. In comparison, total capital spending for these same assets from the Sustained System Performance program comes out to $1.57 billion.

As was the case with the Sustained System Performance program, execution of the risk-based optimization approach will require a similar amount of system investments to be made over the next ten-year period. These results are further illustrated in Figure 12.

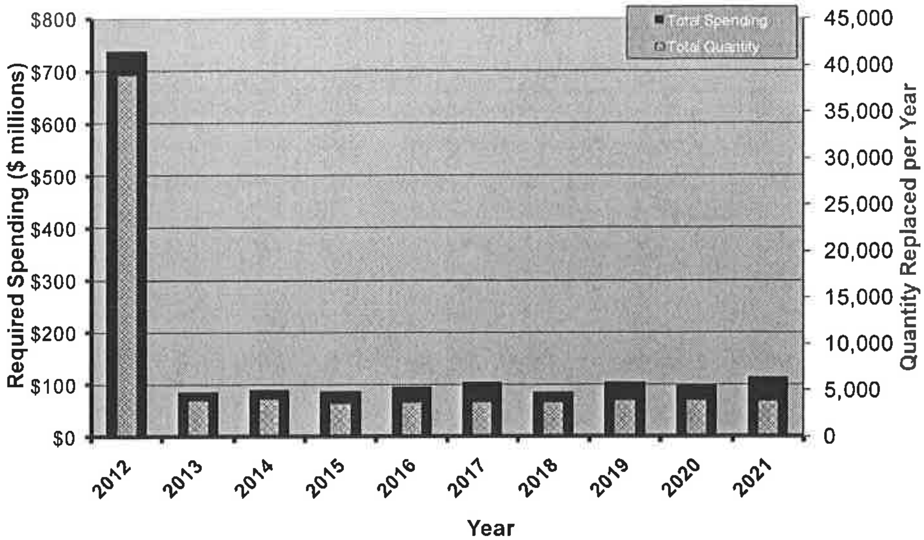


Figure 12 – Risk Optimization Results for Underground, Overhead & Secondary Network System Assets (2012 – 2021)

Figure 13 illustrates the system-wide results of the FIM. Results have been color-coded based upon their respective optimal intervention timing results. Assets that must be addressed immediately have been highlighted in red.

In spite of the investments made with the risk-based optimization approach, significant improvements to system reliability will not be realized, as this approach adopts the same like-for-like asset intervention methodology, and the same associated limitations as the Sustained System Performance approach. This means that the risk-based optimization approach will not account for new technologies, new circuit designs or configurations that can reduce outage restoration time, improve operating flexibility or provide new ways to monitor assets proactively. This approach also does not account for assets that cannot be replaced as per their existing configuration, such as rear lot and box construction.

Figure 13 – Balancing System Performance via Risk-Based Optimization Results

2.3 Modernization

As demonstrated in the last two sections, it is clear that the execution of either the Sustained System Performance or the Risk-Based Optimization approaches results in high capital investment spending, without making significant improvements to system reliability.

Both of these approaches apply a like-for-like asset intervention methodology, where the existing assets are replaced with their standardized equivalents, with no enhancements made to the circuit design and without the installation of enabling technologies that could offer further system improvements.

There are many asset types that are incompatible with the like-for-like intervention methodology, and cannot be captured within either of these investment programs. For instance, rear lot and box construction assets cannot be replaced in a like-for-like manner.

Based upon these conclusions, THESL developed a modernization approach to complement both the Sustained Performance and Risk-Based Optimization approaches with strategic system enhancements that can be implemented throughout the electrical distribution system. These strategic system enhancements include:

- Re-configuration of existing circuits to improve operating flexibility and system contingency
- Installation of new assets to improve operating flexibility and reduce restoration time
- Full replacement of circuits that have reached their end-of-life criteria
- Standardization of key legacy assets and components
- Installation of new technologies designed to reduce outage duration periods
- Installation of new technologies designed to better monitor asset performance

Figure 14 illustrates the total capital spending associated with the grid systems assets, should THESL execute an investment program that seeks to combine the modernization approach with like-for-like asset replacement. Total spending over the ten-year period would total $3.57 billion, compared to the required $3.46 billion of spending to replace assets associated with these same systems using the Sustained System Performance approach. However, unlike the Sustained System Performance approach, the investment program illustrated in Figure 14 also incorporated strategic system enhancements.

GRID SYSTEMS ($M)											
#	Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	UNDERGROUND SYSTEM	$133.2	$143.8	$173.0	$194.7	$191.6	$192.3	$190.8	$191.7	$194.6	$202.3
2	OVERHEAD SYSTEM	$93.0	$99.3	$112.2	$110.8	$109.9	$93.3	$83.9	$84.7	$86.3	$88.3
3	NETWORK SYSTEM	$20.2	$46.4	$63.9	$63.4	$63.4	$63.0	$59.8	$63.4	$57.1	$58.4
4	STATIONS	$24.5	$24.1	$24.0	$24.3	$24.6	$25.0	$25.1	$25.2	$25.2	$25.4
	GRID SYSTEMS TOTAL	$270.9	$313.6	$373.1	$393.2	$389.4	$373.6	$359.6	$365.0	$363.2	$374.4

Figure 14 – Modernization Approach with Like-for-Like Interventions – Sustained Capital Spending ($ Millions)

By placing further emphasis on these modernization techniques, coupled with like-for-like asset intervention approaches, a capital investment program is produced that results in a similar amount of required spending. However, unlike the results achieved by executing the like-for-like asset intervention approaches on their own, the execution of both modernization and like-for-like interventions will result in significant reliability benefits for the electrical distribution system.

These benefits are further highlighted in Figure 15, in the form of the Projected SAIFI in the graph to the left, and the Projected SAIDI in the graph to the right. The red line pertains to a "run-to-failure" approach, where no capital investments are made to proactively replace assets, and reactive investments are made to replace assets that are projected to fail over the next ten-year period. Figure 15 shows that a run-to-failure approach would result in further deterioration in both SAIFI and SAIDI over this ten-year period.

The green line shows to the modernization approach, coupled with like-for-like asset replacements taking place over the next ten-year period. The resulting investment program will impact the majority of the cause codes.[3] Ultimately, at the end of the ten-year period, SAIFI is projected to be reduced to 0.84 outages from 1.41 outages in 2012, and SAIDI is projected to be reduced to 0.52 hours from 0.93 hours in 2012. Ultimately, the execution of this investment program will result in a 40% improvement in SAIFI and a 44% improvement in SAIDI. In contrast, should THESL not execute this program and instead adopt a run to failure approach, SAIFI and SAIDE are forecasted to worsen by another 15%, and 14% respectively over the 2012-2021 period.

For either approach, it is noted that the projected SAIFI and SAIDI levels vary year-to-year, due to the fact that each asset within the total population is reaching its individual end of life criteria at different times within the ten-year period. These results do not include scheduled outages.

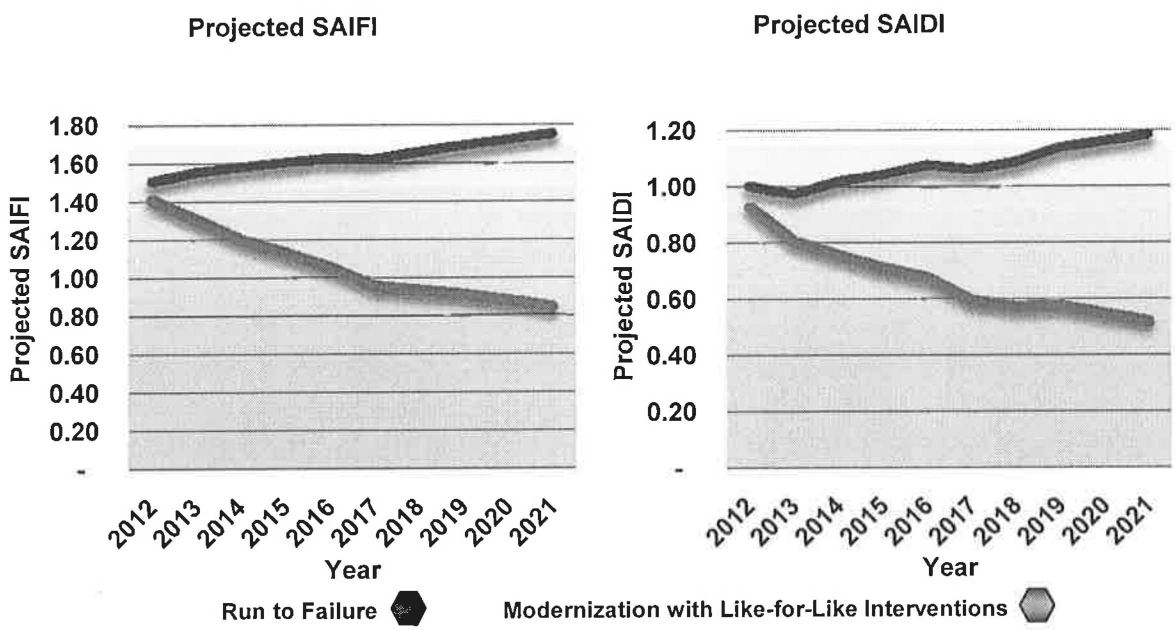


Figure 15 – Projected Reliability Impacts from Different Asset Replacement Approaches

These projected reliability results illustrate the importance of executing both modernization and like-for-like asset replacement jointly. Ultimately, by executing this joint approach, THESL will not only address system needs, but customers will also realize significant system performance improvements. These improvements will help bring Toronto's system reliability into better alignment with other world class cities.

The remainder of this document focuses on the investment programs that will be executed over the ten-year period, which includes the execution of the modernization initiative coupled with like-for-like replacement.

[3] "Electrical Infrastructure Reliability Performance Indicators" schedule (Exhibit D1, Tab 07, Schedule 03)

III Grid Systems

3.1 Overview

The THESL electrical distribution system can be divided into the overhead system, underground system, secondary network system and stations respectively. Each system possesses its own set of assets, and each has its own issues and challenges. Key grid systems issues concerning each of these systems were identified as part of the System Challenges document.

The following chapters provide an overview of each system, along with the programs that will be executed over the next ten-year period to resolve many of the issues related to each system. Total expenditures associated with the Grid Systems are illustrated above in Figure 14.

3.2 Underground Distribution System

THESL's underground distribution system consists of approximately 16,180 underground switches, 29,780 underground transformers, 10,900 cable chambers, 5,700 circuit km of underground primary and 4,700 circuit km of underground secondary cables respectively. Overall, this underground plant covers approximately 48% of the total distribution system within the City of Toronto.

28% of the underground assets evaluated by the Asset Condition Assessment program, fall within the Fair, Poor and Very Poor categories. THESL expects that assets that fall into these categories will require replacement over the next ten-year period.

Key issues within the underground distribution system include underground direct-buried XLPE cables, PILC cables, air-insulated pad-mounted switches, underground residential distribution ("URD") assets and cable chambers. The remainder of this section focuses on the projects that will be executed to remedy these issues and mitigate potential risks.

Figure 16 illustrates the total capital spending required for the underground distribution system. Note that these costs also incorporate costs from the Externally Initiated Plant Expansion program, further described in Section 5.4.

PORTFOLIO 1 - UNDERGROUND SYSTEM SUSTAINING PROGRAM: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
U/G System	$133.2	$143.8	$173.0	$194.7	$191.6	$192.3	$190.8	$191.7	$194.6	$202.3

Figure 16 – Underground System Total Costs ($ Millions)

3.2.1 Underground Direct Buried Cable Replacement

Many locations within THESL's underground distribution system contain direct-buried XLPE cable. These cables, many of which are unjacketed, suffer from high rates of premature end-of-life failure, due to the nature of their installation and impurities within the cables' insulation introduced during the manufacturing process. There are approximately 877 km of this cable remaining within THESL's electrical distribution system, and approximately 56% of these cables have exceeded their useful life. Figure 17 graphically illustrates the various locations within THESL's underground distribution system containing this particular cable type.

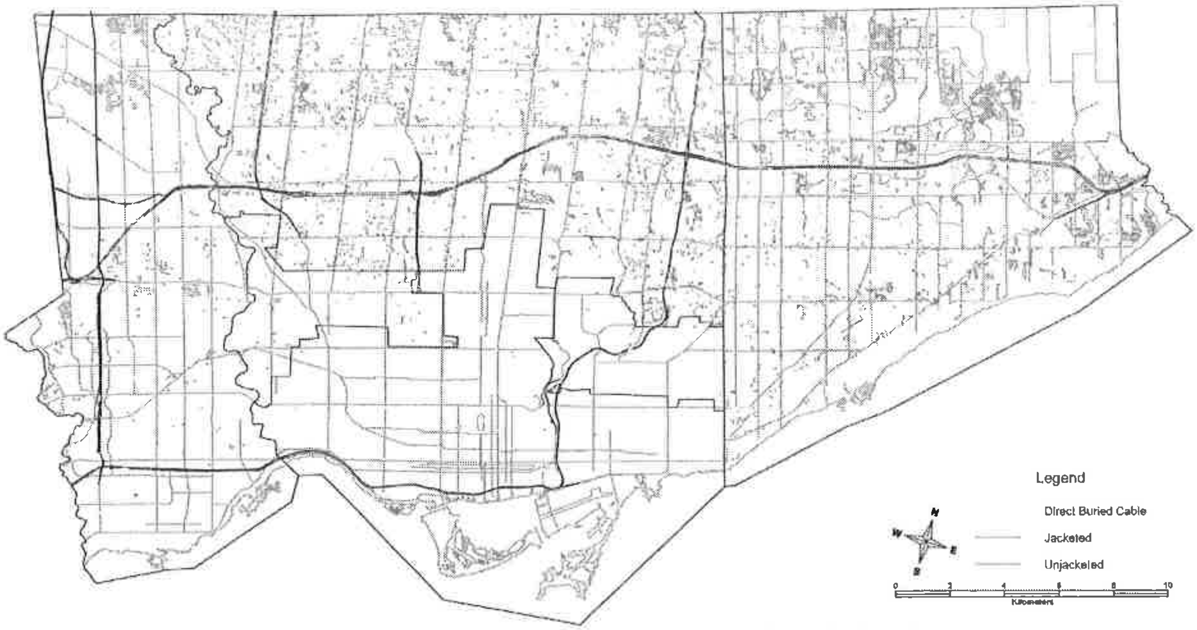


Figure 17 – Direct Buried Underground Cable Population (in Green)

As part of the Underground System Sustaining Program, more than 80% of this cable type will be targeted for replacement over the ten-year period with TR-XLPE in concrete-encased conduit.

TR-XLPE cables use super-smooth, extra clean materials and employ triple extruded, dry cure processes which are intended to reduce impurities and moisture in cable insulation. The incorporation of a Poly Vinyl Chloride ("PVC") or Polyethylene ("PE") jacket, metal foil barriers and other water migration controls further reduces the incidence of moisture ingress, which can lead to the formation of water trees, and ultimately to failure of the cable insulation. The concrete-encased ducts provide improved mechanical protection against external factors and contamination from the surrounding soil and underground environment. When installed in a concrete-encased conduit, these cables can be completely replaced as part of immediate restoration activities.

In tandem with cable replacements, new cable chambers will need to be constructed along the duct bank route. To further optimize the cost efficiencies associated with this program, additional assets that are linearly connected to the existing direct buried plant will also be replaced if they are found to be near or past their useful life criteria.

Any delay to the execution of this program will result in future outages to the underground distribution system. Under a run to failure scenario, more than 2,300 outages are forecasted to take place over the next ten-year period as a result of these direct buried cable assets.

3.2.2 Paper-Insulated Lead-Covered (PILC) Cable Replacement

Out of the total population of PILC cable in THESL's distribution system, approximately 2,650 conductor km, or 68% is installed within the underground distribution system. Figure 18 graphically illustrates the various locations within THESL's underground distribution system containing this particular cable type.

These cables are generally very reliable, with a long useful life rating of 75 years. However, there are also a number of ongoing challenges associated with these cables, including future obsolescence concerns, lack of skilled workers to maintain and install them as well as health and environmental risks. In addition, many of these cables are approaching or are at their end of life criteria, and must be replaced.

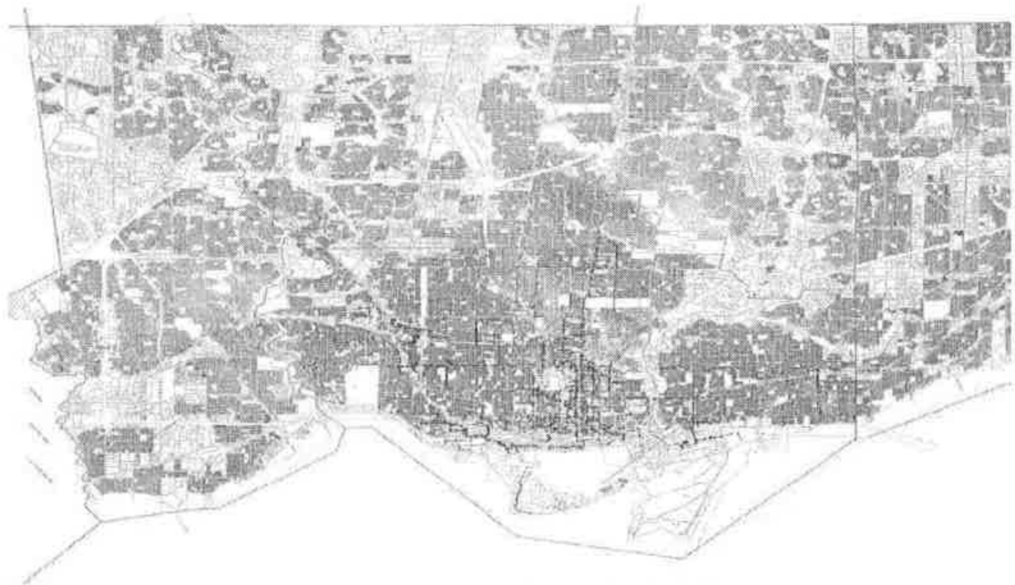


Figure 18 – PILC Cable Distribution (in Red)

THESL has identified specific PILC cables that have been installed on the feeder trunk circuit that will be overloaded under first contingency conditions in the future, because they are undersized relative to the 500 MCM standard. As a result, should an outage occur, these cables will operate under overloaded conditions, which could result in premature cable degradation and cable end-of-life failure. Under a run-to-failure scenario, approximately 250 PILC end-of-life cable failures have been forecasted to occur over the next ten-year period.

This program will target and replace approximately 400 km of overloaded and/or end-of-life PILC cable over the next ten-year period with TR-XLPE cable-in-conduit, which is widely available and easier to install. Further delay of this program will result in continuing exposure to safety and environmental risks, along with future procurement risks because there is only one North American PILC cable manufacturer.

3.2.3 Air-Insulated Pad-Mounted Switch Replacement

Air-insulated pad-mounted switches are used within the underground distribution system to perform switching activities, load transfers, sectionalizing and isolation and offer fusing/protection for downstream lateral circuit connections. These switches are highly susceptible to contamination from dust particles that breach the enclosure.

These switches will be replaced with a sealed-type SF6 gas-insulated pad-mounted switch, which is now the current standard for the pad-mounted switch asset class.

Sealed-type SF6-gas insulated pad-mounted switches address the two main disadvantages of air-insulated pad-mounted switches, as the SF6 units are sealed, preventing the ingress of environmental contaminants and moisture, and they are dead-front, meaning that when the enclosure is opened no energized parts are exposed. Other advantages of SF6-gas insulated units over air-insulated units include:

- Use of resettable circuit breakers rather than fuses, which must be replaced after operating.
- No need for routine CO2 cleaning.
- Dead-front units use standardized elbow terminations, whereas air insulated units require one of a variety of different indoor/outdoor cable termination kits.

Based on the reasons described here, THESL has determined that it is necessary to initiate a program to proactively replace all legacy air-insulated pad-mounted switches with the current equipment standard. There are approximately 800 existing air-insulated pad-mounted switch cubicle installations in THESL's service area. These locations are highlighted in Figure 19. These will be replaced as part of the underground system sustaining program at a total cost of $76 million over a ten-year period.

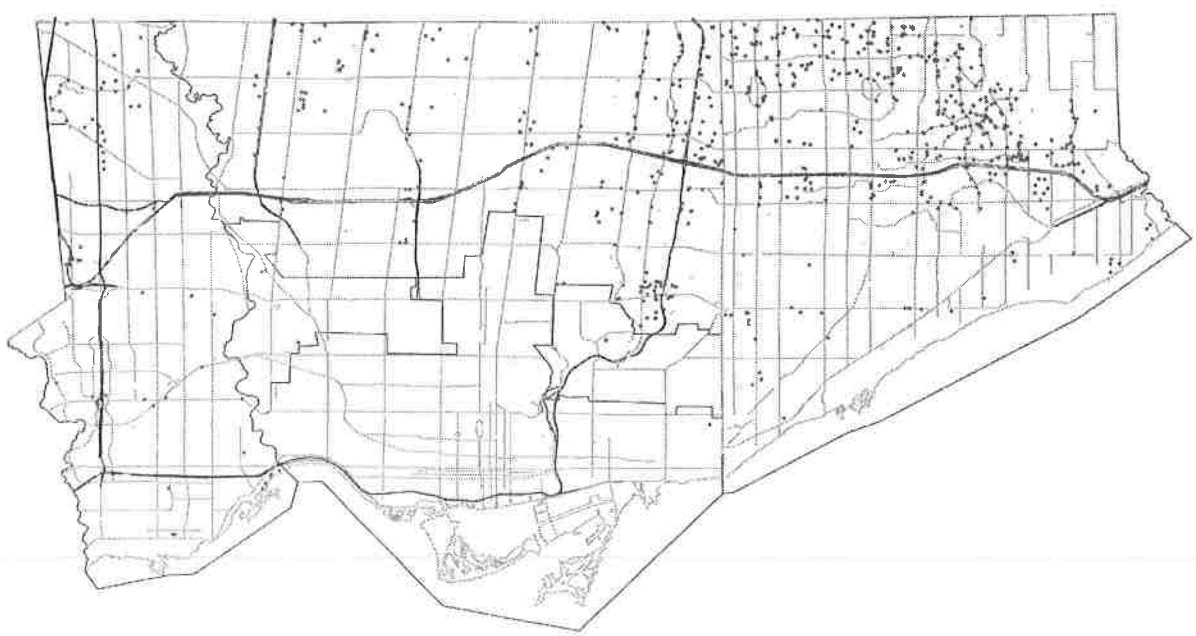


Figure 19 – Air-Insulated Pad-Mounted (PMH) Switch Locations (in Red)

3.2.4 Underground Residential Distribution System Rebuild

Assets within the Underground Residential Distribution ("URD") system are constantly exposed to salt, water and other contaminants, which work together to produce a highly corrosive environment. Switching vault assets in particular have been particularly vulnerable to this corrosive environment resulting in accelerated degradation. The lack of stainless steel material applied to the switching asset enclosures has made these assets particularly vulnerable to degradation.

As part of the URD system rebuild, THESL will be replacing and upgrading all 200A and 600A switching vault assets over the next ten-year period. Enclosures for these new switching vault assets will be comprised of stainless steel material to ensure sufficient resistance to corrosive elements. In addition, all switches will be connected to the Supervisor Control and Data Acquisition (SCADA) system so that power system controllers can remotely operate these switches from within the control room.

This work will be critical to maintaining the overall integrity of the URD infrastructure. Further delays of this program would result in the continued degradation and eventual failure of URD switching vault assets, which will ultimately impact the safety, reliability and operation of the URD system.

3.2.5 Underground System Feeder Automation

The recent availability of micro-processor-based controls and real-time monitoring equipment has allowed utilities to combine traditional electrical assets with modern electronics and intelligent software in order to improve electrical distribution reliability and safety. These developments have provided utilities with new ways to meet the increasing demand for improvements to power quality and system reliability from customers. Feeder Automation ("FA") is a key technology that will allow THESL to make the necessary improvements to the electrical distribution system.

