# ICM Project – Underground Infrastructure and Cable

## Handwell Replacement Segment

**Toronto Hydro-Electric System Limited (THESL)**

# ICM Project | Handwell Replacement Segment

## I EXECUTIVE SUMMARY

### 1. Project Description

The handwell replacement segment described in this document is required to protect the public from the potential safety risk posed by electric shocks from contact voltage. Handwells are essentially electrical junction boxes embedded in sidewalks or other pavement in which the connection is made between the secondary distribution system and street lighting or unmetered scattered loads. Owing to their location, which exposes them to corrosion from salt and water and construction damage, the handwells themselves may become a source of contact voltage and damage to the wires and connections within them may allow other equipment, such as streetlight poles to become energized.

There are approximately 11,700 handwells on the THESL system. Following the Level III emergency that THESL declared in 2009 after children and pets received shocks from energized equipment, THESL began handwell replacement (See Section II, 1). By the end of 2011, THESL had replaced almost 5,600 existing handwells with new, non-conducting composite handwells (See Section II, 2). These replacements were concentrated in the downtown core because that is where both the number of handwells and the potential exposure to contact voltage are greatest.

The segment proposed in this application is to replace the remaining handwells not addressed in prior years. This segment will first target the remaining handwells in the downtown core and then replace handwells located in the surrounding areas of North York, East York, York, Etobicoke, and Scarborough. By the end of 2014, when this segment is complete, some 90 percent of handwells in the City of Toronto are expected to have been replaced. The handwells that remain to be replaced are primarily located in areas where City moratoriums prevent THESL from excavating the sidewalks or other pavement.

The following Table 1 summarizes the cost of the segment.

**Table 1: Summary of Segment Costs**

| Project Estimate Number | Project Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| 20178 | Handwell Standardization and Remediation | 2012 | $12.01 |
| 25009 | Handwell Standardization and Remediation | 2013 | $14.45 |
| 25011 | Handwell Standardization and Remediation | 2014 | $ 7.17 |
| **Total:** | | | **$33.63** |

## 2. Why the Project is Needed Now

Handwells are among the top three structures with the highest number of contact voltage hits as assessed by mobile scanning inspections (See Section III). Common causes include damage from the elements, as handwells are exposed to harsh environmental conditions, third party damage whenever the sidewalk is rebuilt or repaired, degradation of cable insulation, and substandard installation of connections. If left untreated, the public may be exposed to the potential safety risk posed by electric shock through contact voltage from the following sources:

- Contact of exposed conductor with metallic plates and covers;
- Direct contact with exposed conductor; or
- Indirect contact through another medium
    - Concrete structures (including sidewalks)
    - Conductive salt water saturates concrete and a voltage gradient forms
    - Metallic poles

### 3. Why the Project is the Preferred Alternative

Two options were evaluated to mitigate the potential safety risk associated with contact voltage:

(a) Reactive – Take no action and respond to contact voltage incidents.

(b) Proactive – Replace metal handwells with non-conductive handwells. Replacements are prioritized to address the high-risk areas based on proximity to the downtown core, where the majority of handwells are located (and thus where the majority of contact voltage occurrences on handwells are located), and where there is a high volume of pedestrian traffic.

Proactive replacement of handwells is the preferred option as this approach will mitigate the existing public safety hazard. If the segment is not implemented, the risk of contact voltage will continue at current levels until such time as this work can be done.

# II PROJECT DESCRIPTION

## 1. Overview

This segment addresses the immediate need for spending to address replacement of most handwells remaining on THESL's system. Handwells are essentially electrical junction boxes embedded in sidewalks or other pavement in which the connection is made between the secondary distribution system and street lighting or unmetered scattered loads.[1] This segment addresses handwells whose replacement has not been funded in prior years.

The objective of this segment is to mitigate the potential contact voltage risk posed by the metallic handwells by replacing existing handwells with new handwells built to current standards. As discussed more fully below, this work will include installation of composite polymer-concrete units, non-conductive lids, gel connectors, and PVC jacketed cable.

Handwells are typically found in pre-amalgamation Toronto, as well as dense mixed-use areas in other parts of the city (e.g., downtown North York or the Etobicoke core). The secondary bus is run through ducts from handwell to handwell. In each handwell, the cable used to service the streetlight or unmetered scattered load is connected to the bus. A handwell is typically installed adjacent to each individual street lighting pole. Corrosion and other factors can cause a handwell to become energized, leading to potential contact voltage incidents.

## 2. Handwells and Contact Voltage

Contact voltage is an intermittent condition when electricity or voltage is present on street equipment. Secondary electrical plant installed in the field is constantly subjected to environmental factors and susceptible to third party damage whenever the sidewalk is rebuilt or repaired. It endures water, salt and contamination ingress and wide variations in temperature.

[1] Secondary infrastructure refers to the low voltage electrical plant supplying 120/240V single phase, and 208/120V and 600/347V three phase service. Secondary supply is sourced from overhead or underground mains and feeds loads ranging from residential and commercial customers to unmetered scattered loads such as bus shelters, traffic signals, and Business Improvement Area signs, and Street Lighting circuits.

Before 2004, most shocks from utility infrastructure around the world were treated as isolated incidents. Focus on the issue was heightened in 2004, however, when a woman in New York City was fatally shocked after falling onto an energized metal service box cover. This fatality increased scrutiny from the public and regulators and triggered a wide scale awareness of contact voltage issues. In February 2009, Toronto Hydro declared a Level III Emergency after of one dog was fatally shocked in November 2008, and children and another dog received shocks in early 2009. As a result, Toronto Hydro made a decision to inspect and "make safe" all handwells and handholes in Toronto.

As shown in Figure 1, handwells and the wiring within them can corrode due to age and environmental factors. Handwell covers can also corrode (See Figure 2a, below). This corrosion and degradation of components eventually causes the integrity of the connections to deteriorate to the extent that live electrical wires become exposed. This can create a potential safety risk to the public, such as those that led THESL to develop and implement an emergency management plan, internally known as the Level III Emergency response.

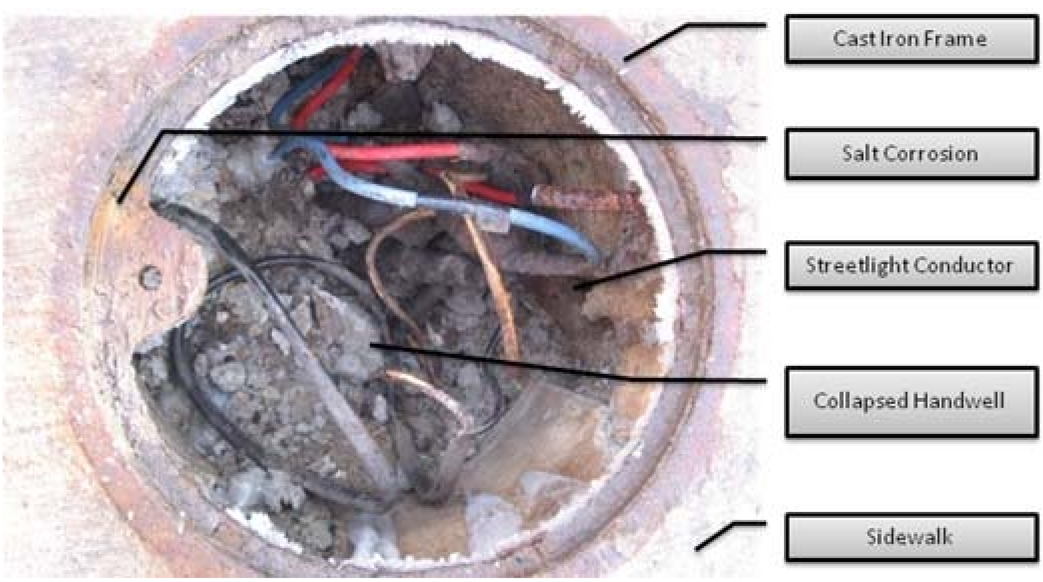



**Figure 1 – Open Handwell Photographed During Inspections**

THESL proposes replacing existing handwells with new non-conductive handwells and lids. The conductive metal covers still found on many handwells are shown in Figure 2a. In THESL's proposal, these conductive lids will be replaced with the non-conductive lids and composite handwells as shown in Figure 2b.

**Figure 2a – Metal Handwell Lids**

**Figure 2b – Non-Conductive Lids and Composite Handwell**

**Figure 3 – Degraded Conditions of Split-Bolt Connectors in Handwells**

Figure 3 shows an exposed connection of a split-bolt connecter wrapped in layers of poly vinyl chloride (PVC) tape and self amalgamative plastic (SAP). Specific procedures have been defined on the amount of PVC and SAP tape required, however this leaves room for human error if not wrapped according to the approved standard and can result in connections with insufficient insulation. Figure 4 displays the new gel connectors introduced to prevent the seepage of water and other contaminants thus eliminating the need for the taped split bolt connections.

**Figure 4 – New Handwell Connectors**

**Figure 5 – Repaired Cable**

Figure 5 shows a damaged bus cable that has been repaired with PVC and SAP tape. For improved insulation, the bus cable specifications have been revised to require a double insulation cable with a PVC jacket instead of the single insulation cable used previously.

## III NEED

Despite the work done in response to the 2009 Level III Emergency (during which time THESL undertook a comprehensive city-wide handwell inspection program), contact voltage remains an issue for pedestrians and pets in the City of Toronto. Contact voltage is most likely to occur in wet, icy, and salty conditions. The potential risk of contact voltage typically occurs in the winter and early spring, when salt is used most and when there is great deal of moisture and other contamination penetrating the handwells.

Since the Level III Emergency, THESL has launched a number of initiatives to prevent contact voltage incidents. These include:

- Adopting designs that no longer include handwells for new installations.
- Introducing new materials to combat environmental stresses including gel-connectors, polymeric-concrete handwells, and non-conductive handwell lids.
- Revising Construction Standards to require new materials.
- Developing Standard Practices for crews to follow when conducting maintenance on connections in handwells to mitigate the risk of these assets becoming energized.
- Developing Standard Practice for classifying and addressing contact voltage occurrences identified through mobile surveying.

To further reduce the risk of contact voltage, THESL must also undertake the replacement of metal handwells proposed here. There have been a number of incidents and data to support the potential safety risks that handwells present.

Since 2009, THESL has been classifying and addressing contact voltage occurrences proactively identified through mobile surveying, which is performed by an external contractor. Figure 6 shows that the number of scanned contact voltage hits has decreased each year since 2009, while Figure 7 shows that since 2009, the average level of contact voltage detected has decreased by 40%.

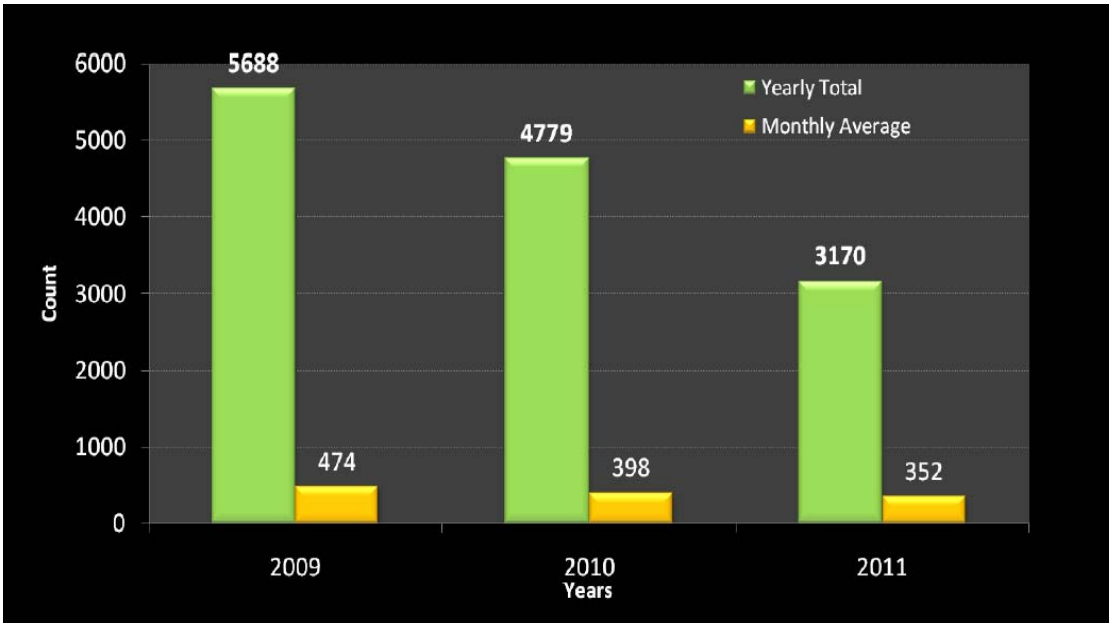



**Figure 6 – Historical Contact Voltage Hits Identified by Mobile Surveying**

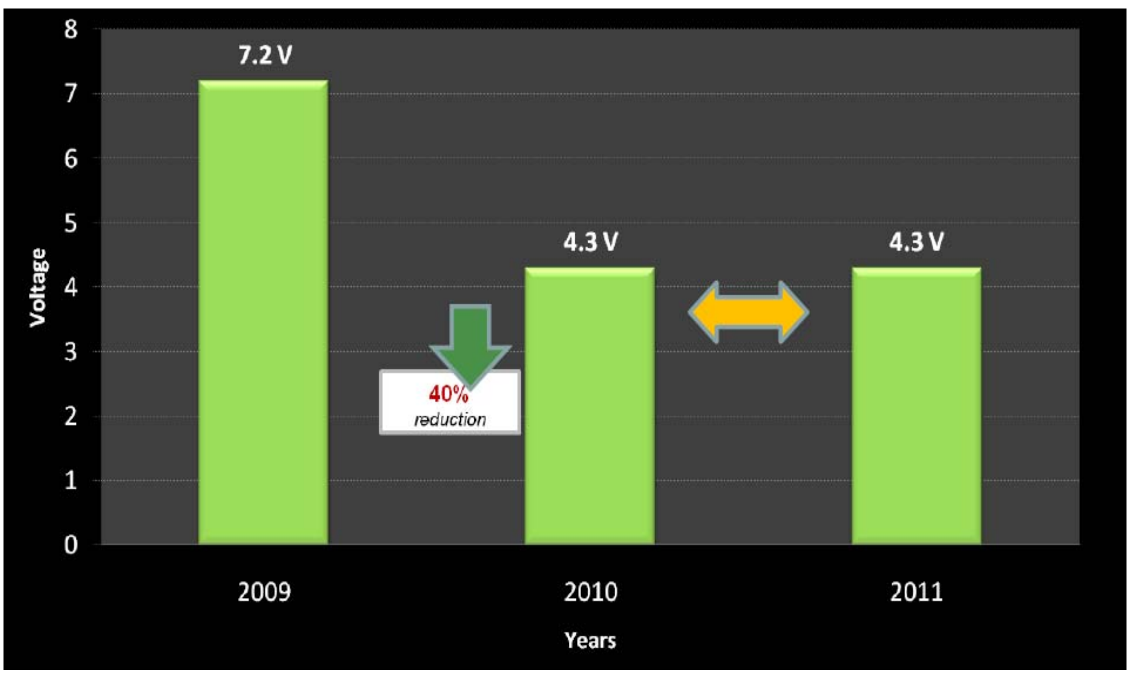



**Figure 7 – Average Level of Contact Voltage Detected**

Figure 8 shows traffic lights, handwells and street lights among the top three sources of contact voltage hits.

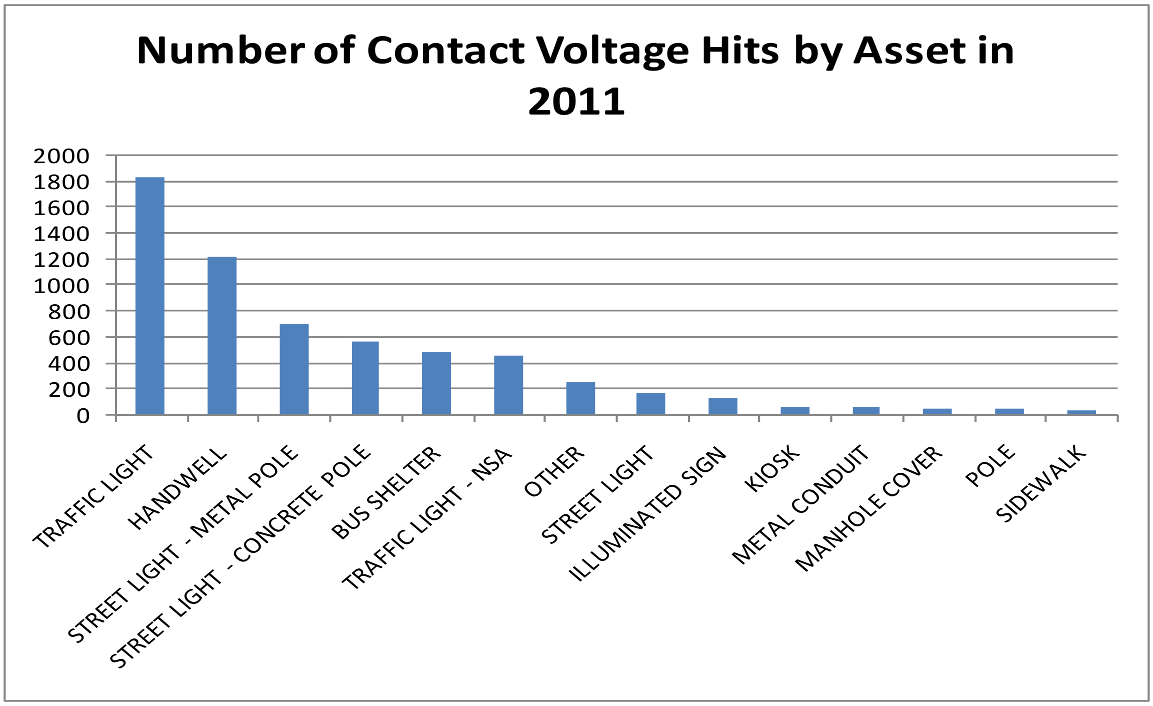



**Figure 8 – 2011 Results by Asset Class**

Additionally, Table 1 shows the number of energized (greater than 1 volt) handwells detected in THESL's service territory.

**Table 1 – Number of Energized Handwells**

| Year | Three of Energized Handwells Detected (>1 Volt) |
|---|---|
| 2009 | 777<br>(Note: scanning commenced partway through 2009) |
| 2010 | 1,219 |
| 2011 | 1,226 |
| 2012 | 524<br>(Note: includes results up to the end of March 2012) |

Any contact voltage occurrences that are not proactively detected through mobile scanning have the potential to harm members of the public. In 2011, there were eight recorded handwell contact voltage incidents which resulted in claims against THESL. These incidents are listed in Table 2.

**Table 2 – Contact Voltage Incidents on Handwells (2011)**

| Date | Location | Description of Incident |
|---|---|---|
| January 4 | Wellesley/Bay | Dog shocked |
| January 6 | Bay/Elm | Dog shocked |
| January 15 | Yonge/St. Clair | Dog shocked |
| January 21 | York/King/Wellington | Person shocked |
| February 11 | 644 Danforth Avenue | Dog shocked |
| March 8 | Eglinton/Scarlett | Dog and person shocked |
| March 26 | 638 Danforth Avenue | Dog shocked |
| August 3 | 56 McGill | Dog shocked |

## IV PREFERRED ALTERNATIVE

### 1. Project Description

The Handwell Replacement program will replace the above components which were installed based on previous standards with new components meeting the current standards. This work is intended to enhance public-safety by mitigating the potential risk of contact voltage through ongoing handwell replacements. This approach is preferred, as opposed to deferring the required work to some later date and not mitigating potential safety risks.

This work begins by addressing the highest risk areas in the downtown core due to higher pedestrian traffic and a greater number of handwells with a resulting concentration of contact voltage occurrences. THESL will then begin replacement in other areas of the City with handwells that are identified as not being constructed to current standards. The cost of this approach is an estimated $33.6 million to remediate about 4,900 handwells. This is expected to result in replacement of the vast majority of metal handwells, thereby reducing the potential safety risk of contact voltage to the public.

The alternative to the proposed replacement program would be to replace handwells reactively when specific instances of contact voltage are identified, or if they fall within the scope of a related distribution project. While this option would defer capital expenditures, it will also result in a higher potential public safety risk. As the existing handwells continue to age and the condition of the cables within them continues to deteriorate, an increase in contact voltage occurrences is expected, further compounding the risk.

Moreover, even if this work is deferred in the short term, the existing handwells eventually will require replacement due to their deteriorated condition. Reactive replacement costs may also be higher for locations identified during contact voltage scans due to the costs of after-hours work and delays in permitting. THESL believes that it is prudent to complete this work in the near term in order to address the potential safety risk.

## 2. Project Scope and Cost

Handwell replacement typically involves the following tasks:

- Excavation and removal of legacy handwells
- Replacement of active handwells with non-conductive units
- Replacement of underground secondary mains cable with a superior, dual-insulation cable
- Remaking all connections in handwells to the current standard

Forecast costs are based on an average a handwell replacement cost of approximately $6,900 per unit and do not include unforeseen locations requiring remediation.

**Table 3: Handwells - Summary of Project Costs**

| Project Estimate Number | Project Title | Project Year | Cost Estimate ($M) |
|---|---|---|---|
| 20178 | Handwell Standardization and Remediation | 2012 | $12.01 |
| 25009 | Handwell Standardization and Remediation | 2013 | $14.45 |
| 25011 | Handwell Standardization and Remediation | 2014 | $7.17 |
| **Total:** | | | **$33.63** |

# ICM Project – Overhead Infrastructure and Equipment

## Overhead Infrastructure Segment

**Toronto Hydro-Electric System Limited (THESL)**

# I EXECUTIVE SUMMARY

## 1. Project Description

### 1.1. Overview

Overall, the overhead plant of Toronto Hydro Electric System Limited (THESL) covers approximately 53 percent of the total distribution system within the City of Toronto. This document discusses the immediate need to address system-wide issues associated with overhead infrastructure and proposes jobs to replace aged, deteriorated and non-standard equipment. The main body of the document begins by describing the issues associated with THESL's existing overhead plant and the options for addressing them (Section II). This is followed by summary of the work that THESL must perform on poles, transformers, conductors, switches and porcelain hardware in 2012, 2013 and 2014 to improve safety and reliability (Section III).

### 1.2. Equipment Categories

#### 1.2.1. Wood Poles

Currently, THESL has a total of 106,860 wood poles, of which 11.4 percent are either in poor or very poor condition. This figure breaks down to approximately 2,650 poles in very poor condition, requiring immediate replacement, and about 9,530 poles in poor condition, requiring replacement in the near future (within three years). The Health Index used to assess the condition of wood poles accounts for a variety of degradation factors. These can lead to irreversible damage and include loss of pole strength, cross-arm rot, woodpecker or carpenter ant damage, surface rot at various levels of the pole, pole top feathering, wood loss and mechanical fire damage. Figures 5 through 13 in Section II below illustrate the causes and effects of pole degradation. In an extreme case pole degradation can lead to collapse as shown in Figure A.

**Figure A: Fallen Pole on Acacia Road with Rotten Base**

Maintaining wood poles in a satisfactory condition is essential for the delivery of reliable service to utility customers; pole failures lead to service disruptions to customers, while weakened poles present risks to THESL crew workers and potential safety risks. As part of the jobs described below, THESL will replace approximately 6,315 poles during 2012-2014.

### 1.2.2. Completely Self-Protected (CSP) Transformers

Completely self-protected ("CSP") internally fused transformers ("CSP transformers") are legacy installations that were put into service prior to amalgamation of the Toronto area's six municipal electric utilities to form Toronto Hydro. CSP transformers contain fusing inside the transformer tank and are typically mounted on 35-foot poles, as shown in Figure B. Once a CSP transformer has failed in the field or the primary fuse has been activated, it must be replaced. In contrast, the current standard for overhead, pole-mounted transformers (non-CSP transformers) requires the fuse to be externally-located, which provides a visible isolation point and the ability to re-fuse the transformer in about half the instances of failure.

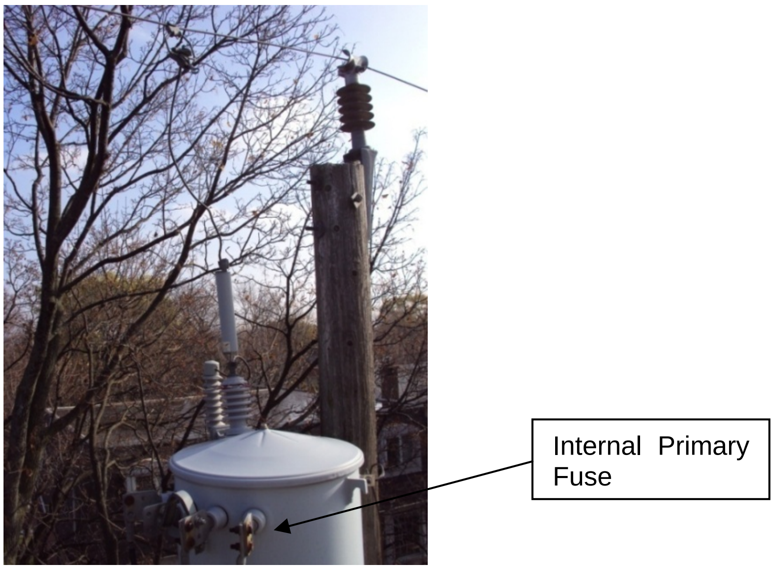



**Figure B: CSP Transformer**

CSP transformers create potential safety risks for THESL crews. CSP transformers lack the external fuse and visible disconnect switch that can be used as an isolation point when restoring standardized non-CSP transformers (See Figure C). In addition, CSP transformer restoration requires that crew members be closer to the transformer when working on it. In contrast, the use of longer equipment for standard non-CSP transformers increases the distance between the crew worker and the transformer during operation, thereby minimizing any potential safety risks that may arise.

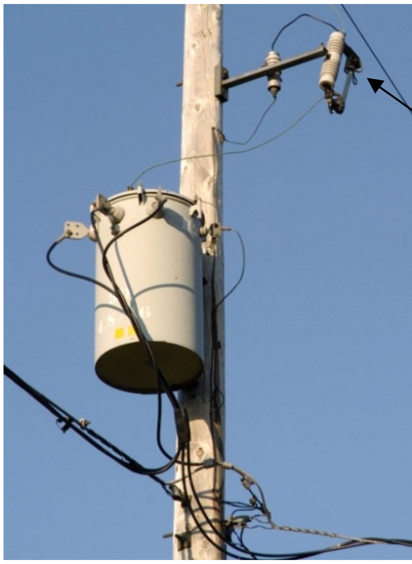



**Figure C: Standard Non-CSP Transformer**

CSP transformers have been failing at an increased rate resulting in poor reliability. In addition, the average repair time for CSP transformers is higher than for standard non-CSP transformers because when the internal fuse operates on a CSP transformer, the entire transformer must be replaced. For standard non-CSP transformers, in about half the outages, transformer replacement is not required because THESL can address the outage by replacing the external fuse while leaving the transformer in place. As a result, standard non-CSP transformer outages have a significantly lower impact on Customer Hours of Interruption than CSP transformer outages (See Section II).

THESL plans to proactively replace 35 CSP transformers with standard non-CSP transformers in conjunction with other overhead capital work conducted the 2012 to 2014 period. The drive to improve the reliability and safety of THESL's distribution system has necessitated voltage conversion and rehabilitation of deteriorated assets throughout the city. CSP transformers encountered within the areas designated this work will be replaced with standard non-CSP transformers.

### 1.2.3. Overhead Conductors

Overhead conductors play a vital role in delivering power from sources of supply to points of consumption. THESL faces two key issues with respect to overhead conductors: insufficient ampacity from undersized conductors, resulting in inefficient feeder utilization and operational constraints; and bare conductor that is susceptible to outages from tree contact.

Load growth in the system necessitates upgrades to undersized conductor to avoid complications during the restoration of feeders. Furthermore, the overhead conductor asset class is also the most susceptible to tree contact interruptions due to the lack of conductor insulation and proximity to mature trees. Sustained interruptions caused by tree contacts on the trunk portion of the feeder have risen by 60 percent from 2010 to 2011.

The replacement of undersized conductors with the current standard will allow for greater amounts of load to be transferred during outages. Implementing this option would improve operational flexibility by permitting system controllers to more effectively restore power through sectionalizing or feeder load transfers. This will lead to more efficient restoration of power to customers.

THESL plans to upgrade seven kilometres of undersized conductor as part of other overhead capital work by integrating this initiative into jobs identified under as part of the Overhead Infrastrucure Capital Segment (See Section II). The cost to upgrade these seven kilometres of undersized conductor on overloaded feeders is $ 220,000.

Upgrading bare insulated conductors with tree-proof conductors will improve reliability and mitigate the risk of further outages as result of tree contact on feeder trunks. Investment in tree-proof conductors also will help control future tree trimming costs. Runnymede TS and Leaside TS have had the largest number of outages related to tree contacts and these outages have had the highest impacts at the station level. Feeders from Runnymede TS and Leaside TS require the upgrade of a total of 61 kilometres from bare insulated overhead conductor to 556.5

kcmil tree proof conductors. The capital cost to permanently upgrade the 61 kilometres of bare insulated conductor is $2.5 million.

#### 1.2.4. Porcelain Switches

Historically porcelain had been the material of choice for electrical insulation of overhead hardware. Though the electrical insulation characteristics of porcelain in and of itself are good, the ability of porcelain to resist contamination build up and electrical tracking is not. Ultimately, this leads to a semi-conductive track that, over time, further weakens the insulator, leading to cracking and breakage that create safety and system reliability concerns. Figure D shows a porcelain switch that broke in the field.

**Figure D: Broken Porcelain Switch Returned From Field**

Three types of porcelain overhead switches found on the THESL distribution system may pose potential safety risks and constrain operations: porcelain in-line disconnect switches, porcelain SMD-20 switches, and manual air break three phase ganged switches. These switch types all serve different purposes in the overhead distribution system, as outlined below. However, they all share common the characteristic of deteriorating in ways that adversely impact safety and reliability. There are approximately 8,774 manual in-line switch locations, 7,442 porcelain SMD-20 switch locations, and 1,200 manual-ganged switch locations in THESL's distribution system.

THESL plans to replace porcelain switches as part of other overhead conversion and rehabilitation work. This option would not only mitigate the potential safety risk that these switches pose; it would also improve reliability and customer service because the switches would be replaced on a planned rather than a reactive basis. Porcelain SMD-20 switches will be replaced with new design polymer SMD-20 switches. Both in-line disconnect switches and manual air break three phase ganged switches that are at the end of their useful lives will be replaced by SCADA-Mate R2 switches.

### 1.2.5. Porcelain Hardware

Porcelain hardware, including insulators and pothead terminations, can pose safety and performance issues for the THESL system. Over the last decade, porcelain has been phased out for new installations in favour of polymer-based materials because porcelain has the following safety and system performance issues:

- Development of hairline cracks leading to failure;
- Potential for catastrophic failure resulting in shards of jagged debris;
- Higher tracking, leakage current, and system losses; and
- Incompatibility with tree-proof conductors that are essential for improving feeder reliability in heavily-treed areas.

Porcelain equipment is also a reliability concern and a significant contributor to customer interruptions within the overhead distribution system. See Figure E for an example of a cracked porcelain insulator installation.

**Figure E: Broken Porcelain Insulator**

THESL intends to replace 400 porcelain insulators yearly with the approved polymer standard in each of 2012, 2013 and 2014. Typically, porcelain insulators would be replaced on feeders in locations with deteriorated pole framing hardware including highly contaminated areas such as those close to major highways as well as congested, heavily treed areas, and other areas where the potential for failure is high and where there may be associated safety risks. Replacements would occur as part of other overhead rebuild work identified under the overhead infrastructure jobs below. The cost of this effort is over three years totals $1.56 million.

Porcelain pothead terminations also have the potential to fail in a catastrophic manner, releasing porcelain shards and dispersing oil. This can damage other nearby electrical equipment and public property. In addition, the dispersion of oil from the damaged terminations may result in a fire or an environmental hazard. Figure F shows the results of a porcelain pothead failure sending shards of porcelain onto the balcony of a nearby home, shattering the window of the family room and causing damage to the windshield of a nearby police car.

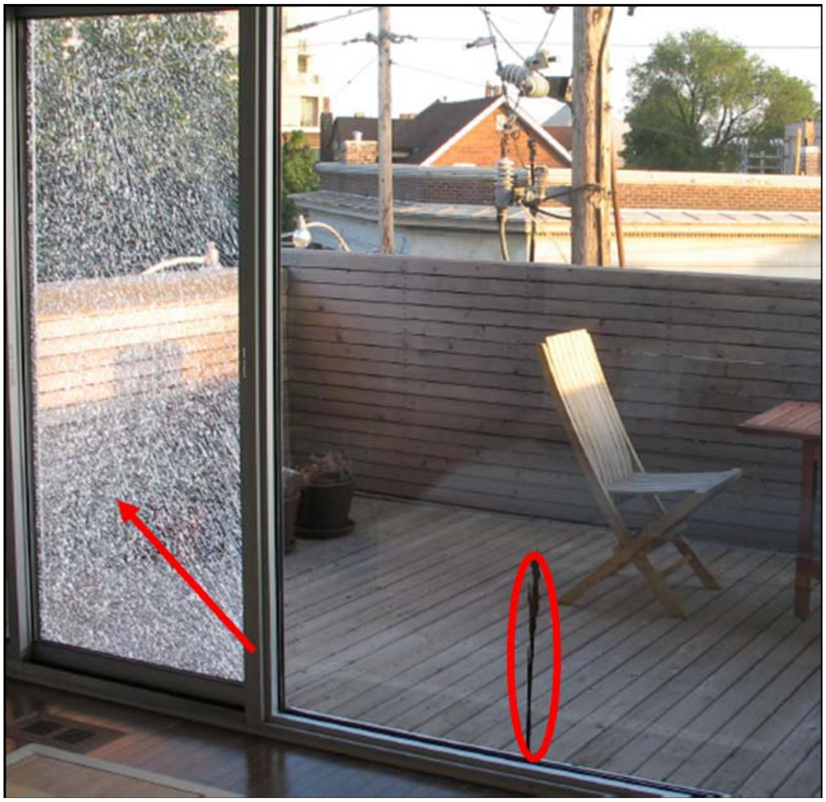


**Figure F: Failure Effects of the Porcelain Pothead Terminators**

There are approximately 565 porcelain pothead locations. The majority of porcelain potheads are located in the downtown core, with the remaining locations dispersed across the former distribution service areas of Etobicoke and Scarborough. Starting in 2012 and continuing through 2014, THESL will look to replace 50 locations annually, for a three year total of 150 locations (approximately 27 percent of the total population), by first targeting public thoroughfare areas such as sidewalks, bus stops and school zones. The cost of this effort over three years totals $3.34 million.

### 1.3. Job Structure

In Section III below, THESL discusses the specific jobs that it is proposing under this segment in each of 2012, 2013 and 2014. The main approach used to structure these jobs is to identify areas with significant numbers of the asset types discussed above and replace them altogether. This approach allows THESL to most productively use its crews and equipment by addressing all issues in an area in a coordinated fashion. This approach also minimizes job set-up time and reduces disruption in the area where the job is being undertaken.

Many of the proposed jobs are associated with voltage conversion projects. In these jobs, THESL replaces aged 4kV feeders and equipment with modern equipment on 13.8 or 27.6 kV feeders. Voltage conversion not only provides an opportunity to modernize poorly performing feeders, but also allows THESL to decommission municipal substations (MS) once all of the feeders emanating from them have been converted.