Typically, when an outage occurs, power system controllers attempt to pinpoint the location of the outage and remotely operate a series of load break switches on the feeder trunk circuit, in order to perform load transfers, sectionalizing and isolation activities such that the outage can be contained and the majority of the feeder can be properly restored. As part of this procedure, power system controllers must also individually analyze each feeder to verify the loading and compare this to the feeders' carrying capacity to ensure that any potential load transfers do not damage to feeder assets. Apart from controlling the SCADA-controlled switches, communication must also be made to the in-field crew workers to operate any manually-controlled switches located along the feeder trunk circuit. Overall, this procedure can take anywhere from a few minutes to a few hours to perform.

Feeder Automation introduces a number of enhancements to this restoration process such that customers are ultimately restored in under a minute. As part of the Feeder Automation program, each selected feeder goes through an extensive overhaul, with all manual-operable load break switches replaced with SCADA-controlled switches. Additional SCADA-controlled switches are included at key locations such that future sectionalizing tasks can be greatly improved.

When an outage takes place under a feeder automation system, SCADA-controlled switches communicate with each other as part of a peer-to-peer mesh communication network to identify the location of the fault. The auto-restoration logic will analyze conditions just prior to the fault occurrence to determine the failed segment.

Throughout this process, the system will determine if it is safe to execute appropriate load transfers, by dynamically determining the available capacities from other feeders, as well as calculating available cable utilization along the feeder trunk circuit from the tie feeder to the impacted area. Once all analysis is performed, the system works quickly to isolate this portion of the circuit and perform appropriate load transferring operations. This entire process occurs in under a minute.

Key benefits of the Feeder Automation program include:

- Reduction of a potential outage to time to under a minute
- Addition of new SCADA-controlled switches for improved operating flexibility
- Deployment of additional monitoring load points (via newly installed SCADA-controlled switches) for improved daily system monitoring
- Monitoring of fault current at the time of outage for root cause analysis
- Elimination of manual processes associated with load analysis, remote switching and restoration tasks by power system controller and in-field operation of switching equipment by field crews.

Each of the ten feeder automation pilot projects executed in 2010 on various portions of THESL's overhead distribution system have demonstrated noticeable reliability improvements following an outage event. Given the success of these pilot programs, THESL intends to expand this technology to the remainder of the 27.6kV looped electrical distribution system and to also implement feeder automation for underground assets.

3.2.6 Underground System Spot Network Expansion

The vast majority of commercial and industrial customers in the "horseshoe" region are supplied via a looped design configuration. When an asset fails, all customers will experience the resulting outage until the power system controller can make the necessary adjustments to isolate the damaged circuit and resupply customers. Under a feeder automation system, power will be restored in under a minute. However, the momentary interruption that is produced can also have sizable impacts on large commercial customers with sensitive equipment.

These interruption-sensitive customers, who require extremely high levels of power quality with minimal-to-no interruptions (both sustained and momentarily), are more likely to benefit from a secondary network system design as opposed to the traditional distribution system from which they are currently supplied.

In order to meet these customers' requirements, new spot secondary network systems will be installed. These systems are designed in such a manner that secondary voltage cables from two network units are connected together in order to supply one or a set of dedicated customers.

As is the case on the secondary network system within the downtown region, should an interruption occur on one of the primary feeders supplying the spot network, the redundant feeder would continue to supply the load and the customer would not see an outage – even a momentary one – under this system design.

3.2.7 Underground System Operational Flexibility Improvement

The underground electrical distribution system currently includes a number of operational constraints which ultimately impact system reliability and operational safety. These constraints include the lack of available unique tie points and lack of tie feeders with spare capacity for load transfer operations. In total, 49 feeders within THESL's 27.6kV electrical distribution system have been identified with less than three unique tie points available. Four of these feeders do not have any available tie points, essentially making these radial systems where the entire feeder will see a sustained outage should an end-of-life failure occur on the feeder trunk circuit. These feeders are further illustrated in Figure 20.

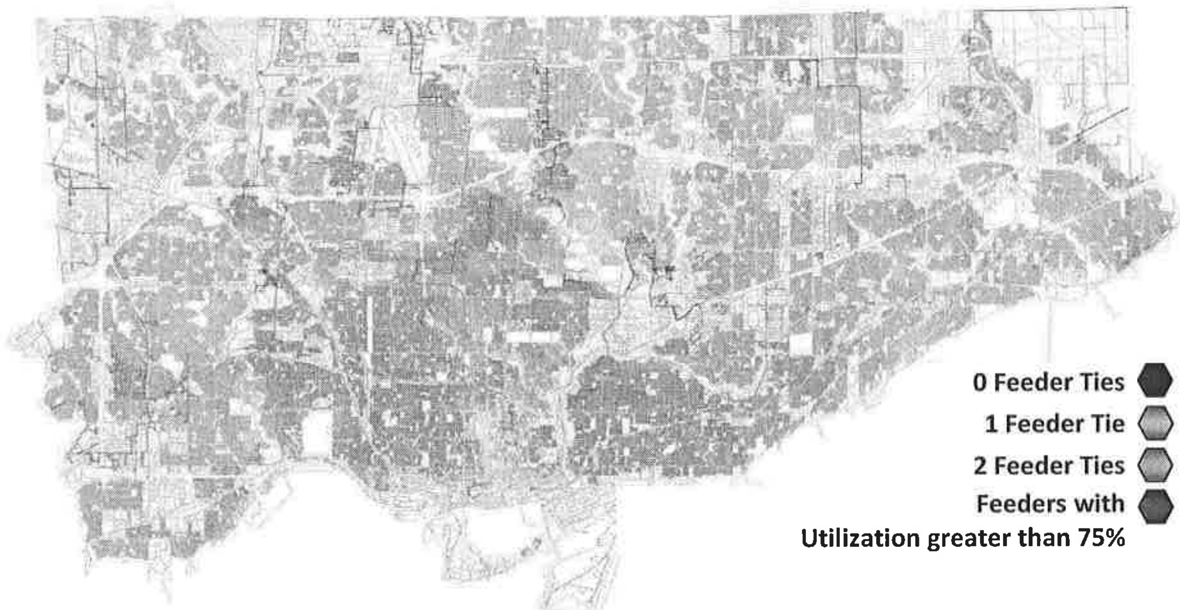


Figure 20 – Feeders with Operational Constraints (Lack of Feeder Ties, Overloaded Feeders)

In addition, there are 34 27.6kV and 13.8kV electrical distribution system feeders that have been identified as possessing utilization values above 75%, where utilization represents the ratio between the current loading and the carrying capacity of the feeder trunk circuit. These feeders are also illustrated in Figure 20. These feeders will typically not be available for use as potential tie feeders during an outage event. At the time of this analysis, there were also three feeders that are currently beyond their carrying capacity, with utilization levels above 100%. These feeders are far more susceptible to asset end-of-life failure, as the underground cables are not designed to manage utilization greater than 100% for prolonged periods of time.

In order to improve the operational flexibility of the underground distribution system, two key initiatives are being recommended:

- Review of 30 new underground distribution feeders throughout the "Horseshoe" region that will examine current utilization and produce resulting actions to construct new feeders if necessary.
- Installing new tie points for feeders that currently have two tie points or less, in order to improve load transfer capabilities.

These programs will collectively assist in reducing outage durations on the underground distribution system as power system controllers will have more flexibility to execute load transfers when required.

3.2.8 Underground System Grid Solutions

The term "grid solutions" refers to the use of proven, cost-effective, energy saving technologies which facilitate the development of an adaptive end-to-end infrastructure. These include the following key initiatives:

- Grid Systems Integration
- Data Analytics
- Active Demand Response

Grid Systems Integration ("GSI") refers to the deployment of applications and services that will allow for the integration of end-to-end demonstration projects. Major efforts will be initiated to integrate real-time system monitoring devices such as transformer monitors and power line monitors ("PLM"), substation automation ("SA"), electric-vehicle ("EV") charging stations, energy storage solutions and demand response units (peaksaver® air-conditioning demand response units) into the electrical distribution system.

In order to test these deployments and retrieve the required data, additional devices such as IP-based Remote Terminal Units ("RTUs"), Intelligent Electronic Devices ("IEDs"), Programmable Logic Controllers ("PLCs"), data collectors and field automation equipment will be deployed and installed within the system. Ultimately, this initiative will allow for the collection of a wide array of data from the field, distribution of this data to the outage management, energy management and SCADA systems respectively, and real-time control of in-field assets.

Data Analytics will translate data captured from the GSI initiative into valuable information to be presented within a software environment. Analytics and analysis can then be performed by the end user on this information within the software environment.

Finally, THESL currently operates demand response resources, which include over 64,000 peaksaver® units, where dispatchable loads such as air conditioning units can be cycled down during the summer months at times of peak electricity demand in Ontario. In order to provide capacity relief during emergency situations and reduce system peak, THESL plans to establish an operating system to selectively dispatch groups of peaksaver® devices based upon operating and grid conditions.

Benefits of each of these initiatives will include improved system reliability and investment decisions due to enhanced planning and targeting of capital projects where required, which will ultimately result in better customer service. The deferral of these initiatives would result in missed opportunities to fully harness and utilize the advanced metering infrastructure ("AMI"), asset monitoring systems, feeder and substation automation systems to their fullest.

3.2.9 Other Underground System Asset Replacements

In addition to the assets described within the various programs contained in this chapter, there are additional assets that are approaching or have exceeded their useful life criteria. These assets pose potential risks to the THESL underground distribution system. These assets include:

- XLPE Primary Cable-in-Conduit
- Underground Distribution Transformers
- Underground Cable Chambers

As per this program, these assets will be replaced as they approach their end-of-life criteria, or as part of the aforementioned underground grid systems programs should they be installed within the same areas.

XLPE Cable-in-Conduit carries many of the same risks as direct buried XLPE cables (described in Section 3.2.1). Many of these risks are due to impurities within the cables' insulation material introduced during the manufacturing process. It is estimated that 7% of these cables are past their useful lives, and approximately 930 cable end-of-life failures are expected to occur over the next ten-year period due to these cables. Figure 21 illustrates the total population of underground cable-in-conduit installed within the underground distribution system.

There are three sub-classes of underground distribution transformers within the underground distribution system. These include submersible, pad-mounted and building vault transformers. Collectively, 24% of these assets are past their useful life criteria. More than 7,400 underground transformer end-of-life failures are forecasted to occur over the next ten-year period. Figure 22 illustrates the total population of underground distribution transformers.

Finally, there exist 10,853 cable chambers installed within the underground distribution system. The entire chamber is estimated to have a useful life of 60 years. However, the roof of a cable chamber has a useful life of 25 years, meaning that the roofs must be repaired on a separate cycle. Approximately 43% of all cable chamber roofs are past their useful life criteria, and must be rebuilt. Over the next ten-year period, approximately 1,300 cable chambers and approximately 6,300 cable chamber roofs are forecast to meet their end-of-life criteria over the next ten-year period. Figure 23 illustrates the total population of cable chambers installed across the system.

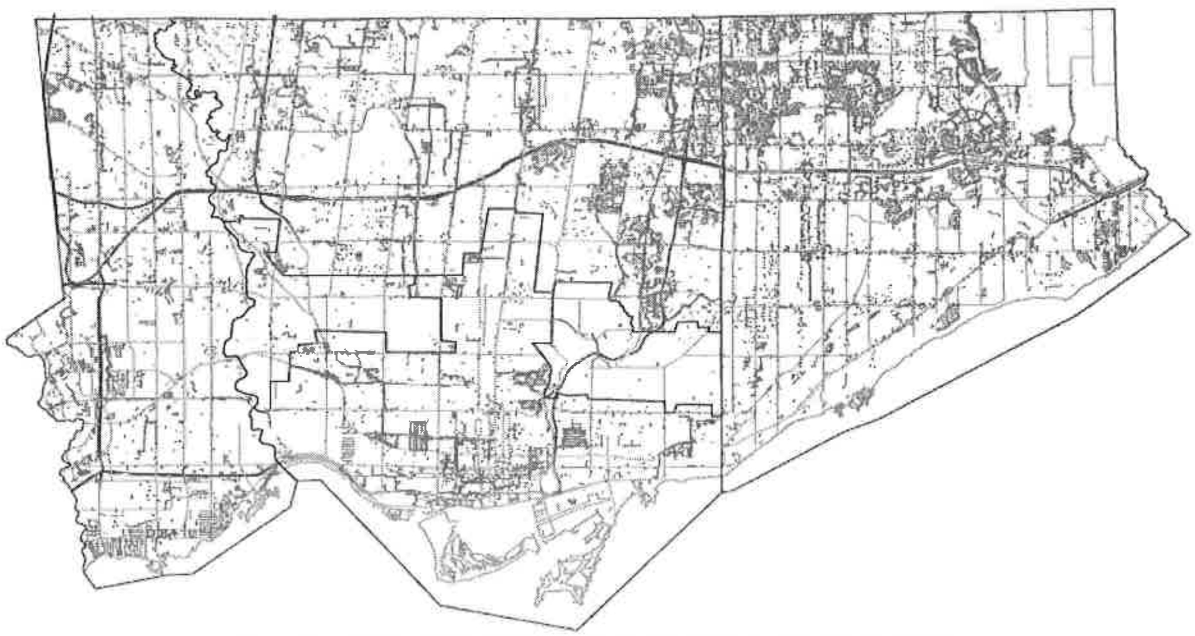


Figure 21 – Cross-Linked Polyethylene (XLPE) Cable-in-Conduit (in Green)

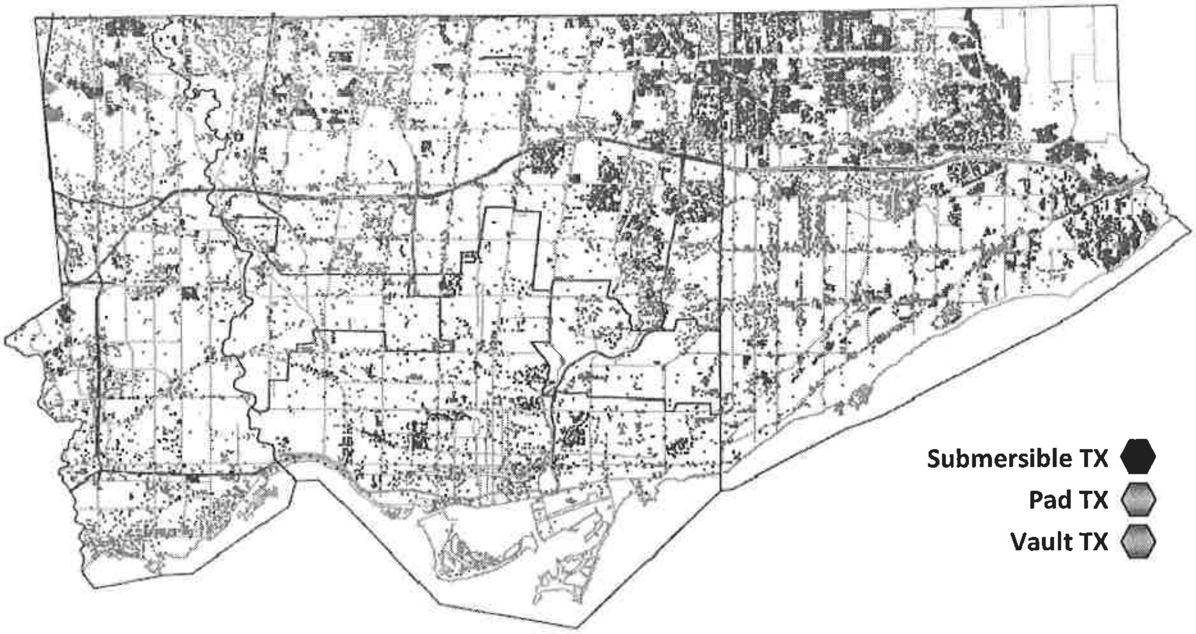


Figure 22 – Underground Distribution Transformers (TX)

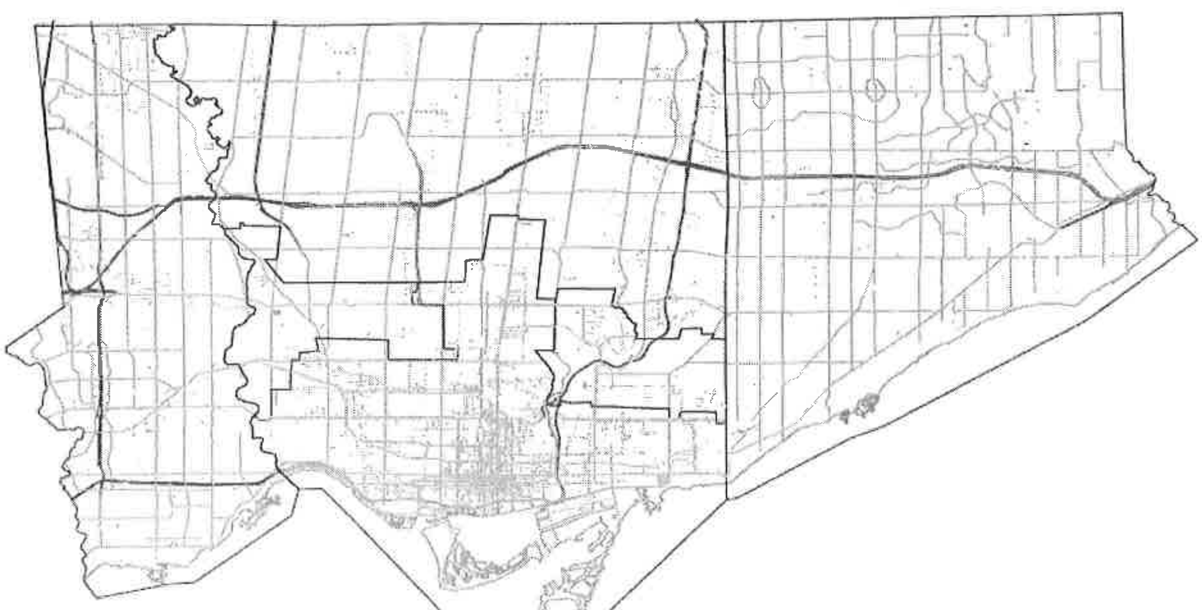


Figure 23 – Cable Chambers (in Green)

3.3 Overhead Distribution System

THESL's overhead distribution system consists of approximately 140,000 poles, 8,220 overhead switches, 30,720 overhead transformers, 4,100 circuit km of overhead primary and 10,900 circuit km of overhead secondary conductors.

Of the overhead assets evaluated within the Asset Condition Assessment program 50% fall within the Fair, Poor and Very Poor categories. It is expected that assets which fall into these condition categories will require replacement over the next ten-year period.

Key issues within the overhead distribution system include legacy rear lot and box construction, aging poles with reduced strength, legacy assets and accessories located near sources of contamination, bare and undersized conductor, improper fuse coordination, overloaded pole-top transformers, manual & remote-controlled gang-operated load break switches, overhead circuit design and overhead line crossings over highways. The remainder of this section focuses on the projects that will be executed to remedy these issues and mitigate potential risks.

Figure 24 illustrates the total capital spending required for the overhead distribution system. Several programs described within this chapter will be executed over the first five-year period, from 2012 to 2016. As a result, overall overhead system spending will begin to decrease in later years.

PORTFOLIO 2: OVERHEAD SYSTEM SUSTAINING PROGRAM: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
O/H System	$93.0	$99.3	$112.2	$110.8	$109.9	$93.3	$83.9	$84.7	$86.3	$88.3

Figure 24 – Overhead System Total Costs ($ Millions)

3.3.1 Overhead System Feeder Automation & Fault Detection

As part of efforts to continually improve the distribution system with new technologies, THESL will be enhancing the overhead distribution system with the expansion of the Feeder Automation program and the installation of new fault indicators. This program will improve the operational flexibility of the system for the power system controllers, while also mitigating the risks associated with outages.

THESL has executed a total of ten Feeder Automation pilot projects over the past year on various portions of THESL's overhead distribution system. Each of these projects has demonstrated noticeable reliability improvements following an outage event. Given the success of these pilots THESL intends to expand this technology to the rest of the 27.6kV looped overhead distribution system. Benefits associated with the overhead system Feeder Automation program are similar to the planned underground system implementation, which are further described in Section 3.2.5. This program will permit the geographical expansion of Feeder Automation beyond the current pilot project feeders. With this expansion, the existing tie point switches connecting FA-enabled feeders to those feeders that currently do not possess this technology can be utilized in the future as part of the full Feeder Automation scheme.

On the overhead system, there are a number of obsolete motorized overhead gang-operated switches controlled via MOSCAD RTUs and a DARCOM radio system that the system operations control centre uses to communicate with these assets. As Feeder Automation is expanded into these areas, these assets will be replaced with new FA-compatible SCADAMATE gang-operated switches and RTUs.

While Feeder Automation is expected to greatly improve the operation and restoration of the feeder trunk circuits, this technology will not have any impact on fused lateral circuits, where a local outage will blow the fuse, and field crew workers will need to travel to the site to diagnose and repair the problem. To help guide field crews to the problematic areas, in-field fault indicators will be used to detect the approximate location of the fault.

Ultimately, this approach will reduce outage time, as the field crews can target the areas where assets need to be replaced. These fault indicators also provide valuable information with respect to momentary outages, which can significantly impact large commercial customers that employ sensitive manufacturing processes. This program will permit the installation of 36,000 new fault indicators throughout the overhead distribution system.

The deferral of this program will result in the continuation of prolonged outages and lack of operational flexibility. The currently installed Feeder Automation pilot project scheme will not be able to operate at its full potential, as many of the peripheral open point tie switches currently link these FA-enabled feeders to feeders that currently do not possess Feeder Automation technology. As such, the FA-enabled feeders will be unable to utilize these tie points to automatically transfer load.

3.3.2 Conversion of Overhead Egress Feeder Trunk Circuits

The egress feeder trunk circuit is defined as the circuit connection between the circuit breaker at the substation and the rest of the feeder trunk circuit. Entire loading on a given circuit will pass through the egress portion of the feeder trunk circuit. If this portion of this circuit fails, the entire feeder and all customers served from the feeder would experience a sustained outage. THESL classifies these as high risk assets.

There are certain feeders where the egress feeder circuit is on the overhead system. Overhead circuits are constantly exposed to non-asset-related risks, including weather-related, animal-related and human-related issues which can result in sustained outages. In some instances, these overhead egress lines connect to underground direct-buried XLPE cables within the station parameter. These portions of the feeder trunk circuit could be impacted by a wind or ice storm, resulting in a sustained outage to the entire feeder. The overall duration of this sustained outage would vary, depending on the available tie feeders and sectionalizing points along the impacted feeders.

The execution of this program will target key overhead egress assets on approximately 100 feeders and convert these to the underground system over the next ten-year period. The existing egress lines and portions of direct buried XLPE within these selected areas will be converted into tree-retardant XLPE in concrete-encased conduit (TR-XLPE).

3.3.3 Overhead System Operational Flexibility Improvement

Similar to the underground electrical distribution system, the overhead electrical distribution system exhibits a number of operational constraints which ultimately impact system reliability and operational safety. These include feeders with two or less distinct tie points to perform switching and load transfers and highly loaded and overloaded feeders that cannot take on any additional load under an outage scenario. The locations of these feeders are illustrated in Figure 20.

As noted in Section 3.2.7, 49 feeders within THESL's 27.6kV electrical distribution system have been identified with two or less available unique tie points, and 603 feeders on the 13.8kV & 27.6kV systems respectively possess utilization values of 25% to 75%.

This program will permit new unique tie points to be installed on feeders that have two or fewer unique tie points. As part of this activity, overhead circuits will be expanded to other nearby circuits in order to establish new tie points. Note that this program will be executed in alignment with the overhead system Feeder Automation program, as FA-enabled feeders must have sufficient feeder tie points and associated tie feeders in order to sufficiently take advantage of this automated system. As part of this exercise, overloaded feeders will also be addressed to ensure that appropriate tie points are created.

These programs will collectively assist in reducing outage durations on the overhead distribution system, as power system controllers will have more flexibility to execute load transfers when required.

3.3.4 Aging Poles with Reduced Strength

From the Asset Condition Assessment program, approximately 51% of wood poles within the overhead distribution system have been identified as possessing a condition grade of Very Poor, Poor or Fair. Most of the assessed wood poles have a condition score of Fair.

Depending on the installation of the pole asset, a number of degradation factors may reduce pole strength, including internal rot and decay at the groundline, shell rot and external infestation.

Poles with reduced strength present operational risks to THESL crew workers, potential safety risks to the public and reliability risks to the overhead distribution system. The combination of poles with reduced strength coupled with severe weather can lead to end-of-life failure scenarios where multiple poles lose their structural integrity and fall to the ground.

It is expected that over 54,500 poles with a condition grade of Very Poor, Poor or Fair will require replacement over the next ten-year period. These poles are further detailed in Figure 25. In addition to these poles, other items attached to the overhead infrastructure will also be replaced, including non-standard porcelain insulators. Should this work be further deferred, the number of poles in the Poor and Very Poor condition categories will grow and present further operational, safety and reliability-related risks. Under a run-to-failure scenario, approximately 13,035 pole end-of-life failures have been forecasted to occur over the next ten years.

3.3.5 Replacement of Legacy Assets & Accessories near Sources of Contamination

Legacy accessory assets include porcelain insulators installed on poles, porcelain lightning arrestors installed on pole-top distribution transformers and overhead switches, and non-standard wildlife guards installed on pole-top distribution transformers.

Porcelain lightning arrestors and insulators are highly susceptible to contamination from external sources, such as salt from major highways. The overhead plant will typically transition to underground assets, in order to properly cross these highways. Therefore, additional sensitive equipment such as switches and terminations will also be exposed in these locations.

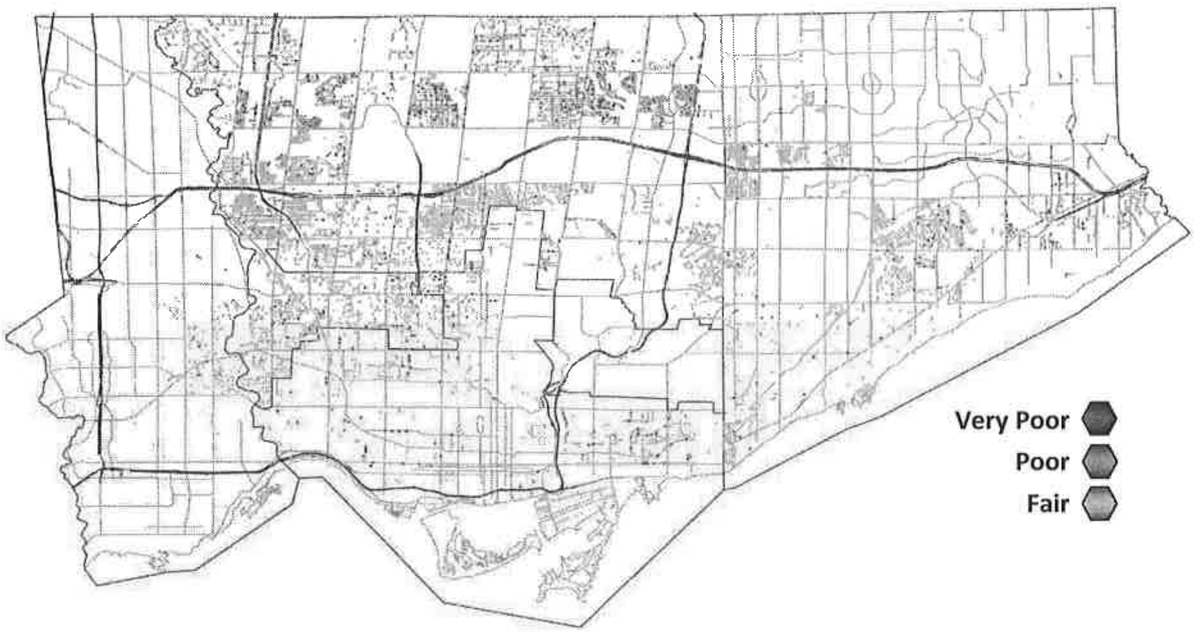
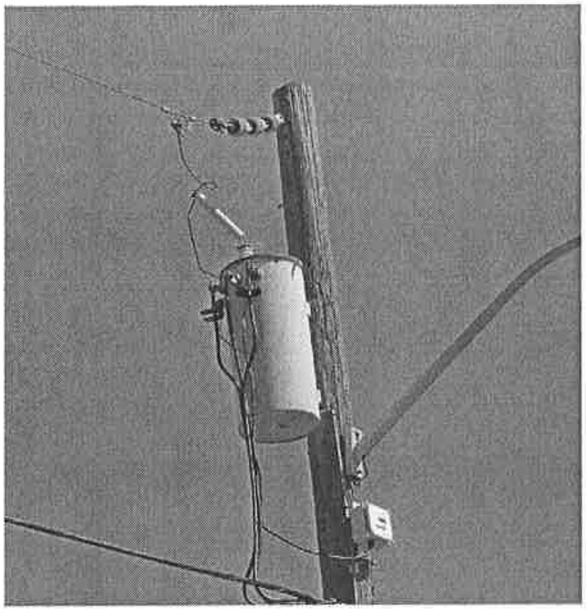


Figure 25 – Locations of Pole Assets with Fair, Poor & Very Poor Condition Ratings

This program will target key overhead infrastructure connected to the feeder trunk circuit that is near major highways. These assets will be completely relocated from these highly contaminated locations. As part of the relocation effort, non-standard porcelain insulators and arrestors will be replaced with new polymeric insulators, which are more resistant to contamination and less likely to be susceptible to tracking or flashovers. Deferral of this program will lead to the continued exposure of these assets to contamination from the nearby and adjacent highways. An asset end-of-life failure along the feeder trunk circuit would result in a sustained interruption to all customers on the feeder.

A separate program will also be initiated to target non-standard wildlife guards, which have proven to be ineffective at shielding exposed electrical connections for pole-top distribution transformers from birds, squirrels and raccoons. New "cone-type" wildlife guards and drop wire protectors will be installed, in order to provide enhanced protection against animal-related contacts.

Figure 26 illustrates the design of the new "cone-type" wildlife guards to be installed within the system.



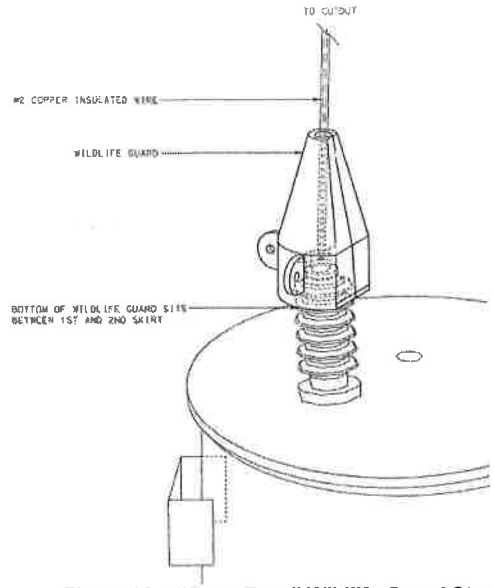


Figure 26 – "Cone-Type" Wildlife Guard Standard

3.3.6 Replacement of Bare & Undersized Overhead Conductor

Bare conductor, despite its long useful life, is extremely susceptible to tree contact interruptions due to the lack of conductor insulation when in proximity to mature trees. In locations where this bare conductor is connected to the feeder trunk circuit, the resulting outage will impact all customers connected to the feeder.

Figure 27 illustrates locations throughout the system where bare conductor is within close proximity to mature trees. A program will be initiated to target these locations and replace the existing bare conductor with insulated tree proof conductor, which provides protection against external contacts with trees and other elements. Any delay in this program would result in the continued occurrences of momentary and sustained outages due to tree contacts.

In addition, there are certain portions along feeder trunk circuits where the existing conductor is incorrectly sized relative to current standards, such that these conductors are not aligned with the remainder of the circuit. These portions of circuit will limit the total carrying capacity of the feeder, which will lead to complications when performing load transfers during outage scenarios.

Locations containing these types of assets are also illustrated in Figure 27. A separate program will target these undersized conductor locations and replace these with standardized conductor sizes. Any delay in this program would result in an increase to the outage duration time on a given feeder, as power system controllers will be unable to perform load transfers as necessary due to the limited carrying capacities of these specific locations.

3.3.7 Rear Lot & Box Construction Conversion

Legacy construction types such as rear lot and box construction contribute to operational constraints to THESL field workers, resulting in prolonged outages to customers. Rear lot overhead plant is installed in locations which are inaccessible by current standard THESL vehicles and machinery. Mature trees and plants in these areas often adversely impact this infrastructure.

Figure 28 illustrates rear lot construction throughout the system. The rear lot conversion program involves the prioritization of existing rear lot feeders for conversion, based upon the age and condition of these assets. Under this program, selected rear lot construction within the overhead distribution system will be gradually phased out over the ten-year period, with emphasis for the phase-out being given to neighborhoods with the least reliable and/or oldest rear lot distribution plant. Deferral of this program will result in the rear lot assets continuing to age and approach their end-of-useful life values, resulting in eventual asset failure and leading to prolonged outages.

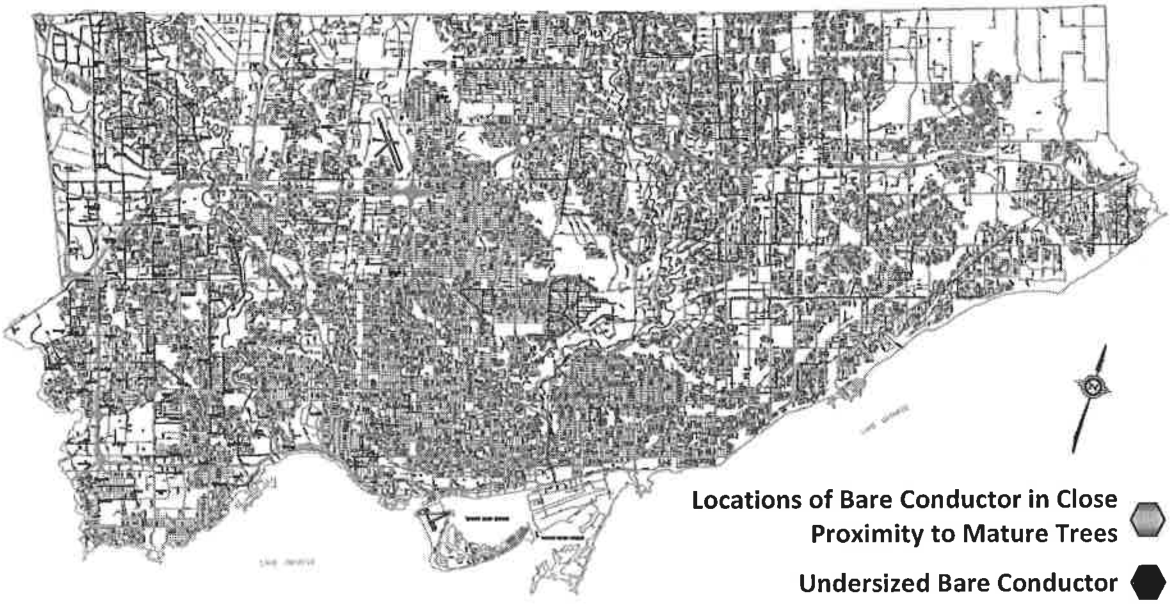


Figure 27 – Locations of Undersized Bare Conductor & Bare Conductor in Close Proximity to Mature Trees

Box construction is another legacy construction type where multiple energized 4.16kV feeders are installed and attached to a single pole, thus creating an operationally constrained working environment, where crew workers may be exposed to potential safety hazards through regular replacement or maintenance activities.

Figure 29 illustrates box construction locations throughout the system. The box construction conversion program will gradually phase out this construction type across the entire overhead distribution system over the next ten-year period. As part of this program, several municipal stations (MS) supplying 4.16kV feeders containing box construction will be decommissioned. Each of these feeders will be converted to the 13.8kV or 27.6kV systems.

Figure 28 – Locations of Rear Lot Construction (in Brown)

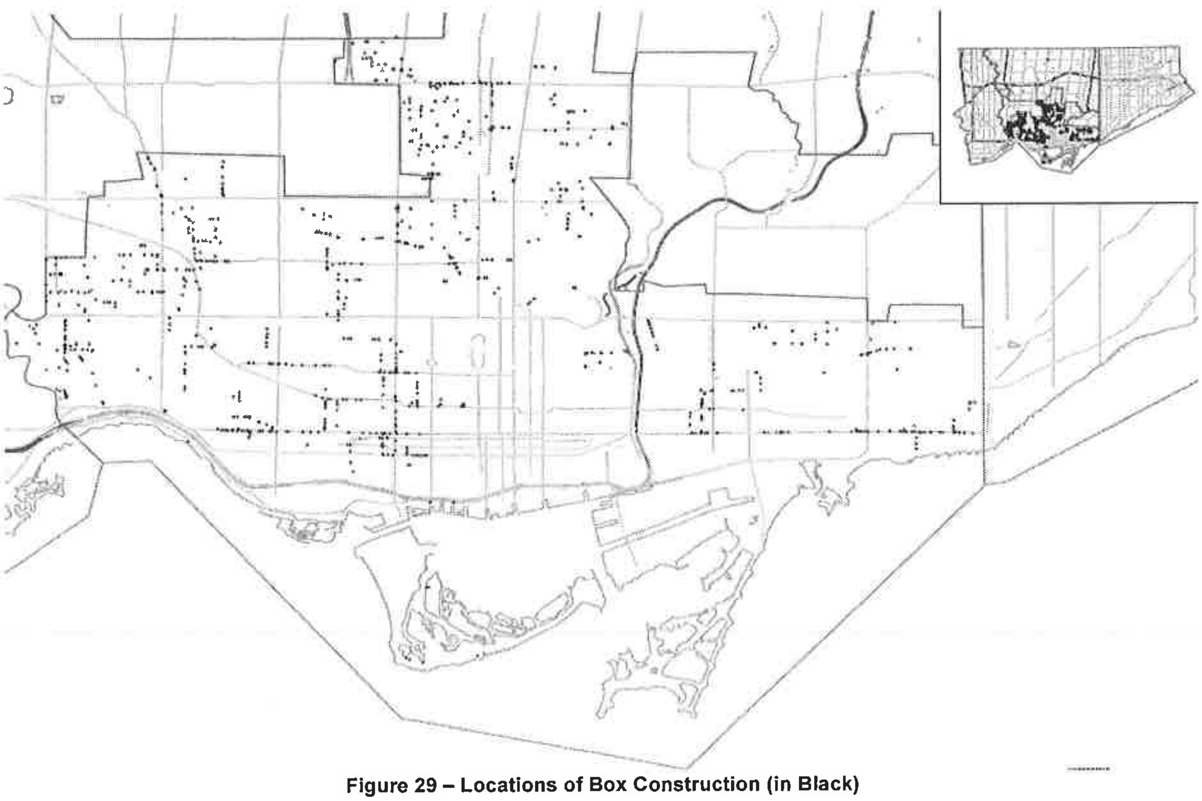


Figure 29 – Locations of Box Construction (in Black)

By converting these circuits, the associated hazards and operational constraints associated with this construction type will be eliminated, as standardized designs will be used for the new circuits. Other safety risks associated with poorly grounded shielded primary 4.16kV cable along these feeders will also be eliminated, as these feeders will be completely converted. There will be savings achieved with the elimination of maintenance for the 4.16kV MSs to be converted. Finally, the available land currently occupied by these municipal stations will then be used to house other projects, such as Downtown Contingency.

Should this program be deferred, the safety risks and operational constraints associated with box construction as well as the shielded primary cables along these 4.16kV feeders will remain. Maintenance costs will continue to be allocated towards the 4.16kV MSs, which are significantly higher when compared to their 13.8kV and 27.6kV counterparts due to the obsolete 4.16kV station assets.

3.3.8 Fuse Coordination

Within the overhead distribution system, locations exist where lateral fuses do not properly coordinate with upstream fuses or the circuit breaker. In these instances, the fuse link will not melt as desired, resulting in the fault current cascading to the upstream assets. In cases where a fuse is improperly coordinated with the circuit breaker, the entire feeder will experience an outage. In certain locations, there are no fuses installed at all for a given lateral connection.

As part of the fuse coordination program, any undersized or improperly coordinated fusing will be upgraded to the standard fuse type and coordinated with the upstream assets. Priority, however, will be given to those lateral fuses that do not possess any fusing at all, since any asset end-of-life failures at these locations would result in an outage to all upstream assets.

This program represents a very cost effective approach at reducing risks along a feeder, as installation of the fuses is relatively low cost and effectively reduces the impact of failure should an outage take place. Deferral of this program would result in the continuation of high impact outages from lateral circuits, where the installed lateral fuse was improperly coordinated or where there was no lateral fusing present.

3.3.9 Overhead Circuit Re-Configuration

There are many portions of the overhead distribution system that could be re-configured in order to minimize potential impacts from overhead asset end-of-life failures. These include radial connections that do not contain alternate supply points and single-phase overhead circuits that are connected directly to the feeder trunk circuit.

Radial configurations within an electrical distribution system result in the longest possible outage duration times, as the connected customers cannot be restored until the failed asset has been repaired. A looped configuration, by contrast, will contain an alternative supply point, coupled with switches to be used for isolation purposes. When an outage occurs within a looped configuration, field crews will perform sectionalization using the available switches to isolate the affected area. They will restore power to remaining customers by utilizing the alternative supply point. This results in the overall minimization of the outage impact.

Low cost solutions can be applied to introduce tie points between existing adjacent radial overhead connections in order to produce new alternative supply points and effectively create a looped configuration. In THESL's planned Overhead Circuit Re-Configuration program, existing radial overhead connections that currently supply a large number of customers will be targeted for improvements. These circuits will be looped with adjacent radial overhead circuits through the installation of tie point switches, thus providing field crews with the capability to perform sectionalization and isolation activities.

Figure 30 illustrates the improvements introduced by this program. In the diagram to the left, the current radial configuration supports 750 customers. In an outage scenario, all 750 customers would experience the full sustained outage, and field crew workers would be unable to perform restoration until the failed asset is repaired. The diagram to the right illustrates the improvement from this program, which would effectively reduce the impact of failure to 200 customers, due to the isolation and sectionalization capabilities that are introduced.

Figure 30 – Conversion from Radial to Looped Configuration – Before & After

Single-phase circuits connected directly to the feeder trunk circuit will also be targeted through this program. New fuses will be installed at these locations in order to effectively convert these circuits to lateral connections.

Finally, fused lateral connections on a given street where additional circuits also exist at the other end of the street will also be targeted for re-configuration. These circuits are currently supplied from one side of the street, as illustrated in the "Original Configuration" in Figure 31. In this program, a new fused lateral connection will be constructed from the available circuit on the other side of the street. This new connection will supply one-half of the customers on the street, as illustrated in the "New Configuration" in Figure 31. As a result, the potential impact of failure will be reduced by 50%.

Deferral of this program will delay the potential reliability improvement benefits to these parts of the overhead distribution system.

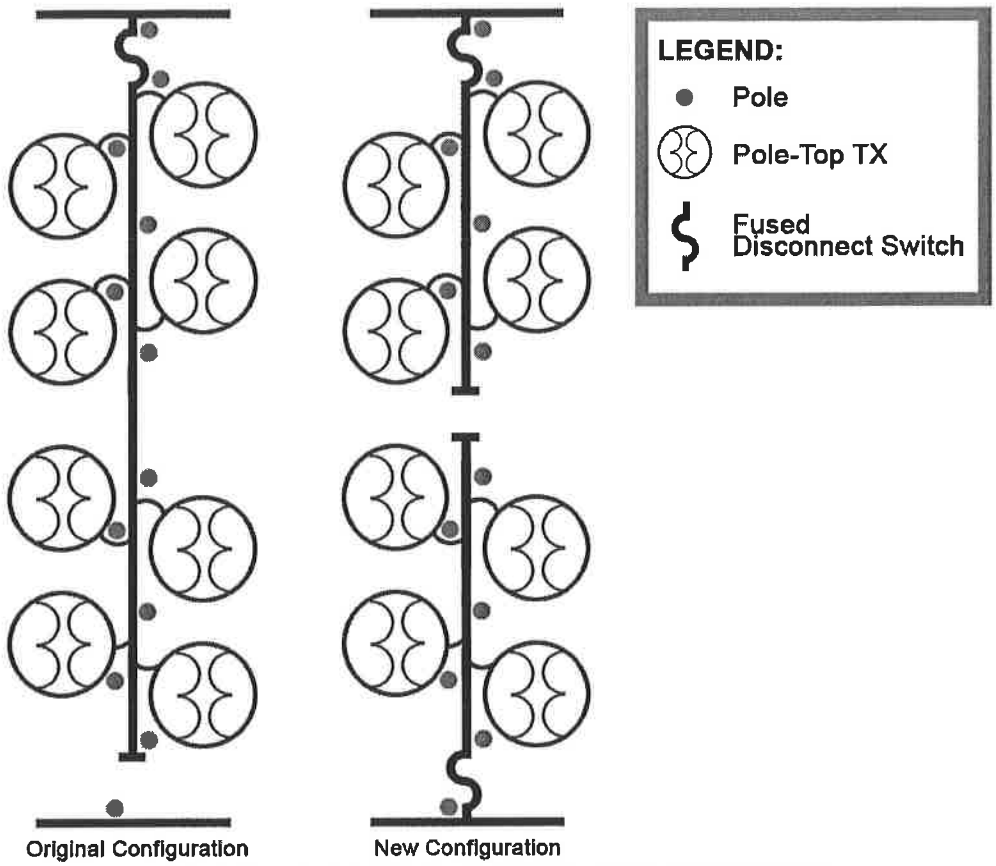


Figure 31 – Re-Configuration of Overhead Lateral/Radial Connection

3.3.10 Replacement of Overloaded Pole-Top Distribution Transformers

There are many overhead pole-top distribution transformers that are overloaded, due to the substantial load growth in since these assets were first installed. In addition, many of the sizes of these older transformers are non-standard, and can be upgraded in order to support a greater capacity.

This program will target and replace these overloaded assets with standardized transformers over a ten-year period.

3.3.11 Underground Conversion of Overhead Highway Crossing Circuits

There are several locations throughout the overhead distribution system where overhead distribution lines cross over major highways. These assets pose potentially significant risks to the public in they were to fail and ultimately fall onto the road surfaces.

This program addresses the conversion of these assets to the underground distribution system. These circuits will be re-routed in such a fashion to eliminate any conflicts with these highways.

3.3.12 Overhead Voltage Conversion

Many portions of the overhead distribution system are supplied at the 4.16kV system voltage. There are instances where 4.16kV assets share the same pole infrastructure as 13.8kV and 27.6kV system voltages. This voltage conversion program will target locations where the 4.16kV assets have been found to be in poor condition when compared to the 13.8kV or 27.6kV infrastructure. In these instances, the existing customers will be transferred over to the adjacent 13.8kV or 27.6kV feeders, and the existing 4.16kV feeders will be removed.

Beyond removing assets nearing or past their useful life criteria, this program also delivers benefits at the station level because it will enable decommissioning of the corresponding 4.16kV MS. This will ultimately allow for savings from avoided maintenance activities on these stations. As first described in Section 3.3.7, the repair and maintenance activities are typically costlier to perform on these 4.16kV station assets, due to their old age and obsolescence.