Most of the MS slated for decommissioning are 50 or 60 years old. The transformers, switches and other equipment within them are at or close to end of life. By converting the feeders necessary to decommission the MS, THESL will not only improve reliability to customers, but also avoid the need to replace the aged and obsolete equipment in the MS.

In a few instances in Section III, THESL has proposed jobs that are focused on addressing a particular issue. For example, under the job entitled “Worst Performing Feeder (WPF) Overhead Rebuilds” in Section IV, 40, THESL will undertake the rebuild of several feeders throughout Toronto that have been identified through the WPF program as having poor reliability. Rebuilding these feeders and replacing the aged and poorly performing equipment on them will improve reliability for customers who currently experience frequent outages.

### 1.4. Project Cost

The overall cost of this segment by year is shown in Table 1. The costs of the individual jobs are presented by year in Section IV in tabular form. The cost for each job is included as part of the description of the job.

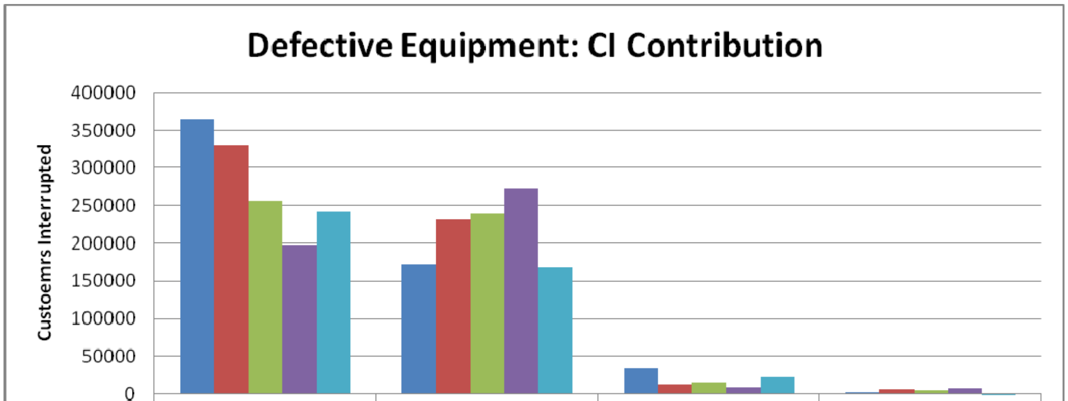
**Table 1 – Project Cost**

| | Project Year | Cost Estimate ($ M) |
|---|---|---|
| Overhead Infrastructure | 2012 | $29.43 |
| Overhead Infrastructure | 2013 | $53.02 |
| Overhead Infrastructure | 2014 | $20.11 |
| **Total** | | **$102.56** |

## 2. Why the Project is Needed Now

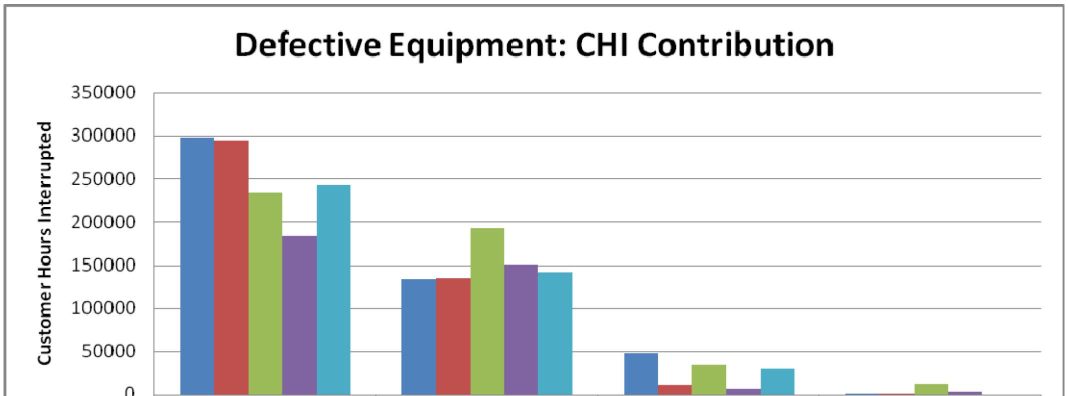
This segment is intended to address safety and reliability issues associated with aged, deteriorated and non-standard equipment types described above. With respect to safety, the failure modes associated with the equipment types described above create potential risks for THESL crews and public at large. Only by beginning to eliminate these equipment types can THESL begin to reduce these potential risks.

In terms of reliability, the general trend shows that overhead system reliability has deteriorated over the five-year period from 2007 to 2011. More specifically, overhead switches, insulators, and lighting arrestor failures have increasingly contributed to system outage levels. These causes account for 69 percent of the Customer Interruptions (CI) and 58 percent Customer Hours Interrupted (CHI) of the total Overhead Equipment failures in 2011. The impacts of overhead equipment on Defective Equipment CI and CHI Contributions are shown in Figures G and H.




| | Underground Equipment | Overhead Equipment | Stations Equipment | Other Equipment |
|---|---|---|---|---|
| 2007 | 365,677 | 171,736 | 34,905 | 2,287 |
| 2008 | 331,518 | 232,167 | 12,633 | 6,681 |
| 2009 | 256,934 | 239,523 | 16,275 | 5,248 |
| 2010 | 197,314 | 273,173 | 9,774 | 8,305 |
| 2011 | 242,697 | 168,023 | 23,852 | 6 |

**Figure G: Defective Equipment Breakdown**




| | Underground Equipment | Overhead Equipment | Stations Equipment | Other Equipment |
|---|---|---|---|---|
| 2007 | 298,330 | 133,632 | 46,958 | 1,598 |
| 2008 | 293,849 | 134,758 | 10,367 | 1,047 |
| 2009 | 233,955 | 192,458 | 33,608 | 11,946 |
| 2010 | 182,550 | 150,597 | 5,685 | 2,116 |
| 2011 | 242,694 | 141,600 | 30,341 | 3 |

**Figure H: Defective Equipment Breakdown**

Defective Overhead Equipment has had a significant impact on overall system reliability. In 2011, Defective Overhead Equipment accounted for about 15 percent of system-wide System Average Interruption Frequency Index (SAIFI) and about 14 percent of system wide System

Average Interruption Duration Index (SAIDI). From a SAIFI perspective, overhead outages account for 46 percent, 56 percent and 39 percent of the Defective Equipment-related outages in 2009, 2010 and 2011, respectively. In terms of SAIDI, overhead outages account for 41 percent, 44 percent and 34 percent of the Defective Equipment-related outages for 2008, 2009 and 2010 respectively.

There are many critical issues regarding the condition of overhead assets which should be addressed immediately. These issues have implications both for reliability and safety as discussed in the following paragraphs.

**3. Why the Proposed Project Is the Preferred Alternative**

For each equipment category discussed in Section II below, THESL presents the range of options considered as alternatives to the proposed project. Where viable alternative replacement options exist, they are explored. For example, wood poles can be replaced with concrete poles. THESL considers this option, but concludes that, except in very limited circumstances, using concrete poles would be inferior to using wood pole owing to the cost and characteristics of concrete poles as explained below in Section II.

For most equipment categories, however, the available options reduced to two: replacing the equipment over the 2012 through 2014 time period as proposed or deferring replacement to a future date. In circumstances where the equipment being replaced is no longer standard owing to safety and reliability issues (e.g., CSP transformers or porcelain insulators), THESL has adopted a new standard equipment type that addresses these issues. Thus, in these circumstances, the preferred replacement technology is already determined, only the timing of replacement remains to be decided. To consider the benefits of the proposed replacement timing versus deferral, THESL performed the Business Case Evaluation attached as Appendix 1.

In the Business Case Evaluation, the Overhead Infrastructure Segment represents an “in-kind” replacement project in which the existing overhead assets are being replaced with new standardized versions of those assets, however the overall configuration associated with this infrastructure remains the same.

In-kind projects are evaluated by calculating the ‘avoided estimated risk cost’ of executing the project immediately in 2012 as opposed to delaying it. The deferral time has been set to 2015, as a proxy for the timing of the next Cost of Service EDR application. In order to calculate the avoided estimated risk cost of performing a project in 2012 as opposed to 2015, the various costs and benefits associated with executing a project in a particular year are taken into account.

When a project analysis is undertaken, assets within the project may be before, at, or beyond their optimal replacement time, thus some assets will have sacrificed economic life and others will have incurred excess risk cost by remaining in service past their optimal replacement date. The cumulative sacrificed life and excess risk costs of the assets involved becomes a cost against the project, as shown by the red curve in Figure I.

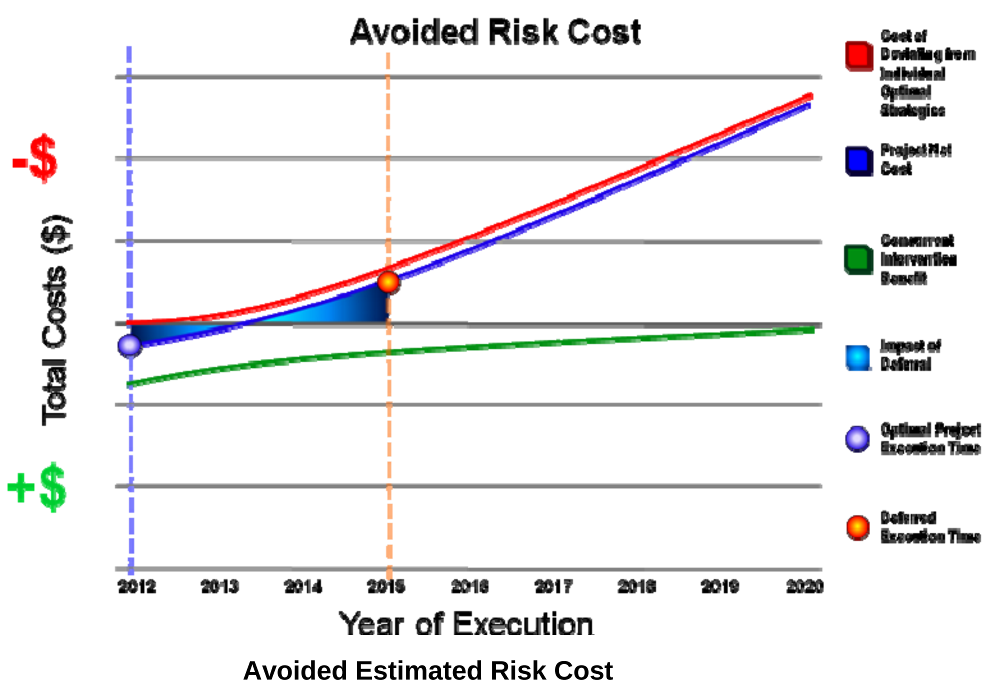



**Figure I: Example of Project Net Benefit Analysis for Job-Based Approach**

Within the Overhead Infrastructure segment, multiple assets are replaced together as part of individual jobs. This approach produces concurrent intervention benefits. Concurrent intervention benefits include factors such as equipment rentals, transportation of crew and material, excavations, and road moratoriums. These benefits are illustrated by the green curve in Figure I. The concurrent intervention benefits are weighted against the total costs (cumulative asset excess risk and sacrificed life values) in order to produce an overall project net cost calculation. Taking the sum of the costs (cumulative asset excess risk and sacrificed life values) and benefits, year-by-year, provides the Net Project Benefit for the Job-Based Approach, illustrated by the blue curve in Figure I.

Since the optimal intervention year is the lowest point on the Project Net Cost curve, represented by the blue curve in Figure I, the estimated risk costs for the project assets in 2015 will exceed the estimated risks that exist today. By performing the work immediately as opposed to waiting until 2015, these estimated risks are eliminated. Therefore, these avoided costs represent the benefits of the in-kind project execution in 2012 as opposed to 2015.

The formula for this calculation is detailed below:

Avoided Estimated Cost = $PV(PROJECT_{NET\_COST}(2015)) – PROJECT_{NET\_COST}(2012)$

Where:

- $PROJECT_{NET\_COST}(2012)$: Represents the total project net costs in 2012.
- $PV(PROJECT_{NET\_COST}(2015))$: Represents the present value of total project net costs in 2015.

Within the Overhead Infrastructure segment, individual optimal intervention timing results were calculated for each of the assets to be replaced. The basis of this calculation is discussed in Appendix 1, Section 1.1.

As noted in the formula above, this Project Net Cost was then calculated for all overhead infrastructure segment assets at years 2012 and 2015, respectively. Project Net Costs quantified in 2015 were brought back to a present value and the difference between this value and the Project Net Cost quantified for 2012 was taken as the Avoided Estimated Risk Cost. The final results are provided in Table 1.

**Table 1: Avoided Estimated Risk Cost for Overhead Infrastructure Project**

| Business Case Element | Estimated Cost ($ M) |
|---|---|
| Present Value of Project Net Cost in 2015 ($PV(PROJECT_{NET\_COST}(2015))$ | $ 186 |
| Project Net Cost in 2012 ($PROJECT_{NET\_COST}(2012)$) | $ 111 |
| **Avoided Estimated Risk Cost = ($PV(PROJECT_{NET\_COST}(2015)) – PROJECT_{NET\_COST}(2012)$)** | **$ 75** |

Based on the safety and reliability benefits from completing this segment and the demonstration in the Business Case Evaluation that undertaking this segment now as opposed to 2015 has a lower net costs, the proposed segment is the preferred alternative. It is the least cost alternative to customers.

# II EQUIPMENT DESCRIPTIONS

## 1. Overhead Infrastructure – Overview

This section discusses various overhead infrastructure equipment categories targeted for replacement. These include:

- Wood Poles
- Completely Self-Protected (CSP) Transformers
- Undersized and Bare Overhead Conductors
- Porcelain Switches, and
- Porcelain Hardware

Each equipment category discussion begins by covering the safety and reliability issues associated with the various types of equipment being addressed. The discussion then provides options for addressing these issues and indicates the preferred alternative selected.

## 2. Equipment Categories

### 2.1. Wood Poles

#### 2.1.1. Issues with Wood Poles in Poor and Very Poor Condition

Wood poles are widely used for overhead distribution and constitute an important component of THESL's assets. As part of THESL maintenance activities, each wood pole is inspected and assessed in terms of condition and strength on a ten-year cycle. This inspection data feeds into the Asset Condition Assessment (ACA) program that assigns condition grades and quantified scores to distribution system assets on a scale from 0 (very poor) to 100 (very good).

Currently, THESL has a total of 106,860 wood poles, of which 11.4 percent are either in poor or very poor condition. This figure breaks down to approximately 2,650 poles in very poor condition, requiring immediate replacement, and about 9,530 poles in poor condition, requiring replacement in the near future (within three years). Approximately 42,650 poles, or almost 40 percent of the population, are in fair condition, requiring replacement within ten years. The useful life of a wooden pole is approximately 45 years based upon studies performed by Kinectrics.

The pole Health Index accounts for a variety of degradation factors including loss of pole strength, cross-arm rot, woodpecker or carpenter ant damage, surface rot at various levels of the pole, pole-top feathering, wood loss, and mechanical fire damage. These factors can arise for reasons such as age, the location of the pole and surrounding environment conditions.

Maintaining wood poles in serviceable condition is essential for the delivery of reliable service. The degradation factors listed above can weaken poles, making them subject to failure, which causes service disruptions. Weakened poles present operational risks to THESL crews and potential safety risks because they can lose their structural integrity and fall, particularly during storms. For all these reasons, wood pole degradation is a significant concern for THESL.

As wood is a natural material, the degradation processes are somewhat different from those which affect other distribution system assets. For example, pole rot is due to the biological processes involving naturally occurring fungi that attack and degrade wood, resulting in decay. Birds and insects also attack poles. The nature and severity of the resulting degradation depends both on the type of wood and the environment. Certain fungi will attack the external surfaces of the pole, while others will target the internal heartwood. Therefore, degradation may occur internally, externally, or in both locations. Depending on the particular pole, a number of degradation factors such as feathering, internal rot, decay at the ground line, shell rot and infestation may combine to reduce pole strength.

Figure 3 illustrates a condition found on poles known as pole-top feathering. The top portion of the pole is quite important because it contains the necessary attachments for insulators, brackets and other hardware used to secure the overhead conductors to the line. In an emergency situation, if a pole with a feathered top were to fail as a result of structural damage, the equipment on the pole would pose a potential safety risk.

**Figure 3: Pole-Top Feathering**

Figure 4 shows internal base rot. This type of deterioration weakens the pole base and when combined with external force can cause the pole to fall. A falling pole creates the risk of injury to THESL crews and the public.

**Figure 4: Internal base rot**

Figure 5 shows major cracks and holes that can also cause the pole to deteriorate. Figure 6 shows damage from rot and fire.

**Figure 5: Pole cracks and holes**

**Figure 6: Body of the pole rot and burnt**

A catastrophic failure was reported on Midland Avenue in June 2011, where 13 poles fell within an industrial area during a windstorm. After inspection, these poles had signs of shell rot (Refer to Figure 7) which led to the deterioration of their bases, which caused them to fall during the storm.

**Figure 7: Deteriorated pole base**

As a result of the windstorm, a cascading failure took place shortly after the first pole failed and fell to the ground. This failure caused the rest of the poles in the line to fall as well (Refer to Figures 8 and 9). Investigation of this incident also found evidence of ant infestation, as shown in Figure 10. This type of infestation cannot be completely eliminated and can affect any pole, independent of age. Fortunately, this incident resulted in no injuries and did not require the payment of any property damage claims; however, it had the potential to cause significant injury and property damage.


**Figure 8: Multiple Pole Failure**

**Figure 9: Multiple Pole Failure**

**Figure 10: Evidence of Infestation**

Another incident involving wood poles occurred on Pape Avenue during a voltage conversion project. Once the crew had completed the approved procedures for the project, they cut the conductor in order to remove it. After so doing, one of the wood poles began to lean over. As shown in Figure 11, this pole fell on a fence and porch roof with the conductors still attached.

The incident was caused by an aging pole with a rotten base (illustrated in Figure 12) and resulted in a property damage claim against THESL.

**Figure 11: Pole Failure on Pape Avenue**

**Figure 12: Pole base rot at Pape Avenue**

A more serious incident occurred on Acacia Road. In this incident, a pole fell onto a residence, causing it substantial damage, as illustrated in Figures 13, 14 and 15. This incident was caused by the poor condition of the pole, which had a rotten base at ground level. The pole, and the transformer attached to it, fell onto the residence, striking the second floor, roof, eaves, rafters, and front door, and damaging personal property belonging to the tenant. The resulting oil leak from the damaged transformer spread across the interior of the home. Fortunately, no one was injured, but the incident had the potential to cause significant injuries to individuals in the residence or standing in the front yard.


**Figure 13: Pole Down on Acacia Road**

**Figure 14: Damage from Pole Down on Acacia Road**

**Figure 15: Fallen Pole on Acacia Road with Rotten Base**

These incidents (Midland Avenue, Pape Avenue and Acacia Road) are examples of the types of events that have been reported due to wood poles in very poor and poor condition.

Wood poles are subject to stringent standards for treatment, inspection and maintenance. However, wood poles still have the potential to become a safety risk as they age because their anti-rot treatment dissipates with time and they deteriorate. Replacement of wood poles in very poor and poor condition poles is the only effective solution to avoid pole failure.

Figures 16 and 17 show how outages due to pole failures have affected Customer Hours Interrupted (CHI) and Customers Interrupted (CI), respectively, over the last few years. Although THESL replaced a growing number of poles in 2010 and 2011, the number of poles recognized to be in poor and very poor condition has continued to increase. This growth is attributable to a combination of continued degradation of the poles and improved pole sampling, which increases the accuracy of THESL's estimates of the condition of the wood pole population. In 2011, there were eight outages due to pole failures from cracks, rot and fire. One of the pole failures took place at Fairbanks TS, where field staff reported a broken pole on Glencairn Avenue affecting about 2,000 customers. The resulting outage lasted more than 11 hours. Similarly, in another incident at Manby TS, field staff reported a rotten pole on Riverbank Drive affecting 27 customers, and resulting in an outage lasting more than ten hours.

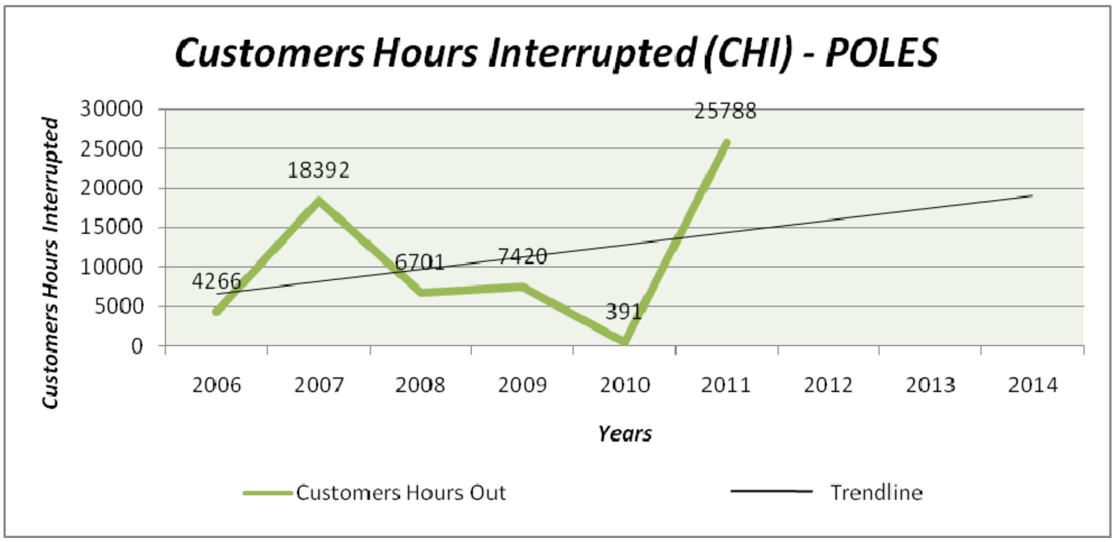



**Figure 16: Customers Hours Interrupted (CHI) – POLES**

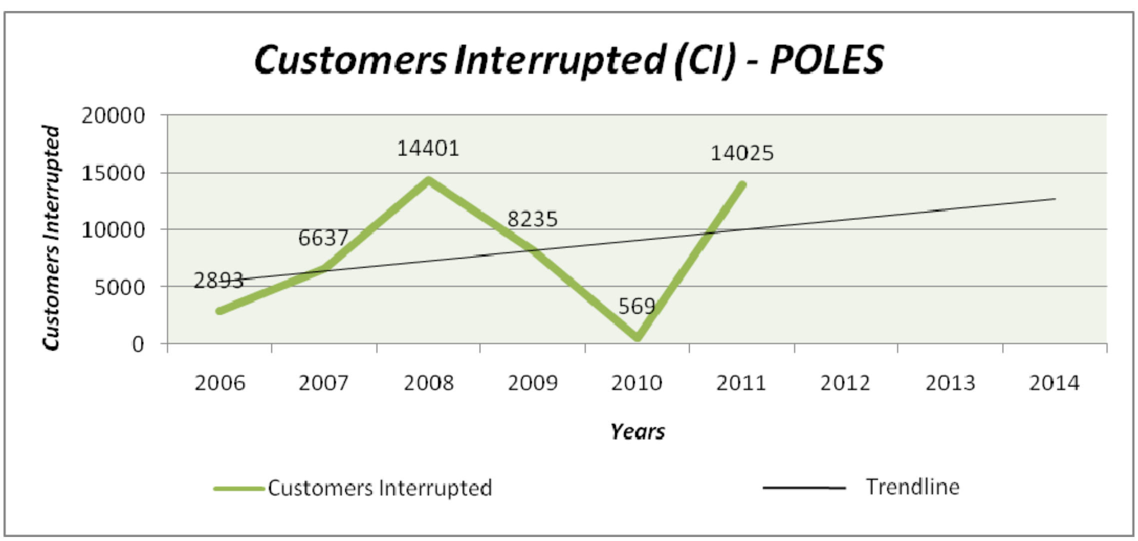



**Figure 17: Customers Interrupted (CI) – POLES**

Figures 16 and 17 also show the extended trend line over the next three years. This trend line demonstrates that failure to increase the replacement rate of poles in poor and very poor condition will likely lead to a continuing decline in overhead reliability. Customers will continue to experience an increase of unplanned outages. Further deferral of asset replacement will also result in a larger backlog of assets requiring attention in the immediate future and increase the difficulty of managing operational constraints that limit asset replacement.

The replacement of poles identified as being in poor and very poor condition, along with associated equipment, as discussed below, is the most practical and cost-effective way to ensure the continued integrity of the distribution system.

### 2.1.2. Options for Addressing Wood Poles

THESL evaluated alternatives to address areas with wood poles in very poor and poor condition, including:

(a) Replace wood poles with concrete poles
(b) Undergrounding current overhead system
(c) Pole treatment to extend poles' service life
(d) Like-for-like replacement of wood poles.

**Option (a): Replace Wood Poles with Concrete Poles**

Option (a) is used only in areas that are currently built with concrete poles in order to keep the poles consistent with the aesthetics in these areas. Concrete poles are more expensive and need to be predrilled. Wood poles are lighter and easier to work with. For all these reasons, wood poles are generally used on overhead distribution projects based on THESL's Standard Design Practice #001 Rev. 3.

**Option (b): Undergrounding Current Overhead Service**

Option (b) converting overhead to underground service, represents a more costly investment because this approach requires constructing concrete-encased ducts and cable chambers, installing underground cable and obtaining city permits. As a result of these activities, the timeline for completing underground conversion is significantly longer than the other options evaluated. Although this option requires greater investment and time, there are some scenarios where transferring the system underground is the preferred alternative. An example would be station egress cables where pole congestion is present. In most cases, however, the cost and time required preclude conversion to underground service.

**<u>Option (c): Pole Treatment to Extend Poles' Service Life</u>**

Option (c) is the treatment of existing wood poles to extend their useful lives. Manufacturers' treatments lose their effectiveness over time. Re-treatment is designed to restore an effective preservative level in a pole and, thereby, extend its service life. THESL incorporates external and internal treatment for poles. Through visual inspection, sounding and scraping, THESL determines whether the pole requires external treatment and applies it where necessary. Internal treatment consists of injecting liquid fumigant to poles with hollow hearts resulting from decay or insect infestation. External and internal pole treatments do not guarantee a pole's integrity. The only option for poles that already have been re-treated several times, and are still in poor or very poor condition, is to replace them.

**<u>Option (d): Like-for-Like Replacement of Wood Poles</u>**

Option (d) is to replace poles in very poor and poor condition with new wood poles. The advantages of replacing wood poles are as follows:

- Wood poles are much lighter than concrete poles. They also are easier to work with because they can be drilled as required, which is particularly important when dealing with angles in the lines. In contrast, the pre-drilled holes on concrete poles are perpendicular to the pole, and are not meant to accommodate lines at angles.
- Wood poles are non-conductive. In contrast, concrete poles are conductive due to the re-bar they contain and thus need to be grounded.
- Wood poles do not require ground rods unless grounding is required to accommodate equipment.
- For most installations, wood poles are more cost effective than concrete poles.

For these reasons, the preferred option, in most cases, is to replace aging wooden poles, which have reached the end of their useful lives, with new wooden poles.

### 2.1.3. Wood Poles Selected for Replacement

The pole replacement program is an initiative aimed at replacing poles that are in very poor and in poor condition. Pole replacements are also included in project areas targeted for overhead work due to poor reliability performance and other ongoing issues with equipment condition.[1] Currently about 2.5 percent of THESL poles are in very poor condition, which represents about 2,650 poles. Of these, 14.8 percent, or about 393 poles, are located on the trunk portion of feeders. In addition, 8.9 percent of poles are in poor condition, which represents 9,530 poles. Of these, about 17.7 percent are located on the trunk portion of feeders, which represents 1,683 poles. Figure 18 illustrates the increasing number of poles in poor and very poor condition from 2010 to 2014. If these poles are not replaced now, they will continue to deteriorate and pose safety and reliability risks. Deferral of replacement to future years will only increase the number of poles in poor and very poor condition requiring replacement.

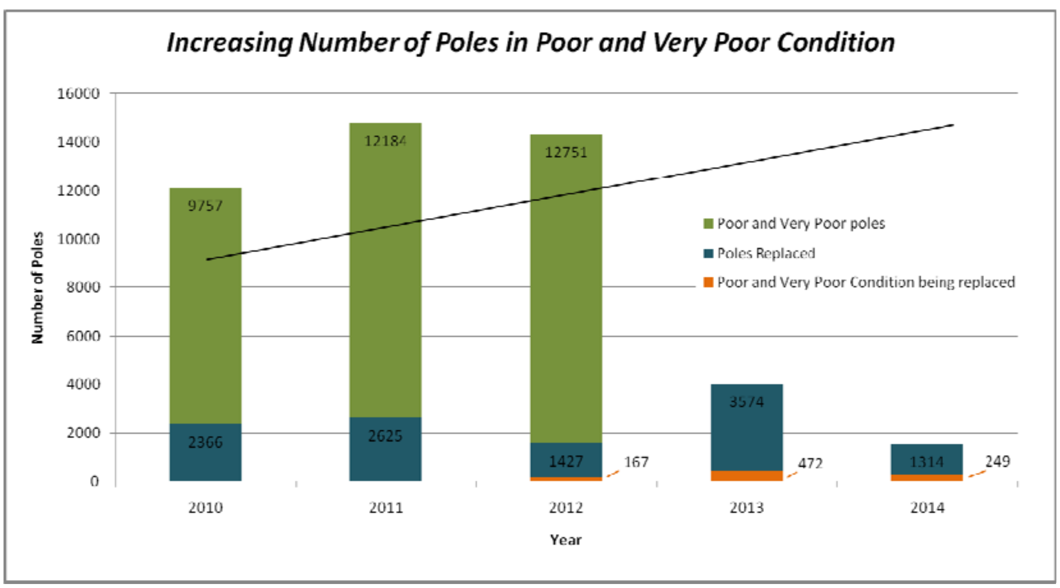



**Figure 18: Increasing Number of Poles in Poor and Very poor Condition**

[1] If THESL is replacing all of the wood poles in an area, it may also replace some poles in fair condition, to avoid having to return to the area and do spot replacements in the next few years. Poles in fair condition, however, are not targeted by the replacement program.

As mentioned previously, outages due to pole failures take a long time to restore (Refer to Figure 16). If the pole causing the outage is located on the trunk portion of a feeder, the outage can impact also as many as 3,000 customers. For these reasons, a wood pole replacement program is necessary to address pole failures before they occur and expose customers to lengthy outages.

Poles replacement priority is determined by pole Health Index information obtained as part of the ACA, by a pole testing program and by field assessments conducted by experienced field crew members and engineers. The poles that are identified for replacement are typically located on the Worst Performing Feeders, except for poles that are identified as Danger and Caution poles through an external contractor, which can be located anywhere.

THESL plans to replace approximately 6,315 poles during 2012-2014 (Refer to Table 2) at an average cost of about $11,854. The total cost of the pole replacement program is $74.86 million. This cost covers all of the costs normally associated with replacing a pole, but does not include the cost of replacing additional equipment located on the pole.

**Table 2: Pole replacement Program**

| POLE REPLACEMENT PROGRAM | | | |
|---|---|---|---|
| **Year** | **2012** | **2013** | **2014** |
| **Poles** | 1,427 | 3,574 | 1,314 |

The replacement of poles is the most practical way to ensure the continued integrity of the distribution system. This would enhance the safety of the public and THESL workforce and avoid pole failures, as well as related customer claims. A reduction in pole replacement expenditures to address end-of-life equipment will ultimately result in a continued rise in poor overhead reliability.

Maintaining poles in satisfactory condition and replacing them when required is essential for the delivery of reliable service to utility customers. Should this work be further deferred, the number of poles in the Poor and Very Poor condition categories will grow and present further operational and reliability-related risks as well as pose a potential safety risk to the public and THESL personnel.

## 2.2. Completely Self-Protected (CSP) Transformers

### 2.2.1. Issues with CSP Transformers

Completely self-protected ("CSP") internally fused transformers ("CSP transformers") are legacy installations that were put into service prior to amalgamation of the Toronto area's six municipal electric utilities to form Toronto Hydro. CSP transformers contain fusing inside the transformer tank and are typically mounted on 35-foot poles, as shown in Figure 19. Once a CSP transformer has failed in the field or the primary fuse has been activated, it must be replaced. In contrast, the current standard for overhead, pole-mounted transformers requires the fuse to be externally-located, which provides a visible isolation point and the ability to re-fuse the transformer in about half the instances of failure.

Most CSP transformers are located in north-central Toronto, with a smaller number located in the former distribution service areas of Etobicoke and Scarborough. Since amalgamation, CSP transformers have been replaced by standard non-CSP pole-mounted transformers. The additional external hardware above the transformer for the non-CSP transformers requires these assets to be installed on taller poles as shown in Figure 20.

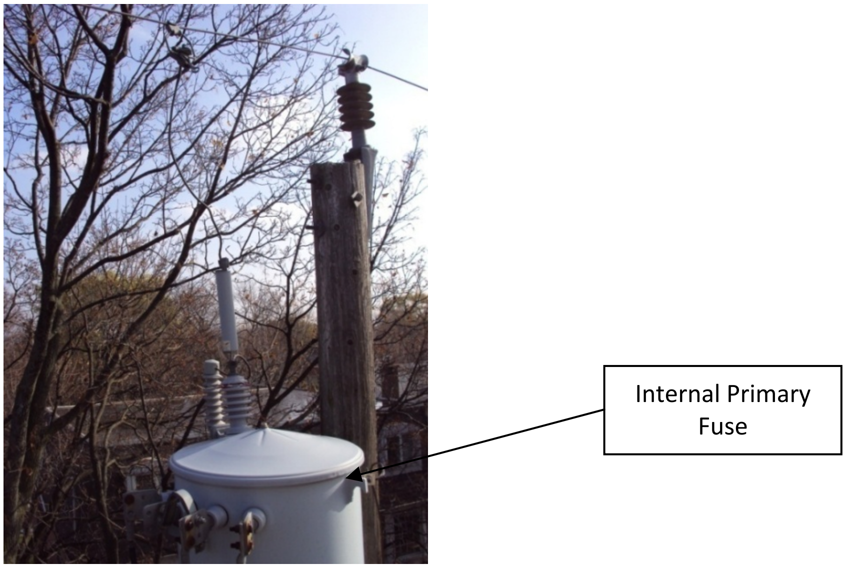



**Figure 19: CSP Transformer**

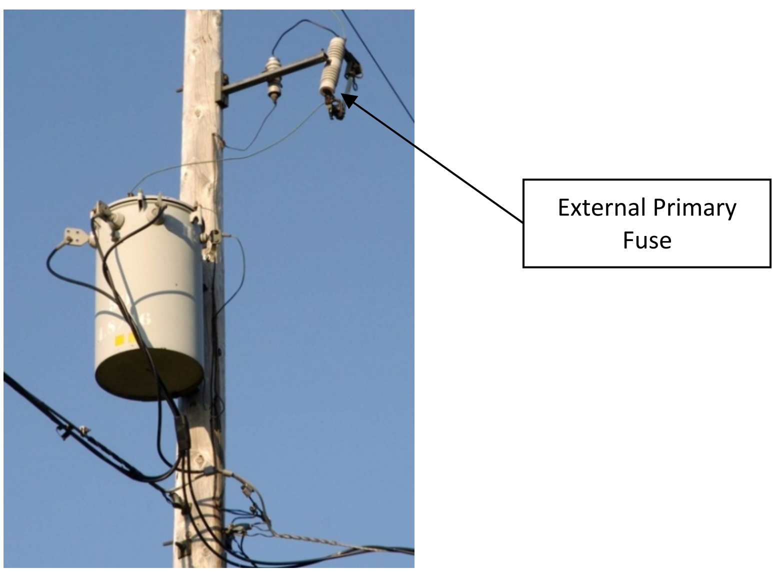



**Figure 20: Standard Non-CSP Transformer**

On CSP transformers, the primary fusing is internal to the transformer. The current-limiting fuse and lightning arrester are externally installed. In addition, a secondary breaker is incorporated as part of the secondary winding for secondary fault protection and isolation as shown in Figure 21. A typical installation is as shown in Figure 22.