The overall conversion process is also extremely cost efficient when compared to other types of conversion activities, as there is no need to install new poles, overhead switches or conductors. The additional load from the 4.16kV feeders can even be supplied by the existing 13.8kV or 27.6kV overhead pole-top distribution transformers, where those transformers have low utilization levels.

3.3.13 Overhead System Grid Solutions

The term “grid solutions” refers to the use of proven, cost-effective, energy saving technologies which facilitate the development of an adaptive end-to-end infrastructure. These include the following key initiatives:

- Grid Systems Integration
- Data Analytics
- Active Demand Response

This program is based on the concepts and principals described in Section 3.2.8, with the exception that this program will focus upon the overhead distribution system and overhead assets respectively.

3.3.14 Other Overhead System Asset Replacements

In addition to the assets described within the various programs contained in this chapter, there are additional assets that are approaching or have exceeded their useful life criteria. These assets pose potential risks to the THESL overhead distribution system. These assets include:

- Overhead Pole-Top Distribution Transformers
- Overhead Switches

Through this program, these assets will be replaced as they approach their end-of-life criteria, or as part of the aforementioned underground grid systems programs should they be installed within the same areas.

Approximately 30% of all overhead pole-top distribution transformers are past their useful life. As these assets continue to operate over time, the paper insulation around the winding will degrade within the dielectric transformer oil, thus gradually transforming the oil to sludge and removing the dielectric properties. Once the paper insulation has completely degraded, the transformer will experience an internal end-of-life failure. Approximately 11,000 overhead pole-top distribution transformers are forecasted to fail over the next ten-year period. Figure 32 illustrates the entire overhead pole-top distribution transformer population within the overhead distribution system.

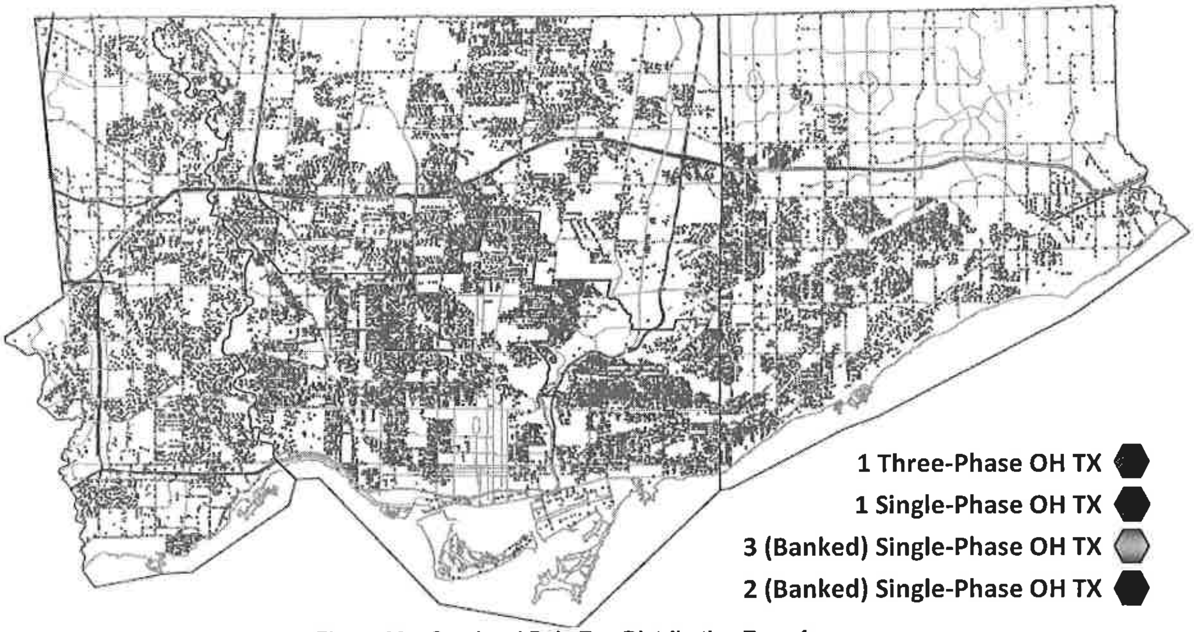


Figure 32 – Overhead Pole-Top Distribution Transformers

Overhead switches gradually wear out in the field. These switches can either mechanically fail when they are used in operation, or electrically fail on their own accord via a flashover. Approximately 30% of all Overhead switches are past their useful life criteria, and approximately 2,600 end-of-life failures are forecast to occur over the next ten-year period. Figure 33 illustrates the load break and remotely-operable SCADAMATE overhead switch population within the overhead distribution system.

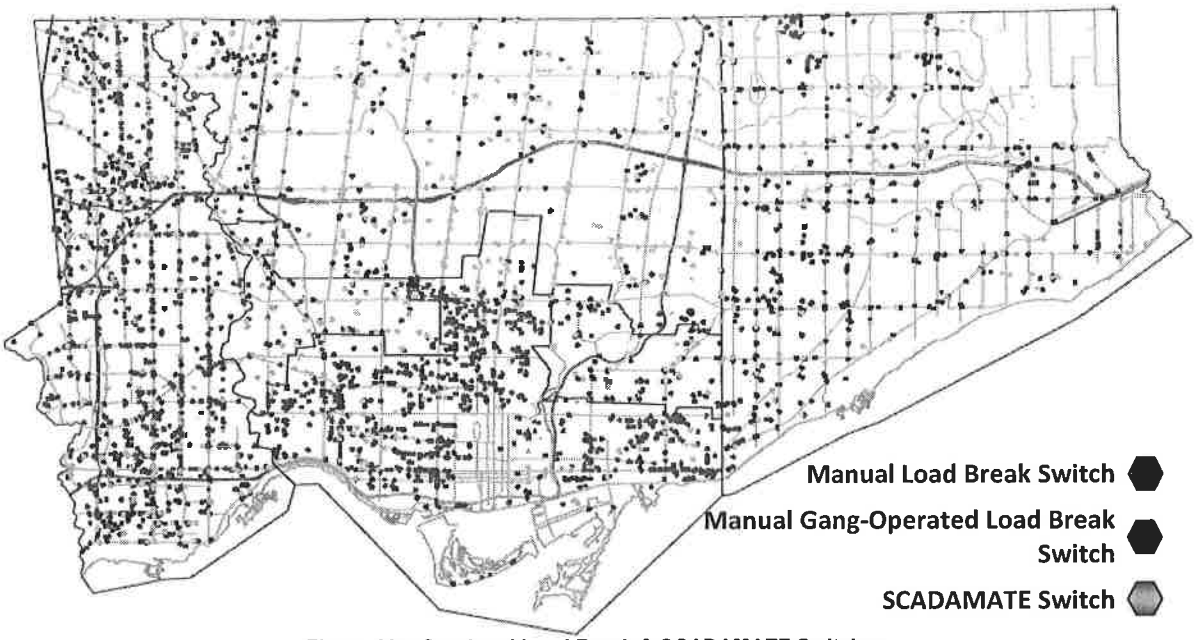


Figure 33 – Overhead Load Break & SCADAMATE Switches

3.4 Secondary Network System

THESL's secondary network system consists of approximately 1,900 network units, 80 automatic transfer switches ("ATS"), 130 reverse power breakers ("RPB") and 1,070 network vaults. There are 45 secondary networks in all – the majority of which are located in the downtown region and the Yonge Street and Bloor Street corridors.

Of the secondary network system assets evaluated in the Asset Condition Assessment program, 7% of these assets fall within the Fair, Poor and Very Poor categories. It is expected that assets which fall into these categories will require replacement over the next ten-year period.

Key issues within the secondary network system include fibertop network protectors, legacy network equipment (ATS & RPB), network vaults, overloaded primary cables and asbestos-insulated lead-covered (AILC) cables. The remainder of this section focuses on the projects that will be executed to remedy these issues and mitigate potential risks.

Figure 34 illustrates the total capital spending required for the secondary network system.

PORTFOLIO 3 - NETWORK SYSTEM SUSTAINING PROGRAM: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Network	$20.2	$46.4	$63.9	$63.4	$63.4	$63.0	$59.8	$63.4	$57.1	$58.4

Figure 34 – Secondary Network System Total Costs ($ Millions)

3.4.1 Fibertop Network Unit Replacement Program

Fibertop network units have been identified as having the greatest probability for a catastrophic end-of-life failure occurrence, due to the assets' design as well as the resulting connections made between these assets and the interconnected low voltage secondary grid. More than 45% of these assets are past their useful life criteria.

As illustrated in the picture to the left in Figure 35, the low voltage secondary connections are directly attached to the top of the protector component within the asset. The top of the protector component is extremely permeable to moisture and contamination. In addition, the connections themselves are spaced very closely together. Together these conditions create an increased potential for catastrophic failure.

This program will target the replacement of these Fibertop units with new submersible network units. These new units, introduced in 2003, re-organize all low voltage connections onto three buses. As illustrated in the picture to the right in Figure 35, these buses are elevated from the surface of the protector and connected to bushings. This new design effectively reduces the probability of inter-phase tracking to occur, due to the separation of the low voltage connections, the elevation of the buses and the bushings themselves, which are extremely resistant to moisture penetration and contamination. This program will replace all Fibertop units over the next five years.

Deferral of this program will allow for continuation of the risks associated with these assets. A recent quantification of these risks came out to $18.1 million, despite the fact that these assets only account for 16% of the total Network Unit population. This quantification accounts for direct and indirect cost attributes associated with the failures of this asset type.

Figure 36 provides the economic end-of-life results of all fibertop network units within the secondary network system. The methodology in regards to these economic end-of-life results is further explained in Section 2.2.

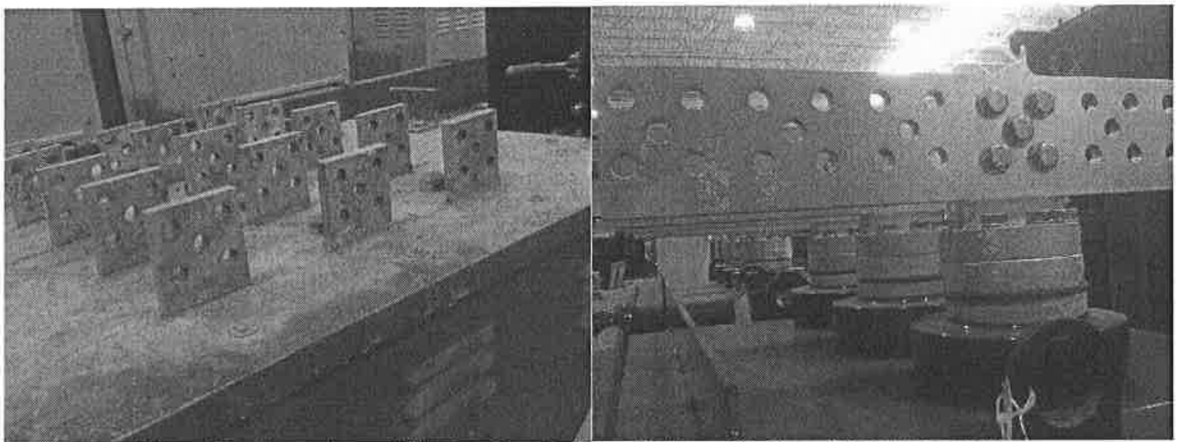


Figure 35 – Comparison of Fibertop-Type (Left) and Submersible-Type (Right) Network Units

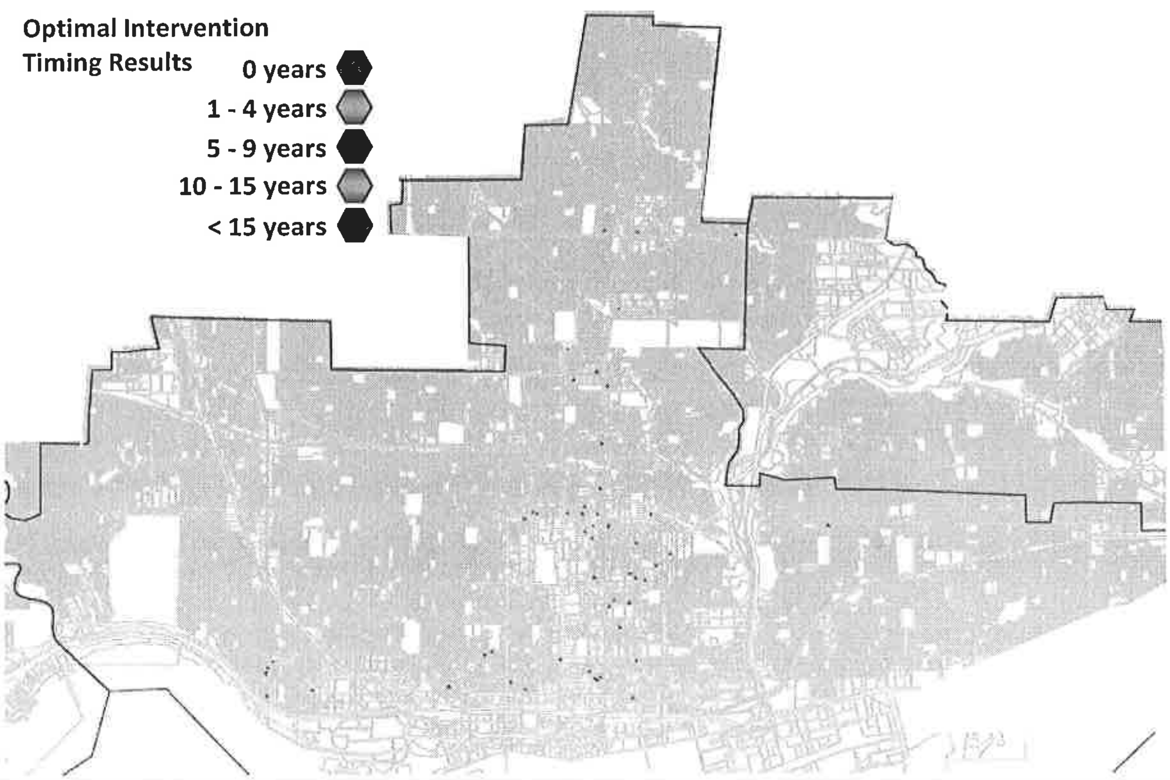


Figure 36 – Optimal Intervention Timing Results of Fibertop Network Unit Assets

3.4.2 Legacy Network Equipment Replacement (ATS & RPB)

There are 23 "hybrid" network grids which supply overhead and dual radial customers, in addition to the standard secondary network customers. Customers with dual radial configurations are connected to the network via an ATS or RPB.

These assets possess poor reliability and performance due to their old age and deteriorating condition. It is becoming more and more difficult to regularly service and maintain these assets due to the lack of manufacturer support and available parts. As a result, repairing these assets takes longer and is more expensive than usual. As per the Asset Condition Assessment program, 48% of ATS assets fall under the Fair, Poor and Very Poor categories, and will require replacement over the next ten-year period.

This program will target the replacement of these assets throughout the secondary network system. An analysis will be performed at each ATS and RPB location, to determine how these locations will be rebuilt and re-configured to meet current standards. These existing assets will be replaced with either a submersible network unit, a stand-alone network protector paired with an underground distribution vault transformer, an underground distribution vault transformer paired with two load break switches as per the Compact Radial Design (CRD), or an underground distribution vault transformer paired with two air-break switches and a fuse cabinet. The network vaults will also be assessed to see if the roof or entire vault requires repair or rebuilding. Through this program, all ATS assets will be replaced over a ten-year period. Approximately 60 RPB assets will be replaced over this same period.

Execution of this program will result in the removal of these poorly performing assets, and create savings by eliminating the maintenance and support costs associated with these obsolete assets. By deferring this program, the complexities associated with the maintenance and support of these assets will continue to increase over time, while performance and reliability continue to worsen.

3.4.3 Network Vault Rebuild Program

Network vaults represent the underground civil infrastructure which house two or more network units, RPBs, ATSs, or CRD assets, and associated primary and secondary cable connections. In some cases, network vaults have reached an unacceptably low physical integrity level, thus posing risks to crew safety as well as the reliable operation of the secondary network system.

This program will target those vaults that are approaching or have surpassed their useful life criteria. Like cable chambers, further described in Section 3.2.9, network vaults have a long useful life rating of 60 years. However, the network vault roofs have a useful life of 25 years. Approximately 81% of all network vault roofs are past their useful life criteria. Depending upon the condition of the vault, the entire vault may be rebuilt or relocated, or the vault roof may be rebuilt. Where possible, the new network vault will be rebuilt in its original location, with existing auxiliary civil infrastructure maintained in place. In other cases, the new network vault may need to be constructed at a new location, which will result in additional primary and secondary cable installations.

As part of a vault rebuild, new ducts may need to be installed, primary and secondary cables may need to be replaced and the network assets within the vault may require replacement or upgrade. Vaults are built according to current standards, meaning that existing rebar and I-beams will be coated with corrosion resistant materials, or new rebar and I-beams will be used in the construction which utilize corrosion resistant steel materials. The ventilation grade of the vaults must be re-designed to maintain alignment to the new by-laws introduced by the City of Toronto. Vault roof rebuilds are less complex, however these projects may also involve the replacement and/or re-arrangement of primary or secondary cables entering the vaults.

The overall complexity of this program is high, as power must be maintained to the customer while the work is being performed. In some cases, this work is located at major downtown intersections with high traffic levels and can only be executed in the evenings and weekends.

Ultimately, this program will eliminate structural deficiencies associated with poor performing network vaults and reduce the associated risks to field crews and the public. Through this program, approximately 190 vaults and 180 vault roofs respectively will be replaced over the next ten-year period.

By deferring this program, these risks will remain in the secondary network system. The potential failure of vaults or vault roofs would have a major impact on system reliability, as well as safety-related impacts to field crew workers and the public.

3.4.4 Network Primary Cable Replacement

The secondary network system contains approximately 1,360 km of primary cable, of which approximately 93% is comprised of PILC cable. There are many challenges associated with PILC cables, including potential safety risks and obsolescence. These challenges are further outlined in Section 3.2.2. As described there, these cables are being phased out in favour of TR-XLPE cables, which comprise the remaining population of secondary network cables in the system.

In addition to PILC cable-related challenges, there are many cables within the secondary network system that have been identified as being loaded beyond 300A. Once these primary cables reach these loading thresholds, they are in danger of approaching their emergency carrying capacity. The normal loading threshold for PILC cables is 381A, while the emergency threshold is 428A. For TR-XLPE cables, the normal loading threshold is 288A, while the emergency threshold is 328A.

The emergency loading threshold is defined as the load which a cable can carry, for an average of one period of not more than 24 hours per year, but for a total of not more than 4 periods in any 12 consecutive months. Ultimately, this means that a cable should not run under emergency loading conditions for more than 96 hours within a given year. Under emergency loading conditions, cables may experience accelerated degradation, which can result in a further decrease to their life cycles.

Under current loading conditions, 2% of the primary cables in the secondary network system are overloaded under normal conditions, and 29% are overloaded under first contingency. Under this program, these cables will be closely examined and various options will be executed in order to eliminate overload conditions. Potential options include the transfer of customers to another secondary network feeder or upgrading the cables to a larger size, which would also require the reconstruction of cable chambers and ducts.

3.4.5 Network Secondary Cable Replacement

AILC cable accounts for approximately 68% of the low voltage secondary (600V) connections within the secondary network system. These cables present potential health hazards to crew workers due to the asbestos. These cables are also deteriorating and nearing their end-of-life criteria.

Under this program, these cables will be replaced across the secondary network system. Replacement of these cables introduces additional challenges as the existing civil plant must also be re-constructed. Therefore, this program will remove all AILC secondary cable from two network grids on average per year. Deferral of this program would result in the continuation of reliability risks to the system and safety risks to THESL crew workers.

3.4.6 Network Automation

As network units are replaced throughout the secondary network system, new technologies are being integrated as part of the Network Automation enhancement program into the new submersible network units that are being installed into the system. These enhancements include SCADA-monitoring systems which will allow for real-time loading to be captured from each unit, along with temperature, pressure and oil level data for the network unit, and temperature and water level data with respect to the Network Vault. SCADA alarms will allow for overloaded network units to be quickly identified.

The network unit loading and temperature data will ultimately allow engineers to gain a better understanding of the assets' utilization and condition. The network vault data will prove to be particularly useful for tracking potential flooding events, and allowing field crews to respond accordingly. This information can be easily captured by field crew workers prior to a field visit. Figure 37 provides a snapshot of the SCADA-based telemetry screen to capture data from both the network unit and vault assets.

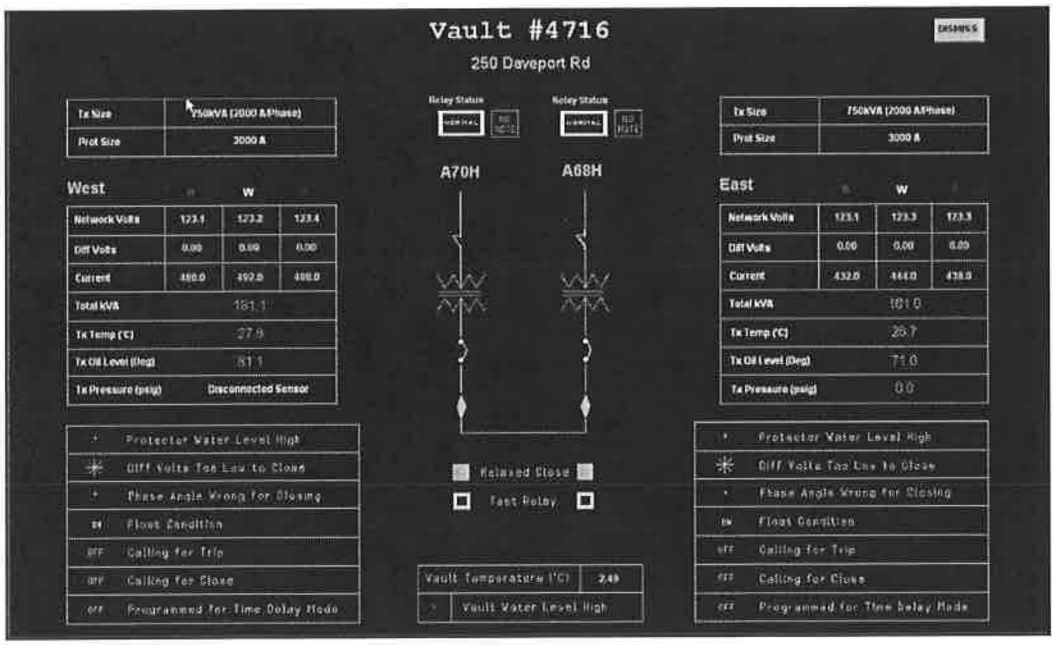


Figure 37 – Network Unit SCADA Telemetry Control Panel

Ultimately, the execution of this program will allow for THESL employees to capture a better understanding of the network unit population. The information provided from this program will ultimately allow for safety and reliability enhancements to the secondary network system.

3.4.7 Network Conversion

As part of voltage conversion activities for the 4.16kV system, certain portions of this system will be converted over to the secondary network system. As discussed previously in Sections 3.3.7 and 3.3.12 respectively, benefits of voltage conversion include the removal of assets that are approaching or have exceeded their useful life criteria and the elimination of costs associated with the regular maintenance and support of obsolete 4.16kV station assets. Following decommissioning activities, the real estate occupied by the 4.16kV MSs within the downtown region will be utilized for switching vaults as part of Downtown Contingency and other initiatives.

While existing 4.16kV infrastructure within the "horseshoe" region will typically be converted to either the 27.6kV overhead or underground distribution systems, infrastructure contained within the downtown region may require conversion to the secondary network system. Much of the 4.16kV infrastructure within this area currently operates off of a four-wire system, whereas the adjacent 13.8kV infrastructure operates off of a three-wire system. Therefore, it would be technically infeasible to perform a direct conversion of the existing 4.16kV single-phase customers from the four-wire to the three-wire system. To execute such a conversion would require the upgrading and conversion of the 13.8kV feeder and station infrastructure to a four-wire system which would be far too costly. Under this scenario, conversion to the secondary network system would become the only feasible option.

In some cases, the secondary network system is already in close proximity to the 4.16kV feeder to be converted. Thus, a conversion to the secondary network would be far more practical and cost effective. In other cases, the existing 4.16kV infrastructure has been encroached over time by trees and man-made structures. As this existing infrastructure is already in unsafe proximity to external structures, it would be impractical to construct new overhead 13.8kV infrastructure in these areas. Under these circumstances, the secondary network system would be the only underground system option with narrow vaults that can be constructed within the limited real estate.

Expansion of the secondary network system to these existing 4.16kV customers will also significantly improve reliability as customers will not be impacted by most single feeder outages. This type of system is especially beneficial for those customers with sensitive manufacturing processes, where even momentary interruptions can produce sizeable impacts.

3.5 Stations

THESL's stations population consists of approximately 170 municipal stations (MS) and 35 transformer stations (TS). THESL owns and operates approximately 260 switchgear enclosures, 280 station power transformers, 2,100 circuit breakers, and 220 direct-current (DC) battery systems within these stations.

Of the stations assets evaluated within the Asset Condition Assessment program, 53% of these assets fall within the Fair, Poor and Very Poor categories. It is expected that assets which fall into these categories will require replacement over the next ten-year period.

Key stations issues include end-of-life obsolete switchgear, end-of-life power transformers, circuit breakers, DC battery equipment and obsolete SCADA RTUs.

The remainder of this section focuses on the projects that will be executed to remedy these issues and mitigate potential risks. Figure 38 illustrates the total capital spending required for stations.

PORTFOLIO 4 - STATIONS SUSTAINING PROGRAM: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Stations	$24.5	$24.1	$24.0	$24.3	$24.6	$25.0	$25.1	$25.2	$25.2	$25.4

Figure 38 – Stations Total Costs ($ Millions)

3.5.1 Switchgear Replacement Program

Switchgear assets are used to distribute power flow to distribution feeders and provide the ability to switch the connected distribution feeders to open or closed positions. All distribution feeders begin from station switchgear assets. Safety-related and technological advances have caused the existing population of older switchgear to become obsolete and un-replaceable on a like-for-like basis. Based on the Asset Condition Assessment program, 61% of these assets fall under the Fair, Poor and Very Poor categories, and will require replacement over the next ten-year period.

The Switchgear Replacement Program will target locations where both the enclosures and circuit breakers present reliability and safety risks. This will include those switchgear enclosures currently employing brick-and-mortar materials, coupled with air-blast circuit breakers. These will be replaced with new arc-proof switchgear enclosures and new vacuum circuit breakers. The new enclosures allow improved performance and a reduction in safety-related risks, as these assets are designed to deflect the energy and potential damage from serious catastrophic failures away from adjacent assets and stations crew workers. In this program, switchgear at 20 TSs and 44 MSs will be replaced over the next ten-year period.

The deferral of this program will allow these reliability and safety risks to continue, and ultimately allow these aging assets to worsen over time. Maintenance costs will also continue to increase as servicing and repair work become more costly to perform.

3.5.2 Power Transformer Replacement Program

Station power transformers are used to step down voltages from higher levels to lower levels in order to permit the distribution of power to customers at appropriate utilization levels. THESL owns power transformers installed at MSs used to step down voltages from either 13.8kV or 27.6kV to 4.16kV.

Many of the power transformers within THESL's 4.16kV distribution system are of older vintage and approaching end-of-life criteria. Approximately 45% of the power transformer population has already surpassed its useful life, and 58% of these assets have received Asset Condition Assessment ratings of Fair, Poor or Very Poor, and will require replacement over the next ten-year period. Should a catastrophic power transformer failure impact all transformers at a given station, it would take approximately 3 to 7 days to deliver new transformers to the station site, provided that spare transformers are on hand.

This program has targeted power transformers based upon their condition, age, the potential risk from collateral damage, potential reliability risks and system contingency needs. At MS where power transformers will continue to be needed, these assets will be replaced with new ones on a like-for-like basis. A total of 65 power transformers will be replaced over the next ten-year period. Deferral of this program would result in higher replacement costs, when replacement is required to be done in an unplanned fashion, and adverse reliability impacts.

3.5.3 Circuit Breaker Replacement Program

Circuit breaker assets are used to immediately interrupt the flow of electricity when a fault current is detected along a feeder trunk circuit. These assets are typically installed within enclosed and metalclad switchgear, but can also be found outdoors within open bus structures.

Out of the total oil circuit breaker population, 92% have received Asset Condition Assessment ratings of Fair, Poor or Very Poor and will require replacement over the next ten-year period. THESL owns approximately 70 oil circuit breakers at the 27.6kV voltage level that are used in outdoor stations.

These oil circuit breakers introduce risks to the electrical distribution system, as these assets can damage adjacent equipment during an end-of-life failure occurrence, due to the flammability of the dielectric oil medium. The resulting outage would impact all customers connected to the station bus.

Through this program, these circuit breakers will be replaced with new standardized vacuum or sulfur-hexafluoride (SF6) circuit breakers. Unlike other oil circuit breakers, where the electric arc is stretched and quenched within the dielectric medium, vacuum circuit breakers operate by sealing the contacts within a vacuum environment, where no ionization can occur. Once these contacts are separated, the arc will be immediately quenched within the vacuum environment. Because there is no oil contained within these breakers, the risk of potential explosion due to an end-of-life failure is eliminated.

Should this replacement program be deferred, the risk of asset failure continues to increase and system reliability will continue to decline.

3.5.4 Control & Communications Replacement Program

Communication to and remote control of, station assets from the control centre improves security and response times. RTUs are the electronic devices that permit control and communication functions between the control centre and the respective station assets.

Certain RTUs within the Etobicoke area must be replaced as they can no longer be repaired or maintained due to a lack of new replacement parts. Under this program, 71 units will be replaced over the next five-years at a pace of 14 units per year. These units will be replaced with new electronic units that utilize a common protocol used by THESL and which are supported by the manufacturer.

In addition, there are 18 stations that do not possess SCADA system capabilities, making manual switching a requirement when a circuit breaker needs to perform an open or close operation. Due to the lack of SCADA capabilities, no alarms or telemetry on these breakers or in the stations can be relayed back to the control centre. This program will seek to install SCADA systems at these 18 stations over the next ten-year period.

THESL utilizes a fiber optic communications system, a copper wire communication system, and leased circuits and lines in order to permit communication between SCADA-enabled devices across the electrical distribution system.

Execution of these activities will ensure that technical support will always be available for all RTU hardware, while also delivering savings in the form of reduced maintenance and support costs. Installations of SCADA system at all MSs will allow for improved operational flexibility and monitoring for these stations. Improvements to the fiber-optic infrastructure will improve the stability and security of the communication systems supporting all Feeder Automation implementations.

3.5.5 DC Battery System Improvements

The DC battery system is utilized to operate the protection systems which are used in the detection of fault current and the resulting operation of circuit breakers. These systems have a useful life of 20 years and, due to their importance, must be constantly monitored and upgraded when required. Failure of these systems could result in a circuit breaker failing to respond to a given outage on the feeder trunk circuit, which would allow a feeder-wide outage to expand to a station-wide outage.

Under this program, replacements of DC batteries and chargers will be driven by asset age and condition as well as potential reliability and operational flexibility risks.

IV Critical Issues

4.1 Overview

There are a number of critical issues that present additional risks to THESL's electrical distribution system. These include safety and health-related risks, system reliability risks, security of supply risks, system capacity and load growth-related risks.

The programs described in this chapter will work to target key assets and locations throughout the electrical distribution system in order to mitigate these critical issues and associated risks. This includes the standardization of key assets and upgrades to secondary voltage infrastructure that present potential safety and health hazards to the public, installation of inter-feeder tie points to introduce improved security of supply, restoration capability and operational flexibility to radial feeders located in the downtown region, the introduction of a new transformer station in order to alleviate potential capacity and load growth risks and finally the targeting and replacement of failure-prone assets across an entire feeder in order to improve reliability at a feeder level. The total investments associated with mitigating critical issues are illustrated in Figure 39.

CRITICAL ISSUES ($M)											
#	Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
5	STATIONS ENHANCEMENTS	$89.6	$49.4	$13.0	$55.0	$48.0	$51.0	$27.0	$28.5	$31.0	$31.0
6	SECONDARY UPGRADES	$8.6	$12.2	$9.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
7	STANDARDIZATION	$9.0	$10.3	$6.1	$6.4	$6.4	$4.8	$4.8	$4.8	$4.8	$4.8
8	DOWNTOWN CONTINGENCY	$1.1	$9.3	$9.2	$9.2	$11.0	$20.4	$16.2	$16.0	$9.2	$9.2
9	WORST PERFORMING FEEDER	$11.0	$10.5	$10.5	$10.0	$9.0	$9.0	$8.0	$8.0	$7.5	$7.5
10	STATION INFRASTRUCTURE	$10.6	$15.2	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5
	CRITICAL ISSUES TOTAL	$129.9	$106.9	$67.1	$99.1	$92.9	$103.7	$74.5	$75.8	$71.0	$71.0

Figure 39 – Critical Issues: Total Costs ($ Millions)

4.2 Stations Enhancements

Some of the most critical issues that exist at the transformer (TS) or municipal station (MS) levels include the security of supply, load growth and operational flexibility. Security of supply pertains to risks that can manifest due a lack of control, coordination or management of upstream transmission assets. The substantial population growth experienced the City of Toronto has also resulted in the creation of capacity-related risks, as the existing infrastructure was not designed to accommodate the growing load requirements.

The following programs have been established in order to address these developing issues. These programs involve the introduction of enhancements at either the TS or MS level:

- Stations Bus Expansion
- Installation of Intra-Station Bus Ties & Mobile Switchgear
- Bremner TS Development

Figure 40 illustrates the total capital spending required for Stations Enhancements.

PORTFOLIO 5 - STATIONS ENHANCEMENTS PROGRAM: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Stn. Enhancements	$89.6	$49.4	$13.0	$55.0	$48.0	$51.0	$27.0	$28.5	$31.0	$31.0

Figure 40 – Stations Enhancements Total Costs ($ Millions)

4.2.1 Stations Bus Expansion

In order to meet new load, and also introduce four-wire configurations where necessary such that voltage conversion activities may be performed, various station bus expansions and power transformer upgrades have been planned over the next ten years. These include:

- Bus expansion at Horner TS with a completion date of 2017. This project will alleviate capacity constraints at Manby TS, where there is no space for expansion.
- Bus expansion at Runnymede TS with a completion date in a 2017. As current loads are exceeding available capacity, this project will provide necessary load relief. Runnymede TS has space for expansion of one more bus.
- Bus expansion at Esplanade TS with a completion date of 2019 to accommodate new loads from Waterfront development. Esplanade TS has space for one more bus.
- Bus expansion at Bathurst TS with a completion date of 2021 to accommodate future load growth requirements. The initiation of this project will also provide load relief for Fairbank TS, which is currently heavily loaded, and where there is no more room for capacity expansion.
- Power transformer upgrade at Bridgman TS (for High Level MS) with a completion date of 2018. This upgrade is required to accommodate load growth and provide four-wire bus configuration for conversion of 4kV system in the High Level MS area.
- Power transformer upgrade at Wiltshire TS with a completion date of 2015. This upgrade is required to accommodate future load growth and provide four-wire bus configuration for conversion of 4kV system in the Wiltshire TS area.
- Transmission reinforcement between Manby and Leaside TS, via the installation of additional transmission circuits, with a completion date of 2014. By introducing new capacity for existing transmission lines between these two transformer stations, future load growth requirements within the Toronto midtown area can be met.
- Re-routing of supply cable for Wiltshire TS with a completion date of 2012. The re-routing of cables at Wiltshire TS will permit THESL to perform replacement activities for Wiltshire TS A1-2W switchgear assets.
- Installation of new 27.6kV circuit breaker at Malvern TS to provide service to a new customer.

THESL will pay capital contributions towards the installation of each of the aforementioned buses and power transformer upgrades.

Should these projects be deferred, the risks associated with load growth and capacity constraints will remain and likely continue to increase. Once available capacity is used up at a given station, it will become more complicated and costly to connect new customers within a given area, as long distance supply connections will need to be installed to connect these customers to the nearest stations with available capacity.

4.2.2 Installation of Intra-Station Bus Ties & Mobile Switchgear

The station intra-ties project is designed to improve the ability of stations to deal with contingencies at the station level. The scope of activities includes the addition of switchgear cells to existing switchgear to enable one switchgear to directly energize another at the same station.

THESL will also introduce mobile switchgear assets for each TS, should a switchgear-related outage take place. Note that when a switchgear failure occurs, resulting in all connected downstream feeders seeing the resulting outage, the aforementioned intra-station bus ties will not be able to assist in restoring supply to customers. As a result, there is a need for mobile switchgear to be made available for each TS within the downtown region.

A total of 14 intra-station bus ties, coupled with two mobile switchgear units, will be introduced over the next ten years.

4.2.3 Bremner TS Development

Windsor TS is one of the largest 13.8kV substations in Toronto, with 304 MVA of load supplying customers within the City of Toronto downtown region. This station contains air-blast switchgear, which are approaching their end-of-life criteria. As described in Section 3.5.1, the air-blast circuit breakers contained within this switchgear exhibit poor reliability and performance and are no longer supported by the original manufacturers. As a result, it is both complex and costly to maintain both the circuit breaker assets as well as their dedicated air compressor systems.

In order to replace these assets entirely, the 55 MVA of bus load that is being supplied by this switchgear must first be transferred to another source of supply. In addition, load growth in the downtown region has increased to the point where Windsor is nearing its capacity. There is no additional room at Windsor TS to support additional feeders or switchgear. In order to mitigate these potential risks, the optimal solution is to introduce a new source of supply. This new supply point will be able to assume all load currently serviced by Windsor TS, while the aforementioned air-blast switchgear is replaced. This new supply point also will mitigate the potential load growth risk. Finally, this supply point will provide improved security of supply to the downtown region, as total supply of this area will be further diversified.

This program consists of the construction of the Bremner Transformer Station (TS) to be located at Bremner Boulevard and Rees Street in downtown Toronto. THESL currently owns this site and will be the station developer. The completed station will consist of interface equipment with incoming circuits from Hydro One Networks Inc. ("HONI"), 115 kV switchgear, three 130 MVA 115 kV/13.8 kV-13.8 kV power transformers, two 13.8 kV switchgear, protection and control and other ancillary equipment. Ultimately, this new source of supply will provide 144 MVA of additional capacity to THESL's electrical distribution system.

Note that as part of this project, THESL will own the power transformers that step down the voltage from 115 kV down to 13.8 kV, unlike typical transformer stations where the power transformers are owned by HONI. By retaining ownership of these assets, THESL will be able to optimize maintenance and inspection activities in alignment with the remainder of the distribution system. Ultimately, this will allow for improved security of supply to downtown customers.

Note that there are alternatives to executing this program, including:

- Status Quo
- Bus-to-Bus Load Transfer and/or Expansion of Windsor TS
- Load Transfer to Existing Stations

By performing no new actions (status quo), the complexities and costs associated with maintenance and support for Windsor TS will continue to increase, due to the lack of manufacturer support for the installed air-blast switchgear. As repairs to both the air-blast breakers and the air compression systems would require the usage of custom-made parts, costs will become prohibitive. Even with these actions performed, reliability will continue to decline due to the overall age of this plant. As a result, the overall reliability risks associated with Windsor TS will continue to increase over time. A resulting catastrophic failure to switchgear would result in a lengthy sustained outage to the 55 MVA of connected bus load. Windsor TS will not be able to support the new load expected to be created by the waterfront redevelopment activities.

Due to the fact that there is not enough firm capacity available on the bus structure for Windsor TS, load transfer or load growth cannot be supported due to the station's high load factor. There is insufficient physical space at Windsor TS to accommodate new capacity via the installation of new switchgear.

The four stations adjacent to Windsor TS do not have sufficient firm capacity to take on any of the 55 MVA of connected bus load via a load transfer. Two stations – Stratchan TS and Esplanade TS – could be expanded to accept additional load and support such a load transfer. However, compared to the Bremner TS location, both of these stations are located further away from Windsor TS, and extensive capital expenditures would be required to install underground cables in order to link these stations. These activities would result in extensive disruption to the downtown area.

Based upon the alternatives noted above, the construction of Bremner TS is the only viable alternative that will allow for the capacity and load growth issues to be resolved, and also permit for the asset renewal activities to be executed at Windsor TS.

4.3 Secondary Upgrades

Streetlighting services are supplied from handwell assets, which contain the associated secondary electrical plant. These handwells and internal components are constantly subjected to natural and man-made environmental factors. They endure water, salt and contamination ingress and wide variations in temperature. These factors will ultimately result in the corrosion and degradation of these secondary components. Public safety risks can emerge as the integrity of these connections deteriorates to the point where live electrical wires become exposed.

As a long term measure, THESL has initiated a secondary upgrade program to replace the existing metallic handwells, secondary main cables and connections with non-conductive handwells and new connections. As part of handwell replacement activities, the entire assembly of the existing metallic handwell is excavated and removed from the sidewalk. A new non-conductive, polymer concrete handwell is then installed in place. The existing TW75 underground secondary mains cable is replaced with a RW90 dual protection cable, which provides improved mechanical and electrical protection. All handwell connections will be redone in order to meet the newest THESL standards and requirements. Any abandoned handwells identified as part of this program will be removed from the system.

Deferral of these activities would result in potential public safety risks. Figure 41 details the costs associated with this program.

PORTFOLIO 6 - SECONDARY UPGRADES: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Sec. Upgrades	$8.6	$12.2	$9.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Figure 41 – Secondary Upgrades Total Costs ($ Millions)

4.4 Standardization

THESL plans, designs and constructs distribution system assets in accordance with approved standards, which are developed to achieve the objectives of public and employee safety in compliance with the requirements of Ontario Regulation 22/04.

There are legacy assets installed prior to the development and adoption of the standards currently in use. The following standardization sub-programs have been established to upgrade these legacy assets to bring them into compliance with current construction standards and support modernization of the distribution system:

- Porcelain Hardware Replacement
- Posi-Tech Switch Replacement
- SCADAMATE R1 Replacement
- Grounding Compliance
- Standoff Bracket Replacement
- Completely Self-Protected Transformer Replacement

Legacy assets are selected for inclusion within these programs based upon the risks that these assets introduce to the public, crew workers and to system reliability. Figure 42 illustrates the total capital spending required for Standardization.

PORTFOLIO 7 - STANDARDIZATION: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Standardization	$9.0	$10.3	$6.1	$6.4	$6.4	$4.8	$4.8	$4.8	$4.8	$4.8

Figure 42 – Standardization Total Costs ($ Millions)

4.4.1 Porcelain Hardware Replacement

The catastrophic failure of porcelain or glass hardware can introduce potentially serious safety hazards to the general public and crew workers. In general, these assets have a greater chance of failure due to their increased susceptibility to contamination from the surrounding environment.

Overhead porcelain insulators connected to pole assets will be targeted under this program and replaced with polymeric insulators. In addition to eliminating potential safety risks, these insulators are less susceptible to contamination. In addition, porcelain pothead terminations, used to transition from PILC cable to TR-XLPE cable will also be replaced with polymer terminations. Finally, porcelain in-line switches will be replaced with their polymeric equivalents, as these switches may fall to the ground following a failure event.

4.4.2 Posi-Tech Switch Replacement

The 200A Posi-Tech switches installed within the 4.16kV electrical distribution system currently present safety hazards to THESL field crew workers, as it is difficult to execute grounding procedures for these assets due to their design. In order to facilitate the installation of grounds, the live primary cable must be removed from these switches. There are currently no other alternative equipment or procedures that can be executed to perform this grounding in a safer manner, without the removal of this live primary cable.

These switches have been identified as being installed in the Toronto Island and Etobicoke areas, and will be replaced with SF6-insulated Pad-mounted switches.

4.4.3 SCADAMATE R1 Replacement

First generation SCADAMATE R1 remotely-gang-operated overhead load break switches manufactured and installed in the mid-1990s have been introducing potential safety hazards and reliability risks to THESL field crew workers and the electrical distribution system.

There have been recent incidents where these SCADAMATE R1 switches were unexpectedly operated during routine maintenance activities in the field. In each of these instances, the switch would unexpectedly transition from the Open to the Closed position. While the physical indicator on the switch would show this unexpected switch position transition, the SCADA indicators would still register the switch as being in the Open position.

This problem appears to be linked to corrosion and overall degradation of the motor operator component. This degradation is the result of moisture penetrating this component. There have been a series of near-miss safety incidents to THESL field crew workers attributed to this particular failure mode. Figure 43 illustrates all SCADAMATE R1 locations throughout the overhead distribution system.

4.4.4 Grounding Compliance

The diagram on the left in Figure 44 illustrates legacy submersible transformer vaults, where there is an inadequate quantity of ground rods to ensure that the resistance to earth is sufficiently low. This lack of ground rods can result in a high step or touch potential in the earth that is surrounding these vault installations. The standardized method for grounding is illustrated in the diagram on the right in Figure 44. Through this program, each of these legacy submersible vaults will be rebuilt, with proper grounding installed.

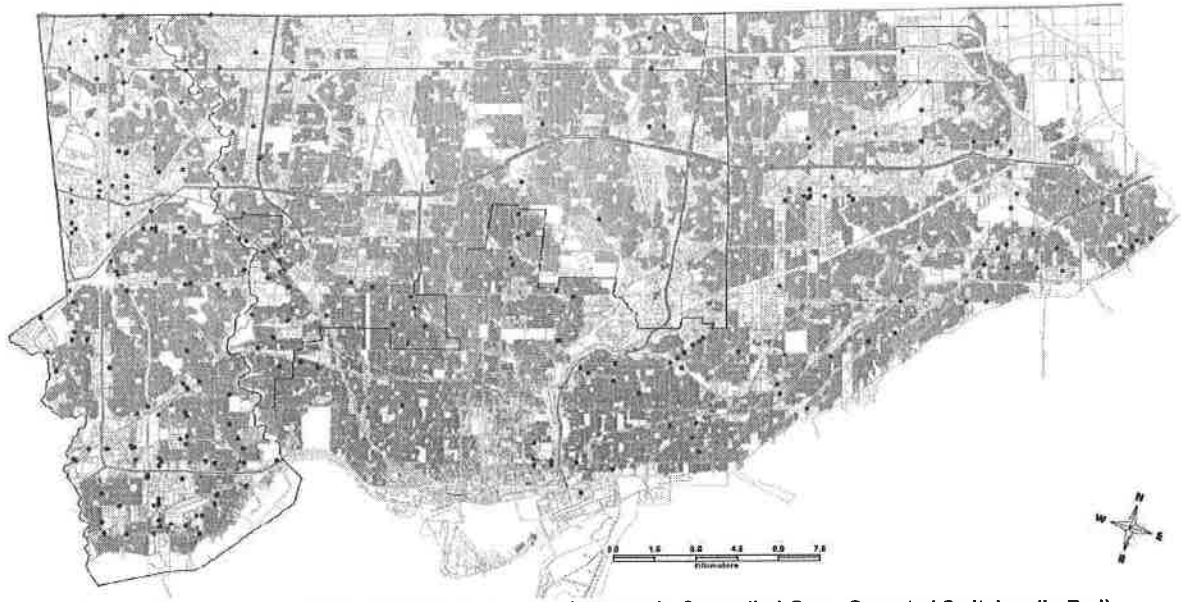


Figure 43 – Locations of SCADAMATE R1 Overhead Remotely-Controlled Gang-Operated Switches (in Red)

In addition, a number of instances of non-conforming pole-top transformer grounding have emerged. These include the lack of a ground rod, the lack of a bonding connection between the transformer and system neutral, incorrect connectors or wire sizes and missing case and H2 grounding connections. These locations present serious safety risks to THESL crew workers and the general public. Grounding will be rebuilt at each of the identified non-conforming locations.