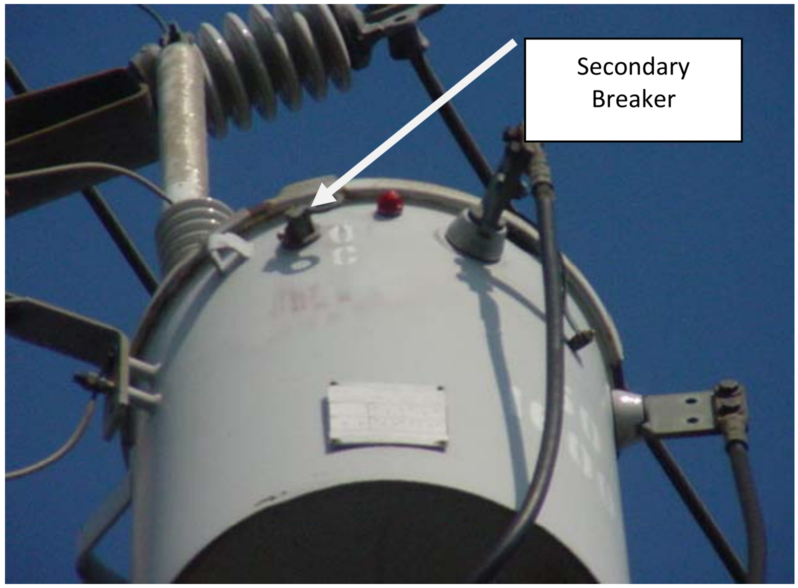



**Figure 21: CSP Pole-mounted Transformer**

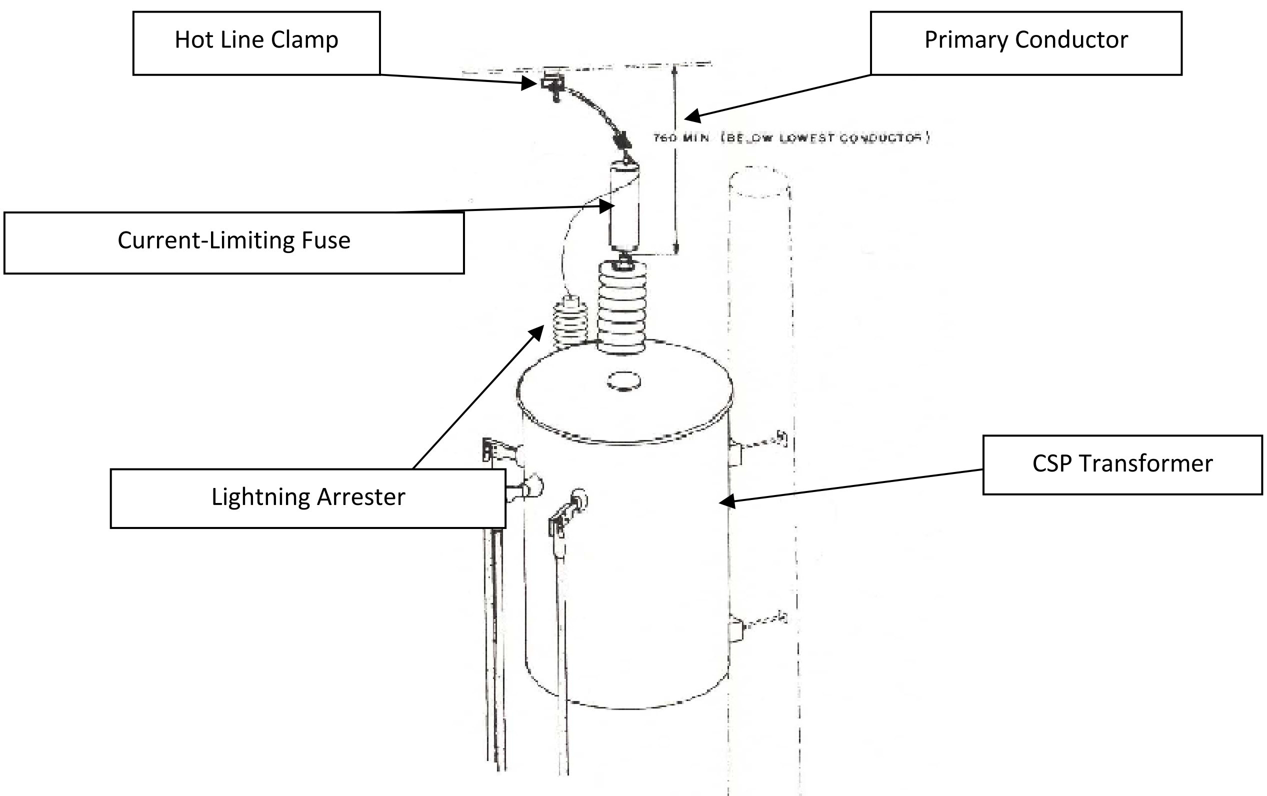



**Figure 22: Typical CSP Pole Installation**

A standard non-CSP transformer has the primary fuse externally mounted using a fused cut-out switch in conjunction with the current-limiting fuse and lightning arrester. A typical installation is shown in Figure 23.

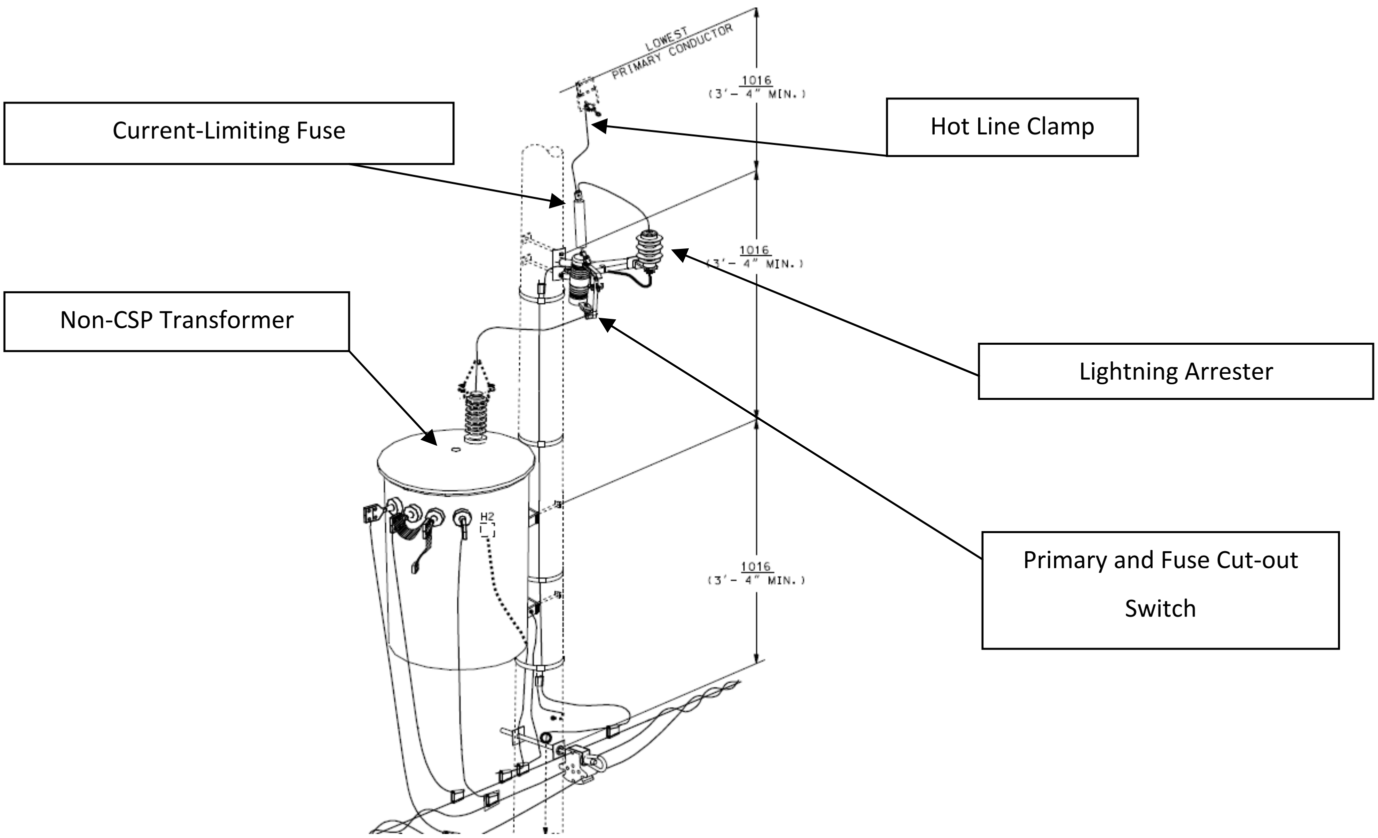



**Figure 23: Typical Non-CSP Pole Installation**

When a CSP transformer has failed, there is no visible indication of the transformer being isolated due to the primary fuse being internal to the unit. The procedure to verify if there is an internal fault on the primary winding is as follows:

- Open secondary breaker, given there is no visible disconnect.
- Disconnect the hot line clamp from the primary conductor.
- Re-install a new arrester and current-limiting fuse.
- Re-attach the hot line clamp to primary conductor using 8-foot grip-all stick.

In cases where there is no primary fault present, the re-energization of the CSP transformer is successful. However, in cases where an internal fault has occurred, the current-limiting fuse should activate at which point the transformer must be replaced.

In contrast, where a standard non-CSP transformer has experienced an outage, a visible indication is present by the fused cut-out switch being in the open position. The procedure to verify if there is an internal fault on the primary winding is as follows:

- If cut-out switch is not open, proceed to open cut-out switch using 12-foot switch stick.
- Disconnect the hot line clamp from the primary conductor.
- Disconnect secondary connections by physically disconnecting leads.
- Re-install a new arrester, current-limiting fuse and primary fuse.
- Re-attach the hot line clamp, using an 8-foot grip-all stick, to the primary conductor prior to closing the fused cut-out switch.
- Close the primary fused cut-out switch using a 12-foot switching stick.

When external cut-out fuses operate on standard (non-CSP) transformers, field observations identified that in approximately 50 percent of the cases, the replaced fuse will operate again indicating an internal fault on the transformer that requires replacement. In the other 50 percent, the replaced fuse does not operate and the standard (non-CSP) transformer remains in service. CSP transformer internal fuses cannot be replaced when activated without replacing the transformer itself.

Thus, the standard non-CSP transformer procedure improves the safety of the crew workers by allowing the visible disconnect to be used as an isolation point, as well as the use of longer equipment which increases the distance of the crew worker to the transformer during operation.

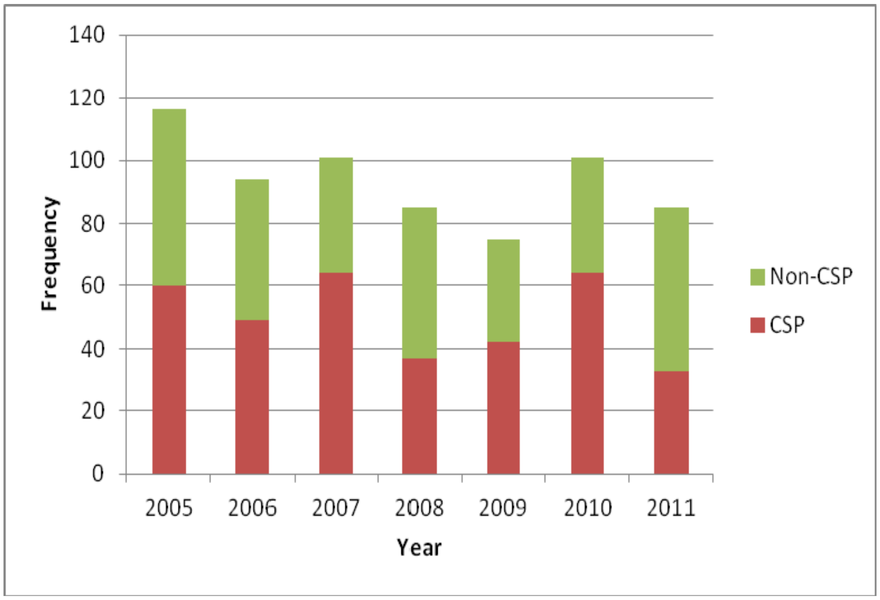
During instances when the current limiting fuse of a CSP transformer does not activate during re-closing, the transformer may experience a failure where its lid blows off. As shown from the above procedure for CSP transformers, the 8-foot grip-all stick is used to re-attach the hot line to energize the transformer as opposed to a 12-foot switching stick that is used to re-energize in the standard non-CSP transformer procedure. The longer stick allows for a greater working distance for the crew worker from the transformer and the potential risk of the lid blowing off during re-energization. Furthermore, the standard non-CSP also has the external fuse in conjunction with the current-limiting fuse to provide additional protection.

On CSP transformers, the internal fuse is designed to coordinate with the current limiting fuse (CLF), but the effectiveness of this coordination depends on the nature of the internal fault and whether the fuse has cleared properly. For example, a CLF was burning at CSP Transformer T13102 on feeder 85M23 on July 05, 2004 and became a potential safety risk for crews at the scene. As another example, on March 18, 2010, a crew arrived to find a lid blown off at CSP Transformer T8040 on feeder SS58-F1. The concern for this crew was operating on such a CSP with an 8-foot grip all stick. Incidents such as these create potential safety risks which can be avoided with standard non-CSP transformers.

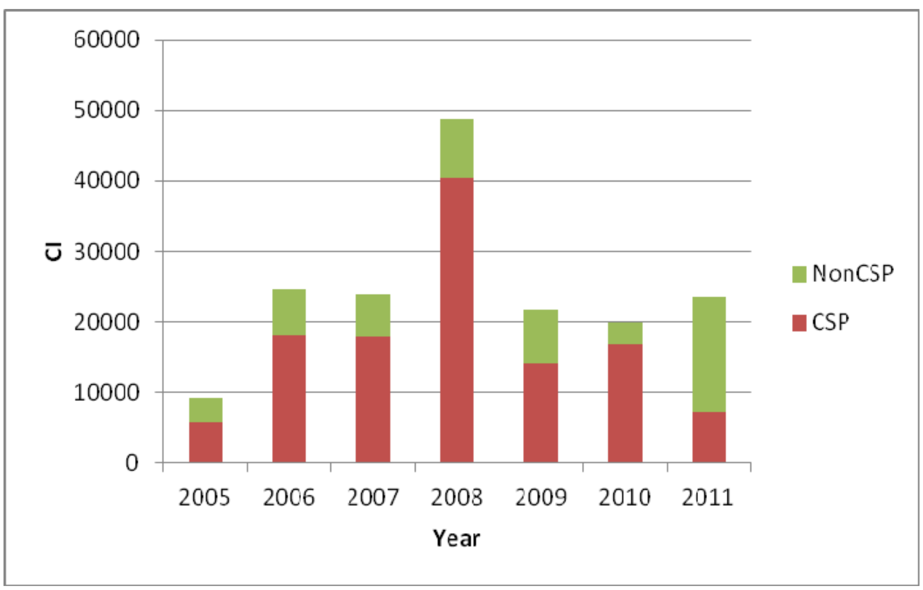
THESL estimates that CSP transformers comprise only 9.2 percent of all overhead transformers. As shown in Table 3 and Figures 24 - 26, however, CSP transformers contribute disproportionately to both the frequency and the duration of outages.

**Table 3: 2005-2011 Transformer Outages**

| | Frequency | | CI | | CHI | |
|---|---|---|---|---|---|---|
| **Year** | **CSP** | **Non-CSP** | **CSP** | **Non-CSP** | **CSP** | **Non-CSP** |
| **2005** | 60 | 56 | 5,652 | 3,630 | 4,923 | 4,925 |
| **2006** | 49 | 45 | 18,128 | 6,442 | 8,197 | 3,727 |
| **2007** | 64 | 37 | 17,868 | 6,033 | 5,872 | 3,229 |
| **2008** | 37 | 48 | 40,494 | 8,230 | 1,843 | 4,872 |
| **2009** | 42 | 33 | 14,149 | 7,618 | 4,062 | 2,709 |
| **2010** | 64 | 37 | 16,774 | 3,218 | 8,777 | 2,354 |
| **2011** | 33 | 52 | 7,160 | 16,331 | 2,774 | 4,900 |




1 **Figure 24: Summary of Outages Due to Transformers**




2 **Figure 25: Summary of CI Due to Transformers**

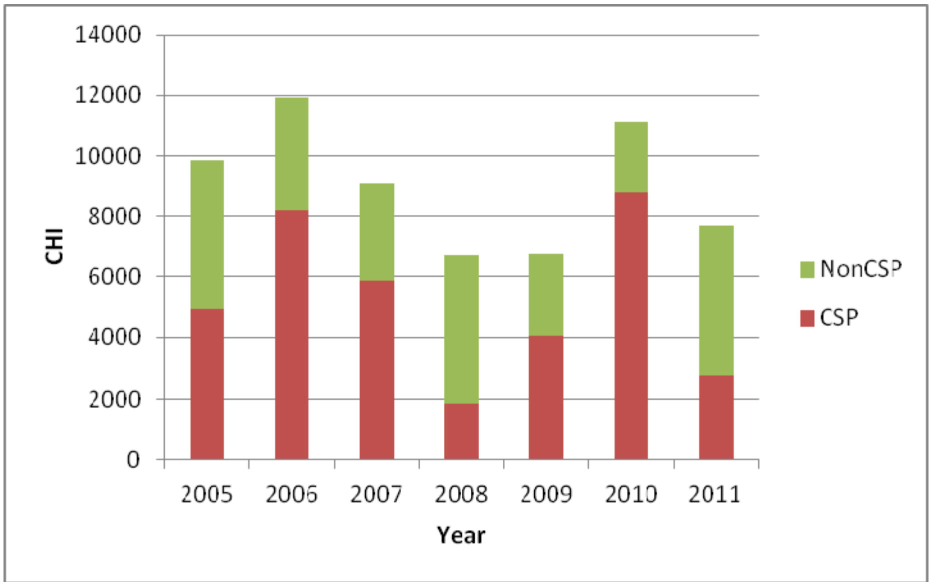



**Figure 26: Summary of CHI Due to Transformers**

Standard non-CSP transformers take approximately 195 minutes to replace. This is slightly longer than the 180 minutes to replace CSP transformers, because the standard non-CSP transformers require an additional 15 minutes to install the external fuse. However, because the standard non-CSP transformers are replaced approximately half as many times as CSP transformers, standard non-CSP transformer outages have a significantly lower impact on Customer Hours of Interruption. Table 4 shows this decrease in outage duration. As this table clearly demonstrates, the standard transformer provides increased reliability compared to its CSP counterpart, due to its lower average restoration time.

**Table 4: CSP vs Standard Non-CSP Transformer Outage Duration Comparison**

| | Standard Installation | CSP Installation | Standardization Improvement |
|---|---|---|---|
| Minutes Out Due to Blown Fuse (Typical) | 15(0.5) + 195(0.5) = 105[1] | 180 | 42% |

Note: [1]The value of 105 minutes is based on a typical replacement time of 15 minutes for the external fuse and 195 minutes for the replacement of both the transformer unit and fuse.

In addition, an outage that causes a CSP transformer fuse to activate will force the transformer to be replaced, even if it is a relatively new unit with a substantial amount of its useful life remaining. In contrast, many standard transformers will continue in operation because the primary fuse can be replaced.

If the status quo is maintained, CSP transformers will continue to pose a greater potential safety risk for field crews than standard non-CSP transformers. In addition, by continuing to install CSP transformers, THESL will lose the opportunity to further harmonize its distribution assets and ensure that all newly installed equipment meets current standards. When CSP transformers were initially installed, specialized shorter poles were used because these poles were sufficiently long for CSP transformer installations, which due to their internal fusing, require smaller clearances. The standard non-CSP transformer installations that replace CSP transformers, require higher poles to accommodate equipment clearances as a result of external fusing.

**2.2.2. Options for Addressing CSP Transformers**

Presently, there are approximately 2,200 CSP transformers in the system. A map of their locations is shown in Figure 27. Where it is efficient to do so, THESL expects to replace CSP transformers as part of other overhead capital work by integrating this initiative into regular work for rebuild jobs identified under the relevant overhead capital jobs.

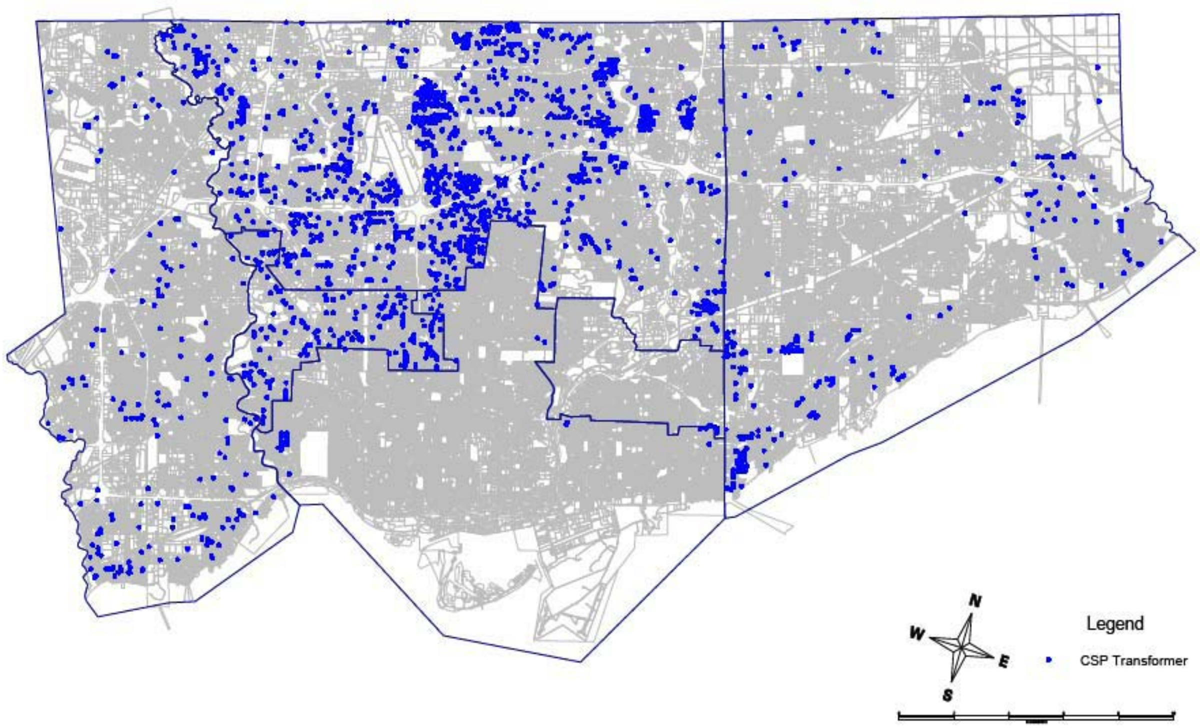



**Figure 27: Map of CSP Transformer Locations**

Three options have been identified to address CSP transformers:

(a) Proactive replacement of CSP transformers with standard non-CSP transformers in conjunction with other overhead capital work

(b) Proactive replacement of all CSP transformers with standard non-CSP transformers through a stand-alone replacement initiative

(c) Reactive replacement of CSP transformers with CSP transformers.

**<u>Option (a): Proactive Replacement with Standard non-CSP Transformers as Part of the Overhead Infrastructure Segment</u>**

The preferred option is to replace the CSP transformers with standard non-CSP transformers in conjunction with other overhead capital work. The drive to improve the reliability and safety of THESL's distribution system has necessitated voltage conversion and rehabilitation of deteriorated assets throughout the city. CSP transformers encountered within the areas designated for voltage conversion and asset rehabilitation work are planned to be replaced with standard non-CSP transformers. THESL plans to replace 35 CSP transformers with standard non-CSP transformers as part of other conversion and rehabilitation work from 2012 to 2014. This replacement is expected to reduce the number of CSP transformers operating past their useful lives and reduce the number of CSP transformers remaining to be replaced.

Each proposed CSP replacement with a standard non-CSP transformer includes replacement of the existing pole with a taller pole and installation of all associated external fusing hardware as shown in Figure 20.

THESL proposes to replace CSP transformers as part of other overhead capital work by integrating this initiative into regular work for rebuild jobs identified as part of the Overhead Infrastructure segment. Replacing this asset as part of an overhead rebuild is the most efficient approach because it allows THESL to undertake this work when crews are already in the area replacing other overhead infrastructure. All CSP transformers in the areas identified for overhead infrastructure rebuild will be replaced.

**Option (b): Proactive Replacement of all CSP transformers with Standard Transformers**

Proactive replacement of all CSP transformers with standard transformers would require that this work be carried out independently of other proposed overhead distribution conversion and rehabilitation activities. This would not be the lowest cost option as it would forego the savings associated with replacing CSP transformers and other distribution equipment at the same time as is proposed in Option (a). Not only does the approach presented in Option (a) result in lower cost, it also concentrates CSP replacements in areas where distribution rehabilitation is most needed because these are the areas where other overhead work is already planned.

**Option (c): Reactively Replace Failed CSP Transformers with New CSP Transformers**

Maintaining the status quo and reactively replacing CSP transformers as they fail would mean that CSP transformers will continue to fail at an increasing rate. As shown in Figures 24 to 26, CSP transformer failures had a disproportionate impact on transformer outages from 2005 to 2011. The failure rate for CSP transformers decreased from 2010 to 2011 because of an aggressive replacement strategy in the last two years. Continuing to install CSP transformers would perpetuate all of the disadvantages previously discussed.

## 2.3. Undersized and Bare Overhead Conductor

### 2.3.1. Issues With Undersized and Bare Overhead Conductors

Overhead conductors play a vital role in delivering power from sources of supply to points of consumption. THESL faces two key issues with respect to overhead conductors: insufficient ampacity from undersized conductors, resulting in inefficient feeder utilization and operational constraints; and bare conductor that is susceptible to outages from tree contact.

An important factor in conductor selection is its ampacity, the maximum amount of current it is capable of carrying. The determination of conductor ampacity needed to effectively operate the distribution system takes into account various operational scenarios including normal operation, contingency, and emergency circumstances. In THESL's 27.6kV distribution system, standard practice dictates the use of 556.5 kcmil (ASC) conductor along feeder trunk circuits. Tables 5 and 6 show ampacities for 336.4 kcmil (ASC) and 556.5 kcmil (ASC) conductor sizes under different operating temperatures and scenarios, respectively. This particular THESL standard, "Overhead Conductor Primary – Bare and System Neutral: Engineering Data, Ampacity, and Selection Table", was originally issued in August 2011.

**Table 5: 336.4 kcmil (ASC) ampacities**

| | Normal (Amps) | Normal (MVA) | Emergency (Amps) | Emergency (MVA) |
|---|---|---|---|---|
| **Summer 30 C Ambient** | 557.0 | 26.6 | 665.0 | 31.8 |
| **Winter 0 C Ambient** | 682.0 | 32.6 | 763.0 | 36.5 |
| **Voltage (kV)** | 4.16, 13.8 | | | |

**Table 6: 556.5 kcmil (ASC) ampacities**

| | Normal (Amps) | Normal (MVA) | Emergency (Amps) | Emergency (MVA) |
|---|---|---|---|---|
| **Summer 30 C Ambient** | 765.0 | 36.6 | 913.0 | 43.6 |
| **Winter 0 C Ambient** | 937.0 | 44.8 | 1047.0 | 50.1 |
| **Voltage (kV)** | 27.6 | | | |

The bare conductor, which is installed on THESL's distribution system, has no elemental barrier to prevent power outages when objects, such as tree limbs, come into contact with it. Given the susceptibility of bare conductor to tree contacts, THESL has an intensive maintenance program to trim the trees around overhead lines to reduce the reliability impact of tree contacts.

### 2.3.2. Undersized Conductor

Undersized conductors are defined as those sections of feeders that use conductor sizes smaller than the current standard practice of 556.5 kcmil (ASC). This standard was based on the rated design capacity of feeders and THESL operational practices of at least 600 Amps for the 27.6 kV system and 400 Amps for the 4.16 kV system. These undersized sections limit the feeders overall carrying capacity and the operational flexibility of the system. The conductor sizes in use include 336 kcmil, 366 kcmil, and 4/0. A total of 96 feeders in the 27.6 kV system contain 82 kilometres of undersized conductor. The percentage of undersized conductor, compared to the entire feeder, ranges from 0-20%. Figure 28 shows existing feeders with undersized conductor, where the undersized portion comprises 2% or more of the feeder.

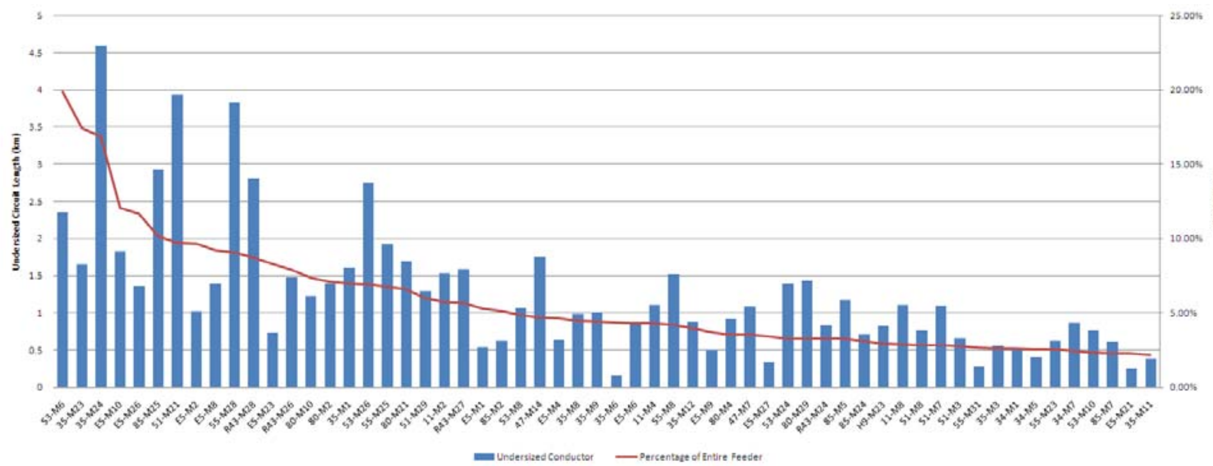



**Figure 28: Undersized Conductor**

Because the 60-year useful life of a conductor is quite long in comparison with other distribution assets, the load growth of the existing customer base over the life of feeders necessitates upgrades to undersized conductors to avoid restrictions during the feeder restoration. Refer to Figure 29 for a map of the 27.6kV system showing the locations of undersized conductors.

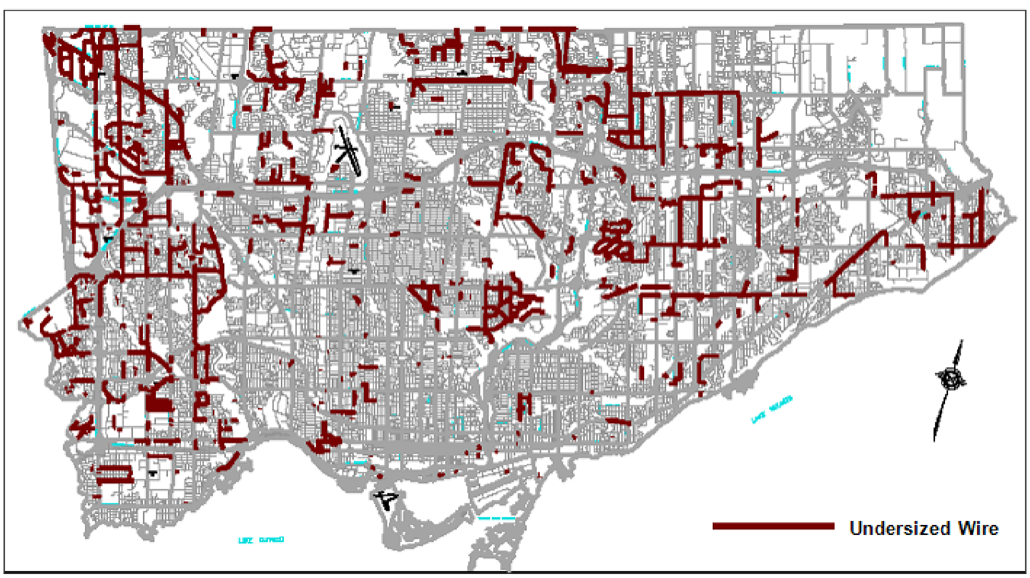



**Figure 29: 27.6 kV System Map of Undersized Conductors**

To accommodate summer and contingency loading conditions, THESL has determined that any feeder operating under normal circumstances at or above 75 percent of its corresponding maximum capacity is overloaded. This is the minimum criteria established to undertake sectionalizing during feeder restoration in the event of an outage. Based on a bus load growth factor of one percent annually, THESL projects 24 feeders in the 27.6kV overhead distribution system will be overloaded in 2012 and expects this number to continue to rise in 2013 and 2014. Figure 30 shows the projected peak loads and percentage utilization for these 24 feeders in 2012, based on one percent bus load growth.

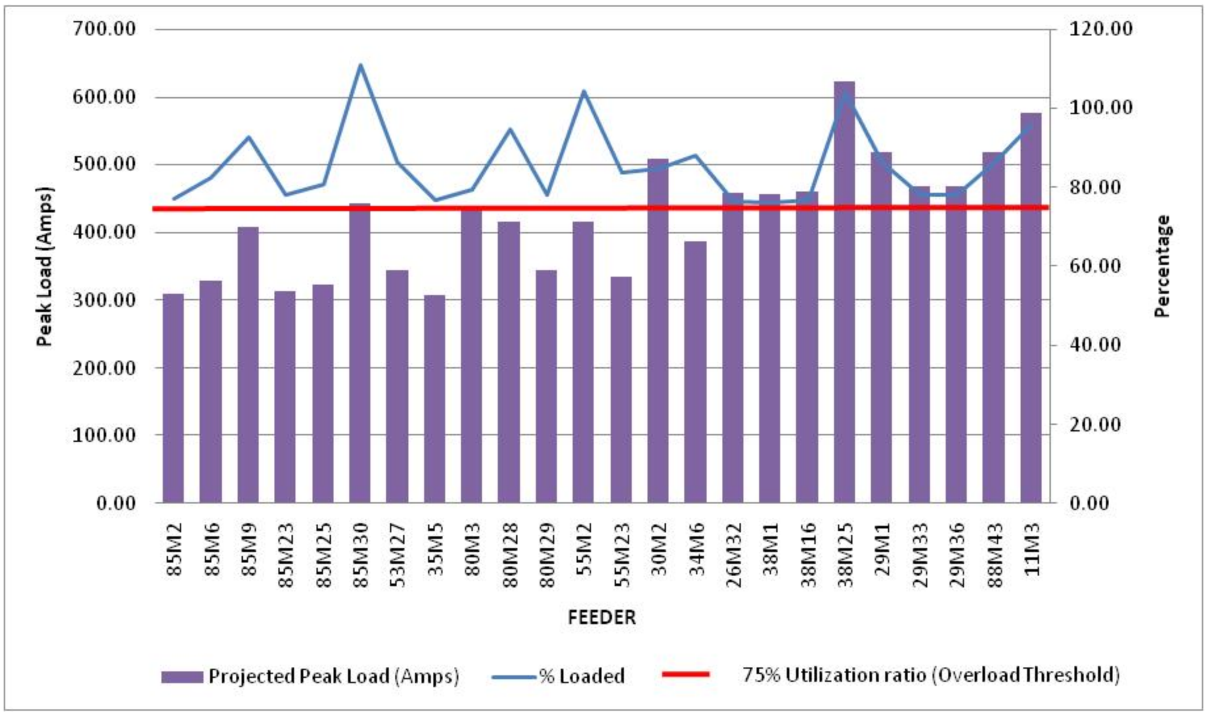



**Figure 30: Projected Overloaded Feeders**

Undersized conductors impede efficient service restoration. During a fault condition, load is typically transferred from one feeder to another, in order to restore as many customers as possible, as quickly as possible. When a fault occurs on a feeder, the feeder receiving the transferred load will be required to carry a higher load than under normal conditions.