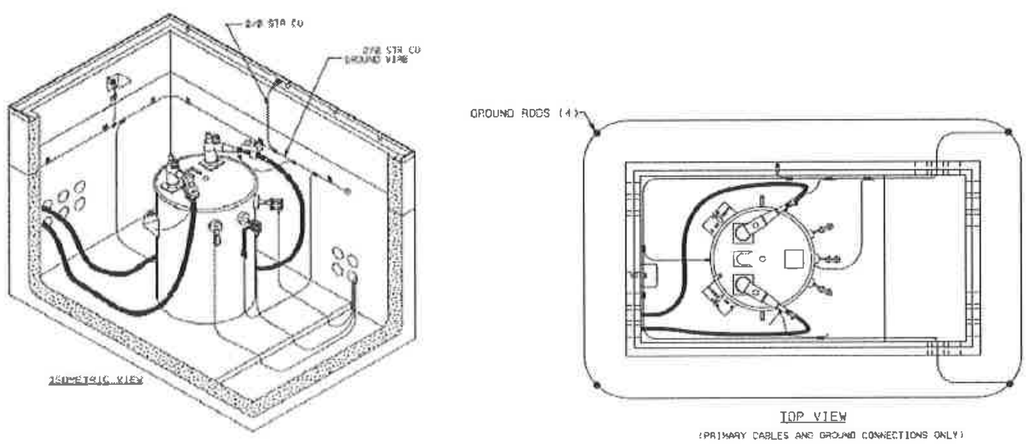


Figure 44 – Legacy & Standardized Grounding Designs for Submersible Transformer Vaults

4.4.5 Standoff Bracket Replacement

Standoff brackets are installed within the overhead distribution system to support the insulators, which connect the overhead tree-proof conductor to the pole assets.

Figure 45 illustrates a standoff bracket containing a 5-3/8" pin, which is used to connect the insulator to the standoff bracket. This pin has been identified as being too short, thus compromising the structural integrity of the installation. These pins do not confirm to the requirements established by the Canadian Standards Association (CSA).

In general, the overhead distribution system has been designed to handle extreme weather conditions and to conform to CSA requirements. However, the installation of these defective standoff brackets exposes these portions of the system to reliability and safety-related risks. In particular, should the pin fail, the insulator can be detached from the bracket entirely under extremely heavy loading due to extreme weather conditions or due to a failure at another location along the overhead distribution line.

Such a failure would ultimately result in the insulator falling to the ground, and the connected overhead conductor to swing freely in the air. A failure of this type could lead to other adjacent insulators along the overhead distribution line to also break off due to the weakened structural integrity.

This program will upgrade these assets to new brackets containing 6" pins. Should this program be deferred, the safety and reliability risks associated with these locations would remain in the system.

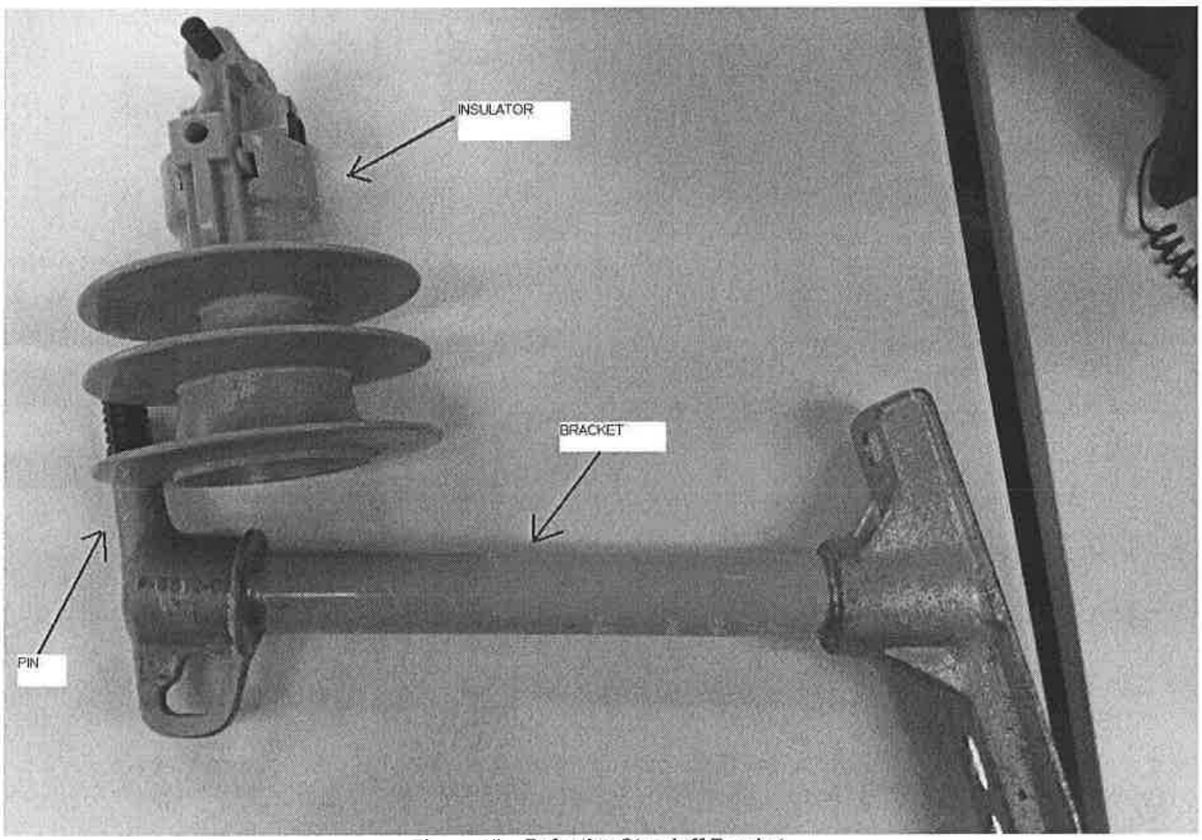


Figure 45 – Defective Standoff Bracket

4.4.6 Completely Self-Protected (CSP) Overhead Distribution Transformer Replacement

Completely Self-Protected (CSP) overhead pole-top distribution transformers represent an outdated asset in which the protective fuse device is built directly into the transformer enclosure. As a result, should the fuse react to an outage, the entire transformer must be replaced, regardless of the condition of the transformer. This ultimately results in a prolonged outage to customers.

These assets will be replaced with standard pole-top distribution transformers, in which the fuses are external to the transformer asset. For these assets, should the fuse react to fault current, the fuse can simply be replaced on its own, without replacing the transformer. This ultimately results in a faster customer restoration procedure. Figure 46 illustrates all CSP transformer locations across the overhead distribution system.

Figure 46 – Locations of Completely Self-Protected (CSP) Overhead Pole-Top Distribution Transformers (in Blue)

4.5 Downtown Contingency

The majority of distribution plant within the downtown region is connected as part of a radial feeder design configuration, meaning that there are no inter-feeder distribution tie points between distribution feeders.

The current radial configuration contains a set of normal and standby buses at the station level, with two or more power transformers supplying these buses. Should a failure occur for any given feeder, customers can be transferred over to the standby feeder. Should a partial failure occur at the station level, for a single bus or single transformer, the remaining bus and transformer can continue to supply customers.

However, should a catastrophic failure occur, either at the power transformer, circuit breaker or switchgear enclosure, this could result in a complete station failure. Because of the radial configuration, a complete failure at the station level would result in a prolonged outage to all connected customers, until the station assets are repaired.

Should a catastrophic power transformer failure impact all transformers at a given station, it would take approximately 3 to 7 days to deliver new transformers to the station site, provided that spare transformers are on hand. A study was performed on three stations within the downtown region in order to quantify the risks associated with a station level outage. This study accounted for the fact that the connected feeders all possessed a radial configuration. The total quantified annual risks associated with a station-level failure amounted to approximately $35 million across all three stations. This quantification includes direct and indirect costs associated with in-service asset failures and the resulting interruption to customers. At present, these configurations limit the available contingency options within the downtown region, and ultimately present operational constraints to power system controllers.

This program includes the following sub-programs that will alleviate the associated risks and ultimately improve contingency to the downtown region:

- Installation of inter-feeder ties
- Installation of station inter-ties
- Installation of mobile generation

Figure 47 illustrates the total costs associated with this program:

PORTFOLIO 8 - DOWNTOWN CONTINGENCY: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Downtown Con.	$1.1	$9.3	$9.2	$9.2	$11.0	$20.4	$16.2	$16.0	$9.2	$9.2

Figure 47 – Downtown Contingency Total Costs ($ Millions)

4.5.1 Installation of Inter-Feeder Ties

This program will initiate the installation of new tie points between stations with radial configurations, in order to provide the capability of performing station-to-station load transfer operations when a station level outage has taken place.

Figure 48 illustrates the configuration to be adopted for the Downtown Contingency program. As per this diagram, a series of 600A SCADAMATE remotely-controlled gang-operated normally-closed switches will be installed at stations X and Y in order to permit the isolation of each of the distribution feeders from its corresponding station should that station experience a complete failure.

Next, the existing radially-configured distribution feeders for stations X and Y will be connected with each other in order to form a series of new feeder tie points. Depending on the feeder layout, either new overhead or underground infrastructure will be constructed to link these feeders with each other. Finally, a series of 600A SCADAMATE remotely-controlled gang-operated switches will be installed to link the distribution feeders of stations X and Y together to establish the tie points.

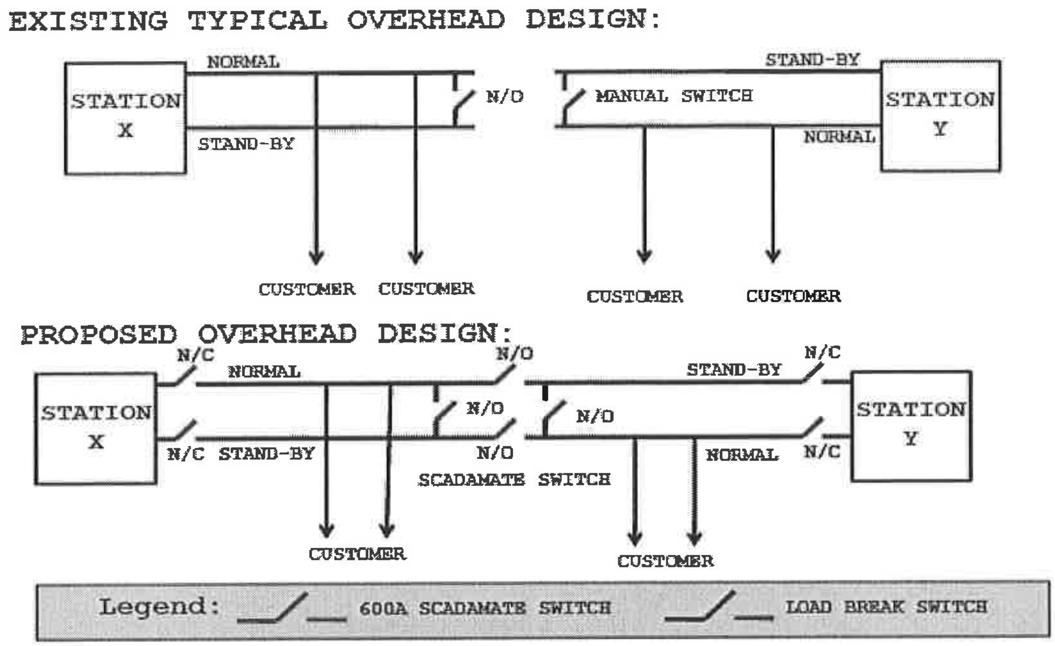


Figure 48 – Downtown Contingency Program – Before & After Program Execution

Through the execution of this program, should a station-level outage occur at a single station, THESL power system controllers will be able to isolate the impacted station, and close in on the tie point switches in order to re-energize all customers connected to both stations. Deferral of this program would allow for the risks associated with station level failures to persist within the distribution system.

4.5.2 Installation of Station Inter-Ties

This program will involve the installation of new underground connections between different TSs located within the downtown region. This will require the construction and installation of new underground cables and concrete-encased conduits along with new switchgear at the respective stations. This newly installed switchgear must be able to support tie capabilities to other stations.

Figure 49 illustrates the proposed station inter-ties to be installed within the downtown region. Ultimately, these inter-ties will allow THESL to react to HONI loss-of-supply emergencies.

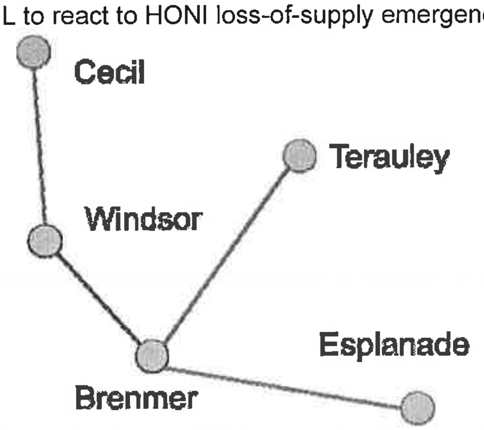


Figure 49 – Proposed Station Inter-Ties Configuration

4.5.3 Installation of Mobile Generation

As part of the Downtown Contingency program, THESL will also be renting mobile generator assets for each TS. THESL will be utilizing 1 to 10MW generators to address HONI-related loss of supply or loss-of-switchgear failures.

In tandem with the purchase and setup of these new assets, new contingency plans and procedures will be developed to fully utilize these assets during either a switchgear failure or HONI loss of supply event.

4.6 Worst Performing Feeders

THESL has adopted both Customers Interrupted ("CI") and Customer Hours Interrupted ("CHI") statistics in order to assess reliability at the feeder level as part of the Worst Performing Feeder ("WPF") program. This program aims to target feeders which are experiencing sustained interruptions, measured over a rolling 12-month period. Planned outages and interruptions due to Loss of Supply and Major Event Days from HONI are excluded from this analysis. Outages at the station level and within the secondary network system are also excluded.

The final outputs from the WPF program are a prioritized list of feeders which contribute heavily to SAIFI and SAIDI respectively. An in-depth analysis can then be performed holistically on the entire feeder by THESL engineers.

A subset of the WPF program is referred to as Feeders Experiencing Sustained Interruptions ("FESI"), which targets those feeders that have experienced seven or more sustained interruptions within a given 12-month rolling period for significant improvements. THESL will continually monitor these feeders and perform in-depth analyses to determine the root causes for the feeder outages, condition of the assets, reasons for long outage duration times, emerging reliability trends and the corresponding reliability impacts to customers.

From these analyses, corrective measures will be executed in the form of short-term mitigation actions and long-term capital work. Short-term mitigation actions will include work that can be completed quickly and typically without extensive civil work. Examples of short-term mitigation actions would include tree trimming, installation of animal guards, fault current indicators and fusing, replacement of porcelain hardware and distribution transformers.

Long-term capital work would apply to those feeders that possess an unacceptable level of performance and require immediate attention. These feeders typically fall into the FESI subprogram. The resulting scope of work would include activities that cannot be performed on a short-term basis, including civil rebuilds, large scale asset replacements and replacements of key assets such as direct buried cables. Activities associated with Long-term capital work are embedded into the Underground and Overhead Grid Systems portfolios. These portfolios are further highlighted in Sections 3.2 and 3.3 respectively.

Deferral of this program would result in these feeders continuing to have sustained outages, which would ultimately result in the gradual worsening of feeder and system reliability. In 2009, the ten worst performing feeders represented nearly 9% of the CI and 7% of the system CHI with the top 41 worst performing feeders representing 35% of the system CI and CHI. The FESI subprogram has included an additional 20 feeders in 2010, and this number is forecasted to double by the end of 2013 should no further actions be executed. This will result in further degradation to system reliability, and further increases to SAIFI and SAIDI indices.

Figure 50 illustrates the total costs associated with short-term mitigation actions performed within the WPF program.

PORTFOLIO 9 - WORST PERFORMING FEEDER: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
WPF	$11.0	$10.5	$10.5	$10.0	$9.0	$9.0	$8.0	$8.0	$7.5	$7.5

Figure 50 – Worst Performing Feeder (WPF) Total Costs ($ Millions)

4.7 Stations Infrastructure

To date, limited capital investments and resources have been allocated towards the refurbishment of THESL-owned MSs and TSs. As a result, key structural interior and exterior elements have begun to deteriorate. In order to mitigate the associated risks, repairs will be performed at various THESL-owned properties over the next ten-year period.

These will include exterior repairs to windows and doors, as well as repairs to eroding foundations and other structural repair work. In addition to performing these repairs, new security and telemetry devices will be incorporated throughout these properties in order to introduce added safeguards against potential disruption of services or damage to THESL assets.

By executing this program, the overall life expectancy of these buildings will be extended. Performing these incremental repairs will ultimately delay the need for full property rebuild. By deferring this program, the condition of these buildings will worsen and public safety and reliability risks will increase. Figure 51 illustrates the total costs associated with this program.

PORTFOLIO 10 - STATIONS INFRASTRUCTURE: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Stations Infras.	$10.6	$15.2	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5

Figure 51 – Stations Infrastructure Total Costs ($ Millions)

4.8 Externally Initiated Plant Expansion

The City of Toronto and other third-party agencies, including GO Transit/Metrolinx, the TTC and Business Improvement Area ("BIA") groups will initiate various infrastructure improvements that will impact installed THESL electrical distribution plant.

As a result, THESL must coordinate asset relocation and replacement activities at the same time, in order to optimize cost savings for road cutting, excavation and trenching activities. By performing these activities in alignment with external parties, any potential customer disruptions and impacts can be minimized. Finally, these activities allow for THESL to replace assets that may be approaching or have exceeded their useful life criteria. New assets installed within the system will be aligned to THESL standards and forecasted load growth requirements.

By not executing this program, THESL will be unable to perform replacement of these assets for a 5-year period, due to the road moratoriums established by the City of Toronto. THESL will also incur higher cost for road cutting, excavation and trenching activities, which can be shared with third-party agencies when all work is completed at a single time.

The costs associated with this program are already incorporated into the Underground Systems portfolio. These costs are further illustrated in Figure 16 within Section 3.2.

V Other Distribution Investments

5.1 Overview

Apart from Grid System and Critical Issues, there remain additional challenges that THESL is currently facing. These include the ongoing tasks associated with the planning, engineering and design of the electrical distribution system, the connection of new customers to the distribution system, the connection of electric vehicles to the distribution system, the need to initiate new capital projects to relocate or expand existing THESL electrical distribution plant in response to third parties and the need to immediately replace failed assets and perform customer restoration during an outage.

This chapter highlights the other distribution investments that are being performed in order to resolve these additional challenges. The total investments associated with mitigating critical issues are illustrated in Figure 52.

OTHER DISTRIBUTION INVESTMENTS ($M)											
#	Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
11	ENGINEERING CAPITAL	$30.6	$33.2	$35.2	$37.5	$36.8	$36.1	$32.9	$34.0	$34.1	$34.8
12	CUSTOMER CONNECTIONS	$26.6	$27.7	$28.7	$27.8	$29.7	$31.7	$33.0	$33.0	$33.0	$33.0
13	EXT. INIT. PLANT RELOCATION	$14.3	$9.5	$5.9	$8.4	$8.8	$9.7	$10.6	$11.8	$12.9	$14.2
14	REACTIVE CAPITAL	$27.3	$28.6	$30.1	$27.5	$28.0	$28.4	$28.8	$29.2	$29.7	$30.1
OTHER DIST. INVESTMENTS TOTAL		$98.8	$99.0	$99.9	$101.2	$103.2	$105.9	$105.3	$108.0	$109.7	$112.2

Figure 52 – Other Distribution Investments: Total Costs ($ Millions)

5.2 Engineering Capital

Engineering capital pertains to the investments associated with the design, construction and operation of the distribution system based upon sound engineering principles and accepted industry practices. These investments specifically encompass the functions supported by engineers, technologists, design technicians and power system controllers.

Over the next ten-year period, engineering capital will be impacted by significant expansions to the capital program in order to address aging infrastructure and system performance, modernization efforts, and the implementation and development of corporate information systems and decision support tools.

THESL engineering and operations staff will be required to maintain acceptable levels of system reliability and safety. To meet these objectives, engineering and operational staff will be required to address known system challenges and leverage the current system to support modernization efforts.

Major system challenges include legacy systems that feature obsolete equipment and outdated materials, as well operational issues with respect to vendor support. Moreover, with substantial load growth within the downtown region, THESL is also mindful of current capacity constraints on stations and the impact of subsequent overloads on the system. As such, THESL engineering and design staff will be required to continually update construction standards, review existing system design practices and upgrade civil structures. Moreover, given that THESL foresees substantial infrastructure renewal over the coming years, THESL operational groups will be required to coordinate switching tasks and energization activities on a significantly larger scale.

As part of modernization initiatives, new advanced technologies and monitoring devices will be incorporated into the electrical distribution system. THESL engineers will be tasked with translating and applying the new data to be received from these initiatives.

THESL will also be investing in efforts to develop corporate information systems to improve data availability and quality, as well as investing in enhanced decision-support tools. THESL's Mobile Workforce Program is an example of an enhanced decision support tool which uses handheld devices when inspecting distribution assets. This program allows THESL engineers and planning staff to identify assets that require immediate treatment and assists with problems that need to be rectified. Similarly, THESL will also be implementing an Outage Management System ("OMS") and Demand Management System ("DMS") for enhanced decision-making capabilities during outage incidents and when managing loads across the system. Over the long-term, these tools and systems will enable THESL's planning staff to assess and quantify system risks, as well as establish triggers to proactively address these risk factors.

Should funding for engineering capital be deferred, THESL's ability to perform necessary planning and analysis activities at a safe and manageable pace will be constrained. Ultimately, THESL would lose the opportunity to perform the required transition activities to ensure that knowledge of legacy assets, design and infrastructure is retained within the organization.

Figure 53 illustrates the total costs associated with the Engineering Capital program.

	PORTFOLIO 11 - ENGINEERING CAPITAL: TOTAL COSTS ($ MILLIONS)									
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Eng. Capital	$30.6	$33.2	$35.2	$37.5	$36.8	$36.1	$32.9	$34.0	$34.1	$34.8

Figure 53 – Engineering Capital Total Costs ($ Millions)

5.3 Customer Connections

When THESL receives a request to connect a new customer load or upgrade connection capacity for an existing customer, an Offer to Connect is issued to the customer. The Offer to Connect consists of basic and variable connection costs, capital contribution and security deposit. The basic connection cost represents the cost for connecting the standard 30-metre overhead service including the connection and transformation equipment.

An economic evaluation is carried out to determine if the future revenues from the connected customer(s) will adequately cover the costs pertaining to the new connection or the capacity upgrade. Should the net present value ("NPV") of the costs and revenues associated with the expansion be less than zero, a capital contribution in the amount of the shortfall is required. The amount of the capital contribution is set out in THESL's Offer to Connect to the customer.

New expansion costs consist of the capital expenditures associated with the installation of new distribution facilities and circuits when these are essential to accommodate new customer loading and which are not used to serve other customers.

For the purpose of determining operating, maintenance & administration (OM&A) costs, THESL uses system average operating and maintenance expenditures as a proxy for incremental OM&A expenditures, and apportions them as fixed costs (for residential and general service 0-50kW customers) or as a function of dollars per kilowatt ($/kW) of demand. These values are updated annually.