Feeder utilization is defined as the actual loading of the feeder in relation to its maximum rated capacity. The greater the utilization value for a given feeder, the less flexibility there is for power system controllers to shift a desired amount of load to a feeder. Feeder load transfers provide faster service restoration. However, transferring load requires that the receiving feeder be loaded to no more than 50 percent; this permits the receiving feeder to support the entire load of another feeder and not go above the maximum 110 percent utilization standard. Another option is to sectionalize and segment the feeder into parts, in order to distribute and restore load evenly. In both circumstances, undersized conductors are the weak link in achieving effective restoration. This situation is compounded by the operational constraint of not loading undersized conductors above 100 percent for more than two hours. Future load growth will only make matters worse.

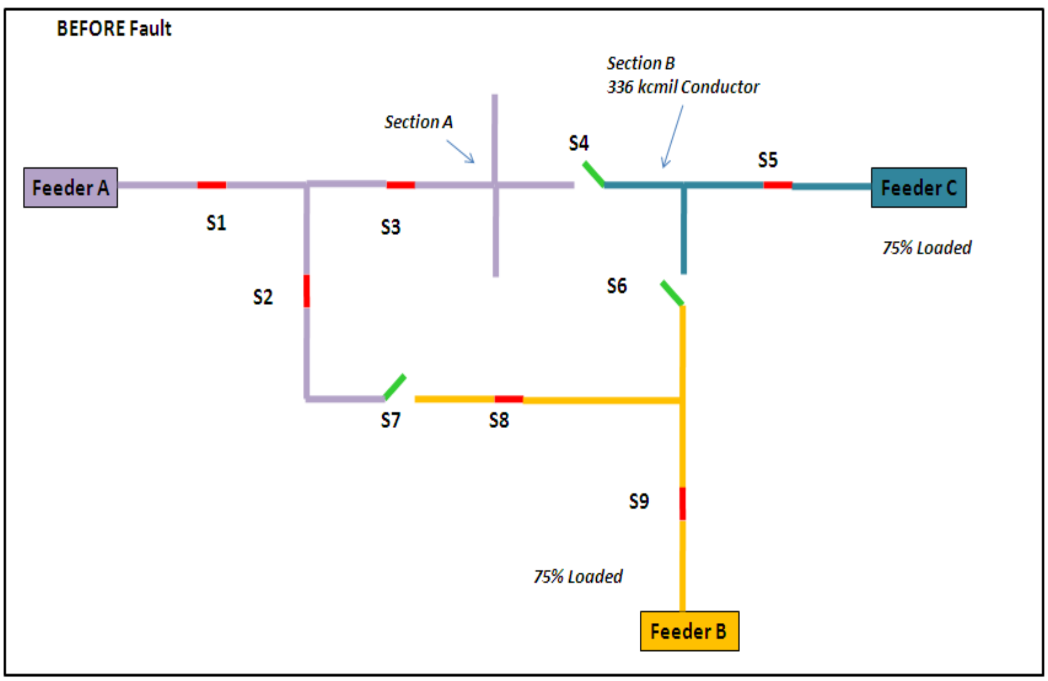



**Figure 31: Feeder Trunk Circuit with Undersized Conductor Prior to Fault**

Figures 31 (above) and 32 (below) illustrate the impediment that an undersized conductor creates when performing sectionalizing operations during load restoration. Together, they show that an undersized conductor limits the current carrying capacity of the entire feeder. Figure 31 illustrates the situation before the fault. When the fault occurs on Section A of Feeder A, the controllers analyze the various options such as feeder load transfers and sectionalizing. If feeder load transfer is not feasible because the potential receiving feeders have utilization ratios greater than 50 percent, then sectionalizing is the next approach considered. As both adjacent feeders do not have sufficient capacity, it is sectionalized and isolated by opening the normally closed switches S1, S2, and S3, as shown in Figure 32.

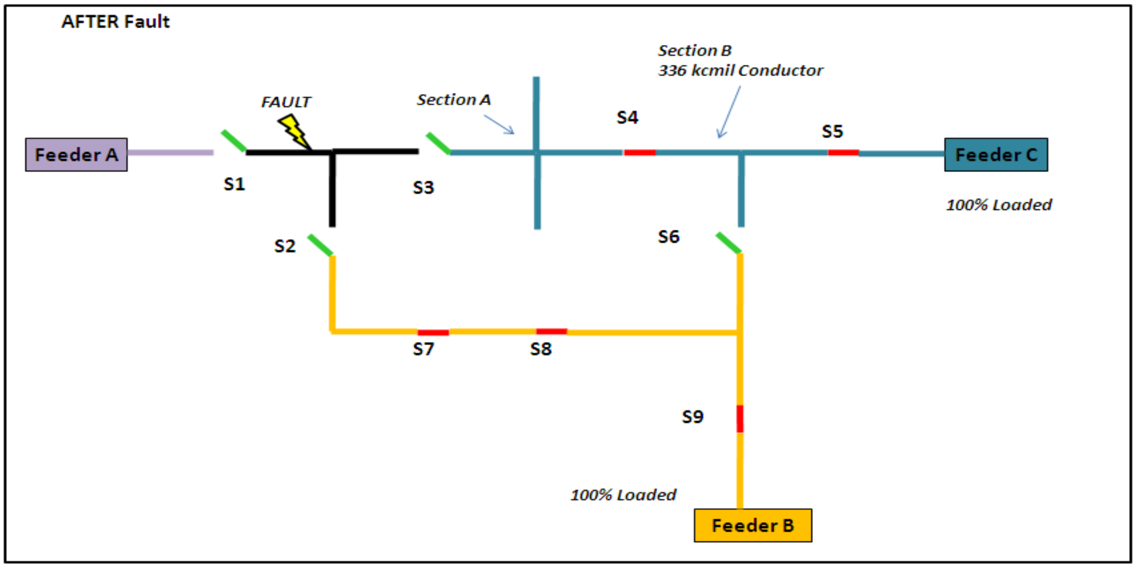



**Figure 32: Feeder Trunk Circuit with Undersized Conductor Following Fault**

However, in a configuration such as the one presented in Figures 31 and 32, even sectionalizing becomes difficult because the 75 percent loaded Feeder C (Refer to Figure 31) cannot accommodate Section A due to the limited carrying capacity of the 336 kcmil conductor. Due to this weak point on Feeder C, power system controllers will have to look for other options to restore all customers on section A. In the worst case scenario, one where there is no other load transfer option available, power system controllers will be forced to sectionalize load onto Feeder C, thus placing this feeder at or above 100 percent utilization. Controllers will not maintain this arrangement for more than two hours. Crew workers will then be forced to construct new lines on a reactive basis, which significantly increases the cost of, and the time required for, restoration.

Table 7 and Figure 33 show that undersized conductor is found on nine of the 24 feeders that are projected to be overloaded in 2012. Overloaded feeders with undersized conductors present the greatest challenges to service restoration efforts; these 9 feeders have approximately seven kilometres of undersized conductor. When these feeders were initially constructed, a 336 kcmil conductor had satisfactory ampacity to accommodate their loads. However, due to the rapid growth in some parts of the city, the current ampacity is often insufficient, particularly during feeder restoration.

The problem is not a function of the proportion of undersized conductor on these nine overloaded circuits, which varies from one to ten percent. The existence of any length of 336 kcmil conductor becomes the weak link in the entire circuit. This limits the current carrying capacity to the point of limiting the total current carrying capacity of the feeder and restricts options for controllers during feeder restoration. Whether viewed against the need to have a maximum loading of no more than 50 percent to accommodate transferring the load of an entire feeder, or the 75 percent maximum for sectionalizing, THESL has a number of feeders that pose major impediments to using load transfers to quickly restore service.

**Table 7: Nine overloaded feeders with undersized conductor.**

| Feeder | Undersized Circuit Length (kilometres) | Total Circuit Length (kilometres) | Percentage of Feeder (%) |
|---|---|---|---|
| **85-M2** | 0.6259 | 12.30236 | 5 |
| **85-M6** | 0.2343 | 21.59896 | 1 |
| **85-M9** | 0.3118 | 16.432 | 2 |
| **85-M23** | 0.1397 | 25.12292 | 1 |
| **85-M25** | 2.9292 | 28.95557 | 10 |
| **80-M29** | 1.4315 | 44.03987 | 3 |
| **55-M2** | 0.1947 | 13.20283 | 1 |
| **55-M23** | 0.6218 | 24.64877 | 3 |
| **34-M6** | 0.3448 | 28.08046 | 1 |

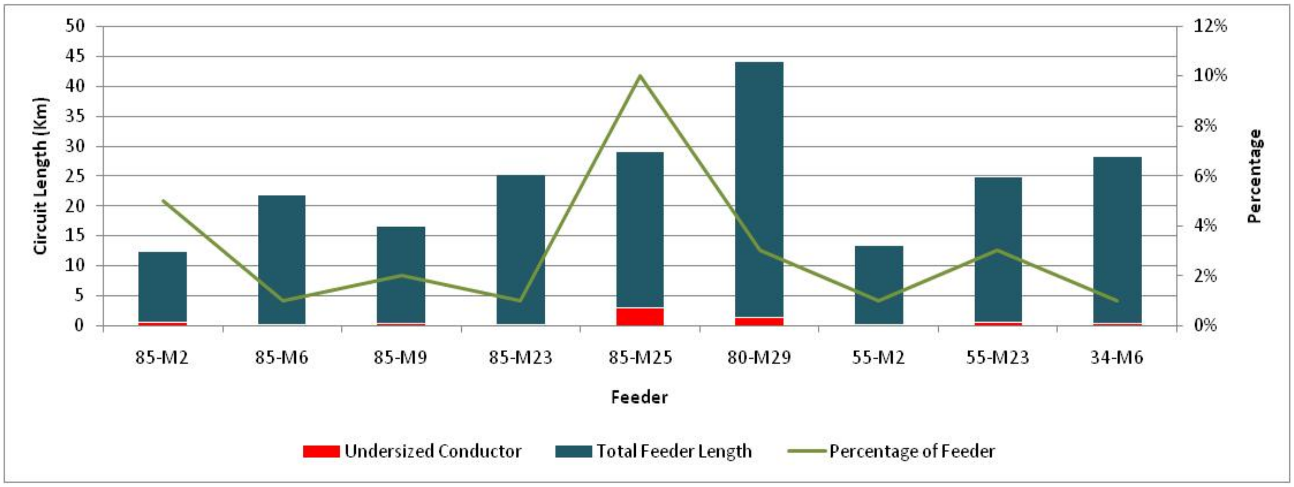



**Figure 33: Overloaded feeders with undersized conductor**

### 2.3.3. Bare Conductor

The overhead conductor asset class is susceptible to tree contact interruptions, due to the lack of conductor insulation and the proximity of mature trees. The ten-year historical reliability analysis in Table 8 shows the outage frequency and impact of tree-related (including adverse weather and brush contacts) interruptions.[2]

[2] "Interruption" means the loss of electrical power to one or more customers, including interruptions scheduled by the distributor but excluding part power situations, outages scheduled by a customer, interruptions by order of emergency services, disconnections for non-payment or power quality issues such as sags, swells, impulses or harmonics. "Momentary interruptions" or "Auto" means an interruption of less than one minute. "Sustained interruptions" or "forced" means an interruption of one minute or more.

**Table 8: Tree contact trunk outages (2001-2011)**

| | Forced | | | Auto | | Total | | |
|---|---|---|---|---|---|---|---|---|
| **Year** | **Frequency of Outage** | **CI** | **CHI** | **Frequency of Outage** | **CI** | **Frequency of Outage** | **CI** | **CHI** |
| **2001** | 5 | 10366 | 12264 | 14 | 36757 | 19 | 47123 | 12264 |
| **2002** | 6 | 18367 | 17495 | 7 | 23884 | 13 | 42251 | 17495 |
| **2003** | 18 | 34800 | 28289 | 20 | 50632 | 38 | 85432 | 28289 |
| **2004** | 6 | 20809 | 10968 | 3 | 10108 | 9 | 30917 | 10968 |
| **2005** | 18 | 45498 | 28198 | 12 | 34098 | 30 | 79596 | 28198 |
| **2006** | 30 | 83175 | 49672 | 19 | 47184 | 49 | 130359 | 49672 |
| **2007** | 11 | 24194 | 27217 | 20 | 58767 | 31 | 82961 | 27217 |
| **2008** | 13 | 41802 | 28699 | 14 | 40784 | 27 | 82586 | 28699 |
| **2009** | 15 | 50208 | 29086 | 7 | 20487 | 22 | 70695 | 29086 |
| **2010** | 15 | 52002 | 44211 | 10 | 30970 | 25 | 82972 | 44211 |
| **2011** | 24 | 60429 | 64807 | 8 | 19754 | 32 | 80183 | 64807 |
| **Total** | **161** | **441650** | **340905** | **134** | **373425** | **295** | **815075** | **340905** |

**CI: Customers Interrupted**

**CHI: Customer Hours Interrupted**

Momentary interruptions caused by tree contacts on the trunk have been generally declining during this ten year period, as shown in the above Table 8. Conversely, Figure 34 depicts an increasing trend in the number of forced outages on the trunk portions of feeders resulting from tree contacts over the last decade. In particular, there was a signicant percent increase from 2009 to 2011.

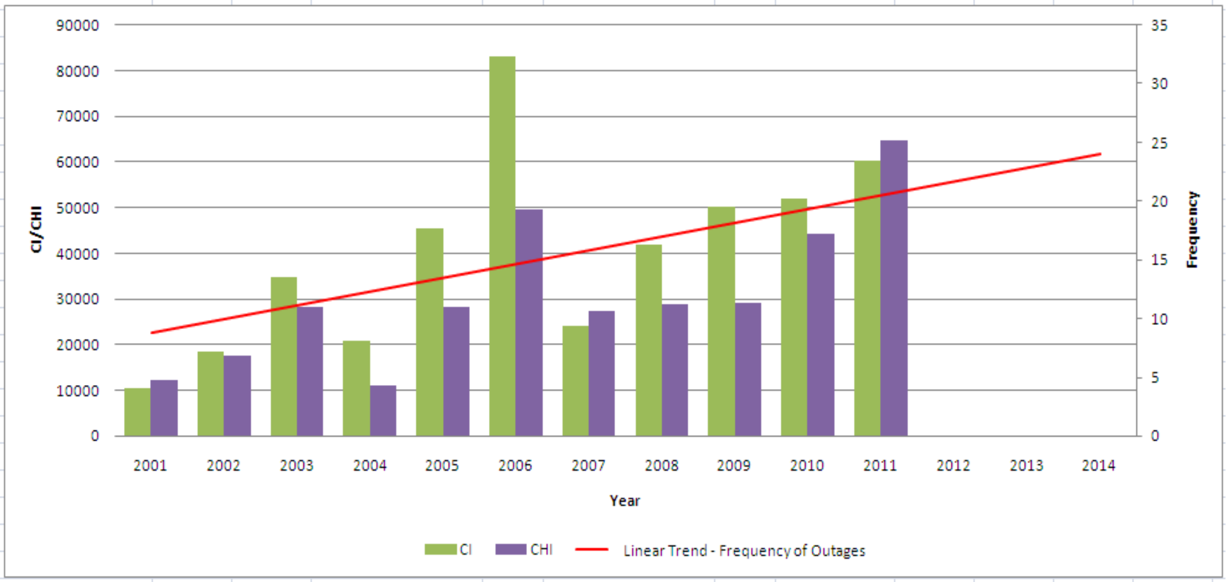



**Figure 34: 2001-2011 Forced tree outages on trunk portions of feeder**

Figure 35 and Table 9 (below) present a breakdown of the 12 feeders in Runnymede TS and Leaside TS that were affected by tree-related outages on the feeder trunk circuit. There is approximately 61 kilometres of bare insulated conductor on these 12 feeders. The proportion of such bare conductor on the trunk varies between two to 50 percent.

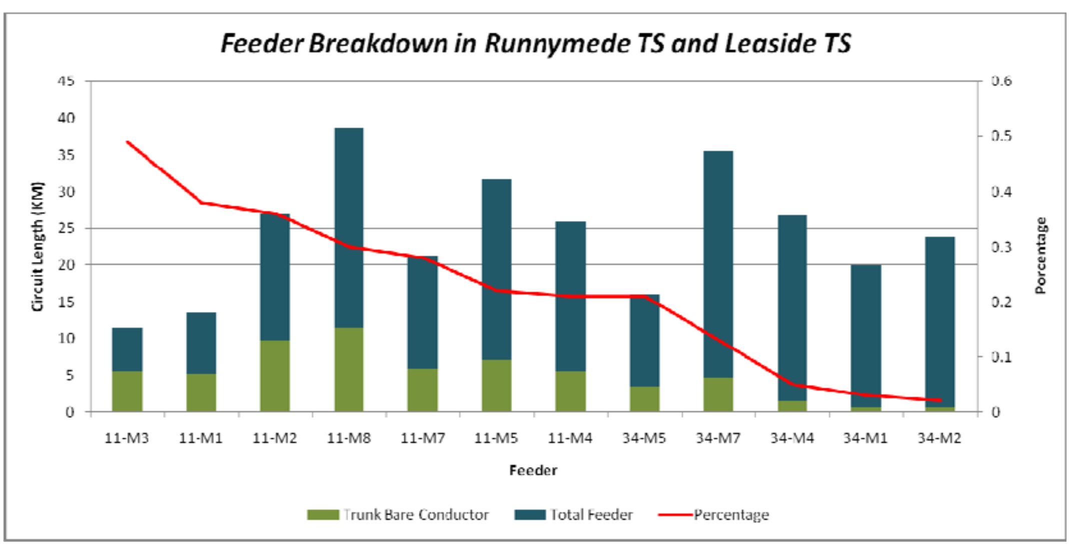



**Figure 35: Runnymede TS and Leaside TS feeder breakdown**

**Table 9: Runnymede TS and Leaside TS feeder breakdown**

| Feeder | Trunk Bare Conductor (kilometres) | Total Feeder (kilometres) | Percentage (%) |
|---|---|---|---|
| **11-M1** | 5.1136 | 13.48179 | 38 |
| **11-M2** | 9.7512 | 26.9035 | 36 |
| **11-M3** | 5.5771 | 11.32926 | 49 |
| **11-M4** | 5.5373 | 25.95147 | 21 |
| **11-M5** | 6.9671 | 31.56462 | 22 |
| **11-M7** | 5.898 | 21.34093 | 28 |
| **11-M8** | 11.4738 | 38.69671 | 30 |
| **34-M1** | 0.5 | 19.91791 | 3 |
| **34-M2** | 0.5555 | 23.86875 | 2 |
| **34-M4** | 1.417 | 26.64363 | 5 |
| **34-M5** | 3.3918 | 15.91608 | 21 |
| **34-M7** | 4.7133 | 35.59178 | 13 |
| **TOTAL** | **60.9** | **291.21** | **21** |

Tree contacts on a feeder trunk circuit will result in an outage that impacts all customers connected to the feeder, and cause the station circuit breaker to lock out. Figure 36 shows the total number of customers on each of the 12 identified feeders from Runnymede TS and Leaside TS. Thus, on each of these feeders, approximately 2,800 customers on average would experience a forced outage should there be tree contact with the feeder trunk. Tree contacts on certain feeders such as 11-M8 and 11-M5 would have the greatest impact because of the number of customers they serve and the amount of bare insulated conductors on their trunks.

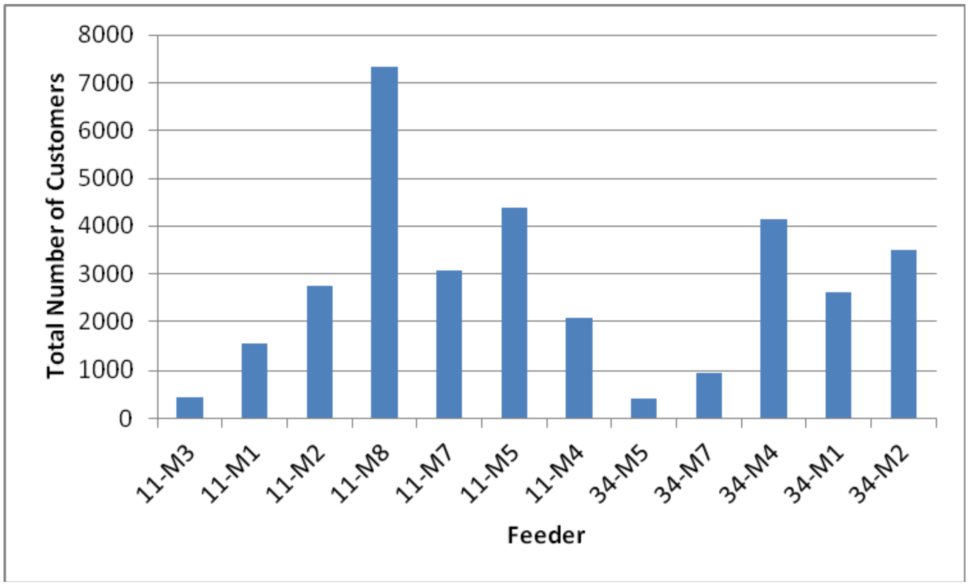



**Figure 36: Total Number of Customers**

### 2.3.4. Options for Addressing Conductors

#### 2.3.4.1. Undersized Conductors

Three options are available to address the lack of operational flexibility associated with undersized conductors:

(a) Upgrade undersized conductor on feeders projected to be overloaded
(b) Feeder reconfiguration, as part of other capital projects, to balance overloaded circuits and relieve strain due to undersized conductor
(c) Defer work on undersized conductor until 2015

**<u>Option (a) Upgrade undersized conductors on feeders projected to be overloaded</u>**

The replacement of undersized conductors with the current standard will allow for greater amounts of load to be transferred during outages. This will lead to more efficient restoration of power to customers. This specific option will target those undersized conductors on overloaded feeders, and replace them with the standard capacity conductor. Implementing this option is expected to improve operational flexibility by permitting system controllers to more effectively restore power through sectionalizing or feeder load transfers.

As previously stated, there are 96 feeders on which a portion of the conductor is undersized (less than 556.5 kcmil). These undersized portions total 82 kilometres of undersized conductor located on the trunk portions of THESL's 27.6 kV distribution system. Anticipated load growth on feeders with undersized conductor will exacerbate load transfer challenges during feeder restoration. Of the 96 feeders with undersized conductor, nine of them will be overloaded in 2012 (utilization ratio of greater than of 75 percent). The nine feeders that are both overloaded and have undersized conductor are shown on Figure 33. These nine feeders have approximately seven kilometres of undersized conductor that inhibits effective load restoration. These nine feeders need to be upgraded to THESL's standard size of 556.5 kcmil immediately.

THESL plans to upgrade the seven kilometres of undersized conductor as part of other overhead capital work by integrating this initiative into jobs identified below in Section III. The cost to upgrade these seven kilometres of undersized conductor on overloaded feeders is estimated at $0.22 million.

**Option (b) Feeder reconfiguration, as part of other capital work, to balance overloaded circuits and relieve strain due to undersized conductor**

Feeder reconfiguration capital projects allow for permanent load shifting and phase balancing to reduce the existing overall state of feeder operating loads. It includes permanent switching operations, switch relocations and installations, and other asset installations or upgrades such that operating loads are manageable and suitable points for load transfer exist to improve operating flexibility. This approach can alleviate excess loads on feeders with undersized conductor. However, depending on the specific feeder analysis, the options for reconfiguration on any given overloaded feeder may require intensive capital work to install, upgrade, or relocate assets. The cost of reconfiguration would likely be significantly greater than the $220,000 cost to replace the seven kilometres of undersized conductor on overloaded feeders in Option (a).

**Option (c) Defer work on undersized conductor until 2015**

The efficiency of power delivery will continue to deteriorate as load grows. Undersized conductors will have an increasingly negative impact on the ability to respond to outages and arrange planned work. Undersized conductors will limit THESL's ability to transfer load amongst feeders and to sectionalize feeders. This will reduce the ability to restore customers during outages and lead to longer outage durations.

#### 2.3.4.2. Bare Conductor

Several options are available to address tree contact with bare overhead conductors:

(a) Upgrade bare conductors with tree-proof conductors along those feeder trunk circuits with significant tree contacts

(b) Perform tree trimming along feeder trunk circuits with bare conductors and significant tree contacts.

(c) Defer work on bare overhead conductors until 2015

**Option (a) Upgrade bare insulated conductors with tree-proof conductors along feeder trunk circuits with significant numbers of tree related contacts**

Upgrading bare insulated conductors with tree-proof conductors is expected to improve reliability and mitigate the risk of further outages as result of tree contact on the trunk. Investment in tree-proof conductors also will help control future tree trimming costs. Runnymede TS and Leaside TS have had the largest number of outages related to tree contacts and these outages have had the highest impacts at the station level. The identified 12 feeders in Figure 36, from Runnymede TS and Leaside TS, require the upgrade of a total of 61 kilometres from bare insulated overhead conductor to 556.5 kcmil tree proof conductors. The capital cost to permanently upgrade the 61 kilometres of bare insulated conductor is estimated to be $2.5 million.

The percentage of feeders affected within these two stations is significant and can create operational strain. Concentrated groups of customers in heavily treed areas are affected by this issue. Where it is efficient to do so, THESL expects to upgrade bare insulated conductor as part of other overhead capital work. More specifically, conductors on four of these critical feeders from Runnymede TS and Leaside TS, 11M8, 11M7, 11M4, and 11M1, are being addressed and encompassed as part of larger overhead rebuilds.

**Option (b) Perform tree trimming along feeder trunk circuits with bare conductors and significant tree contacts:**

THESL currently manages tree trimming based on a maintenance cycle. Table 10 shows the tree trimming cycle on the identified feeders with a history of frequent tree related contacts on the feeder trunk.

**Table 10: Tree Trimming Maintenance Schedule on the indentified feeders having significant tree-related contacts**

| Outages (Forced/Auto) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2001** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** |
| 34M1 | 3 | 3 | 0 | 1 | 0 | 0 | 0 | 1 | 0 | 1 | - |
| 34M2 | 0 | 0 | 0 | 0 | 5 | 1 | 1 | 0 | 0 | 0 | - |
| 34M3 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | - |
| 34M4 | 0 | 0 | 1 | 0 | 2 | 1 | 0 | 0 | 0 | 1 | - |
| 34M5 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | - |
| 34M7 | 2 | 3 | 0 | 0 | 0 | 3 | 0 | 1 | 1 | 1 | - |
| 11M1 | 1 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 1 | - |
| 11M2 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | - |
| 11M3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 1 | - |
| 11M4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | - |
| 11M5 | 0 | 1 | 0 | 1 | 4 | 1 | 0 | 0 | 2 | 0 | - |
| 11M7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | - |
| 11M8 | 0 | 0 | 1 | 2 | 0 | 1 | 0 | 2 | 0 | 1 | - |

Scheduled Maintenance

Decrease in Outage after Tree Trimming

Increase in Outage after Tree Trimming

Although the maintenance program for these feeders is on an aggressive two-year cycle and succeeds in avoiding performance deterioration, it does not permanently remedy the problem of tree-related contacts on trunks. Although the tree trimming program addresses the situation in the short term, the underlying problem continues to exist. A viable, long-term solution is required.

**Option (c) – Defer Work until 2015**

Delaying plans to replace bare overhead conductor in close proximity to trees will result in more tree-contact outages. The CI and CHI contribution of tree related contacts will continue to increase.

Upgrading bare insulated conductor areas along feeder trunk circuits with historically significant tree contacts is the most effective option. It would be executed as part of other overhead work. Tree trimming should continue, but it alone cannot address the problem. If critical areas are upgraded with tree-proof conductors, reliability metrics will improve and tree-trimming cycles in these areas can subsequently be reduced.

## 2.4. Porcelain Overhead Switches

### 2.4.1. Issues with Porcelain Overhead Switches

Three types of porcelain overhead switches found on the THESL distribution system may pose potential safety risks and constrain operations: porcelain in-line disconnect switches, porcelain SMD-20 switches and manual air break three-phase ganged switches. These switch types all serve different purposes in the overhead distribution system, as outlined below. However, they all share common the characteristic of deteriorating in ways that adversely impact safety and reliability. There are approximately 8,774 manual in-line switch locations, 7,442 porcelain SMD-20 switch locations, and 1,200 manual ganged switch locations in THESL's distribution system.

The age of a switch is a major factor in determining its health index. Other factors include the manner the switch has been manufactured, installed, operated, the observed failure modes of the switch and the insulator material. Forced outages due to non-repairable failures drive the need to replace the overhead switches. The rate of failure of the switches varies with age, and certain well known patterns exist. These patterns are:

- "burn-in" failures which occur early in the life of the switch and are due to product or installation defects;
- "random" failures which are not related to the age of the failing switch – an example is a lightning strike or vehicle interference on the pole on which the switch was mounted; and
- "wear-out" failures where the rate increases with age, examples being fatigue or embrittlement of component parts.

#### 2.4.1.1. Wear-Out Failures

Overhead switches gradually wear out in the field. The switches can either fail mechanically or electrically. Approximately 30 percent of all overhead switches are past their useful life criteria and 2,600 end-of-life failures are forecast to occur over the next ten-year period. One hundred thirty-five end-of-life failures are forecast for 2012, as illustrated in Figure 37, which is based on the data in Table 11.

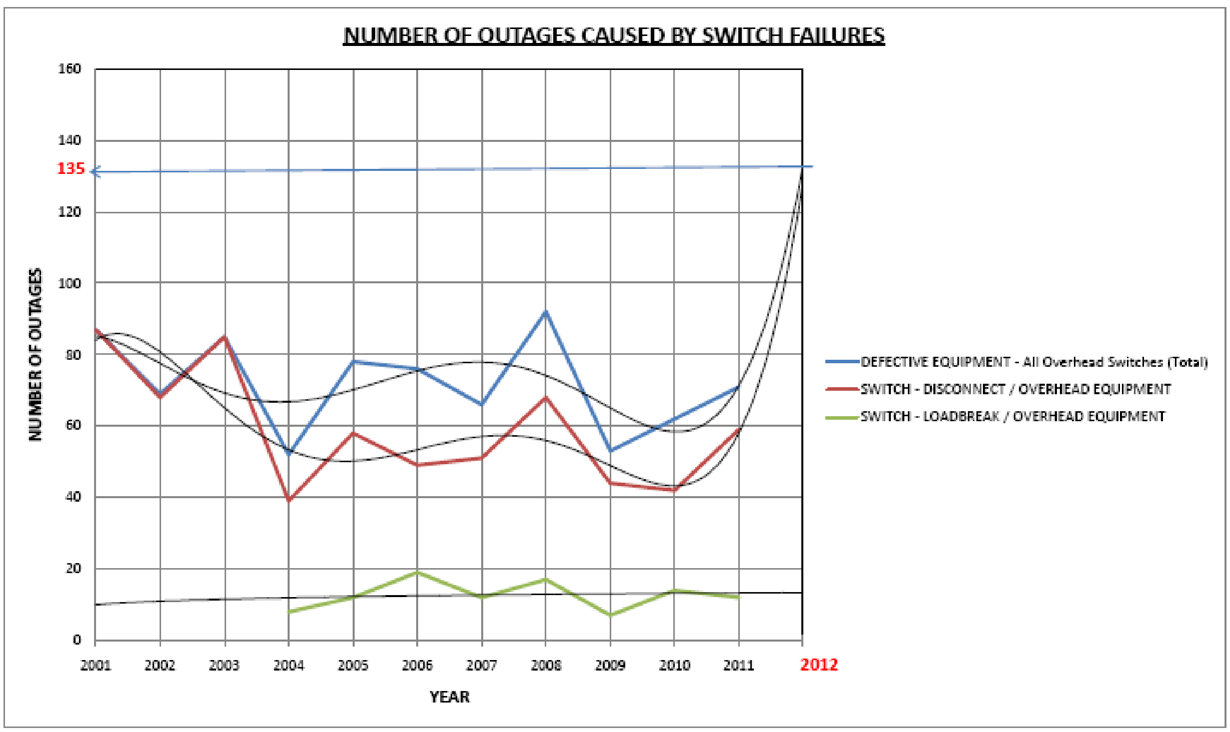



**Figure 37: Outage due to switch failures in 2001-2011 and 2012 forecast**

**Table 11: Data on switch failures from 2001 to 2011**

| Number of Outages | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DEFECTIVE EQUIPMENT - All Overhead Switches (Total) | 87 | 69 | 85 | 52 | 78 | 76 | 66 | 92 | 53 | 62 | 71 | 791 |
| SWITCH - DISCONNECT / OVERHEAD EQUIPMENT | 87 | 68 | 85 | 39 | 58 | 49 | 51 | 68 | 44 | 42 | 59 | 650 |
| SWITCH - LOADBREAK / OVERHEAD EQUIPMENT | | | | 8 | 12 | 19 | 12 | 17 | 7 | 14 | 12 | 101 |
| ALL MANUAL OVERHEAD SWITCHES ALONE *(sub-Total = DISCONNECT + LOADBREAK )* | 87 | 68 | 85 | 47 | 70 | 68 | 63 | 85 | 51 | 56 | 71 | 751 |
| SWITCH - MOTORIZED / OVERHEAD EQUIPMENT | | 1 | | 1 | 7 | 5 | 2 | 4 | 1 | 2 | | 23 |
| SWITCH - SCADAMATE / OVERHEAD EQUIPMENT | | | | 4 | 1 | 3 | 1 | 3 | 1 | 4 | | 17 |
| Total | 87 | 69 | 85 | 52 | 78 | 76 | 66 | 92 | 53 | 62 | 71 | 791 |
| | | | | | | | | | | | | |
| % contribution by manual switches | 100.00% | 98.55% | 100.00% | 90.38% | 89.74% | 89.47% | 95.45% | 92.39% | 96.23% | 90.32% | 100.00% | 94.94% |
| % contribution by manual loadbreak switches | 0.00% | 0.00% | 0.00% | 15.38% | 15.38% | 25.00% | 18.18% | 18.48% | 13.21% | 22.58% | 16.90% | 12.77% |
| % contribution by remotely operated loadbreak switches | 0.00% | 1.45% | 0.00% | 9.62% | 10.26% | 10.53% | 4.55% | 7.61% | 3.77% | 9.68% | 0.00% | 5.06% |

Projects identified for execution in 2012 include the replacement of switches that are defective and those with operational health conditions that could impede THESL field crew and impact safety. The replacement of these defective switches will lead to improved system reliability and mitigate potential safety risks throughout the distribution system.

#### 2.4.1.2. Insulator Material

Historically, porcelain was the material of choice for insulating electrical overhead hardware. Though the electrical insulation characteristics of porcelain are good, porcelain is susceptible to contamination build-up and electrical tracking, which can cause cracking, rupture or even explosion. Over 30 percent of the porcelain switches in service at THESL are either at, or beyond, the typical useful life of 50 years.

It is well known in the utility industry that certain vintage (and manufacturer) porcelain switches and cut-outs that are installed in colder climates have failed prematurely due to the type of cement used to bond the metal stud to the porcelain. The manufacturing process has also been implicated in causing premature failure in colder climates. The majority of the failure modes for porcelain cut-outs and switches are typically cracking and falling apart, resulting in injuries to operating line personnel, and in some cases, violent explosions which also could endanger any member of the public in proximity to the failure.

The weather conditions in Toronto are conducive to contaminant build up on the porcelain insulation of switches, which can lead to electrical tracking. Tracking causes the switch to fail, either by cracking the insulation, rendering the switch inoperable (as the structural integrity of the switch has been reduced to a point that prevents the switch from safely withstanding the force required to open or close it), or through a more catastrophic failure where the porcelain explodes. Exploding porcelain insulation has the potential to produce a safety risk as shards of porcelain fall from above. Recognizing the issues posed by porcelain switches, THESL no longer installs any switches containing porcelain insulation.

THESL proposes to replace SMD-20 porcelain switches with new design polymer SMD-20 switches, which use safer and more durable materials and are better designed.[3] Inline and manually-controlled gang-operated switches will be replaced with SCADA-Mate remotely-controlled gang-operated switches. The operating functionalities – opening and closing – of

[3] First generation polymer SMD-20 switches had a manufacturing defect which requires their replacement as described in Tab 4, Schedule B7 "Polymer SMD-20 Switches Segment." All porcelain SMD switches will be replaced with the redesigned polymer switches.

SCADA-Mate R2 switches are accomplished within sealed interrupters, in a controlled environment reducing the tendency to corrode. The SCADA-Mate replacements also offer improved reliability benefits, as outage restoration times are reduced from three hours to 30 minutes.

Generally, as the non-standard porcelain switches in service deteriorate, they tend to reduce the reliability of feeders and create potential safety risks. The non-standard porcelain switches are replaced along with other overhead plant equipment when voltage conversion and feeder modernization projects are executed in areas where deteriorated distribution and substation equipment have negatively impacted system reliability.

#### 2.4.1.3. SMD-20 switch

This is a fused disconnect switch typically used in THESL's overhead system to protect lateral circuits on a feeder. It is mounted near the top of the pole and exposed to various conditions including rain, and, in the winter, salt spray from roads and highways, in addition to snow and ice. Figure 38 below shows a picture of a cracked porcelain switch.

**Figure 38: Cracked porcelain insulation**

The design of the SMD-20 switch is such that the insulation also provides structure. This insulation is subjected to external forces applied when the switch is opened and closed by a line person. In order to maintain safe clearance from the switch during operation, a hot stick is used to operate the switch from a distance. Operation from a distance means that a switch could be severely cracked, resulting in significantly reduced structural integrity, without these cracks being noticeable. This can create a potential safety risk for the crew when a switch breaks during operation.

**Figure 39: Broken Porcelain Switch Returned From Field**

Figure 39 above is a picture of a porcelain SMD-20 which ruptured during operation. This rupture could have posed a potential safety risk to anyone below when the porcelain debris fell. In addition, tracking along the porcelain insulation can lead to a more catastrophic type of failure. Figure 40 below shows a new design polymer SMD-20 switch.

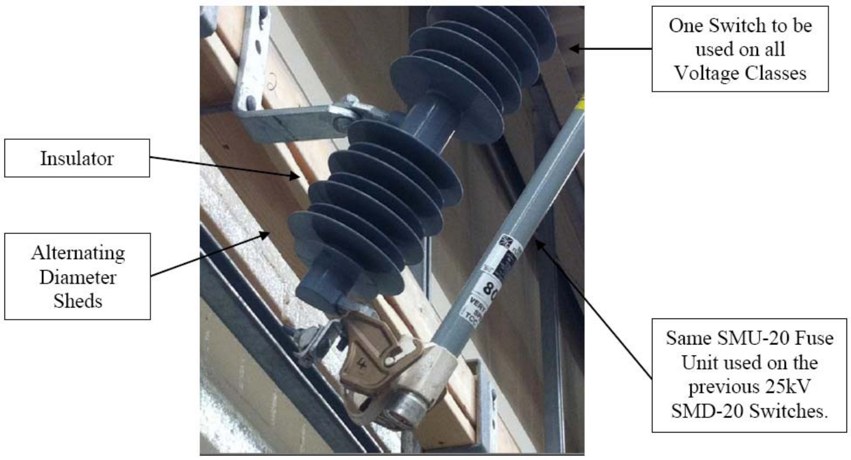



**Figure 40: New Design SMD-20 switch**

In addition to failures during manual operation, switches also fail while in service. The safest way to remedy a situation of the type shown below in Figure 41 would be to open the next upstream isolation device so that a THESL crew can replace the broken switch. The resulting outage may impact a large number of customers for an extended time.

**Figure 41: Broken SMD-20 still in service**


**Figure 42: Failed Porcelain SMD-20 Switches from OS 46849 P19 Gooderham at Brian Ave**

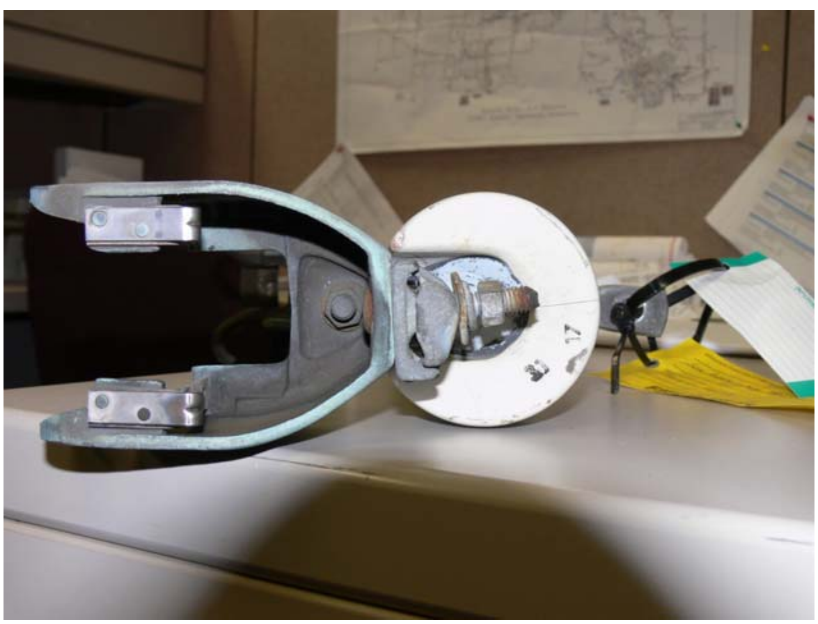


**Figure 43: Failed Porcelain SMD-20 Switches OS 46849 P19 Gooderham at Brian Ave**

In addition there are SMD20 style switches that have been modified from the original state (Refer to figure 44A). The modification involves the addition of a pin at the bottom of the switch assembly (Refer to figure 44B).

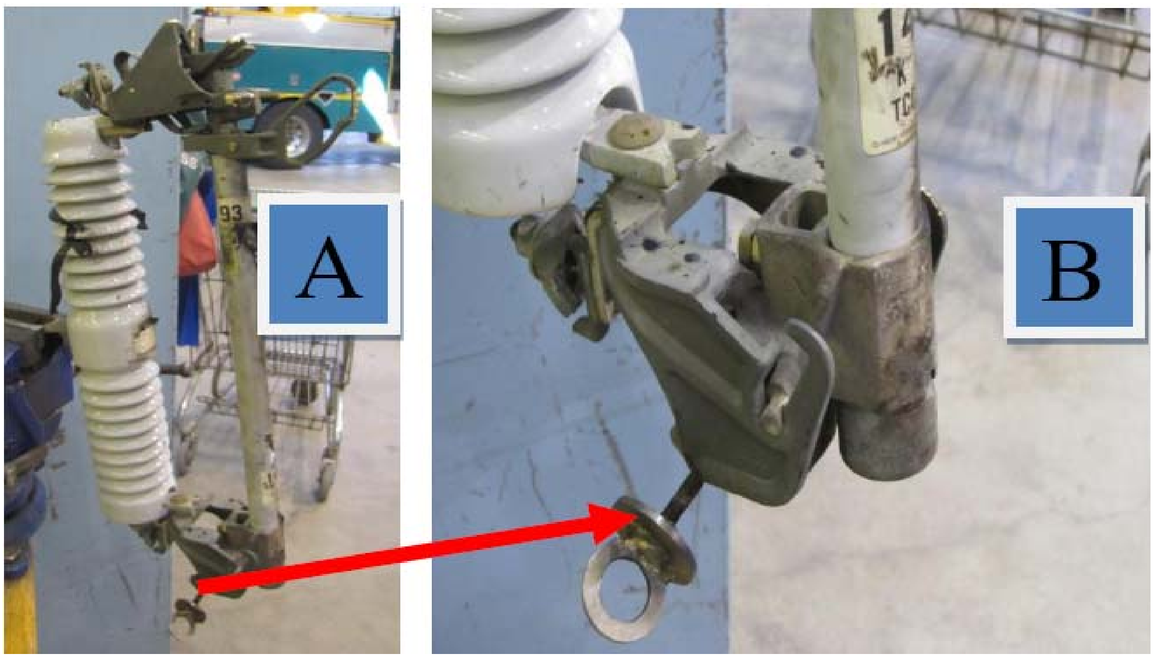



**Figure 44: SMD-20 switch with modified pin assembly**

Switches containing this modification have been primarily found in the South end of Etobicoke. The purpose of the modification was to limit the travel of the fuse when the switch was in an open position, so that the fuse would not swing open fully (approximately 180 degrees) and potentially contact any other apparatus that may be below it.

There are several concerns with this modification. First, the pin may limit the travel of the fuse such that there will be inadequate air clearance to prevent arcing between the top of the fuse and the top of the switch. Second, limiting the fuse travel may also further interfere with other activities, such as using the loadbreak tool or fuse replacement.

#### 2.4.1.4. In-Line disconnect switch

The in-line disconnect switch is a cost-effective means of further sectionalizing single-phase overhead laterals during extreme conditions, such as severe weather causing falling trees to bring the overhead conductor to the ground. In-line disconnect switches typically are used for isolation when performing maintenance or asset replacement tasks within a given area. These switches can also be found in THESL's overhead system on the trunk portion of 27.6kV feeders where they were previously installed as a cheaper alternative to manual ganged switches.

The primary reason to replace these switches is the potential safety risk posed by the failure of their porcelain insulation. In addition, the fact that some are installed on the trunk portion of feeders means that their failure can significantly impact SAIFI and SAIDI. Failure of an in-line disconnect switch on the trunk portion of a feeder would likely cause the circuit breaker to lock out. This would interrupt power to all customers on the feeder, which could potentially impact thousands of people.

#### 2.4.1.5. Failure Rate and Age

There are approximately 1,200 porcelain in-line disconnect switches on the overhead distribution system with an average age of 39 years. Some 30 percent of these porcelain switches are 50 years of age or older, which is the typical life for an overhead switch. In comparison, in-service polymer in-line switches have an average age of 13 years with 70 percent of these switches less than 20 years old. Age related failures tend to be associated with fatigue, oxidation, corrosion and evaporation.

Figure 45 provides an age distribution of all the 8,774 in-line disconnect switches in the system. In this figure, 4,406 (approximately 50 percent) switches are over 30 years old, 1,629 (or 19 percent) are over 50 years old, and 25 (or 0.28 percent) are over 60 years old. The disconnect switches over 50 years old need to be changed urgently. The units over 60 years old need to be replaced in 2012.

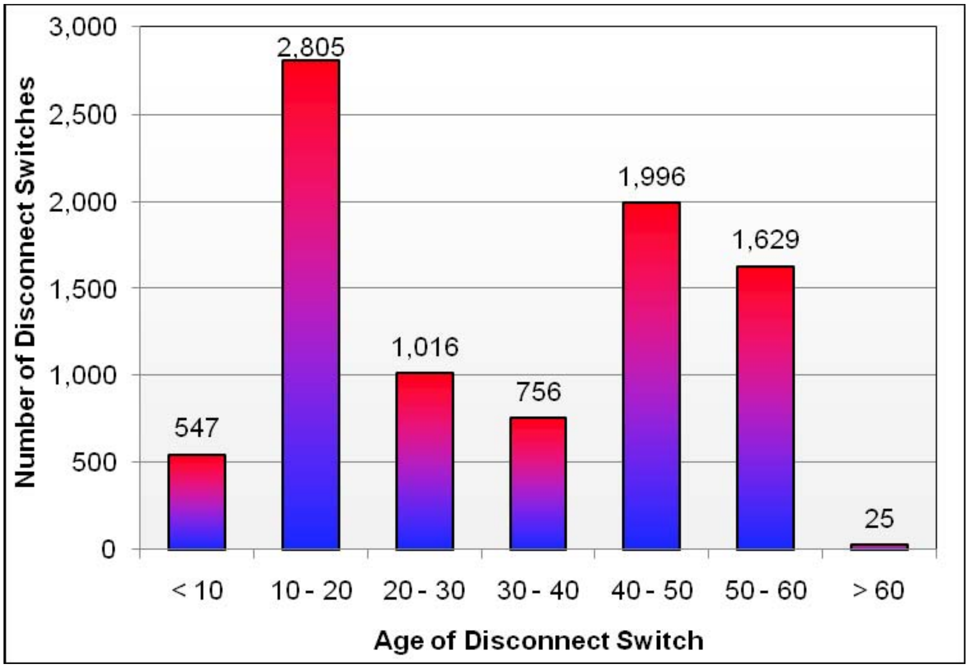



**Figure 45: Age-Profile of In-Line Disconnect Switches**

An example of a failure which is hard to detect at the pre-failure stage is fatigue cracking leading to failure of the component parts of the switch. This failure mode is undetectable by normal inspection but is related to age and to vibration exposure. Vibration exposure of overhead switches results from the Galloping and Aeolian Vibration of the conductors on which they are mounted. Galloping Vibration is the large amplitude low frequency vibration, which, in its most severe form, can rip the cable from its tower. Galloping Vibration may be experienced during high wind conditions, which are sometimes experienced in Ontario.

The Aeolian Vibration is of much smaller amplitude and higher frequency (100s of Hz) that occurs when laminar wind flows across a conductor causing vortices to be shed alternately from the top and bottom of the conductor. This continuous shedding of vortices causes an alternating force to be applied to the conductor, causing vibration predominantly in the vertical plane.

Figure 46 illustrates an in-line disconnect switch where part of the porcelain insulation has broken off. This is a potential safety risk as large pieces of porcelain could fall to the ground from switches mounted up to 50 feet (15.24 metres) high, creating the potential for significant injury or damage to property.

**Figure 46: In-line disconnect with part of the porcelain insulation broken off**

A THESL construction worker recently detected a failed switch during a routine switching operation. The single-phase switch had failed while the worker was restoring a normally open point between 13.8kV feeders. This particular switch is bracket-mounted and used to supply and isolate equipment. The failure was found to have been caused by a fracture along a weak point where the porcelain mounts to the base. It was later determined that similar switches can break off at various other points, as seen in Figure 47 and 48.

**Figure 47: Broken Porcelain In-Line Switch**

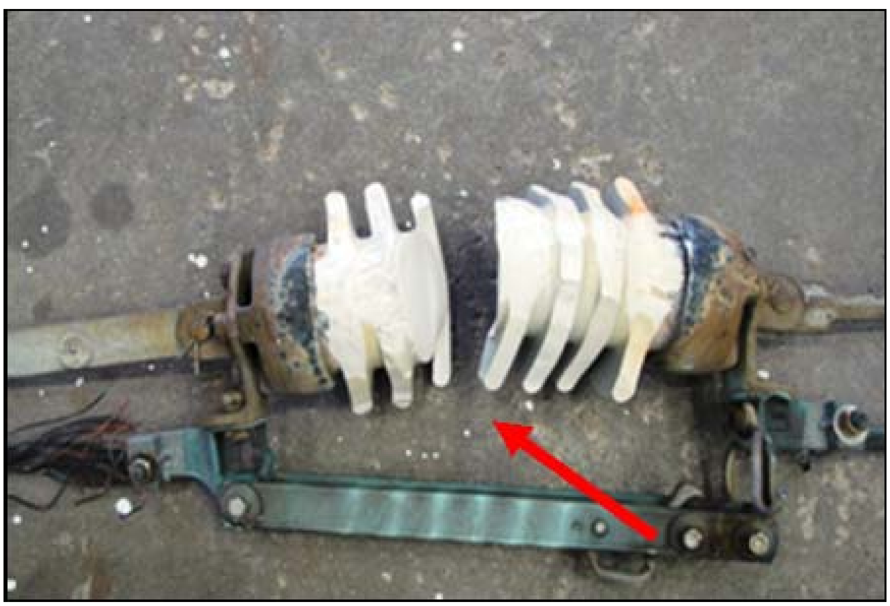


**Figure 48: Broken Porcelain In-Line Switch**

#### 2.4.1.6. Manual air break ganged switch

Three phase air break gang operated switches are installed on the trunk portion of overhead feeders. They are used to subdivide the trunk into smaller portions, a process known as sectionalizing.  Sectionalizing occurs during power outages, where the station breaker has locked out, or in other situations where part of the feeder load must be transferred.

Similar to the aforementioned switches, the insulation medium for these switches is also porcelain.  The porcelain components of these switches are also susceptible to contamination, which leads to tracking across the insulator and eventually failure.  Figure 49 below shows a situation where one of the center-phase insulators has broken and fallen off.


**Figure 49:  OSL65907 with broken center phase insulator**

Figures 50 and 51 below show close-up views of the damage to the insulator, caused by electrical tracking over time along the surface.

**Figure 50: Close-up of Damaged Porcelain Switch Insulator showing tracking**

**Figure 51: Close-up of Damaged Porcelain Switch Insulator showing tracking**

In addition to the potential safety risk presented by the failure of porcelain insulators on the switch, environmental conditions also cause corrosion of the load interrupting switch blade, which further accelerates the degradation of the switch as a whole. Figure 52 (below), is a picture of one such blade after the switch had been removed from service.

**Figure 52: Severely corroded switch blade**

Since these switches utilize the air as an insulation medium to extinguish the arc created by interrupting normal load current, any contaminants present on the switch blade during a load break operation may cause the electrical arc to elongate, which can lead to excessive and premature damage to the blade itself.

In addition, corrosion of the metal blades, which naturally occurs from road salt and water settling on the switch blades, can result in excessive heating of the blade. Over time, this may cause the blades to fail to conduct or to break load. As a result, the entire switch has to be replaced. Also, when the lubrication dries out, the switch operating mechanism may seize, making the disconnect switch inoperable. When blades fall out of alignment, excessive arcing may result. Corrosion can cause seizing on the manual switches. Air pollution, which typically occurs in heavy industrial areas or where road salt is used, can also affect support insulators reducing the useful lifespan of the switch.

The spread of reliability indices over the last six years is illustrated in Figure 53 and Table 12. The linear trend on the graph shows an increase in average restoration time per outage from 0.25 hours (15minutes) in 2006 to 0.3 hours (20minutes) in 2011. This equates to a 33 percent increase over the five-year period. This increase in the average restoration time associated with overhead switch failure confirms that the switches get more difficult to replace as their lifecycle is exceeded even without an increase in their probability of failure. The trend shows the increasing severity of the challenges caused by failing switches and underscores the need to address them.

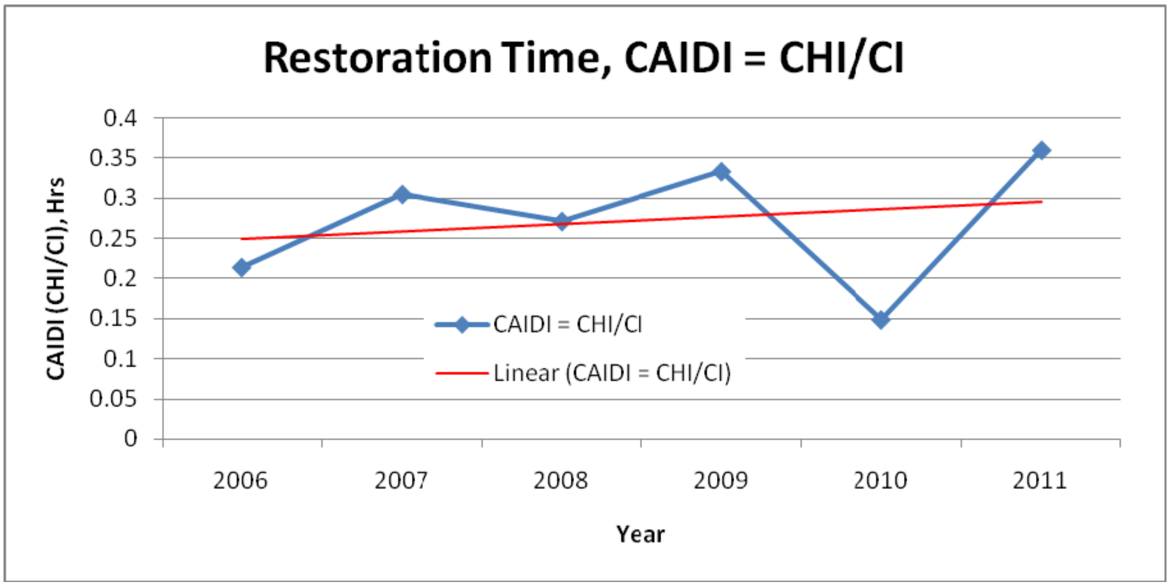



**Figure 53: Trend of Customer Average Interruption Duration Index (CAIDI) due to OH Switch Failures**

**Table 12: CI and CHI Attributable to Overhead Switches as a Percent of System Values**

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|
| **CI** | | | | | | |
| OH Switches | 103,365 | 81,570 | 132,765 | 74,417 | 88,851 | 72,677 |
| System | 3,099,595 | 3,167,050 | 3,064,864 | 3,131,880 | 2,827,094 | 2,638,807 |
| Ratio of CI by OH Switches alone to Overall System | 3% | 3% | 4% | 2% | 3% | 3% |
| **CHI** | | | | | | |
| OH Switches | 22,169 | 24,912 | 36,069 | 24,844 | 13,249 | 26,197 |
| System | 814,406 | 1,034,770 | 613,235 | 1,750,382 | 974,703 | 766,560 |
| Ratio of CHI by OH Switches alone to Overall System | 3% | 2% | 6% | 1% | 1% | 3% |
| **CAIDI = CHI/CI** | 0.214473 | 0.305406 | 0.271676 | 0.333848 | 0.149115 | 0.360458 |

### 2.4.2. Options for Addressing Overhead Switches

Below are the options available to address the specific issues associated with each switch type.

#### 2.4.2.1. SMD-20 switch

The available options to mitigate the potential safety risk posed by these porcelain switches are as follows:

(a) Replace the porcelain switches before they fail with polymer switches
(b) Eliminate the use of fused switches on the overhead distribution system
(c) Allow the porcelain switches to fail and replace them on a reactive basis

**Option (a): Replace the porcelain switches with polymer switches before they fail**

This option would replace porcelain SMD-20 as part of other overhead conversion and rehabilitation work. This option would not only mitigate the potential safety risk that these switches pose; it would also improve reliability and customer service because the switches would be replaced on a planned basis. This is the preferred option.

**Option (b): Eliminate the use of fused switches on the overhead distribution system**

Though this option would require the least initial cost, it would essentially result in the transfer of all customers onto feeder trunk circuits. As a result, the only upstream protection available would be the station circuit breaker, which would trip and lock out for every permanent fault on a feeder. Aside from being an inherently poor distribution system design, this would lead SAIDI and SAIFI to deteriorate to multiples of their current values. This is not a feasible option.

**Option (c): Allow the porcelain switches to fail and replace them on a reactive basis**

Though this option slowly will reduce the number of porcelain switches in the system by attrition, it does nothing to address the potential safety risk and reliability impacts associated with the switches and their failure. This is not preferred option in terms of safety and reliability.

#### 2.4.2.2. In-Line Disconnect and Manual Air-Break Gang-Operated Switches

The available options to mitigate the potential safety risk posed by these two types of switches are the same and so they are discussed together, as follows:

(a) Replace the In-Line Disconnect and Manual Air-Break Gang-Operated switches at the end of their useful lives with SCADA-Mate R2 switches

(b) Replace In-Line Disconnect and Manual Air-Break Gang-Operated switches on the overhead distribution system with SCADA-Mate R2 switches

(c) Allow In-Line Disconnect and Manual Air-Break Gang-Operated switches to fail and replace them on a reactive basis

**Option (a): Replace the In-Line Disconnect and Manual Air-Break Gang-Operated switches at the end of their useful lives with SCADA-Mate R2 switches**

This option limits replacement only to those switches at end of life. It will help mitigate the potential safety risk posed by these switches and also have a positive impact on reliability and customer service. This is the preferred option.

In 2012 through 2014, THESL plans to replace a total of 899 porcelain in-line disconnect and manual air-break gang-operated switches. The yearly breakdown is as follows: 238 locations in 2012, 547 in 2013 and 114 in 2014. The replacements will be targeted at 4kV and 27.6kV locations across the system (4kV switches will be replaced with 27.6kV units in voltage conversion projects). The proposed replacements represent approximately five percent of THESL's installed overhead switch population.

**Option (b): Replace All In-Line Disconnect and Manual Air-Break Gang-Operated switches on the overhead distribution system with SCADA-Mate R2 switches**

The functions of these switch types cannot be eliminated as they are required for the operability of the distribution grid. SCADA-Mate R2 switches can be used instead of these switch types to perform the necessary functions. The SCADA-Mate switches are faster and remotely operable, which will reduce restoration times, improve SAIDI and allow THESL to better manage service interruptions during outages. While this option could address the safety and reliability issues associated with these switches, it is not feasible because of the number of units involved. The cost and outage time required for this option would be prohibitive.

**Option (c): Allow the In-Line Disconnect and Manual Air-Break Gang-Operated switches to fail and replace them on a reactive basis**

Though this option slowly reduces the number of In-Line Disconnect and Manual Air-Break Gang-Operated switches on the system by attrition, it does nothing to address the potential safety risk associated with the switches and their failure. Deferring the replacements of the end-of-life switches is also not an option as the health of the switches will only get worse over time and lead to longer restoration times. This is not a feasible option because it does not address the problems posed by these switches.

## 2.5. Porcelain Hardware

### 2.5.1. Issues with Porcelain Hardware

Porcelain insulators are a potential safety concern because their failures can result in shards of jagged debris falling from the overhead distribution system. They are also a reliability concern and a significant contributor to customer interruptions within the overhead distribution system. As porcelain insulators become contaminated due to environmental conditions, a lower resistance path forms across the insulator that eventually allows for a voltage discharge, or arc to ground. Ultimately, this leads to a semi-conductive track that, over time, further weakens the insulator. See Figure 54 for example of typical porcelain insulator installation.

**Figure 54: Typical Porcelain Insulator**

Over the last decade, porcelain has been phased out for new installations in favour of polymer-based materials because porcelain has the following safety and system performance issues:

- Development of hairline cracks leading to failure
- Potential for catastrophic failure resulting in shards of jagged debris
- Higher tracking, leakage current, and system losses
- Incompatibility with tree-proof conductors that are essential for improving feeder reliability in heavily-treed areas

Figure 55 shows a broken porcelain insulator. In addition to the safety concerns about falling debris, porcelain fragments can also trigger pole fires.

**Figure 55: Broken Porcelain Insulator**

Porcelain pothead terminations also have the potential to fail in a catastrophic manner, releasing porcelain shards and dispersing oil. This can damage other nearby electrical equipment and public property. In addition, the dispersion of oil from the damaged terminations may result in a fire or an environmental hazard.

In 2009, THESL received a Public Safety Concern from the ESA as a result of a pothead failure sending shards of porcelain onto the balcony of a nearby home, shattering the window of the family room and causing damage to the windshield of a nearby police car. The effects of the failure are seen in Figure 56. THESL replaced the failed porcelain pothead with a new polymer termination shown in Figure 57.

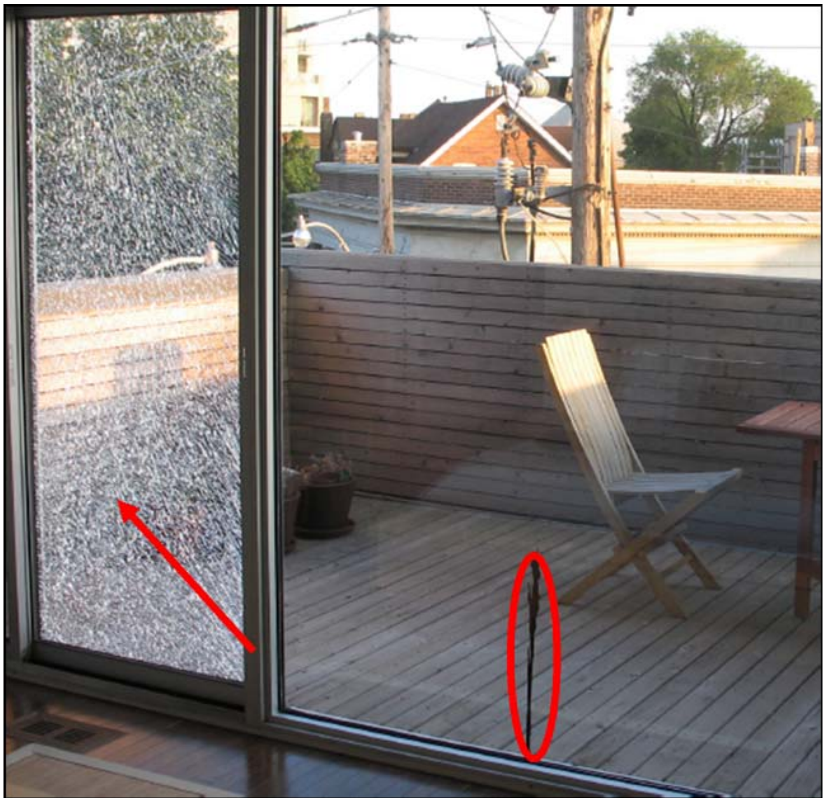


**Figure 56: Failure Effects of the Porcelain Pothead Terminators**


**Figure 57: Replaced Porcelain Pothead Terminator**

With regard to arresters and terminators, many utilities in North America are switching over from porcelain to polymer due to reasons enumerated earlier in this document. Porcelain post insulators mounted on steel, concrete and word structures have experienced cascading mechanical failures due to impact loads because of the rigidity of the structures. In THESL's experience, probably due to pressure-fitted mountings, the failure mode of arresters and terminators is typically explosive, which leads to safety concerns for both crews and the public.

Deferral of porcelain insulator replacement would increase the potential risk to public and worker safety as the equipment continues to age and failure rates climb. Porcelain potheads are legacy standards associated with PILC cables. Current work practices require the use of XLPE cables with polymer terminations for most applications since they are lighter, have improved electrical and thermal properties and require less specialization for termination and splicing. Deferral of this work would prolong the use of PILC, which is increasingly difficult to source and requires worker specialization that is difficult to maintain.

The current practice would be to reactively replace failed porcelain insulators, and porcelain potheads with the current approved polymer standard. Waiting for failures to occur before replacing these items will continue to expose the public and THESL workers to potential safety risks.

### 2.5.2. Options for Addressing Porcelain Hardware

The following options were considered in mitigating the risks associated with these assets:

(a) Proactively replace porcelain equipment with the approved polymer standard
(b) Reactively replace porcelain equipment with the approved polymer standard

**Option (a): Proactively replace porcelain equipment with the approved polymer standard**

Under this option, THESL proposes to replace 400 porcelain insulators yearly with the approved polymer standard in each of 2012, 2013 and 2014. Typically, porcelain insulators will be replaced as part of other overhead rebuild work identified overhead infrastructure jobs shown below in Section III. The estimated cost of this effort is over three years totals $1.56 million.

Currently there are approximately 54,100 porcelain insulators in the overhead distribution system located across all of the THESL distribution service area.

THESL will be replacing porcelain insulators on feeders in locations with deteriorated pole framing hardware including highly contaminated areas such as those close to major highways as well as congested, heavily treed areas and other locations where the potential for failure is high and where there may be associated safety risks.

There are approximately 565 porcelain pothead locations. The majority of porcelain potheads are located in the downtown core, with the remaining locations dispersed across the former distribution service areas of Etobicoke and Scarborough. Starting in 2012 and continuing through 2014, THESL plans to replace 50 locations annually, for a three-year total of 150 locations (approximately 27 percent of the total population), by first targeting public thoroughfare areas such as sidewalks, bus stops and school zones. The estimated cost of this effort over three years totals $3.34 million.

**Option (b): Reactively replace porcelain equipment with the approved polymer standard**

In Option (b), THESL would reactively replace porcelain insulators and potheads with the current approved polymer standard for each asset when they fail.

Option (a) is preferred because it better addresses the associated safety and reliability issues. As this equipment poses reliability and potential safety concerns, the sooner it is removed from the system the less likely it is to cause outages, injuries and property damage. Option (b), reactive replacement, also would result in a higher unit cost for replacement. Unit costs would be higher because crew members will be required to make replacements on an incident by incident basis.

### 2.6. Avoided Risk Costs from the Overhead Infrastructure Segment

The effectiveness of the Overhead Infrastructure segment can be further highlighted by determining how much cost is avoided by executing this work immediately as opposed to executing it in 2015. These avoided costs include quantified risks, taking into account the assets' probability of failure, and multiplying this by the various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement.

Carrying out immediate work on this asset class will result in an avoided estimated risk cost of $75 million, which represents the avoided cost of executing the work immediately as opposed to deferring until 2015. This figure shows that there are substantial economic benefits from executing this work immediately. These results are further explained within the Appendix section. In addition to the avoided risk cost, by the time the Overhead Infrastructure segment is completed in 2014, approximately 30,000 CI and 18,500 CHI can be mitigated when compared to a run-to-fail approach.