THESL will also be initiating a program to fully evaluate the impacts associated with electric vehicles (EV) on the electrical distribution system. As part of this program, metering data from separately metered EV infrastructure connections will be aggregated into existing systems, in order to understand the impacts and benefits. An EV infrastructure connection is defined as the additional portion of the distribution system that is required to ensure a separately metered supply point to an electric vehicle.

Due to the fact that a typical electric vehicle can draw as much power as a residential home, THESL will be providing EV infrastructure connections across the City of Toronto via dedicated smart meters, power line monitoring ("PLM") and transformer smart metering ("TSM"). From the data that is collected, load profiles, charging behaviors and impacts to power quality and harmonics will be determined. In addition, this program will also investigate the future creation of a rate class for electric vehicles, in order to offer EV users rates that encourage them to charge during off-peak hours or utilize the Time-of-Use billing schedule.

Figure 54 illustrates the total ten-year costs associated with Customer Connections.

PORTFOLIO 12 - CUSTOMER CONNECTIONS: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
THESL	$38.8	$40.0	$41.0	$40.0	$43.0	$45.0	$47.0	$47.0	$47.0	$47.0
Customer Contributions	$12.2	$12.3	$12.3	$12.3	$13.3	$13.3	$14.0	$14.0	$14.0	$14.0
Net Costs	$26.6	$27.7	$28.7	$27.8	$29.7	$31.7	$33.0	$33.0	$33.0	$33.0

Figure 54 – Customer Connections Total Costs ($ Millions)

5.4 Externally Initiated Plant Relocations

Each year, the City of Toronto identifies projects to expand or maintain infrastructure located on the "right of way", including the reconstruction of roadways, road widening, repairs or expansion of sewer lines, replacement of water mains, repair of bridges and additional streetscape improvements. This work will impact THESL's electrical distribution assets, since the majority of these assets are installed within roadway or on other property owned by the City of Toronto.

Therefore, THESL must work with the City of Toronto, the TTC and other organizations to coordinate work programs, to minimize scheduling conflicts and to identify potential opportunities for joint benefits. Long term plans from the City of Toronto are reviewed by THESL such that priorities can be negotiated, scheduling can be coordinated and infrastructure requirements can be established. THESL can receive a capital infrastructure recovery cost for a portion of infrastructure relocation activities.

THESL relocation activities are divided into two components: overhead plant and underground plant relocations. Overhead plant relocation activities are initiated as a result of City roadway alignments, the additional of new lanes or adjustments to roadway dimensioning. These activities result in the potential relocation of all overhead infrastructure, including overhead pole-top distribution transformers, conductors, switches and poles. Underground plant relocation activities are initiated as a result of bridge rehabilitation, adjustments to road elevation or other developments from public or private organizations, at locations where THESL underground distribution system plant currently exists. These would result in the potential relocation and construction of new conduit, cable chambers, transformer vaults and switching vaults.

Figure 55 illustrates the total ten-year costs associated with externally initiated plant relocation activities.

PORTFOLIO 13 - EXTERNALLY INITIATED PLANT RELOCATION: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
THESL	$17.9	$11.9	$7.4	$10.5	$11.0	$12.1	$13.3	$14.7	$16.1	$17.8
Customer Contributions	$3.6	$2.4	$1.5	$2.1	$2.2	$2.4	$2.7	$2.9	$3.2	$3.6
Net Costs	$14.3	$9.5	$5.9	$8.4	$8.8	$9.7	$10.6	$11.8	$12.9	$14.2

Figure 55 – Customer Connections Total Costs ($ Millions)

5.5 Reactive Capital

Reactive Capital investment includes the funds associated with the replacement of failed distribution assets and the process of restoring service to customers. Expenditure levels are derived from historical performance and future trending with funds allocated to address the failures of assets within the overhead distribution, underground distribution and secondary network systems and stations.

Overhead reactive capital allocates funding to replacement of overhead pole-top distribution transformers, switches, primary and secondary conductors and poles. Underground reactive capital allocates funding to replacement of cables, transformers, switches and civil assets as well as installation of splices for direct buried cables. Secondary network system assets are also accounted for within underground reactive capital investments, including network unit, ATS and RPB replacements. Stations reactive capital allocates funding to those stations assets between the demarcation point with HONI and the line disconnect device on distribution system feeders.

Deferral of these reactive activities will result in negative impacts to system reliability, as customers will see longer sustained outages. Total expenditures for reactive activities are detailed in Figure 56.

PORTFOLIO 14 - REACTIVE: TOTAL COSTS ($ MILLIONS)										
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Reactive Capital	$27.3	$28.6	$30.1	$27.5	$28.0	$28.4	$28.8	$29.2	$29.7	$30.1

Figure 56 – Reactive Capital Total Costs ($ Millions)

VI Long Term Maintenance Plan

6.1 Overview of THESL Maintenance Programs

THESL maintenance programs are designed to extend the life of distribution assets and maintain the expected reliability of these assets. Maintenance programs allow THESL to extract the maximum value out of its assets. Equipment maintenance complements the capital programs by allowing THESL to sustain the intended operating condition of its asset and preserve operability. Equipment condition is also critical to the safe operation of distribution assets and directly affects THESL employees and the public. Furthermore, equipment maintenance is essential to minimize the environmental impact of assets.

In addition, the maintenance program strives to maximize the customers' satisfaction by minimizing the impact observed by asset replacement and asset failure. This is done by prioritizing maintenance tasks in areas of the distribution system that show high historical outage rates, in areas which are more susceptible to weather related outages, and in areas which have been identified as requiring maintenance through predictive methods. THESL's focus on customer satisfaction has led to the adoption of the current maintenance program.

Since 2004, THESL has employed the Aladon approach Reliability-Centred-Maintenance (RCM II) in designing and planning its various maintenance programs. RCM II is designed to establish the optimal maintenance program required to achieve a desired level of operational performance from an asset within its current operating context. RCM II also provides an understanding of when it is better to replace a given asset, as opposed to performing corrective maintenance tasks to restore operational requirements. This model ensures that investments are cost effective and are focused on the critical distribution plant equipment. In comparison with traditional maintenance approaches, RCM II offers the utility best practices for managing the functionality of the assets in operation.

THESL's maintenance programs are categorized into the following program streams:

- Preventive Maintenance
- Predictive Maintenance
- Corrective Maintenance
- Emergency Maintenance

These programs are further described in the sub-sections below. Additional details on THESL's maintenance programs can be found THESL Plant Maintenance Manual.

6.1.1 Preventive Maintenance

This program is focused on cyclical inspection and maintenance of assets in order to extend their useful lives. By conducting the required maintenance practice for different asset classes, THESL aims to increase the probability that assets achieve their expected performance during their life cycle and to maintain performance, operability and safety. Preventive maintenance cycles are based RCM analysis and optimize the balance between equipment condition and costs. This program includes items such as overhead switch inspections, tree trimming, insulator washing, and line patrol.

On a go-forward basis, THESL plans on performing multiple forms of reviews on its preventive maintenance programs. These reviews include performing audits of the crews performing the work, analyzing each maintenance program, recognize the maintenance needs of the system – both on the technical tasks performed as well as on task execution – to identify possible improvements, and reviewing the results to understand the maintenance program's effectiveness. As part of these reviews, advancements in technology and the changing profile of assets will also be considered.

6.1.2 Predictive Maintenance

This program revolves around testing and auditing of equipment for predetermined conditions that predict failures. Corrective measures are then taken to remedy these conditions and prevent equipment failure or minimize the severity of failure. The anticipatory nature of this program requires highly sophisticated component tests that detect potentially destructive conditions. Similar to preventive maintenance, predictive maintenance relies on the RCM methodology to determine the most cost effective maintenance option. Predictive maintenance includes items such as overhead and cable infrared audits, wood pole inspection and contact voltage scans.

From a continuous improvement perspective, the future of the predictive maintenance program requires continuous verification that each program is achieving its intended purpose. This can be done by identifying the trending of equipment that has received predictive maintenance; the trends should show an increased life of the asset. In addition, predictive maintenance has the potential for the greatest change in the future, due to the evolution of technology. As tools become more effective at identifying indicators of future failure, and the number of monitoring devices in the system increases, there will be a larger and more accurate supply of data to use for making and verifying predictions. With the advancement in technology it is becoming more feasible to implement real-time monitoring and data capturing. It is also becoming more feasible to receive, store and manage the data that comes back from such monitoring. An example of this would be the cable monitoring program which THESL plans on implementing. By capturing the condition of a cable (loading, temperature, partial discharge, etc.) it may be possible to predict failures well in advance on when they would actually occur.

6.1.3 Corrective Maintenance

This program involves repairing or replacing equipment after it has been reported faulty. Corrective maintenance typically follows emergency maintenance after power has been restored to customers. This program can also include short-term actions that would result from deficiencies realized through preventive or predictive maintenance or other planned work. The work carried out by the corrective maintenance program results in the elimination of safety and environmental hazards as well as the improvement of reliability and customer service. Since corrective maintenance aims to remedy equipment issues as they emerge, it varies based on system performance over the years.

The future of the corrective maintenance program will rely heavily on the ability of the preventive and predictive maintenance programs to identify necessary corrective actions. As the predictive maintenance program becomes more capable of predicting failures, the breakdown of work should become more comprised of tasks generated from the predictive maintenance program and less from emergency maintenance. In addition, THESL has plans for large capital investments to renew the asset population, which should help stem future increases in corrective maintenance.

Other improvements sought by the corrective maintenance program include finding ways to minimize the impact seen by the customer as well as finding more efficient ways to restore power. A measure currently being undertaken by THESL is the implementation of Feeder Automation. By automating the isolation of a fault, as well as the transfer of load, the customer impact is minimized and the control room is notified immediately that corrective work is required. These technological improvements also mean an increase in data availability. This data will allow for analysis to take place regarding failure trends as well as support root cause analysis investigations.

6.1.4 Emergency Maintenance

This program comprises urgent repair or replacement of equipment that has caused a power interruption. It can also include immediate response to safety or environmental hazards pertaining to distribution equipment. The goal of this program is to ensure safe and timely restoration of power to THESL customers. Similar to corrective maintenance, the required level of emergency maintenance varies based on system performance.

Emergency maintenance plays an important role in the THESL maintenance program as it captures failures that were unpredictable, either due a lack of monitoring capability or failure modes which are unpreventable (e.g., automobile accidents). Due to the reactive nature of emergency maintenance, it is difficult to implement any significant changes or improvements to the program. It is expected, however, that as the preventive and predictive maintenance programs become more capable of identifying future failures, the number of emergency maintenance events should trend downwards. In addition, THESL's implementation of its capital plans should also contribute to a decrease in emergency maintenance required.

6.2 Long Term Maintenance Outlook

This section outlines THESL's proposed maintenance requirements for the next ten years. As THESL continues to modernize the distribution system, the maintenance requirements of the system will be evolving. Capital programs will be renewing the asset base and thereby changing the age profile of the distribution assets. The changing asset age profile directly affects the condition of the system and changes the system's maintenance needs. Maintenance effectiveness, dictates that maintenance program should also change over time in order to adequately adjust to the needs of the system.

THESL will continue to refine and optimize its maintenance cycles for various programs as the age profile of assets targeted by these programs change. Furthermore, new tools and technologies will be introduced as part of the maintenance programs to increase the efficiency and effectiveness of these programs.

This section presents the ten-year maintenance program requirements and discusses how various maintenance programs will change over the years. Tools and technologies to be incorporated into THESL's maintenance programs will also be discussed.

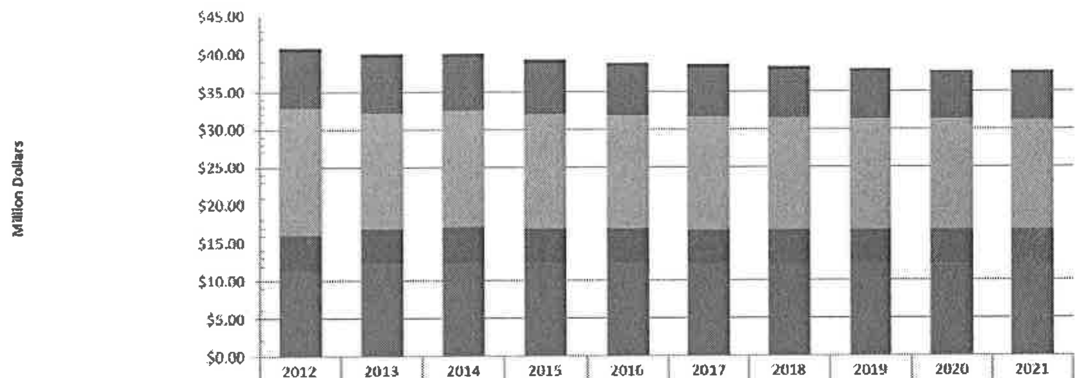
6.3 Long Term Maintenance Requirements

Figure 57 below, summarizes THESL's ten-year maintenance and elaborates on changes in each program over the ten-year planning period.

Program	Year									
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Preventive Subtotal	**$11.41**	**$12.16**	**$12.27**	**$12.21**	**$12.17**	**$12.14**	**$12.11**	**$12.08**	**$12.06**	**$12.03**
Preventive Maintenance Overhead	$5.29	$6.30	$6.28	$6.26	$6.25	$6.24	$6.22	$6.21	$6.20	$6.20
Preventive Maintenance Underground	$1.75	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.01	$2.01
Preventive Maintenance Network	$1.39	$1.19	$1.17	$1.15	$1.13	$1.11	$1.09	$1.07	$1.06	$1.04
Preventive Maintenance Stations	$2.97	$2.67	$2.82	$2.79	$2.79	$2.79	$2.79	$2.79	$2.79	$2.79
Predictive Subtotal	**$4.53**	**$4.77**	**$4.80**	**$4.61**	**$4.60**	**$4.60**	**$4.63**	**$4.63**	**$4.64**	**$4.64**
Predictive Maintenance Overhead	$0.62	$0.73	$0.77	$0.77	$0.77	$0.77	$0.81	$0.81	$0.81	$0.82
Predictive Maintenance Underground	$2.57	$2.71	$2.70	$2.69	$2.68	$2.67	$2.67	$2.67	$2.67	$2.67
Predictive Maintenance Stations	$1.34	$1.34	$1.34	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15
Corrective Subtotal	**$16.77**	**$15.30**	**$15.40**	**$15.09**	**$14.97**	**$14.88**	**$14.73**	**$14.67**	**$14.58**	**$14.53**
Corrective Maintenance Overhead	$3.18	$2.91	$2.90	$2.89	$2.89	$2.88	$2.88	$2.87	$2.87	$2.86
Corrective Maintenance Underground	$9.73	$8.96	$8.87	$8.80	$8.74	$8.69	$8.65	$8.61	$8.58	$8.55
Corrective Maintenance Network	$1.19	$0.70	$0.71	$0.63	$0.57	$0.53	$0.44	$0.42	$0.35	$0.34
Corrective Maintenance Stations	$2.68	$2.73	$2.92	$2.77	$2.77	$2.78	$2.77	$2.77	$2.78	$2.77
Emergency Subtotal	**$7.68**	**$7.29**	**$7.15**	**$6.82**	**$6.64**	**$6.49**	**$6.33**	**$6.22**	**$6.09**	**$6.00**
Emergency Maintenance Overhead	$4.87	$4.77	$4.70	$4.62	$4.55	$4.49	$4.44	$4.39	$4.34	$4.29
Emergency Maintenance Underground	$2.50	$2.19	$2.10	$1.87	$1.76	$1.67	$1.56	$1.50	$1.42	$1.38
Emergency Maintenance Stations	$0.32	$0.33	$0.36	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33
Maintenance Improvement Investments	**$0.50**	**$0.50**	**$0.50**	**$0.50**	**$0.40**	**$0.40**	**$0.40**	**$0.30**	**$0.30**	**$0.30**
TOTAL	$40.89	$40.03	$40.13	$39.23	$38.79	$38.51	$38.20	$37.90	$37.67	$37.50

Figure 57 – Summary of Long Term Maintenance Plan (2012 – 2021) ($ Millions)

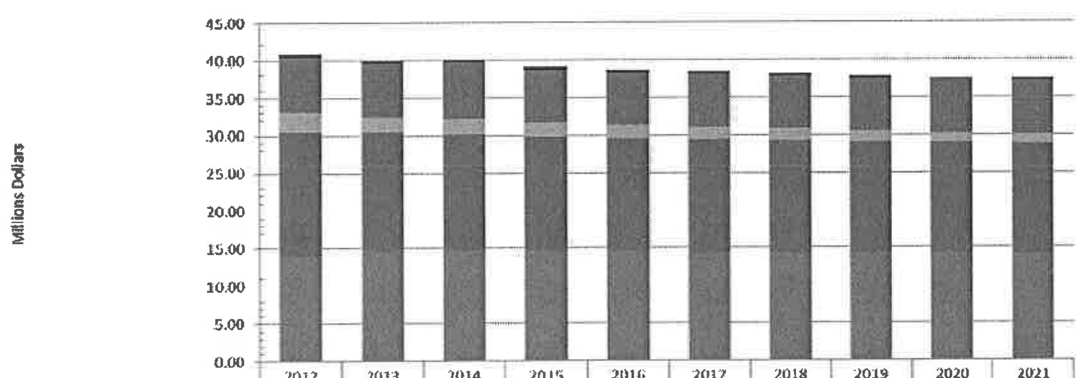
Figure 58 illustrates the year by year variations to each category of maintenance programs over the period 2012-2021.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Maint. Improvement Investments	$0.50	$0.50	$0.50	$0.50	$0.40	$0.40	$0.40	$0.30	$0.30	$0.30
Emergency Maintenance	$7.68	$7.29	$7.15	$6.82	$6.64	$6.49	$6.33	$6.22	$6.09	$6.00
Corrective Maintenance	$16.77	$15.30	$15.40	$15.09	$14.97	$14.88	$14.73	$14.67	$14.58	$14.53
Predictive Maintenance	$4.53	$4.77	$4.80	$4.61	$4.60	$4.60	$4.63	$4.63	$4.64	$4.64
Preventive Maintenance	$11.41	$12.16	$12.27	$12.21	$12.17	$12.14	$12.11	$12.08	$12.06	$12.03

Figure 58 – Summary of Long Term Maintenance Plan by Program (2012 – 2021) ($ Millions)

Figure 59 illustrates the cost proportions pertaining to each system type. This figure combines the costs for preventive, predictive, corrective, and emergency maintenance plans to provide a holistic view of system maintenance needs.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Maint. Improvement Investments	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3
Stations	7.30	7.07	7.43	7.04	7.05	7.06	7.04	7.05	7.06	7.04
Network	2.58	1.90	1.88	1.78	1.70	1.64	1.53	1.49	1.41	1.38
Underground	16.55	15.86	15.67	15.35	15.18	15.03	14.88	14.78	14.68	14.61
Overhead	13.96	14.70	14.65	14.55	14.46	14.38	14.35	14.28	14.22	14.16

Figure 59 – Long Term Maintenance Plan by Asset Type (2012 – 2021) ($ Millions)

6.4 Preventive Maintenance

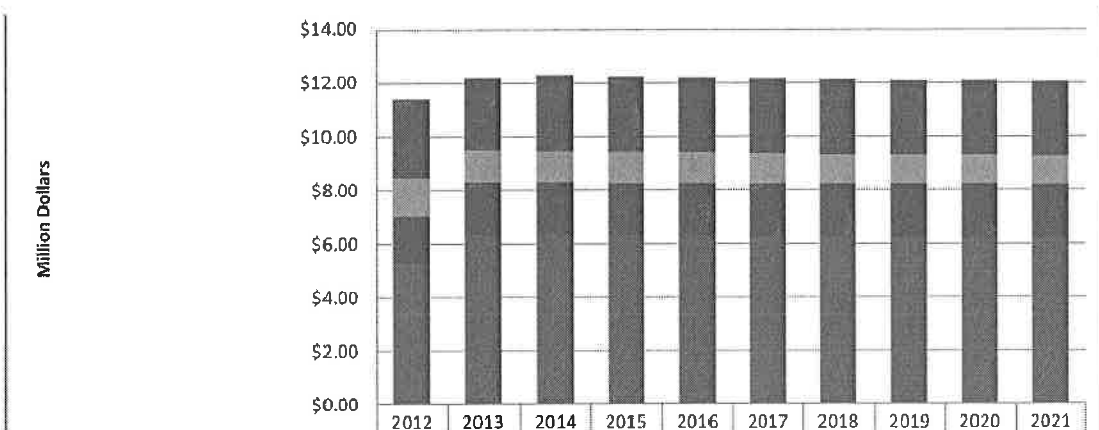
Preventive maintenance programs focus on equipment cyclical inspection and maintenance tasks to preserve equipment condition. Such inspections are crucial to maintain equipment operability and employee and public safety. THESL's long-term capital program will focus on renewing the asset base and changing the age profile for different asset classes. While a portion of the asset base will be replaced through capital programs, the remaining portion will continue to age. As such, the preventive maintenance requirements will change throughout the planning period. Programs pertaining to asset classes that are to be target for replacement will show lower costs, while other programs, targeting emerging system deficiencies, will increase.

Overall, preventive and predictive maintenance will remain relatively stable over the ten-year planning period. The ten-year maintenance plan includes allowance for on-the-job training for new apprentices. The overhead, underground, network, and stations preventive programs include this training in the overall cost.

Figure 60 illustrates the total preventive maintenance requirements and demonstrates the proportions attributed to each part of the distribution system.

6.4.1 Preventive Overhead Maintenance

Preventive maintenance for the overhead system will be increasing throughout the planning period due to emerging system needs. Furthermore, in the past overhead line patrols were mainly concerned with identifying assets in need of immediate replacement as well as assets that were safety hazards to THESL employees or the public.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Preventive Maintenance Stations	$2.97	$2.67	$2.82	$2.79	$2.79	$2.79	$2.79	$2.79	$2.79	$2.79
Preventive Maintenance Network	$1.39	$1.19	$1.17	$1.15	$1.13	$1.11	$1.09	$1.07	$1.06	$1.04
Preventive Maintenance Underground	$1.75	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.01	$2.01
Preventive Maintenance Overhead	$5.29	$6.30	$6.28	$6.26	$6.25	$6.24	$6.22	$6.21	$6.20	$6.20

Figure 60 – Long Term Preventative Maintenance Requirements (2012 – 2021) ($ Millions)

In response to the fact that the impact on reliability due to defective overhead equipment has been increasing over the past five years, THESL will be increasing overhead line patrols in order to identify equipment in poor condition and prevent foreseeable equipment failures. Moreover, increased line-patrols enable THESL to collect additional information on condition of the assets.

Insulators and overhead switches have been the largest contributor towards overhead equipment failure. THESL will continue to replace sub-standard porcelain insulators through its capital programs, hence as the number of porcelain insulators throughout the system decreases through capital replacement, the insulator washing program which aims to reduce the likelihood of failure within this asset base will also decrease. In the past, the insulator washing program targeted areas of higher contamination within the system. For instance, insulators on poles along highways and high traffic areas are generally highly exposed to contamination and are more likely to fail. As THESL replaces porcelain insulators, the insulator washing program will focus on insulators in relatively less contaminated areas that have accumulated contamination and debris over the years and are now at an increased risk of failure.

Conversely, overhead switches will continue to require cyclical inspections. As THESL replaces some manually operated switches with SCADA switches, the total number of switches in the system will relatively stay steady. As more SCADA switches are introduced into the system as part of the feeder automation initiative, the maintenance methodology will change and adjust to the new needs of the system, however, the overall program budgetary requirement is forecast to remain steady over the planning period. As feeder automation expands throughout the system, maintenance programs will have to adjust to reflect this change.