# IV DESCRIPTION OF WORK

## 1. LISTING OF ALL JOBS

### 1.1. 2012 Jobs

| Job Estimate Number | Job Title | Year | Cost Estimate ($, millions) | Section Reference |
|---|---|---|---|---|
| 24951 | Danger and Caution pole replacement | 2012 | $4.64 | 4.3 |
| 20572 | Magellan / Giltspur OH Rebuild | 2012 | $1.62 | 4.4 |
| 20556 | Lomar Dr. OH Rebuild | 2012 | $0.43 | 4.4 |
| 20456 | Spenvalley OH Rebuild | 2012 | $1.12 | 4.4 |
| 20892 | Arrowsmith Overhead Rebuild | 2012 | $0.76 | 4.5 |
| 20893 | Flamborough Overhead Rebuild | 2012 | $0.85 | 4.5 |
| 20873 | Riverside Dr VC Part #2 | 2012 | $1.34 | 4.6 |
| 20499 | W12339/P03 FESI CSP and Conductor Replacement on YK11M1 off Weston Road and Jane Street | 2012 | $0.85 | 4.41 |
| 20379 | CSP and Conductor Replacement | 2012 | $1.02 | 4.41 |
| 21025 | O/H Rebuild – Keele St and Milford Ave | 2012 | $1.01 | 4.41 |
| 23677 | Chipping Crossburn 53M10 OH Rebuild | 2012 | $0.30 | 4.41 |
| 20875 | George Andersen and Culford Rd. Overhead Rebuild | 2012 | $1.63 | 4.41 |
| 24669, 24668, 24851, 24881 | Rebuild Broadlands MS Area with VC | 2012 | $3.40 | 4.7 |
| 16616 | Manby TS Load Transfer to Horner TS | 2012 | $0.78 | 4.9 |

| Job Estimate Number | Job Title | Year | Cost Estimate ($, millions) | Section Reference |
|---|---|---|---|---|
| 19581 | Replacement of non-standard and overloaded transformer | 2012 | $0.48 | 4.42 |
| 19785 | X12156 Replacement of the manual tie switches with SCADA 53-M8 | 2012 | $0.30 | 4.43 |
| 19454 | X11524 Replacement manual switch with SCADA, EYA11L | 2012 | $0.07 | 4.43 |
| 19453 | X11525 Replacement manual switch with SCADA, EYA12L | 2012 | $0.07 | 4.43 |
| 19455 | X11526 Replacement manual switch with SCADA, EYA14L | 2012 | $0.08 | 4.43 |
| 19837 | X12163 Replacement of manual tie switches with SCADA 53-M6 | 2012 | $0.52 | 4.43 |
| 19806 | W12089-Remote SCADA Switch Install Bathurst TS | 2012 | $0.09 | 4.43 |
| 19792 | X12158 Replacement of manual tie switches with SCADA 53-M7 | 2012 | $0.51 | 4.43 |
| 19892 | X12176 Replacement of manual tie switches with SCADA 53-M5 | 2012 | $0.35 | 4.43 |
| 19894 | X12182 Replacement of manual tie switches with SCADA 34M5, 34M6 34M7 | 2012 | $0.19 | 4.43 |
| 23354 | W12253 11M7 SWITCH REPLACEMENT JANE/WOOLNER | 2012 | $0.08 | 4.43 |
| 19452 | X10449 Replacement of manual switch with SCADA EYA13L | 2012 | $0.07 | 4.43 |
| 18456 | E11374 SCADA Installation 34M6 | 2012 | $0.20 | 4.43 |
| 17801 | E10387 Bermondsey SCADA | 2012 | $0.33 | 4.43 |

## ICM Project | Overhead Infrastructure Segment

| Job Estimate Number | Job Title | Year | Cost Estimate ($, millions) | Section Reference |
|---|---|---|---|---|
| 20391, 19965 | E11088 North York SCADA 53M10 Area A | 2012 | $0.45 | 4.43 |
| 24060 | E12744 - Bell Line Conversion | 2012 | $0.08 | 4.43 |
| 21531 | Overhead Rebuild R43M28 | 2012 | $0.74 | 4.10 |
| 24666 | 80M6 Feeder OH Enhancement | 2012 | $0.53 | 4.11 |
| 24598, 22850 | E12436 – NY80M6 Feeder OH Enhancement Phase 3 NY80M6 | 2012 | $1.40 | 4.11 |
| 18523 | W11289 – FESI Rowntree Contingency 55M22 | 2012 | $0.53 | 4.44 |
| 19871 | Replacement of CSP Transformer | 2012 | $1.34 | 4.12 |
| 20946 | W12462 – 3 Phase Extension along Rockford | 2012 | $0.27 | 4.46 |
| 23134 | E11805 – porcelain secondary Insulation Inspection | 2012 | $0.03 | 4.49 |
| 20684 | W12397 - Safety Alert SMD-20 Switch Replacement | 2012 | $0.50 | 4.8 |
| 23696 | W12669 – Martin Ross and Flint Rebuild NY85M7 | 2012 | $0.42 | 4.13 |
| **2012 Overhead ICM TOTAL** | | | **$29.43** | |

## 1.2. 2013 Jobs

| Job Estimate Number | Job Title | Year | Cost Estimate | Section Reference |
|---|---|---|---|---|
| 20565 | FESI CSP and Conductor Replacement | 2013 | $4.41 | 4.41 |
| 20416 | X12318 34M1 SCADAmates Installation | 2013 | $0.17 | 4.43 |
| 20659 | W12383-OH Switch Replacements to SCADA Controlled Switches | 2012 | $0.21 | 4.43 |
| 22598 | W13271 3 Feeder Riser SCADA Switch Installations Hydro RoW | 2013 | $0.29 | 4.43 |
| 20578 | E12358 OH Rebuild of sections of the Overhead Distribution on NY51M21, Part 1 | 2013 | $1.58 | 4.14 |
| 20595 | E12361 OH Rebuild of sections of the Overhead Distribution on NY51M21, Part 2 | 2013 | $0.83 | 4.14 |
| 20848 | E12459 Banbury/Post Rd OH Rehab: NY34M6, NY53M24, NY51M21 | 2013 | $0.26 | 4.14 |
| 20774 | E12433 Conversion feeder SCKHF2 to 27.6kV | 2013 | $0.82 | 4.15 |
| 21190 | E12508 OH Rebuild of the Overhead Distribution on NY80M4 Phase 1 | 2013 | $1.79 | 4.16 |

## ICM Project | Overhead Infrastructure Segment

| Job Estimate Number | Job Title | Year | Cost Estimate | Section Reference |
|---|---|---|---|---|
| 21193 | E12509 OH Rebuild of the Overhead Distribution on NY80M4 Phase 2 | 2013 | $1.08 | 4.16 |
| 21785 | E13153 Rebuild of the Overhead Distribution on NY51M8 | 2013 | $1.69 | 4.17 |
| 19886 | X12179 - Replacement of CSP transformers | 2013 | $1.29 | 4.42 |
| 20023 | X12204 - Replacement of CSP transformer | 2013 | $1.19 | 4.18 |
| 19775 | X13109- 34M6 -Replacement of non –standard CSP transformers and conductor | 2013 | $0.97 | 4.18 |
| 20965 | W12491 - FESI CSP and OH Conductor Replacement Ph#3 | 2013 | $1.58 | 4.19 |
| 20939 | W12442 - FESI Rebuild and CSP Replacement Ph#1 NY85M1 | 2013 | $1.39 | 4.19 |
| 21113 | W13054 - FESI - Refurbish OH Feeder 85M23 - Phase 1 | 2013 | $1.04 | 4.20 |
| 21118 | W13055 - FESI - Refurbish OH Feeder 85M23 - Phase 2 | 2013 | $0.71 | 4.20 |
| 21122 | W13056 - FESI - Refurbish OH Feeder 85M23 - Phase 3 | 2013 | $0.72 | 4.20 |
| 21123 | W13057 - FESI - Refurbish OH Feeder 85M23 - Phase 4 | 2013 | $0.80 | 4.20 |
| 21517 | W13113 - FESI Feeder Rehab and CSP replacement Ph#1 | 2013 | $0.71 | 4.21 |

| Job Estimate Number | Job Title | Year | Cost Estimate | Section Reference |
|---|---|---|---|---|
| 21518 | W13115 - FESI Feeder Rehab and CSP replacement PH#2 | 2013 | $0.50 | 4.21 |
| 21639 | W13130 - Refurbish OH Feeder - Epsom Downs | 2013 | $2.05 | 4.22 |
| 21690 | W13131 - Refurbish OH Feeder Falstaff Area Ph#2 | 2013 | $1.40 | 4.22 |
| 22184 | W13198 – Refurbishment of trunk feeder – Regent Road and Wilson Avenue | 2013 | $1.24 | 4.23 |
| 22208 | W13205 – Refurbish Feeder Laterals Phase 1 of 2 | 2013 | $1.21 | 4.23 |
| 22211 | W13206 - Refurbish Feeder Laterals Phase 2 of 2 | 2013 | $1.71 | 4.23 |
| 22180 | W13204 - Elynhill_Ellerslie_Betty Ann_ Park Home Ph#2 Overhead Rehab NY80M1 | 2013 | $0.80 | 4.26 |
| 21920 | W13185 - 80M1 Carney Rd Distribution Rehab | 2013 | $0.70 | 4.26 |
| 22037 | W13188 - 80M1 Finchhurst Dr and Fleetwell Crt OH Rebuild | 2013 | $0.15 | 4.26 |
| 22041 | W13189 - 80M1 Stafford Rd and Cloebury Crt | 2013 | $0.19 | 4.26 |
| 21876 | W13182 - Rehab Eldora_Kensington_Elmview 80M1 | 2013 | $0.13 | 4.26 |
| 21998 | Clarkhill Glenborough Park Ancona Overhead Rebuild | 2013 | $0.64 | 4.26 |

| Job Estimate Number | Job Title | Year | Cost Estimate | Section Reference |
|---|---|---|---|---|
| 22173 | 80M1 Ellerslie_Betty Ann_ Park Home Ph#1 OH rehab | 2013 | $0.58 | 4.26 |
| 23567 | W13351 FESI Rebuild and CSP Replacement Ph#2 (NY85M1) | 2013 | $2.01 | 4.19 |
| 24161 | W13376 Voltage Conversion Rennie Park (TOB1RK) | 2013 | $1.59 | 4.27 |
| 20296 | OH Rebuild Spenvalley Dr and Surrounding Area | 2013 | $0.69 | 4.44 |
| 22203 | E12570 - NY53M25 Rehabilitation of the OH Distribution on | 2013 | $1.20 | 4.28 |
| 21578 | E11742 - Rehabilitation of the OH Distribution on SCNA47M13 | 2013 | $0.42 | 4.28 |
| 20773 | W12123 - Churchill/Wynn OH Rehab and VC (SS60-F2 to 80M1) | 2013 | $1.02 | 4.29 |
| 20412 | W12306 - FESI NY55M25 OH Feeder Equipment Rehab | 2013 | $0.91 | 4.46 |
| 21999 | W13167 – Clayson/Bartor Trunk Feeder Reconfiguration and Refurbishment | 2013 | $1.10 | 4.47 |
| 22229 | E12574 Overhead Rehabilitation of SCREF3 | 2013 | $0.83 | 4.49 |
| 21457 | E13110 NYSS68-F9 OH Rebuild at Pleasant View | 2013 | $0.54 | 4.49 |
| 21569 | W13122 – FESI Refurbish OH Feeder (30M10) | 2013 | $0.50 | 4.24 |
| 23430 | P03 Evans Avenue and Royal York Rd, Reconfiguration of Feeders | 2013 | $0.80 | 4.50 |

## ICM Project | Overhead Infrastructure Segment

| Job Estimate Number | Job Title | Year | Cost Estimate | Section Reference |
|---|---|---|---|---|
| 20881 | E12457 - CSP Transformer and Pole Replacement | 2013 | $0.44 | 4.51 |
| 19976 | X13004-Convert 4kV Dupont B71DU to 13.8kV TOB71DU | 2013 | $2.71 | 4.38 |
| 22040 | W13169 – Weston Railway – OH Rebuild | 2013 | $1.23 | 4.47 |
| 22245 | W13211 - Goulding MS F1 and F2 VC Ph#1 | 2013 | $1.20 | 4.32 |
| 22248 | W13216 - Goulding MS F1 and F4 VC Ph#2 | 2013 | $0.99 | 4.32 |
| **2013 Overhead ICM Total** | | | **$53.02** | |

1 **1.3. 2014 Jobs**

| Job Estimate Number | Job Title | Year | Cost Estimate | Section Reference |
|---|---|---|---|---|
| 24169 | E14319-New SCADA Switch on 43M24 | 2014 | $0.20 | 4.43 |
| 24139 | E14318-New SCADA Switches on NY51M3 | 2014 | $0.19 | 4.43 |
| 22994, 22995 | E14136 OH Upgrade SCNAR43M24 Hollis Milne Birchmount | 2014 | $0.88 | 4.30 |
| 22958 | E14117 OH Rebuild R43M28 Aylesworth Kennedy | 2014 | $.75 | 4.30 |
| 23978 | E14286 OH Rebuild and Voltage Conversion of NYSS64F2 from Ruddington MS | 2014 | $0.94 | 4.31 |
| 22859 | W14073 - 55M31 OH Rebuild at intersection Steels Ave W and Weston RD. | 2014 | $0.80 | 4.44 |
| 22960 | 38M27 North Queen conductor Upgrade | 2014 | $0.21 | 4.33 |
| 23089 | W14150 - OH Feeder Rehab - Milvan / Penn | 2014 | $1.02 | 4.34 |
| 23093 | OH Feeder Rehab - Finch / Weston / Toryork | 2014 | $0.64 | 4.34 |
| 23873 | W14278-Overhead Rebuild Duplex/Church/Parkview | 2014 | $0.72 | 4.25 |
| 23364 | OH Feeder Rehab - Alexdon, Chesswood, Champagne | 2014 | $0.54 | 4.45 |
| 24129 | W14320 - Ardwick Overhead Spot Replacement | 2014 | $0.49 | 4.35 |

| Job Estimate Number | Job Title | Year | Cost Estimate | Section Reference |
|---|---|---|---|---|
| 24166 | W14326 - Nabenby Overhead Rebuild | 2014 | $0.93 | 4.35 |
| 24218 | W14329 - P03 Gracedale Blvd. Overhead Rebuild Finch TS NY55M27 | 2014 | $0.62 | 4.35 |
| 24257 | W14333 - Aviemore Dr. Overhead Rebuild Finch TS | 2014 | $0.60 | 4.35 |
| 24269 | W14334 - Duncanwoods Dr. Overhead Rebuild Finch TS | 2014 | $0.58 | 4.35 |
| 24295 | W14340 – Lindylou Overhead Rebuild | 2014 | $1.12 | 4.35 |
| 23878 | W14276 OH Feeder Rehab –Signet, Weston, Fenmar (NY55M1) | 2014 | $1.97 | 4.36 |
| 24320 | W14343-Voltage Conversion RB-F3 Phase 1 | 2014 | $0.45 | 4.37 |
| 24321 | W14344-Voltage Conversion-Westmount MS RB-F1 | 2014 | $0.60 | 4.37 |
| 24333 | W14345-Voltage Conversion-Westmount MS Phase 1 | 2014 | $0.48 | 4.37 |
| 24052 | W14306 - 85M5 - McAllister Rd. Overhead Rebuild | 2014 | $0.30 | 4.39 |
| 24089 | W14315 - 85M5 – Carmichael Ave. OH rebuild and conductor upgrade | 2014 | $0.71 | 4.39 |
| 23979 | W14285 - Pellatt OH and UG lateral Rebuild | 2014 | $0.24 | 4.39 |
| 24007 | W14289 - OH Rebuild off Gary Avenue | 2014 | $0.80 | 4.39 |
| 23361 | 30M7 OH Upgrade and ETRF2 OH VC | 2014 | $2.04 | 4.40 |
| 23312 | E14170 Rouge Park OH Rebuild Phase and VC of 3 SCXGF3 | 2014 | $0.62 | 4.49 |

| Job Estimate Number | Job Title | Year | Cost Estimate | Section Reference |
|---|---|---|---|---|
| 23323 | W14181 - Kingsway MS – OH Voltage Conversion (ETEF1) | 2014 | $0.66 | 4.48 |
| **2014 Overhead ICM Total** | | | **$20.11** | |

## 2. Pole Replacement of Level 4 and 5 Poles (Danger and Caution poles)

### 2.1. Objectives

The purpose of this job is to replace poles that have been identified as level 4 and 5 poles (Danger and Caution poles) by an external contractor "Ontario Pole Inspection Services". This contractor uses different method of inspection to determine the pole condition such as sound and bore inspection and software engineered to determine remaining pole strength. The poles are tested at different points to identify pole-top feathering, cross-arm rot, cracks, surface rot at ground level, above ground level and below ground level. Poles tested receive a score from 0 to 5. A score of 0 means that there is no evidence of pole damage and a score of 5 indicates that the pole is in very bad condition. A level 4 pole is one that should be replaced in a short period of time to avoid failures. A level 5 pole is a pole that should be replaced as soon as possible.

### 2.2. Scope of Work

The scope of work for this job is to replace 275 poles that have been identified in level 4 and 5 (Danger and Caution poles). The replacement of the poles will occur across the City of Toronto. There is a back-log of poles in level 4 and 5 condition that require replacement. In 2010, testing of 83 poles with an average pole Health Index (HI) score of 15, indicating that the poles are in very poor condition. For 2011 there are 192 poles with an average HI score of 28, falling under the category of poles in very poor conditions. The poles require immediate replacement in order to prevent pole failures.

### 2.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 24951 | Danger and Caution pole replacement | 2012 | $4.64 |
| | | **Total:** | **$4.64** |

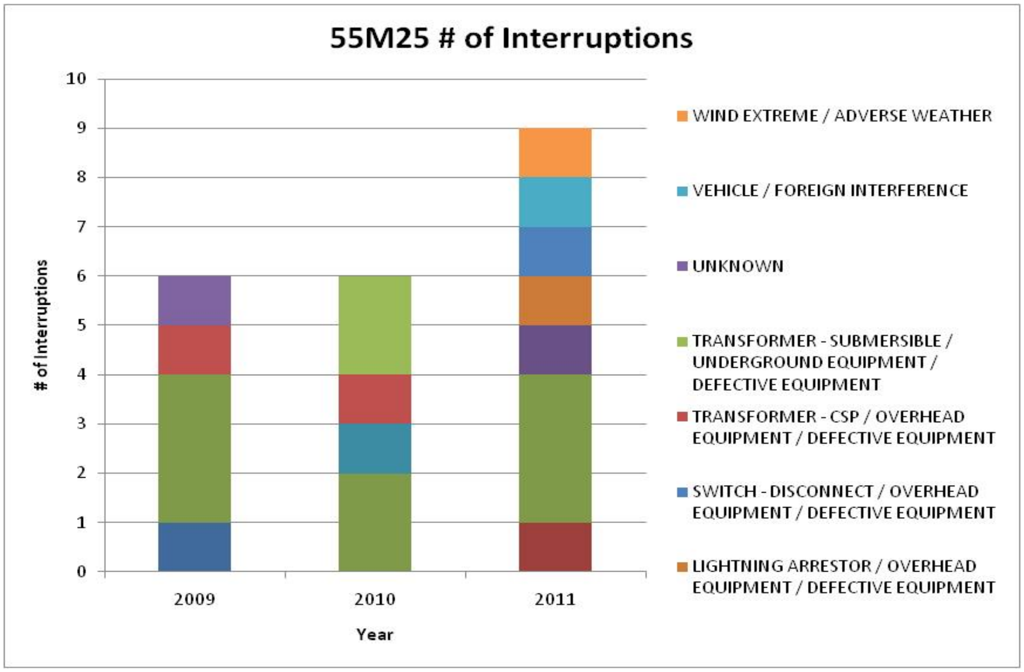
## 3. Magellan / Giltspur / Lomar / Spenvalley Overhead Rebuild

### 3.1. Objectives

The purpose of this job is to rebuild sections of the distribution feeder 55M25 in the Magellan / Giltspur / Lomar area. The primary overhead distribution plant on 55M25 requires short-term targeted rehabilitation in order to address reliability concerns (Refer to Figures 58 and 59). 55M25 has experienced seven sustained interruptions in the past year.

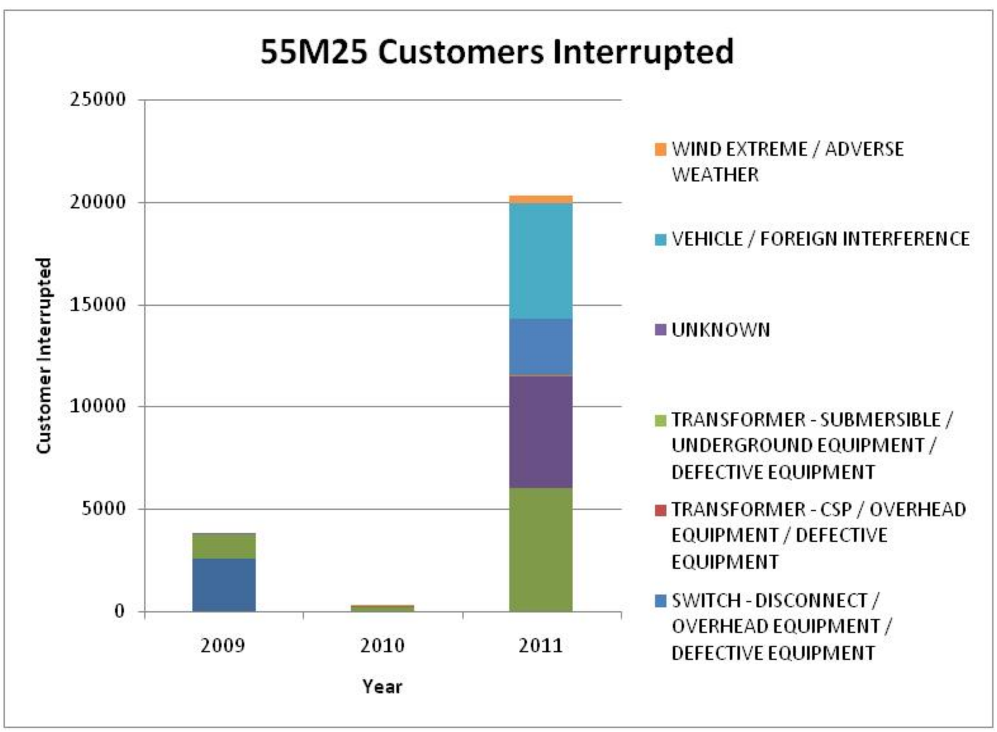
### 3.2. Scope of Work

The scope of work for this job is to rebuild the existing overhead distribution to THESL standards in the area along Magellan/Giltspur / Lomar. This job will address aging and non-standard assets such as poles, switches, CSP transformers, insulators and undersized conductor in areas that have failed or have a high probability of failing in the near future. The number of sustained outages has increased with a high proportion due to faults on the overhead plant. These sustained outages have significantly impacted the number of customers affected at over 20,000 customers interrupted in 2011. An immediate rebuild targeting end of life and non-standard equipment will likely reduce the probability of future outages and improve the reliability to the customers in this neighbourhood. Deferral will increase the risk of future outages on these aging assets that have a high probability of failure.




1 **Figure 58: 55M25 Number of Interruptions**

2




3 **Figure 59: 55M25 Customers Interrupted**

### 3.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20572 | Magellan / Giltspur OH Rebuil | 2012 | $1.62 |
| 20556 | Lomar Dr. OH Rebuil | 2012 | $0.43 |
| 20456 | Spenvalley OH Rebuild | 2012 | $1.12 |
| | | **Total:** | **$3.18** |

## 4. Arrowsmith and Flamborough Overhead Rebuild

### 4.1. Objectives

The purpose of this job is to rebuild the existing overhead distribution system in the Arrowsmith and Flamborough area with standardized equipment. Outages on this portion of the distribution system are attributable to overhead equipment failures and contacts by animals. The primary overhead distribution plant requires immediate targeted rehabilitation in order to address reliability concerns

### 4.2. Scope of Work

Figure 60 shows the increasing trend of outages on 35M12, particularly due to overhead equipment such as defective transformers; disconnect switches, lightning arrestors, and conductor.

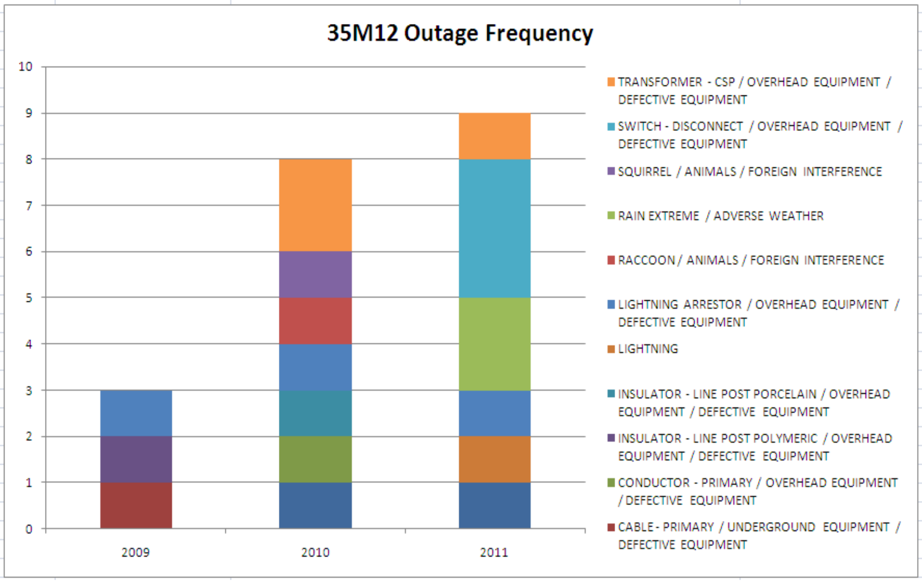



**Figure 60: 35M12 Outage Frequency**

The overhead plant surrounding Arrowsmith Avenue and Flamborough Drive consists of deteriorating equipment. The scope of work for these jobs is to rebuild the overhead infrastructure on feeder 35M12 specifically in the area of Arrowsmith Avenue and Flamborough Drive. The job will include the replacement of poles porcelain equipment, overhead transformers to adjust to current THESL standards.

## 4.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20892 | X12460 - Arrowsmith Overhead Rebuild | 2012 | $0.76 |
| 20893 | X12461 - Flamborough Overhead Rebuild | 2012 | $0.85 |
| | | **Total:** | **$1.62** |

## 5. Riverside Drive Voltage Conversion Jobs

### 5.1. Objectives

The purpose of this job is to extend feeder ET38M29 along Riverside Drive to convert the 4 kV to 27.6 kV, in order to prepare Queensway MS for decommissioning. Queensway MS has reached the end of its serviceable life due to the extensive station work that would be required to replace switchgear and transformers. Before Queensway MS can be decommissioned, THESL must first convert the 4 kV load served by the station.

### 5.2. Scope of Work

The scope of work for this job is to prepare Queensway MS for decommissioning. The job further extends feeder ET38M29 into Morningside Avenue between South Kingsway and Riverside Drive with the installation of new wooden poles and the replacement of switches, transformers, conductors that had been on the 4kV feeders TOB1KY and TOB2QU.

This job is expected to protect the safety of the 1021 customers on both 4kV feeders and improves the reliability in the area. Dangers and outages from defective poles, non-standard conductors, porcelain switches, porcelain insulators, porcelain potheads, porcelain lightning arresters and non-standard cross arms will be avoided, as 80% (or 34 units) of the polemount transformers to be replaced in this job are the non-standard CSP types. Only nine of the 59 existing poles in the area had ACA health index scores established to be in good condition and the pole framing components and line switches are non-standard porcelain insulated.

### 5.3. Required Capital Costs

| **Job Estimate Number** | **Job Title** | **Year** | **Estimated Cost ($M)** |
|---|---|---|---|
| 20873 | Riverside Dr VC | 2012 | $1.34 |
| | | **Total:** | **$1.34** |

## 6. Rebuild Broadlands MS Area – Voltage Conversion

### 6.1. Objectives

The objective of this job is to rebuild this area by converting the non-standard 4kV system to the standard 27.6kV system. This 4kV distribution system is an island of two aging substations surrounded by 27.6kV feeders.

### 6.2. Scope of Work

Broadlands MS was built between 1961 and 1968 and most of the surrounding distribution system was built around that time. This job is to facilitate the decommissioning of this aging substation and the distribution grid in the area. The substation has aging transformers and circuit breakers. Sloane MS was built in 1973 and contains aging non standard oil circuit breakers. The oil of the circuit breakers has reached its end of life, based on The Dissolved Gas and Fluid Analysis Report, which indicates the circuit breaker is in poor condition. There is high risk of collateral damage if the oil circuit breakers were to fail catastrophically. There is very little load connected to the 4kV system supplied from Sloane MS. As such, it is more prudent to convert the 4 kV distribution system to a higher voltage in order to avoid the high capital station investment required. Furthermore, since these two stations are not surrounded by other 4kV plant, each station acts as backup to the other in the event of an outage. As a result, one station cannot be decommissioned in isolation of the other.

THESL proposes to convert the area to 27.6kV to modernize the distribution system in this area. Along most of the streets whereby 4kV distribution is present there is also 27.6kV distribution present. This is beneficial in that new 27.6kV plant is generally not required to be installed in these areas.

Broadlands and Sloane MS are the only two 4 kV stations in the midst of 27.6KV distribution area and they back up each other. They are both lightly loaded and can easily transfer load to nearby 27.6kV feeders. Once the entire load is converted to 27.6kV, it will be easy to dismantle the 4kV lines and clean up the OH systems and decommission the stations.

### 6.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 24669, 24668, 24851, 24881 | Rebuild Broadlands MS Area with VC | 2012 | $3.40 |
| | | **Total:** | **$3.40** |

## 7. Safety Alert SMD-20 Switch Replacement

### 7.1. Objectives

The purpose of this job is to replace SMD-20 Switches whose pin assembly had been modified from the original design at various locations around Etobicoke.

### 7.2. Scope of Work

The scope of work is to remove 81 porcelain switches that were identified to have their pin assembly modified and replace with new polymer type SMD-20 units at different locations in the South end of Etobicoke.

Switches containing this modification have been primarily found in the South end of Etobicoke. The modification was to limit the travel of the fuse when the switch was in an opened position so that the fuse would not swing open fully (approximately 180 degrees) and potentially contact other apparatus that may be below it. The problem is that the pin may limit the travel of the fuse such that there will be inadequate air clearance between the top of the fuse and the top of the switch needed to prevent arcing. The primary concern is that the modification may cause arcing that could compromise the safety of people in the vicinity as well as THESL field crews. Limiting the fuse travel may also further interfere with other activities such as using the loadbreak tool or fuse replacement. A further concern with these switches is the porcelain construction which has been identified as a safety issue as well as reliability problem considering the high failure rate observed with porcelain insulated switches.

### 7.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20684 | W12397 - Safety Alert SMD-20 Switch Replacement | 2012 | $0.50 |
| | | **Total:** | **$0.50** |

## 8. Manby TS Load Transfer To Horner TS

### 8.1. Objectives

Based on the latest load forecast, Manby TS is approaching maximum capacity. In 2010, Bus B-Y was utilized at 68 MVA while the 100% firm capacity is 63 MVA. It is expected to continually increase if no load relief solution is provided. THESL studied the possibility of transferring load to a nearby substation and has decided to transfer some of the load south to Horner TS so as to make room for future load re-distribution and prevent overloading.

### 8.2. Scope of Work

As seen in Figure 61, the red figures depict over loading beyond the firm capacity of the buses.

| MANBY (230KV/27.6KV) TS | Firm Capacity (MVA) | | | | YEAR | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Present | | Future | | | | | | | | | | | | |
| | 100% | 95% | 100% | 95% | 2010* | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| B&Y | 63 | 60 | 63 | 60 | 68 | 68 | 69 | 70 | 71 | 71 | 72 | 73 | 73 | 74 | 74 |
| Q&Z (Bus load includes load supplied to Hydro One) | 63 | 60 | 63 | 60 | 61 | 61 | 61 | 62 | 63 | 63 | 64 | 65 | 65 | 66 | 67 |
| V&F | 112 | 106 | 112 | 106 | 94 | 97 | 99 | 100 | 101 | 102 | 103 | 104 | 105 | 107 | 108 |
| | | | | | | | | | | | | | | | |
| Total of all Buses | 238 | 226 | 238 | 226 | 223 | 226 | 228 | 231 | 234 | 236 | 238 | 241 | 243 | 246 | 249 |
| Surplus MVA | | | | | 15 | 12 | 10 | 7 | 4 | 2 | 0 | -3 | -5 | -8 | -11 |
| %Loading (Load/2010 firm Cap) | | | | | 94 | 95 | 96 | 97 | 98 | 99 | 100 | 101 | 102 | 103 | 105 |

**Manby TS:**
B-Y Bus requires load relief in 2011

**Manby TS:**
Q-Z Bus requires load relief in 2014

**Figure 61: Loading Capacity**

In order to transfer the proposed load, THESL must run two feeders north from Horner TS to pick up the Manby TS loading. This requires civil construction at Horner TS egress and along the east side of Kipling Avenue. The scope of work for this job involves three new poles including two feeder risers, eight cable chambers, two kilometres of underground cable, and eight switches.

### 8.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 16616 | Manby TS Load Transfer to Horner TS | 2012 | $0.78 |
| | | **Total:** | **$0.78** |

## 9. Overhead Rebuild on feeder SCNAR43M28

### 9.1. Objectives

The objective of this job is to rebuild the overhead infrastructure on feeder SCNAR43M28 with the replacement of deteriorated poles, porcelain infrastructure (insulators and switches), CSP transformer as well as replacing the bare conductors on some locations with tree proof conductor.

### 9.2. Scope of Work

The scope of work for this job is to rebuild the overhead infrastructure on SCNAR43M28 to address the main cause of outages on this feeder. As shown in Figure 62 the main cause of the outages on the feeder are animal contact, tree contact, porcelain insulators and overhead conductor.