Cyclical tree trimming and pruning programs which are intended to reduce the frequency of tree contacts related outages will continue at the same levels over the 2012-2021 period. Since the introduction of the tree trimming model, which is used to identify optimal tree trimming cycles, THESL has been able to stabilize the level of tree trimming related outages. As THESL continues to manage the tree trimming program, it will monitor the reliability impact of tree trimming related outages. For instance, initially the tree trimming model targeted high impact areas where tree contacts were a large contributor to poor reliability. Since then, these areas have seen improvements in the reliability impacts of tree contacts, allowing THESL to focus its tree trimming program on other areas that are vulnerable to tree contacts. If the desired reliability improvements are not realized through the tree trimming program, trimming and pruning cycles could be adjusted to further target high tree contact areas.

6.4.2 Preventive Maintenance Underground

This program focuses on maintaining THESL's underground distribution plant including underground vaults, cable chambers, submersible assets, pad-mounted assets, and building vaults. Since some parts of the underground plant are highly exposed to contamination by external factors, cyclical inspections and cleaning tasks are required in order to sustain plant condition.

Over the next ten years as THESL renews its underground plant, it will continue to require inspections on the underground equipment and to conduct cyclical cleaning in order to maintain the condition of these newly installed assets. As underground vaults in poor condition are rebuilt through capital programs, the newly rebuilt vaults will require the same inspection and cleaning cycles as the old vaults since they too are exposed to contamination and debris. Furthermore, even though the age profile of the underground plant will be changing through capital replacement programs, the number of underground vaults, chamber, and pads will stay relatively steady over the ten year period. As inspection cycles will be constant over the planning period, the costs are also expected to remain stable over the next ten years.

6.4.3 Preventive Maintenance Network

The low-voltage network distribution system consists of transformer vaults which house various network assets such as network transformers, network protectors, and reverse power breakers. Network assets typically have low-probability high-impact failure modes. The high impact is due to the interconnection of the network system as well as to the location of the network system as the network system is used to supply the Toronto urban core area. Similar to other underground distribution vaults, network vaults are typically located below sidewalk grade and are therefore exposed to contamination and debris from the street level. As such, cyclical inspection and cleaning are required on these vaults regardless of their age.

Since the total population of the network vaults and the inspection frequency required on these vaults will remain consistent over the planning period, the maintenance funding requirements for this program will stay stable. Vault cleaning programs have shown to be effective in improving the overall condition of the network system and reliability by preventing vault flooding.

On the other hand, as network protectors and reverse power breakers deteriorate and exceed their useful lives, they will be undergoing replacement through the THESL capital plan. Maintenance programs targeting these two asset classes will decrease as the asset base is renewed. Overall preventive maintenance requirements pertaining to the network system will fall over the planning period.

6.4.4 Preventive Maintenance Stations

Preventive stations maintenance consists of station seasonal maintenance (including THESL equipment in customer locations) and specific asset class focused maintenance on assets such as circuit breakers, transformers, switches, and batteries and chargers.

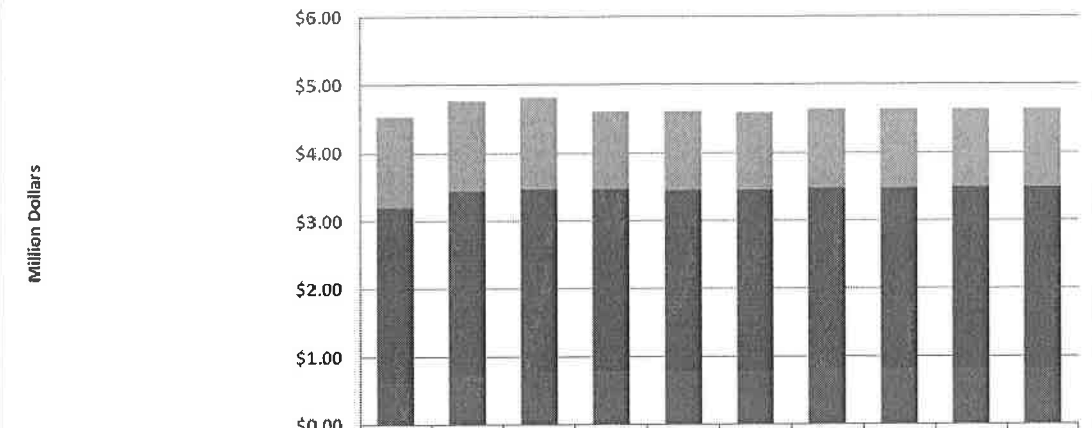
Station assets have maintenance cycles that vary from one to eight years in length. Because of the cyclical nature of the maintenance and the need to schedule outages and perform the maintenance in groups of assets, the year to year preventive maintenance requirements fluctuate.

Assets such as circuit breaker have varying maintenance needs that depend upon the interrupting technology used. Capital programs to replace air-blast, oil and air-magnetic breakers with vacuum and SF6 breakers will slightly decrease the total hours needed for preventive maintenance over time. Transformer maintenance requirements remain stable if units are replaced but they will decrease proportionally if units are removed from service due to station decommissioning.

6.5 Predictive Maintenance

Predictive maintenance programs aim to identify asset conditions that could be used to predict asset failures. Due to the proactive nature of this program, predictive maintenance can provide reliability improvements by identifying assets prone to failure and correcting conditions that anticipate failure. As THESL continues to embark on a proactive approach towards asset maintenance, predictive maintenance requirements increase throughout the ten-year planning period.

Figure 61 illustrates the total predictive maintenance requirements and demonstrates the proportions attributed to each system.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
■ Predictive Maintenance Stations	$1.34	$1.34	$1.34	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15	$1.15
■ Predictive Maintenance Underground	$2.57	$2.71	$2.70	$2.69	$2.68	$2.67	$2.67	$2.67	$2.67	$2.67
■ Predictive Maintenance Overhead	$0.62	$0.73	$0.77	$0.77	$0.77	$0.77	$0.81	$0.81	$0.81	$0.82

Figure 61 – Long Term Predictive Maintenance Requirements (2012 – 2021) ($ Millions)

6.5.1 Predictive Maintenance Overhead

Overhead maintenance tasks categorized under predictive maintenance includes wood pole inspection and treatment, and overhead infrared scans. THESL anticipates failure investigation requirements on the overhead system to remain steady over the planning period. The wood pole inspection program determines the inspection and treatment cycles for wood poles based on condition of the poles as well as the age of the poles. Poles that have deteriorated in condition over the years or have passed their useful lives are inspected more frequently. Increased inspection frequency on these high risk poles allows for problematic poles to be identified and replaced earlier. Anticipated maintenance costs for pole inspections take into account the aging pole asset base as well as requirement for increased inspection frequency on high risk poles. Costs associated with this program are expected to increase over the ten-year planning period since, due to the large population of wood poles in the system, the asset base is aging at a faster rate than anticipated replacement through the capital program.

Infrared scans on overhead plant can identify electrical "hot spots". Such scans are intended to detect faulty insulation on an asset before the complete failure of the asset. Once an asset is identified as problematic corrective maintenance is performed to avoid asset failure. Infrared inspections are conducted on all 3-phase overhead feeders on an annual basis. Since the number of overhead feeders as well as inspection cycles remains steady over the ten-year planning period, the infrared scanning program is forecast to remain steady over this period.

6.5.2 Predictive Maintenance Underground

This program includes maintenance tasks such as pad-mounted switches inspection, cable chamber infrared audit, and contact voltage scan. Pad-mounted switches are routinely inspected for contamination under the predictive maintenance program. Currently, the majority of pad-mounted switches in the system are live-front switches, which by design are more susceptible to failure due to contamination. Capital replacement initiatives will be replacing live-front switches with dead-front switches which provide better reliability and require reduced maintenance. As THESL removes replaced live-front switches, the maintenance requirements for pad-mounted switches decrease over the planning period until all such assets are replaced. Once all live-front switches are removed from the system, only cyclical visual inspections will be required for pad-mounted switches and hence, the costs associated with this program will be remain stable thereafter.

The cable chamber infrared audit program will be held steady over the planning period as the total number of cable chambers and the frequency of such audits will stay consistent. The contact voltage scan program aims to measure contact voltage on distribution assets across the system. Since total asset population and inspection frequency in this program is consistent throughout the ten year period, maintenance cost requirements will remain steady over the planning period.

Cable testing is a new predictive maintenance initiative which aims to identify primary cables that are prone to failure. This program will be initiated due to the fact that primary cable failures are the largest contributor to outages due to effective equipment. By monitoring and testing cable condition on a proactive basis, maintenance programs can measure failure predictive variables in order to anticipate cable failures on the underground system.

6.5.3 Predictive Maintenance Stations

Predictive stations maintenance consists of station visual inspections, diagnostic testing of equipment including transformer oil analysis and battery testing. THESL is increasing its capability to perform diagnostic testing of switchgear which is currently hampered by the physical design and other attributes of the present equipment. Capital projects are underway to modify the switchgear to overcome these issues. Diagnostic testing of switchgear is expected to increase in the future as a result. At the same time, efforts are underway to automate diagnostic testing of transformers in 2011 and this will be expanded if found to be successful.

The most significant factor in predictive maintenance trends though is the number of stations to be maintained. As municipal stations assets decrease through decommissioning work in the future, the number of hours spent on stations predictive maintenance is expected to decrease.

6.6 Corrective Maintenance

THESL will be modernizing and revitalizing its asset base, through replacement of assets in poor condition as well as assets that have surpassed their useful life. Furthermore, preventive and predictive maintenance programs aim to identify assets in poor condition and anticipate asset failure, respectively. Provided that capital and maintenance programs are executed as planned, THESL anticipates a downward trend in equipment failures and thereby, a downward trend in corrective maintenance requirements.

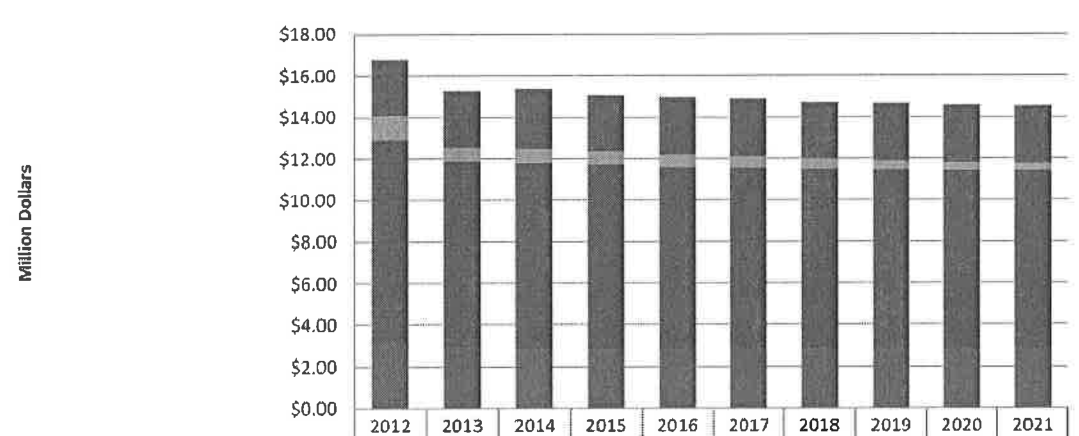
Historically the budget available for the corrective maintenance has been less that the needs of the distribution system. In years where asset deficiencies exceeded the allocated budget, lower priority activities have been deferred to the following year.

Due to the lack of resources in previous years, equipment deficiencies have accumulated. Such deficiencies present a priority for the corrective maintenance programs and should be addressed as soon as possible. While the number of deficiencies has increased significantly on a yearly basis over the past few years, the aging infrastructure and assets in poor condition have also increased over these years. Moving forward, THESL will continue to target the accumulated deficiencies and will target new deficiencies that are identified every year. Corrective maintenance programs for overhead, underground, and network systems include planned deficiencies to be addressed on a yearly basis.

Figure 62 illustrates the corrective maintenance requirement for the 2012-2021 period.

6.6.1 Corrective Maintenance Overhead

Corrective maintenance on the overhead system focuses on restoring the distribution system to its original state after a power outage. This program also includes mitigation of issues identified in both preventive and predictive maintenance. As the overhead asset base is renewed, THESL anticipates lower frequency of asset failures. As such, corrective maintenance requirements for the ten-year period decrease slightly.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Corrective Maintenance Stations	$2.68	$2.73	$2.92	$2.77	$2.77	$2.78	$2.77	$2.77	$2.78	$2.77
Corrective Maintenance Network	$1.19	$0.70	$0.71	$0.63	$0.57	$0.53	$0.44	$0.42	$0.35	$0.34
Corrective Maintenance Underground	$9.73	$8.96	$8.87	$8.80	$8.74	$8.69	$8.65	$8.61	$8.58	$8.55
Corrective Maintenance Overhead	$3.18	$2.91	$2.90	$2.89	$2.89	$2.88	$2.88	$2.87	$2.87	$2.86

Figure 62 – Long Term Corrective Maintenance Requirements (2012 – 2021) ($ Millions)

6.6.2 Corrective Maintenance Underground

Similar to the overhead system, as portions of the underground system undergo capital rebuild and assets in poor conditions are replaced, THESL foresees reduced asset failures and therefore, reduced corrective maintenance requirements on this system.

6.6.3 Corrective Maintenance Network

The network system will also be revitalized through capital programs over the ten-year period. As THESL removes high probability of failure assets from the system, it foresees a considerable reduction in the corrective maintenance requirements for the network system of the 2012-2021 period.

6.6.4 Corrective Maintenance Stations

This program includes the corrective repair of failed assets that have caused a forced outage, or have been identified as defective during planned maintenance inspections, or during routine equipment operation. This is the follow-up response and permanent repair and it is typically performed after the problem is identified and initial measures taken.

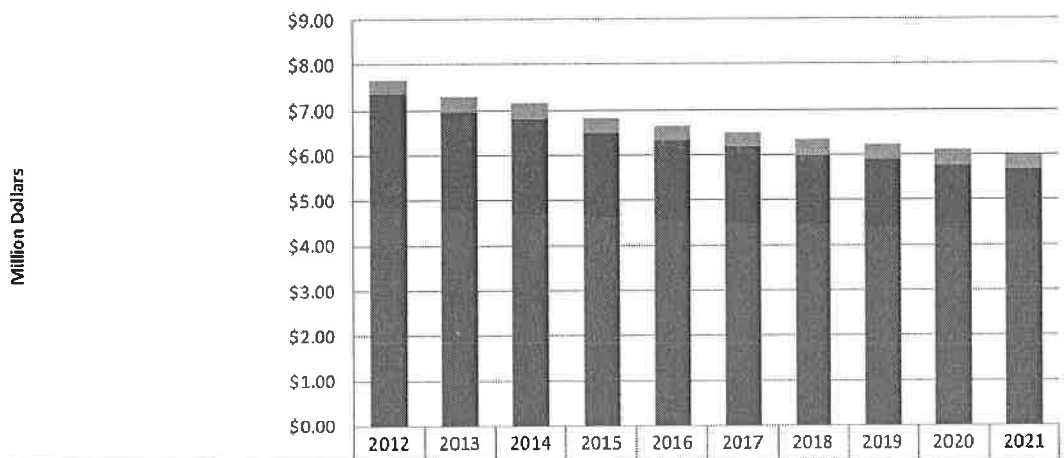
Corrective maintenance consist of the repair/modify/retrofitting of the following items: transformer, tap changer, cooling system, switchgear, bus-bar, air compressor, overhead crane, station auxiliary and power supply, instrument transformers, relays, meters, fire alarms, remote control and data acquisition. The corrective maintenance needs are expected to remain stable over the foreseeable future.

6.7 Emergency Maintenance

Emergency maintenance is directly proportional to the frequency and severity of power interruptions in a given year. THESL foresees a reduction in the frequency of power interruptions over the planning period. The severity of these interruptions, however, can vary year to year. Nonetheless, as the asset base is renewed, THESL anticipates emergency maintenance requirements for the 2012-2021 planning period to decline.

The stations emergency program is the first response to a loss of a feeder, of a transformer or bus-bar or of any problems or alarms within a station. The response team carries out the process of emergency power restoration and response to system/customer needs. The emergency maintenance needs for station assets are expected to remain steady over the foreseeable future.

Figure 63 illustrates the emergency maintenance requirement for the 2012-2021 period.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Emergency Maintenance Stations	$0.32	$0.33	$0.36	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33
Emergency Maintenance Underground	$2.50	$2.19	$2.10	$1.87	$1.76	$1.67	$1.56	$1.50	$1.42	$1.38
Emergency Maintenance Overhead	$4.87	$4.77	$4.70	$4.62	$4.55	$4.49	$4.44	$4.39	$4.34	$4.29

Figure 63 – Long Term Emergency Maintenance Requirements (2012 – 2021) ($ Millions)

6.8 Maintenance Improvement Investments

The ten year outlook for THESL's maintenance plan is based on a continuous improvement model. The plan strongly emphasizes efficiency. This approach includes identifying internal opportunities for improvement, investigating new technologies (both hardware and software based) and understanding what other utilities employ as 'best practices', as well as whether they would be beneficial to THESL.

Internal opportunities for improvement relate to identifying - and closing - gaps in the process as well as improving the training and knowledge of maintenance crews. These improvements can be achieved through process mapping and evaluation, internal auditing, crew engagement and updating training materials.

By investigating and potentially piloting new technologies THESL is able to ensure the best use of the available resources. This can include employing brand new technologies that have the potential for large scale changes to the maintenance program, but must also consider recent improvements made to existing products. New or improved technologies can potentially benefit crews carrying out the work, administration staff supporting the maintenance program, or both. THESL monitors the industry for new and emerging technologies, however technologies will only be piloted when they are deemed to be potentially useful and have passed internal reviews and evaluations.

Understanding programs implemented by the other leaders within the industry can provide insight into alternative approaches to maintaining assets. In addition, this allows THESL to gain the knowledge acquired, including lessons learned, from programs implemented by other utilities, without having to spend the resources that would be required for implementation. Comparing other programs against the one implemented at THESL can lead to incremental improvements or even full scale overhaul of the particular maintenance task. In reviewing programs run by other utilities THESL must evaluate them based on the particular needs of its system, as they may not be the same as the company implementing the alternative maintenance scheme.

VII Conclusions

THESL's electrical distribution system is facing a number of key issues that are impacting all parts of the system. These include grid system issues pertaining to specific system types, critical issues impacting the system as a whole, and other operational and day-to-day challenges. While there have been some successes with respect to system reliability, on an overall basis, THESL's system reliability is still three times worse than the international reliability average, when ranked against other world-class cities.

In order to mitigate these issues and potential risks, while also improving system reliability, THESL believes that a combined investment program which pairs modernization initiatives with like-for-like asset replacement is required. THESL's models show that the execution of only a like-for-like replacement investment program will result in high spending, but will only yield minimal improvements to system reliability. This is due to the limitations associated with like-for-like investments, including the fact that certain assets cannot be replaced under this approach, and that this approach does not account for new technologies, circuit reconfiguration or other improvements to operational flexibility that could potentially reduce outage durations and/or impacts of failure.

THESL's evidence shows that the execution of a combined investment program with a broad focus on modernization initiatives results in a similar amount of spending as in the like-for-like-only approach, but with significant improvements to system reliability. With the execution of this combined capital investment program, THESL forecasts SAIFI to be improved by 40%, and forecasts SAIDI to be improved by 44% over the next ten-year period.

As shown in Figure 64, a total of $5.51 billion is expected to be invested into the electrical distribution system over the next ten-year period. This capital investment program will go beyond the replacement of assets and will include the resolution of critical issues associated with system contingency and operational flexibility, will include the installation of new technologies to improve outage restoration and system monitoring, will account for future load growth by developing new sources of available capacity, will eliminate safety-related risks for THESL employees and the public, will manage externally-driven asset replacements and renewal, will reduce the quantity of worst performing feeders, and will manage deteriorating stations infrastructure. This plan will also continually manage the day-to-day challenges associated with a retiring technical workforce, externally-driven plant relocation activities, connection of new customers to the system and the restoration of customers following an outage event.

If this capital investment plan is not executed, THESL's electrical distribution system will continue to be exposed to serious risks that will impact system reliability, safety and the organization as a whole. The total collective risks associated with overhead and underground distribution transformers and switches, underground cables, poles and network units has been quantified to total approximately $7 billion over the next ten-year period, where various direct and indirect cost attributes associated with in-service asset failures are taken into account, including the costs of customer interruptions; the costs of emergency repairs and replacement; and the indirect costs associated with potential catastrophic failures of assets. In a run-to-failure approach, SAIFI is expected to worsen by 15% and SAIDI by 14%.

In conclusion, the execution of this capital investment program ensures that THESL will continue to improve system reliability, will modernize the distribution system, will mitigate potential safety risks, and will ultimately provide quality services to the customer. Following the deployment of this program over the next ten-year period, the THESL electrical distribution system will achieve alignment with the system reliability levels of other world class cities.

Electrical Distribution Capital Plan (EDCP) - 2012 - 2021 - Total 10-Year Capital Budget (in $Millions)

SUSTAINING / GRID SYSTEMS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
U/G System	$135.6	$146.8	$176.6	$196.7	$193.6	$195.1	$193.6	$194.5	$197.4	$205.1	$1,835.0
O/H System	$94.6	$101.3	$114.6	$113.8	$112.9	$97.5	$88.1	$88.9	$90.5	$92.5	$994.7
Network System	$20.2	$46.4	$63.9	$63.4	$63.4	$63.0	$59.8	$63.4	$57.1	$58.4	$558.8
Stations	$24.5	$24.1	$24.0	$24.3	$24.6	$25.0	$25.1	$25.2	$25.2	$25.4	$247.4
Reactive Work	$27.3	$28.6	$30.1	$27.5	$28.0	$28.4	$28.8	$29.2	$29.7	$30.1	$287.7
Customer Connections	$34.8	$35.0	$35.0	$35.0	$38.0	$38.0	$40.0	$40.0	$40.0	$40.0	$375.8
Customer Capital Contribution	-$15.8	-$14.6	-$13.7	-$14.4	-$15.5	-$15.7	-$16.7	-$16.9	-$17.2	-$17.6	-$158.1
Externally Initiated Plant Relocations	$17.9	$11.9	$7.4	$10.5	$11.0	$12.1	$13.3	$14.7	$16.1	$17.8	$132.7
Capital Contribution to HONI	$22.8	$17.4	$7.0	$50.0	$43.0	$50.0	$26.0	$19.0	$30.0	$30.0	$295.2
Engineering Capital	$30.6	$33.2	$35.2	$37.5	$36.8	$36.1	$32.9	$34.0	$34.1	$34.8	$345.3
TOTAL ($M)	$392.5	$430.1	$480.0	$544.5	$535.6	$529.5	$491.0	$491.9	$502.9	$516.6	$4,914.5

EMERGING REQUIREMENTS / CRITICAL ISSUES	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
Standardization	$9.0	$10.3	$6.1	$6.4	$6.4	$4.8	$4.8	$4.8	$4.8	$4.8	$62.3
Downtown Contingency	$1.1	$9.3	$9.2	$9.2	$11.0	$20.4	$16.2	$16.0	$9.2	$9.2	$110.8
FESI/WPF	$11.0	$10.5	$10.5	$10.0	$9.0	$9.0	$8.0	$8.0	$7.5	$7.5	$91.0
Stations System Enhancements	$66.8	$31.9	$6.0	$5.0	$5.0	$1.0	$1.0	$9.5	$1.0	$1.0	$128.2
Secondary Upgrades	$8.6	$12.2	$9.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$30.6
Station Infrastructure	$10.6	$15.2	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5	$18.5	$173.8
TOTAL ($M)	$107.1	$89.4	$60.1	$49.1	$49.9	$53.7	$48.5	$56.8	$41.0	$41.0	$423.0

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
TOTAL PROGRAM ($M)	$499.6	$519.5	$540.1	$593.6	$585.5	$583.2	$539.5	$548.8	$543.9	$557.6	$5,511.2

Figure 64 - Total Ten-Year Capital Budget