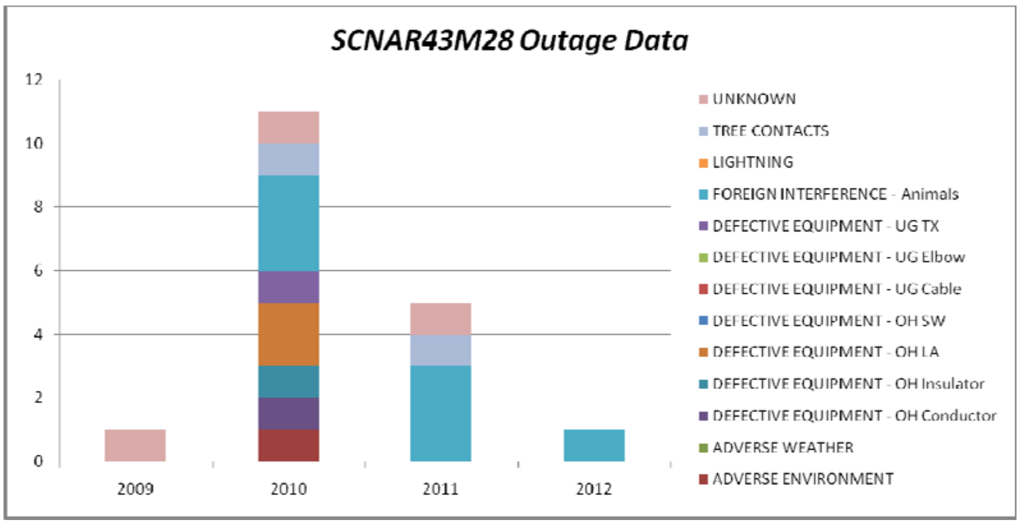
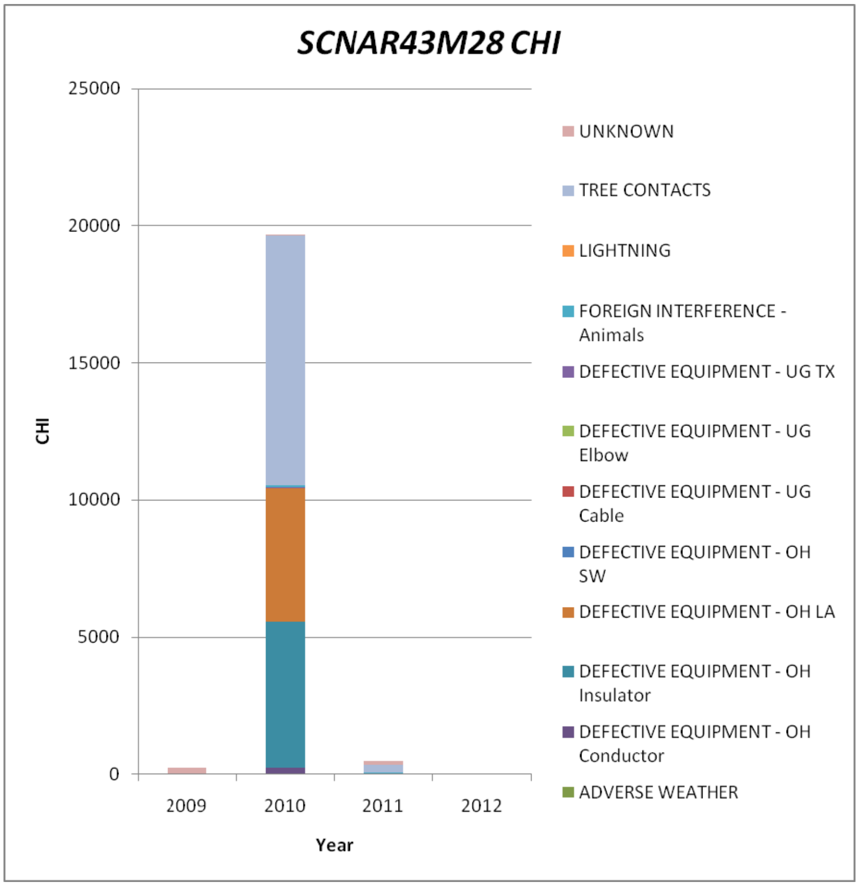



**Figure 62: SCNAR43M28 Outage Data**




1 **Figure 63: SCNAR43M28 CHI**

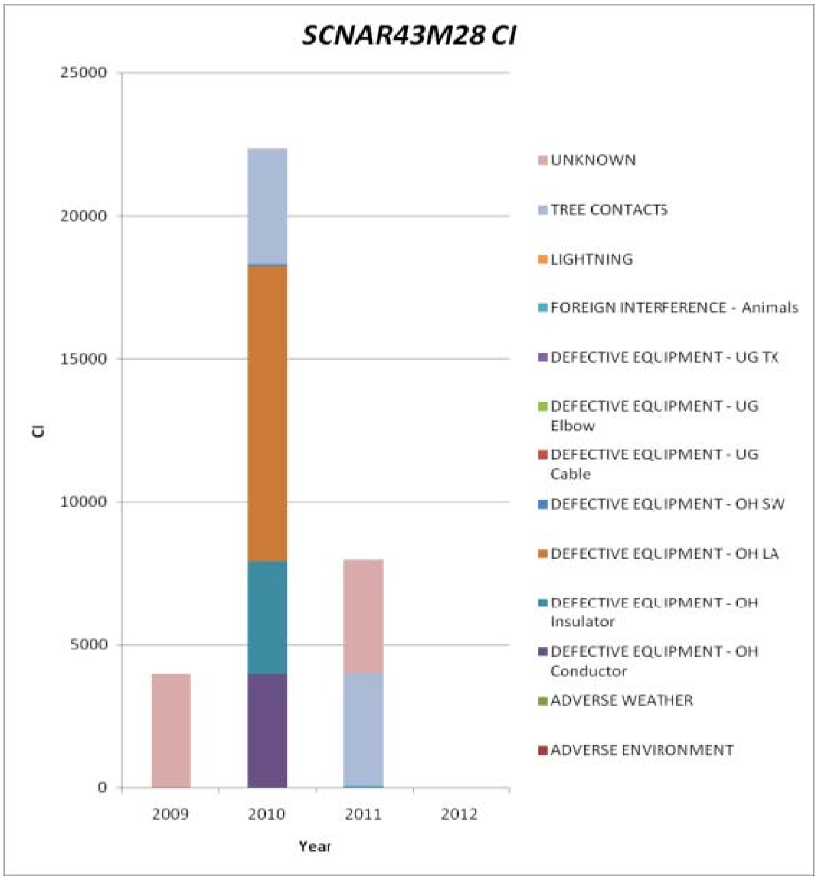



**Figure 64: SCNAR43M28 CI**

Figures 63 and 64 show the impact of Customers Hours Interrupted and Customers Interrupted (CI) (CHI) for tree contact and porcelain switches.

This job will take place in the area bounded by Midland Avenue, Warden Avenue, St. Clair Avenue and Lake Ontario.

## 9.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 21531 | E13111Overhead Rebuild SCNAR43M28 | 2012 | $0.74 |
| | | **Total:** | **$0.74** |

## 10. Overhead Rebuild and Feeder Rehabilitation on NY80M6

### 10.1. Objectives

The purpose of this job is to improve the reliability of feeder NY80M6 by rebuilding and refurbishing the overhead infrastructure that has past its useful life.

### 10.2. Scope of Work

Feeder 80M1 has sustained nine outages during the past year (Refer to Figure 65). Most of the assets have approached end-of-life and are non-standard.

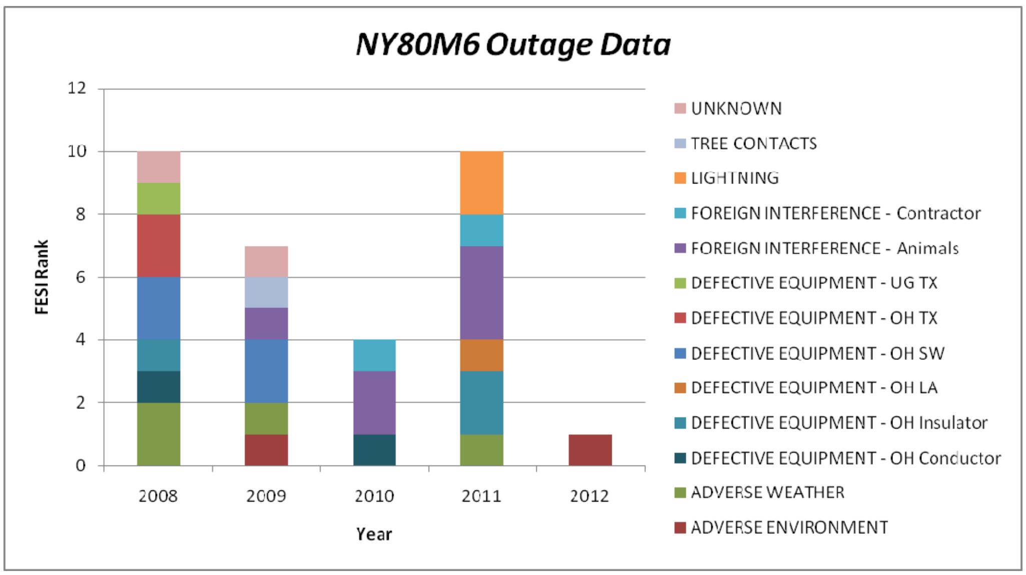



**Figure 65: NY80M6 Outage Data**

Results from crew personnel have come in through feeder patrols on the condition of the feeder. NY80M6 possesses a significant count of non-standard equipment and assets past their useful life posing a potential safety risk for THESL personnel and the public.

The scope of this work for these jobs is to replace end-of-life and non-standard assets which include poles in poor condition, porcelain insulators, porcelain switches, CSP transformers that will be replaced to current standard allowing proper animal guard installation to prevent future animal contacts and will target the replacement of bare conductor with tree-proof conductor in this heavily-treed area in order to prevent further outages due to tree contact. The area for job 2466 is bounded by Kenneth Avenue, Bishop Avenue, Estelle Avenue and Sheppard Avenue East. The area for job 24598, 22850 is bounded by Bayview Avenue, Empress Avenue, Dudley Avenue and Sheppard Avenue East.

### 10.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 24666 | E11243 – 80M6 Feeder OH Enhancement | 2012 | $0.53 |
| 24598, 22850 | E12436 – NY80M6 Feeder OH Enhancement Phase 3 NY80M6 | 2012 | $1.40 |
| | | **Total** | **$1.92** |

## 11. Overhead Rebuild on feeder 35M1

### 11.1. Objectives

The objective of this job is to reduce the probability of outages due to the failure of CSP transformers and non-standard equipment on feeder 35M1. The non standard equipment had been the major contributor to the rise in the number of sustained outages on this feeder from seven outages in 2009 to nine outages in 2010 and then to 15 outages in 2011. The significant decline in the reliability of this feeder indicates the need to address it in 2012 to improve service to the 1,854 customers that it serves.

### 11.2. Scope of Work

As shown in Figure 66, there were 15 sustained interruptions in 2011. In the first three months of 2012, the feeder has already experienced five outages. There is an urgent need to upgrade deteriorating assets on this feeder, which have contributed the increase in CHI from 420 in 2009 to 74,383 in 2010 and 13,997 in 2011.

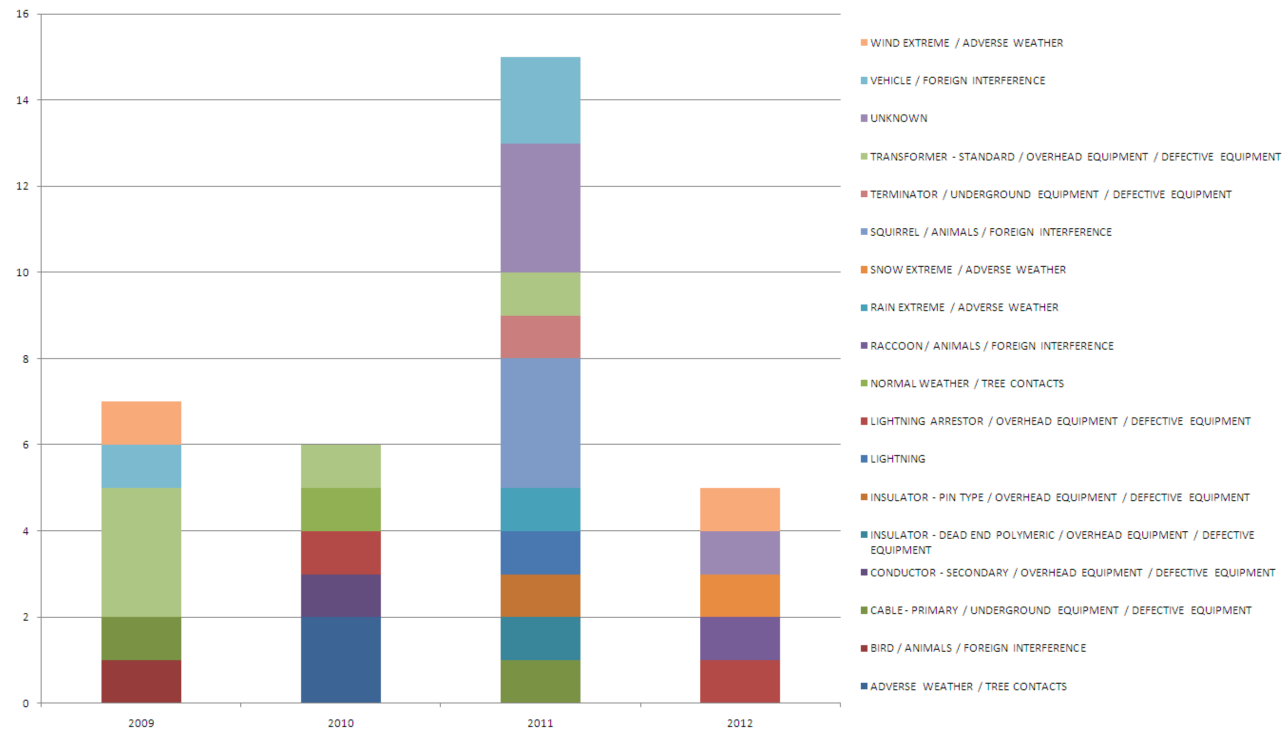



**Figure 66: 35M1 Outage Frequency**

The scope of this job is to replace the non-standard equipment on the feeder. This job will target CSP transformers, aging poles, porcelain switches and lightning arrestors, and will install tree proof conductor in areas of the feeder that are heavily treed. Animal guards will be installed to reduce any faults that may occur from animal interference.

### 11.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 19871 | X12175 Replacement of CSP Transformer | 2012 | $1.34 |
| | | **Total:** | **$1.34** |

## 12. Martin Ross and Flint Road Overhead Rebuild

### 12.1. Objectives

The objective of this job is to rebuild the overhead distribution system in the area of Martin Ross Avenue and Flint Road due to the deteriorating condition of the assets that are past their useful lives. This job will replace non-standard and deteriorating equipment that pose a potential safety risk to the public and THESL personnel.

### 12.2. Scope of Work

Feeder NY85M7 has experienced eight outages in the past year. There is an urgent need to upgrade deteriorating assets on this feeder to avoid further outages.

The scope of this job is to replace the non-standard equipment on the feeder. This job will target CSP transformers, aging poles, porcelain switches and will install tree proof conductor in areas of the feeder that are heavily-treed. Animal guards will be installed to reduce any faults that may occur from animal interference.

### 12.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 23696 | W12669 – Martin Ross and Flint Rebuild NY85M7 | 2012 | $0.42 |
| | | **Total:** | **$0.42** |

## 13. Overhead Rebuild of Sections of Feeders NY34M6, NY53M24, NY51M21

### 13.1. Objectives

The purpose of this job is to replace old and deteriorating overhead assets and undersized conductors on sections of the feeders with newer and more reliable lines and equipment that meet current standards. Proactive replacement of these assets will cost less than reactive replacements as these assets fail. The deferral of this job could lead to deteriorating reliability with a high risk of increased outage frequency and duration. Potential safety risks in the job area to THESL crews and the public also would increase if it is deferred.

### 13.2. Scope of Work

As shown in Figure 67, NY53M24 and NY34M6 have had increasing trend of sustained outages. NY51M21 had 18 outages in 2010 and has already had 4 outages this year in the first 3 months of 2012.

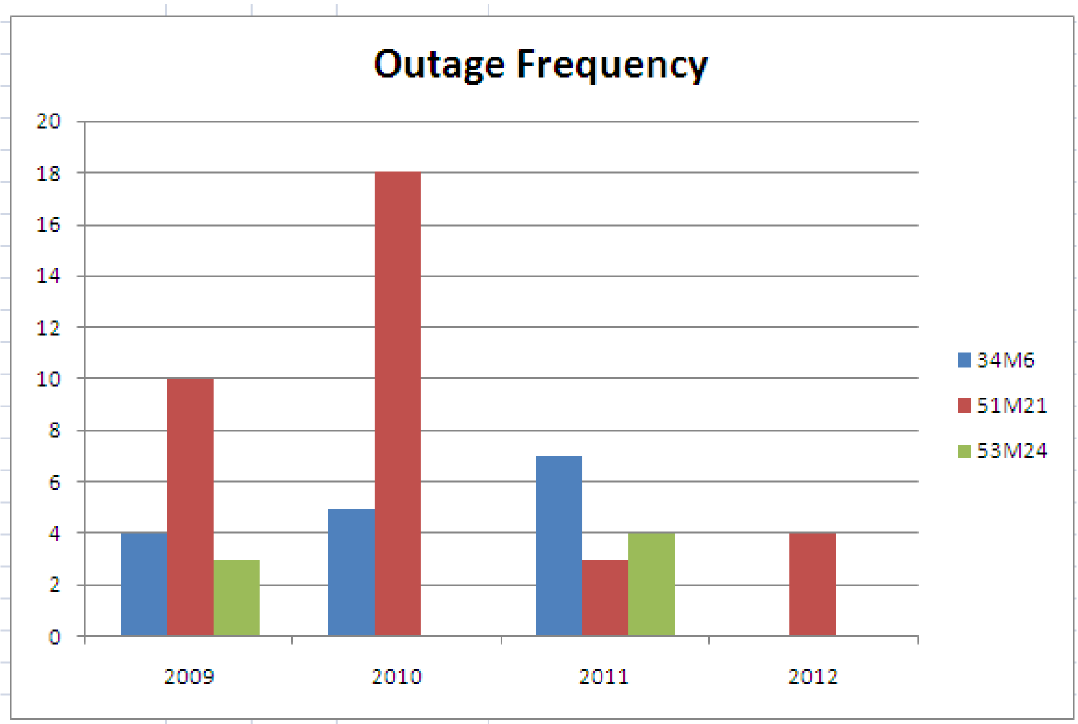



**Figure 67: Outage Frequency**

The scope of work includes the replacement of trunk 336 kcmil conductors, tree proof conductor in heavily treed areas, deteriorated poles, porcelain equipment, and CSP transformers. This rebuild will cover 570 metres along Northdale Road West of Gerald, 120 metres from Bayview Avenue single-phase spar to Baytree Court, 720 metres along Gerald Street up to Berkindale Drive, 635 metres on the Single-Phase OH spar to Forest Heights, 325 metres from Berkindale Drive to OH Harrison, 455 metres along Harrison Road and 508 metres along Heathcote Avenue E-W and South (ends 27F3 NOP).

### 13.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20578 | E12358 OH Rebuild of sections of the Overhead Distribution on NY51M21, Part 1 | 2013 | $1.58 |
| 20595 | E12361 OH Rebuild of sections of the Overhead Distribution on NY51M21, Part 2 | 2013 | $0.83 |
| 20848 | E12459 Banbury/Post Rd OH Rehab: NY34M6, NY53M24, NY51M21 | 2013 | $0.26 |
| | | **Total:** | **$2.67** |

## 14. Voltage conversion on feeder SCKHF1 and SCKHF2

### 14.1. Objectives

The purpose of this job is to transfer the load supplied by 13.8kV overhead distribution feeder SCKHF2 to the 27.6kV feeder. This will allow THESL to dismantle and remove all 13.8kV overhead lines in the area and enable the decommissioning of the Brimley Sheppard Municipal Station built in 1965.

### 14.2. Scope of Work

The scope of work is to convert the overhead load supplied by SCKHF2 on Brimley Road to SCNAH9M23. Brimley Sheppard (KH) MS station was built in 1965. Both transformer and 13.8kV breakers are very old. To enable decommissioning of the station and distribution equipment and to modernize the electrical distribution equipment in the area, THESL proposes to convert the distribution fed from this Municipal Station with the modern 27.6kV equipment built to current standards.

### 14.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20774 | E12433 Conversion feeder SCKHF2 to 27.6kV | 2013 | $0.82 |
| | | **Total:** | **$0.82** |

## 15. OH Rebuild of the Overhead Distribution on NY80M4

### 15.1. Objectives

The purpose of this work is to rebuild the overhead distribution on this feeder, in the area of Yonge Street and Cummer Avenue, with the replacement of porcelain insulators, lightning arresters, non-standard CSP transformers and other end-of-life assets.

### 15.2. Scope of Work

As seen in Figure 68, this feeder has experienced nine outages in 2011 and there have already been 2 sustained outages in the first three months of 2012. The number of outages along the feeder indicates the poor performance of the assets associated with it. The frequent outages underscore the urgency for this remedial job.

Proactive replacement of these assets is expected to cost less than reactive replacement when they fail. The deferral of this work would likely lead to deteriorating reliability with a high risk of increased outage frequency and duration. Potential safety risk to THESL crews and the public also would increase if the job is deferred.

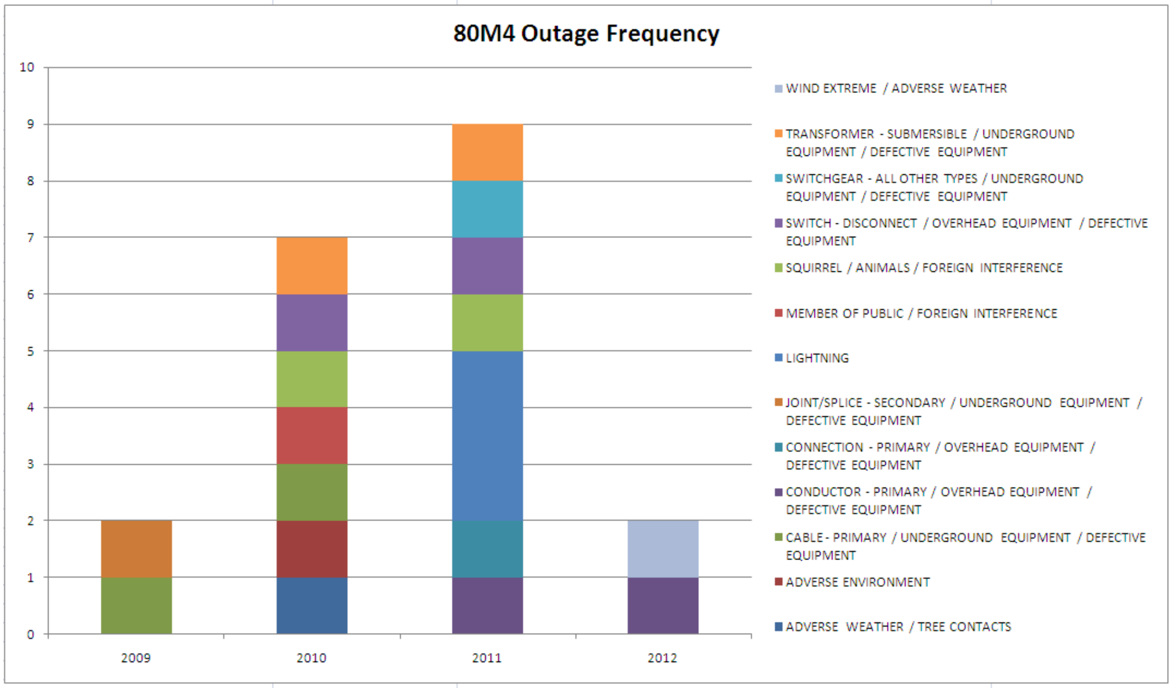



**Figure 68: NY80M4 Outage Frequency**

The scope of work is to replace end-of-life poles, CSP transformers, overhead conductor, and non-standard porcelain insulators and arrestors in the area bounded by Conacher Drive, Yonge Street, Nipignon Avenue, and Cummer Avenue.

### 15.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 21190 | E12508 OH Rebuild of the Overhead Distribution on NY80M4 Phase 1 | 2013 | $1.79 |
| 21193 | E12509 OH Rebuild of the Overhead Distribution on NY80M4 Phase 2 | 2013 | $1.08 |
| | | **Total:** | **$2.87** |

## 16. Rebuild of the Overhead Distribution on NY51M8

### 16.1. Objectives

The purpose of this job is to rebuild the overhead distribution assets associated with this feeder including replacement of deteriorated poles, porcelain insulators, lightning arresters, non-standard CSP transformers and bare conductor in treed areas. The scope includes installation of a SCADA switch, fuses and fault indicators. This feeder has experienced eight outages in the last 12 months (FESI-8) and has a WPF rating of 91. The number of outages along the feeder indicates the poor performance of the assets associated with it.

### 16.2. Scope of Work

The scope of work is to replace poles, CSP transformers, as well as porcelain insulators and arrestors in the area south of the intersection of Finch Avenue East and Bayview Avenue. The job also includes the installation of a new SCADA-Mate load break switch on Finch Avenue East near Page Avenue.

### 16.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 21785 | E13153 Rebuild of the Overhead Distribution on NY51M8 | 2013 | $1.69 |
| | | **Total:** | **$1.69** |

## 17. Replacement of non-standard Overhead Equipment

### 17.1. Objectives

The objective of these jobs is to replace under-performing assets in the overhead distribution system. The replacement of non-standard CSP transformers, switches, insulators and arresters will be undertaken under this job for feeders YK53M5 and YK34M6 to improve reliability.

### 17.2. Scope of Work

The scope of work includes the replacement of poles, overhead conductors, non-standard CSP transformers, switches, porcelain insulators and arresters in the areas primarily between Mount Pleasant Road, York Mills Road, Eglinton Avenue East and The Donway West then between Victoria Park Avenue, Bermondsey Road, Eglinton Avenue and Northline Road.

### 17.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20023 | X12204 - Replacement of CSP transformer | 2013 | $1.19 |
| 19775 | X13109- 34M6 -Replacement of non – standard CSP transformers and conductor | 2013 | $0.97 |
| | | **Total** | **$2.16** |

## 18. Rebuild and CSP transformer replacement

### 18.1. Objectives

The objective of this job is to replace the aging and non-standard primary overhead distribution equipment on feeder 85M1, which has a high probability of future outages, in order to improve reliability. Feeder NY85M1 had sustained eight interruptions during the past year (FESI-8) predominately caused by failing equipment and foreign interference on the overhead plant. The area is primarily comprised of non-standard poor performing assets such as CSP transformers, undersized conductor, deteriorating poles, porcelain insulators, arrestors and switches. These two jobs are expected to address the issues that are contributing to the poor reliability of the feeder, and improve the safety and reliability of this feeder.

### 18.2. Scope of Work

The scope of work for these jobs is to replace poles, undersized conductor, non-standard CSP transformers and other non standard assets such as porcelain switches and arrestors that have contributed to past outages and have a high probability of causing future outages. Furthermore, the age and condition of some non-standard assets can pose a potential safety risk to the public and field staff if not proactively replaced due to their age and condition. As seen below in Figure 69, there have been a number of outages over the last three years, which have had a significant impact on the customers served by this feeder, due to failing equipment and foreign interference on the overhead plant. The scope of work for this job is expected to address this feeder and improve the reliability for the customers in this area.

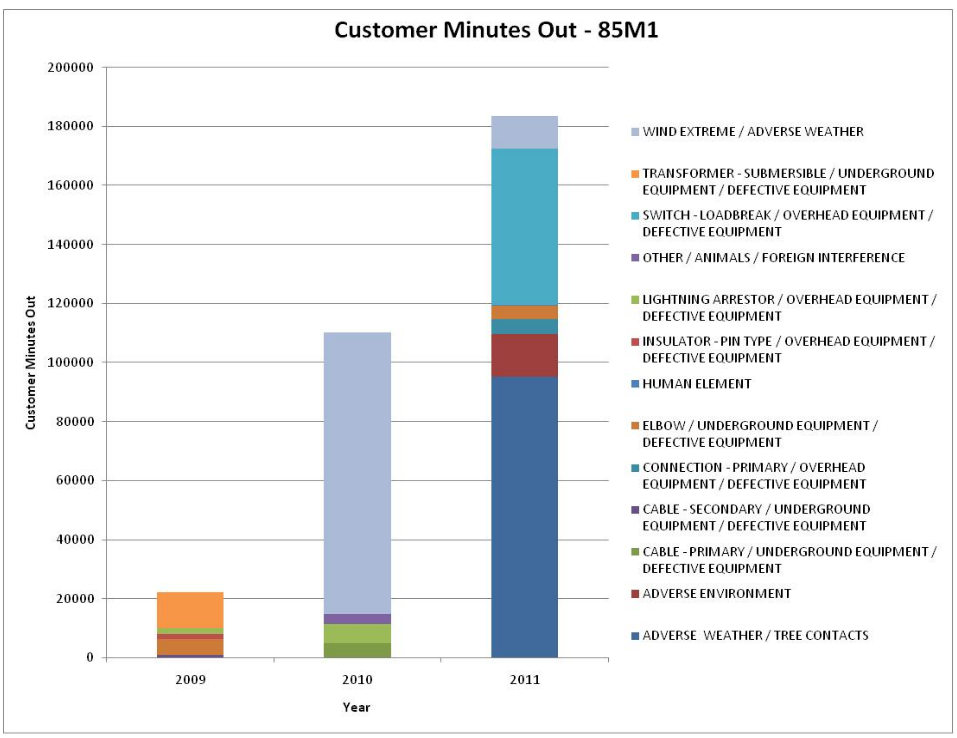



**Figure 69: NY85M1 CMO**

### 18.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20939 | W12442 - FESI Rebuild and CSP Replacement Ph#1 NY85M1 | 2013 | $1.39 |
| 23567 | W13351 FESI Rebuild and CSP Replacement Ph#2 (NY85M1) | 2013 | $2.01 |
| 20965 | W12491 - FESI CSP and OH Conductor Replacement Ph#3 | 2013 | $1.58 |
| | | **Total** | **$4.98** |

## 19. Overhead Refurbishment on feeder NY85M23

### 19.1. Objectives

The primary purpose of this job is to upgrade non-standard CSP transformers and poor condition overhead distribution assets in the area to improve the stability of feeder NY85M23 (Refer to Figure 70, below, for outage frequency).

### 19.2. Scope of Work

Feeder NY85M23 had 13 sustained interruptions in 2011 The equipment on this feeder is primarily comprised of non-standard and poorly performing assets such as poles CSP transformers, insulators, arrestors, and switches.

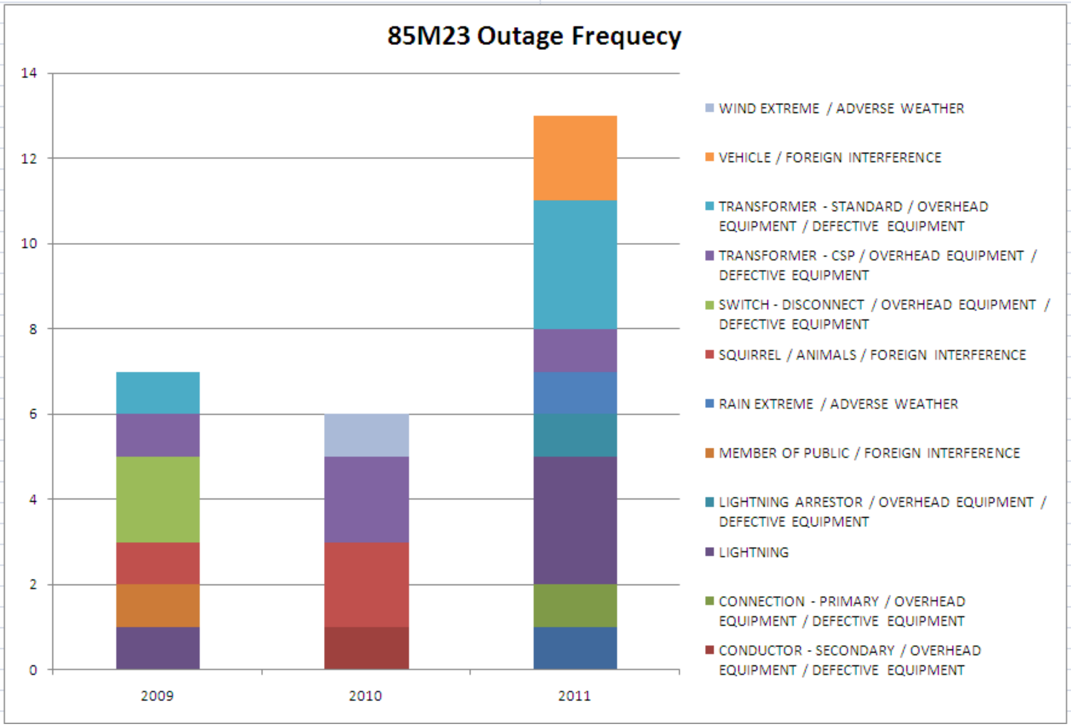



**Figure 70: NY85M23 Outage Frequency**

The scope of this job is to replace the existing overhead conductor with tree-proof along the feeder's overhead line on nine streets (Deloraine Avenue, Ledbury Street, Grey Road, Brookdale Avenue, Kelso Avenue, Clyde Avenue, Carmichael Avenue, Joicey Boulevard and Dunblaine Avenue). In addition, replacement of CSP transformers and poles will be done as part of these jobs. New telcon drop wire with a cone installed over the primary bushing will be installed on the new transformers. Non-standard or deteriorated hardware at the pole and transformer locations including porcelain insulators and porcelain arrestors will be replaced by new units that conform to current THESL standards.

### 19.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 21113 | W13054 - FESI - Refurbish OH Feeder 85M23 - Phase 1 | 2013 | $1.04 |
| 21118 | W13055 - FESI - Refurbish OH Feeder 85M23 - Phase 2 | 2013 | $0.71 |
| 21122 | W13056 - FESI - Refurbish OH Feeder 85M23 - Phase 3 | 2013 | $0.72 |
| 21123 | W13057 - FESI - Refurbish OH Feeder 85M23 - Phase 4 | 2013 | $0.80 |
| | | **Total** | **$3.27** |

## 20. WPF Feeder Rehabilitation on NY80M8

### 20.1. Objectives

The purpose of this job is to rehabilitate feeder NY80M8 by replacing poles that were identified in poor conditions, non-standard CSP transformers, conductors and porcelain insulators.

### 20.2. Scope of Work

The scope of work for these jobs involves the replacement of bare overhead conductor with tree-proof conductor along the feeder's overhead line. In addition to this, the job will replace CSP transformers and poles. New telcon drop wire with a cone installed over the primary bushing will be installed on the new transformers. Non-standard or deteriorated hardware at the pole and transformer locations including porcelain insulators and porcelain arrestors will be replaced by new units that conform to current THESL standards. The streets where these replacements will take place are on Bathurst Street, Finch Avenue West, Wilmington Avenue, Virgilwood Drive, Dubbyne Court, Purbrook Court, Transwell Avenue, Peckford Road, Robson Place, Kenton Drive, Dallas Road, Lister Drive, Pinnard Court and Dornfell Street.

Feeder NY80M8 has experienced eight outages in the past year and as shown in Figure 71. Since 2009, the feeder has seen an increasing number of outages. The areas are primarily comprised of end-of-life equipment. The average Health Index scores for the assets that are being replaced is 61 based on the results from half of the asset population.

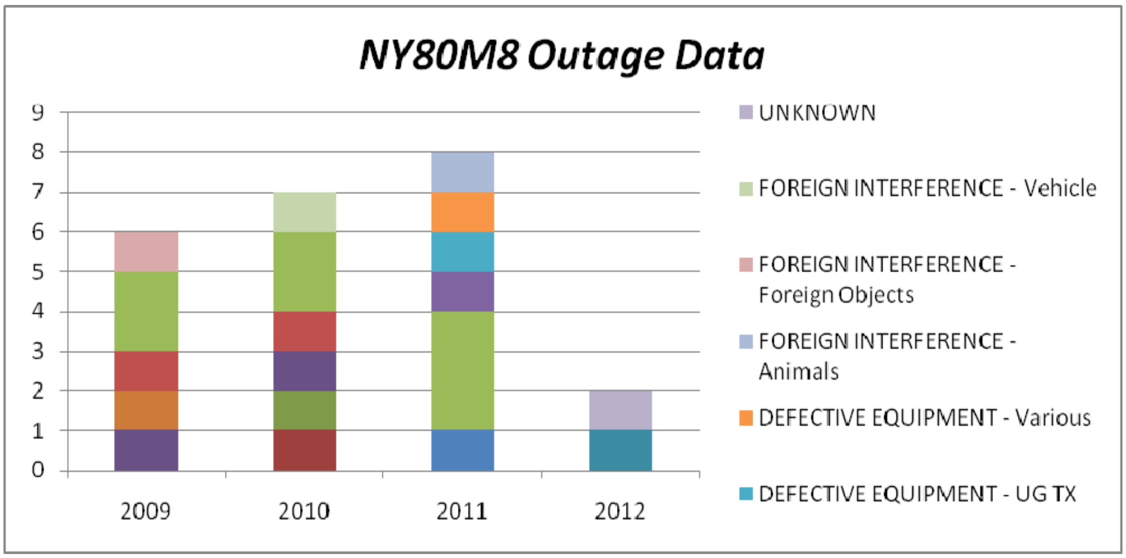



**Figure 71: NY80M8 Outage Data**

## 20.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 21517 | W13113 - FESI Feeder Rehab and CSP replacement Ph#1 | 2013 | $0.71 |
| 21518 | W13115 - FESI Feeder Rehab and CSP replacement PH#2 | 2013 | $0.50 |
| | | **Total** | **$1.21** |

## 21. Overhead Feeder Refurbishment on NY55M28

### 21.1. Objectives

The objective of these jobs is to rebuild the plant on NY55M28. It will replace the aging and non-standard primary overhead distribution equipment and the XLPE lateral services with tree retardant cable to improve reliability.

### 21.2. Scope of Work

The scope of work for these jobs is to replace poles, overhead primary conductor and non-standard CSP transformers. Also, poor performing assets such as porcelain insulators and arrestors will be replaced as well. In addition, undersized primary overhead conductor will be replaced to standard size. In areas where underground laterals are serviced with early vintage XLPE cable, it will be replaced with standard tree retardant cable.

### 21.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 21639 | W13130 - Refurbish OH Feeder - Epsom Downs | 2013 | $2.05 |
| 21690 | W13131 - Refurbish OH Feeder Falstaff Area Ph#2 | 2013 | $1.40 |
| | | **Total** | **$3.45** |

## 22. Refurbishment of trunk feeder and laterals on NY85M10

### 22.1. Objectives

The objective of this job is to rebuild and replace the aging and non-standard primary overhead distribution equipment on feeder NY85M10 in order to improve reliability. These jobs also will replace XLPE lateral services with tree retardant cable to improve reliability.

### 22.2. Scope of Work

As seen from Figure 72, there have been a consistent number of outages every year on this feeder from causes including animal interference and overhead transformer failures.

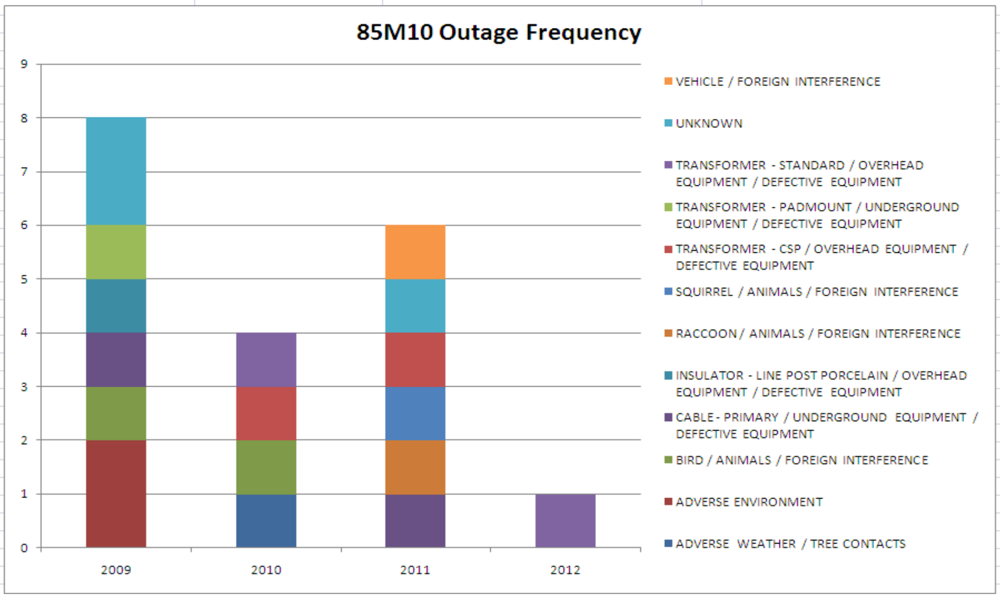



**Figure 72: NY85M10 Outage Frequency**

The scope of this work is to replace poles and non-standard CSP transformers. Poorly performing assets such as non-standard porcelain insulators and arrestors will be replaced as well. In addition, undersized primary overhead conductor will be replaced to standard size. In areas where underground laterals are serviced with early vintage XLPE cable, it will be replaced with standard tree retardant cable. The assets being replaced by this job are located in the vicinity of the intersection of Wilson Avenue between Keele Street and Dufferin Street.

### 22.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 22184 | W13198 – Refurbishment of trunk feeder – Regent Road and Wilson Avenue | 2013 | $1.24 |
| 22208 | W13205 – Refurbish Feeder Laterals Phase 1 of 2 | 2013 | $1.21 |
| 22211 | W13206 – Refurbish Feeder Laterals Phase 2 of 2 | 2013 | $1.71 |
| | | **Total** | **$4.16** |

## 23. Overhead Feeder Refurbishment on ETR30M10

### 23.1. Objective

The objective of this job is to replace the non-standard and aging equipment that pose a high risk of failure on feeder ETR30M10 from Horner TS. The feeder has experienced poor reliability due to failing equipment since 2009 and refurbishment work will target high risk equipment to mitigate the risk of future outages.

### 23.2. Scope of Work

The scope of work is to replace all non-standard and aged poles, porcelain insulators and switches, and steel brackets in the job area between Royal York Road, Kipling Avenue, Dundas Street and Evans Avenue. Animal guards and insulated drop wires will be installed at strategic locations to reduce the probability of a fault due to animal interference. Fuse coordination work is included where necessary to reduce outage impacts.

### 23.3. Required Capital Costs

| Job Estimate Number | Job Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 21569 | W13122 – FESI Refurbish OH Feeder (30M10) | 2013 | $0.50 |
| | | **Total:** | **$0.50** |

## 24. OH Rebuild Duplex, Church, Parkview NY80M3 (W14278)

### 24.1. Objectives

The objective of this job is to rebuild a portion of NY80M3 in order to improve the service reliability to customers connected on this feeder in the vicinity of Yonge Street and Finch Avenue (Refer to Figure 73 for number of interruptions). The overhead equipment on feeder NY80M3 is reaching end of life and in many areas the assets are non-standard. Over the last few years the most prevalent cause of outages on this feeder was component failure. In addition, fusing the unfused lateral connections to the trunk will mitigate the impact of an outage to the entire feeder that would otherwise affect all 614 residential and commercial customers on it.

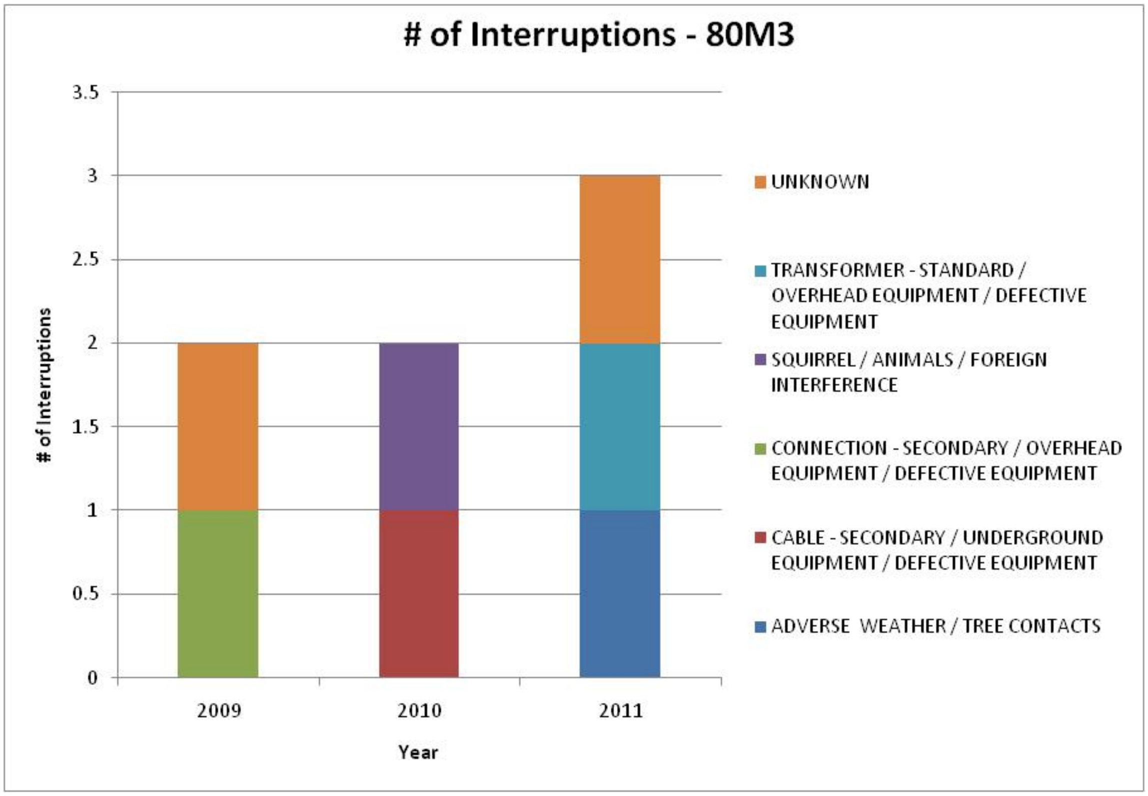



**Figure 73: Number of Interruptions on NY80M3**

### 24.2. Scope of Work

The scope of work consists of replacing non-standard and aging equipment on feeder NY80M3 that have a high probability of future failure. The equipment slated for replacement will be aging poles and CSP transformers. THESL will also install tree proof conductor in heavily treed areas and improve the feeder's configuration by installing additional fusing on lateral portions that are currently connected to the trunk without protection.

### 24.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 23873 | W14278-Overhead Rebuild Duplex/Church/Parkview | 2013 | $0.72 |
| | | **Total:** | **$0.72** |

## 25. 4.26 Overhead Rebuild and Feeder Rehabilitation on NY80M1

### 25.1. Objectives

The purpose of these jobs is to improve operational reliability and refurbish power supply by rehabilitating aging distribution infrastructure on feeder NY80M1.

### 25.2. Scope of Work

Feeder 80M1 has sustained 15 outages during the past year with three outages having already taken place in 2012. Most of the assets are approaching end-of-life and many are non-standard. The majority of the outages of this feeder have been caused by overhead equipment, see Figure 74.

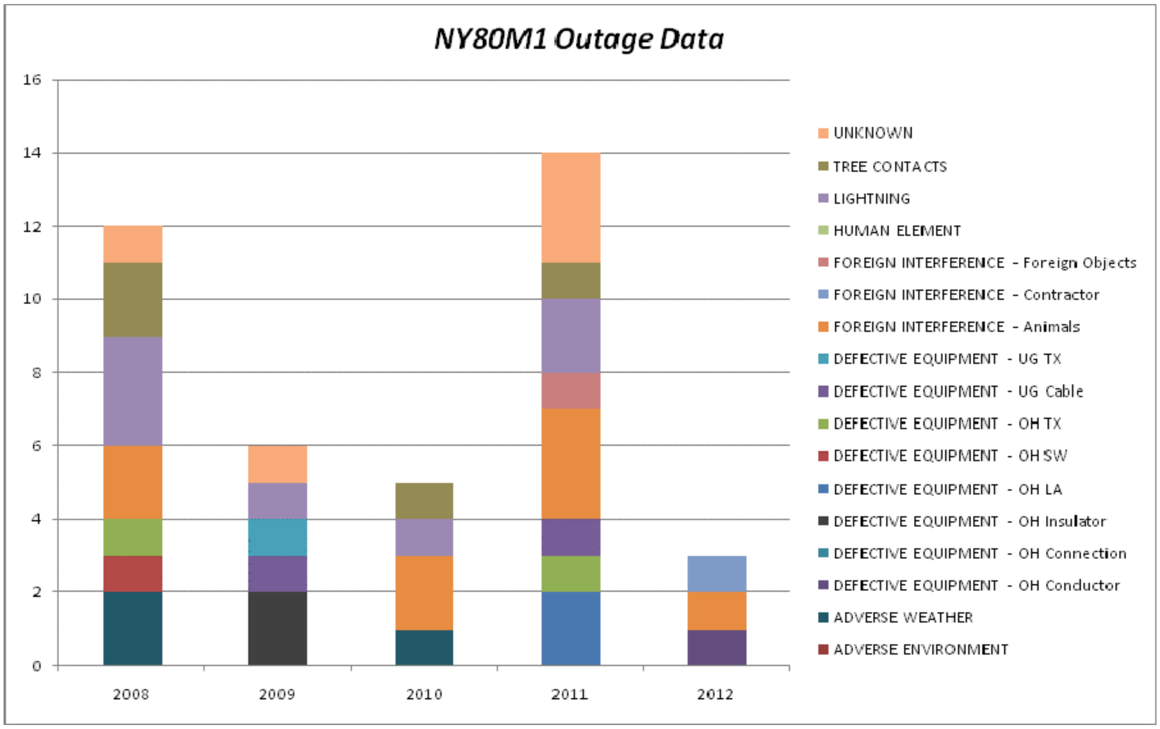
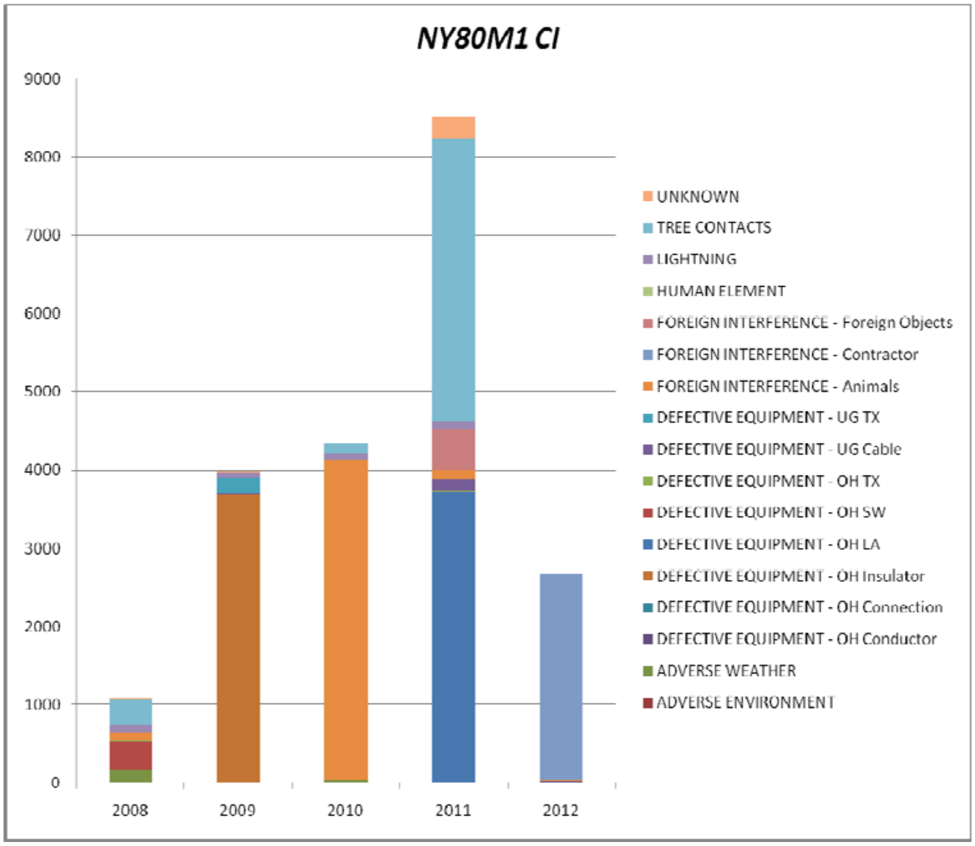
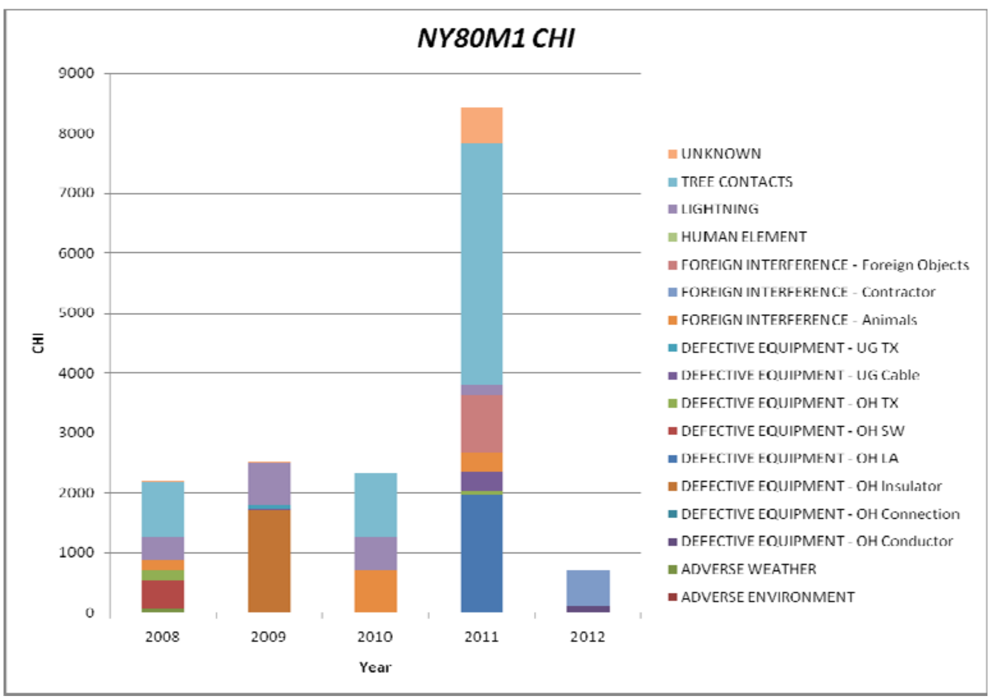



**Figure 74: NY80M1 Outage Data**

Information on the condition of the feeder has come in through feeder patrols. NY80M1 possesses non-standard equipment and assets past their useful lives, which pose a potential safety risk to THESL personnel and the public. In addition to this, the increase of outages and the duration of the outages have greatly impacted customers. Figures 75 and 76 show the breakdown of the CI and CHI on this feeder. Tree contact has been one of the main contributors to CI and CMO. For this reason bare conductor will be replaced by tree-proof conductor in areas that are heavily-treed with follow-up tree trimming.




1 **Figure 75: NY80M1 CI**




2 **Figure 76: NY80M1 CHI**

The scope of work for these jobs is to replace end-of-life and non-standard assets, which include poles in poor condition and porcelain insulators that have contributed to high CI and CHI, CSP transformers will be replaced to current standard allowing proper animal guard installation to prevent future animal contacts. The job area is bounded by Bathurst Street, Blake Avenue, Talbot Road and Park Home Avenue.

### 25.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 22180 | W13204 – Elynhill_Ellerslie_Betty Ann_ Park Home Ph#2 Overhead Rehab NY80M1 | 2013 | $0.80 |
| 21920 | W13185 – 80M1 Carney Rd Distribution Rehab | 2013 | $0.70 |
| 22037 | W13188 – 80M1 Finchhurst Dr and Fleetwell Crt OH Rebuild | 2013 | $0.15 |
| 22041 | W13189 – 80M1 Stafford Rd and Cloebury Crt | 2013 | $0.19 |
| 21876 | W13182 – Rehab Eldora_Kensington_Elmview 80M1 | 2013 | $0.13 |
| 21998 | W13187 - Clarkhill Glenborough Park Ancona Overhead Rebuild | 2013 | $0.64 |
| 22173 | W13197 - 80M1 Ellerslie_Betty Ann_ Park Home Ph#1 OH rehab | 2013 | $0.58 |
| | | **Total** | **$3.19** |

## 26. Voltage Conversion on Rennie Park MS

### 26.1. Objectives

The objective of this job is to extend 38M29 along Morningside Avenue to enable conversion from 4kV to 27.6kV in order to prepare Rennie Park MS (RK) for decommissioning. This substation and its associated overhead equipment consist of end of life and non-standard equipment. A decision has been made to decommission the substation instead of replacing costly breakers and power transformers to support the obsolete equipment on the feeders it supplies. This will avoid the cost of switchgear replacement. A voltage conversion on these feeders will upgrade the equipment to current system standards and will reduce the risk of future outages on equipment considered to have a high probability of failure.

### 26.2. Scope of Work

This job will convert all components necessary to migrate to 27.6kV. Components that will be replaced/upgraded are CSP transformers, poles, under–sized conductor and tree proof conductor in heavily treed areas. The job is located in the vicinity of Morningside Avenue and Ellis Avenue.

### 26.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 24161 | W13376 Voltage Conversion Rennie Park (TOB1RK) | 2013 | $1.59 |
| | | **Total:** | **$1.59** |

## 27. Rehabilitation of the Overhead Distribution System

### 27.1. Objectives

The objective of these jobs is to rebuild the overhead distribution on these feeders by replacing deteriorated poles, porcelain insulators, lightning arresters, non-standard CSP transformers and bare conductors with tree proof in treed areas. The work addresses issues found by the feeder patrol and are based on components that are considered a safety issue or have a high probability of failure in the near future. The jobs will take place near the intersection of Victoria Park Avenue, Highway 401, Don Mills Road, Lawrence Avenue East, Port Union Road, Sheppard Avenue West, Kingston Road and Meadowvale Road.

NY53M25 has experienced five outages in the last 12 months and has a WPF rating of 198. SCNA47M13 has experienced six outages in the last 12 months and has the very high WPF rating of 5, underscoring the urgency of this job.

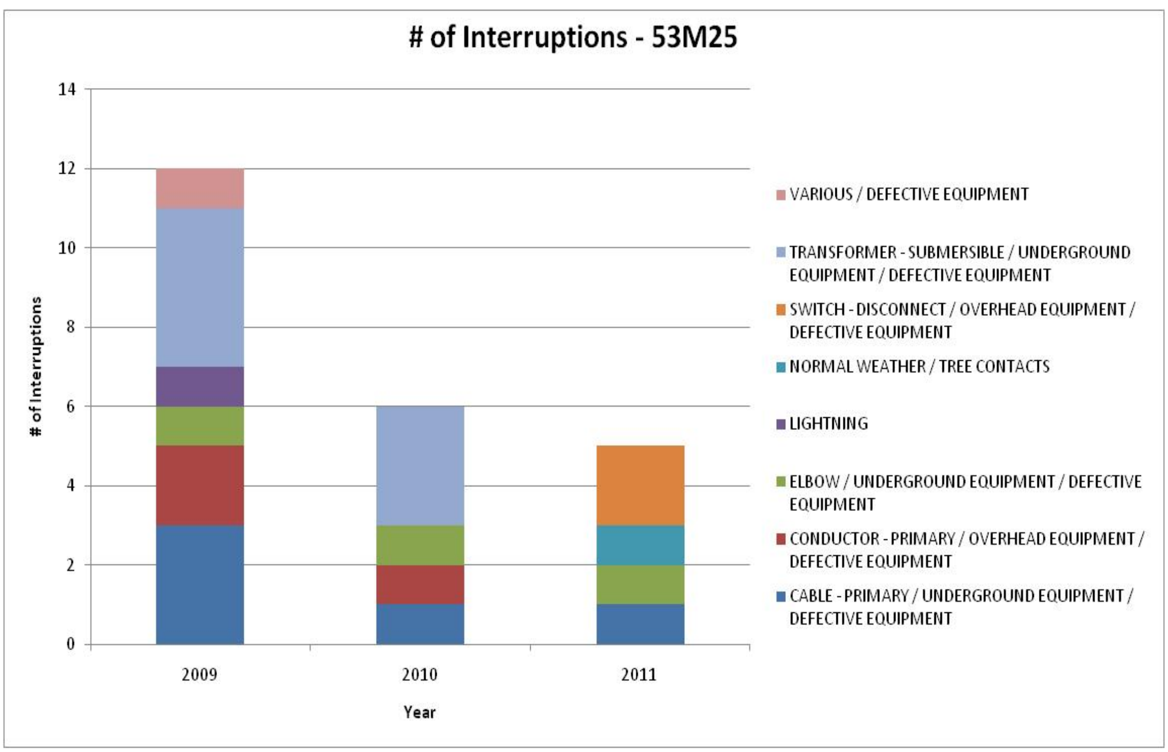



**Figure 77: Number of interruptions in 53M25**

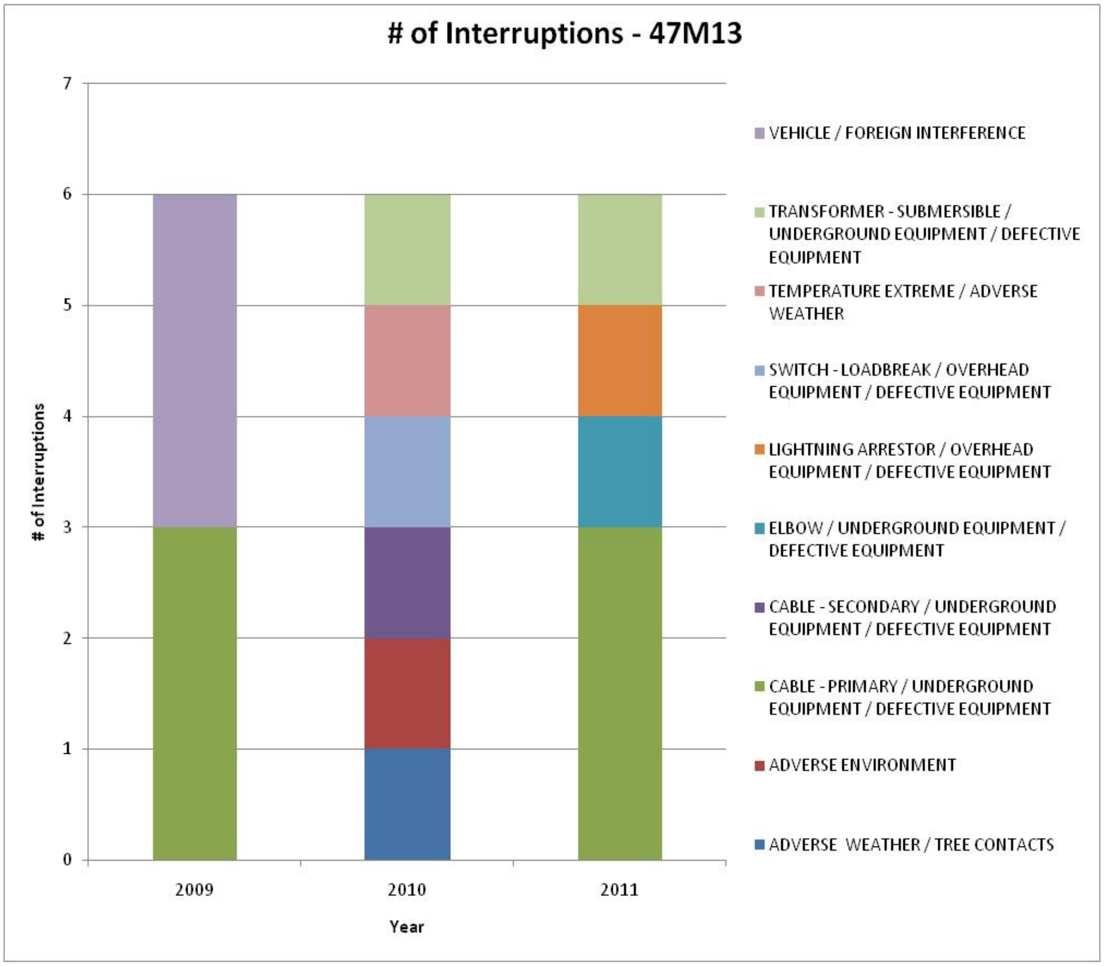



**Figure 78: Number of interruptions in 47M13**

### 27.2. Scope of Work

The scope of work is to replace non-standard and end-of-life components such as non-standard porcelain insulators and arrestors. These assets are considered to have a high probability of failure and in some cases pose a potential safety risk to the public and field crews. The average Health Index score of the poles addressed in these jobs is 50.1 (poor). Undersized primary overhead conductors will be upgraded to standard size.

### 27.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 22203 | E12570 - NY53M25 Rehabilitation of the OH Distribution on | 2013 | $1.20 |
| 21578 | E11742 - Rehabilitation of the OH Distribution on SCNA47M13 | 2013 | $0.42 |
| | | **Total:** | **$1.62** |

## 28. Overhead Rehabilitation and Voltage Conversion of feeder NYSS60F2

### 28.1. Objectives

The purpose of this job is to partially convert feeder NYSS60F2 from Churchill MS from 4kV to 27.6kV. This work will also address service reliability problems due to the poor condition plant supplied by 4kV feeder NYSS60F2 (Churchill MS).

### 28.2. Scope of Work

As shown in Figure 79, SS60F2 had more frequent outages in 2011 compared to 2009.

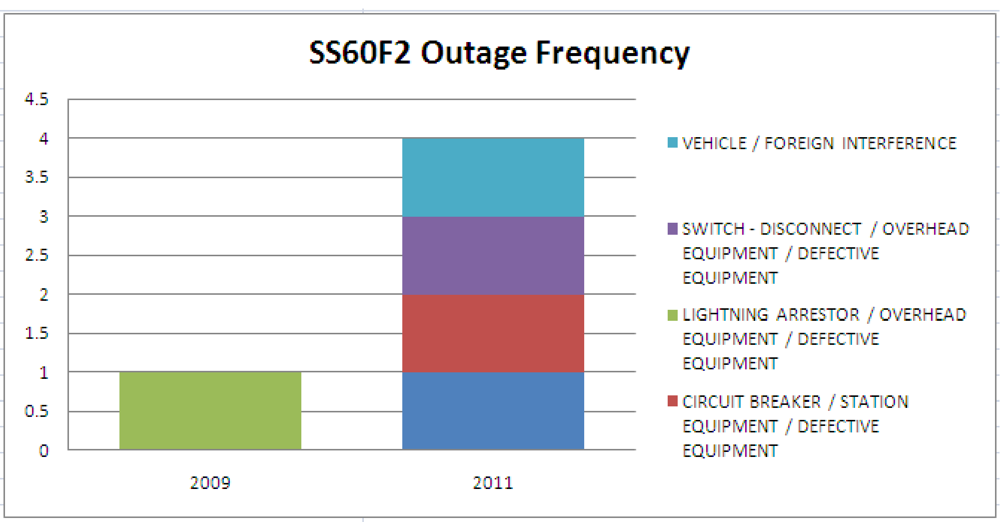



**Figure 79: SS60F2 Outage Frequency**

Churchill MS was originally built in 1961 and voltage conversion has begun to address obsolete construction standards and deteriorated plant conditions. NYSS60F2 is in poor condition. It consists of old, defective poles as well as non-standard overhead assets such as porcelain insulators, porcelain switches, conductors, pole heights, porcelain lightning arrestors, animal guards, and transformers.

The scope of work includes converting the 4 kV system (Churchill MS, NYSS60-F2) to a 27.6kV distribution system, utilizing NY80M1 on Wynn Road, Hosham Avenue, Hounslow Avenue, Yorkview Drive, Muirkirk Road, Wallbridge Court, Fleetwell Court and Finchurst Drive. Poles, single-phase pole-top transformers, single-phase banked pole-top transformers, three-phase pad-mounted transformers and overhead primary and secondary lines will be replaced as part of this work.

### 28.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| **20773** | **W12123 - Churchill/Wynn OH Rehab and VC (SS60-F2 to 80M1)** | **2013** | **$1.02** |
| | | **Total** | **$1.02** |

## 29. Overhead Feeder Upgrade

### 29.1. Objectives

The objective of this job is to replace the undersize conductors of the main trunk of feeders SCNAR43M24 and SCNAR43M28 with THESL standard 556.5 kcmil conductor. The job mainly involves the replacement of undersized conductor, but in some locations poles that have been identified as being in poor condition will be replaced and new overhead transformers will be installed to avoid the impact upon customers in the future.

### 29.2. Scope of Work

During load transfers, especially at peak load time, the undersized sections tend to be overloaded. This job will create a full capacity on the feeder's main trunk.

Feeder SCNAR43M24 is ranked 75th in WPF list and feeder SCNAR43M28 is ranked 16th in WPF. These jobs are expected to enable quick load transfer in the event of contingencies. When completed, these jobs will likely improve restoration time and the reliability profile of the feeder to the benefit of customers in the job area.

The scope of work for this job is to replace the undersized conductor on feeder SCNAR43M24 in the areas of Hollis Avenue, Milne Avenue, part of Mack Avenue and Birchmount Road. This will establish a full capacity feeder main and transfer ties with SCNAR43M23 and SCNR43M28. Undersized conductor will also be replaced on feeder SCNAR43M28 in the areas of Kennedy Road, Aylesworth Avenue, Highview Avenue and Aylesford Drive. This will establish a full capacity feeder main and transfer tie with SCNAR43M30.

### 29.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 22994, 22995 | E14136 OH Upgrade SCNAR43M24 Hollis Milne Birchmount | 2014 | $0.88 |
| 22958 | E14117 OH Rebuild SCNAR43M28 Aylesworth Kennedy | 2014 | $0.75 |
| | | **Total:** | **$1.64** |

## 30. Overhead Rebuild and Voltage Conversion on Ruddington MS

### 30.1. Objectives

The purpose of this work is to convert a 4kV primary distribution system that was built in the early sixties to 27.6kV. These lines are fed by Ruddington MS (SS64), which contains transformers and circuit breakers that are past their useful life. There is a high risk of damage to other equipment if the oil circuit breakers were to fail catastrophically. These jobs will enable conversion of Ruddington MS. They are expected to lower the risk of outages with the replacement of the aged assets and reduce system losses.

### 30.2. Scope of Work

The scope of work for this job is to convert the primary distribution of all overhead feeders from Ruddington MS. The job will cover replacing overhead transformers along Bayview Avenue and the installation of overhead conductor on Manorcrest Drive, Winlock Park and Feldbbar Court.

### 30.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 23978 | E14286 OH Rebuild and Voltage Conversion of NYSS64F2 from Ruddington MS | 2014 | $0.94 |
| | | **Total:** | **$0.94** |

## 31. Goulding MS Voltage Conversion

### 31.1. Objectives

The purpose of this job is to convert the existing 4kV feeders NYSS47F1 and NYSS47F2 from Goulding MS to 27.6kV with the final objective of decommissioning the station. Goulding MS was originally built in 1967.

### 31.2. Scope of Work

The scope of work is to expand existing 27.6kV feeders NY80M2 and NY80M10 to replace NYSS47F1 and NYSS47F2 that have been in service for over 40 years. The expansion of these feeders includes new overhead conductor, poles and transformer. The job area is bounded by Hilda Avenue, Theresa Avenue, Moore Park Avenue and Tefley Road.

### 31.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 22245 | W13211 – Goulding MS F1 and F2 VC Ph#1 | 2013 | $1.20 |
| 22248 | W13216 – Goulding MS F1 and F4 VC Ph#2 | 2013 | $0.99 |
| | | **Total** | **$2.19** |

## 32. North Queen Conductor Upgrade

### 32.1. Objectives

The objective of this job is to upgrade the undersized conductor to a standard conductor for the feeder trunk circuit. An undersized conductor limits transfer capacity and can become a potential safety risk if overloaded for sustained periods of time.

### 32.2. Scope of Work

The scope of this work is to replace the undersized 3/0 OH primary located on the feeder trunk with 556.5 kcmil ASC. Non-standard and aging equipment such as porcelain insulators and poor condition poles will also be replaced.

### 32.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 22960 | 38M27 North Queen conductor Upgrade | 2014 | $0.21 |
| | | **Total:** | **$0.21** |

## 33. Overhead Feeder Rehabilitation on NY55M9

### 33.1. Objectives

The purpose of this job is to replace defective poles and non-standard equipment along Milvan Drive, Penn Drive, Finch Avenue West, Toryork Drive and Weston Road on feeder NY55M9.

As shown in Figure 80, NY55M9 experienced 4 outages in 2011. Approximately 65% of the outages over the last ten years were due to overhead related faults and recent feeder patrol reports have shown that most of the poles in the job area are aged, feathered at the top and are at the risk of cracking, breaking and toppling over. Non-standard equipment on the overhead distribution was also identified by feeder patrols. Approximately 20 percent of the overhead related faults in the last ten years are related to defective insulators, terminators and arrestors.

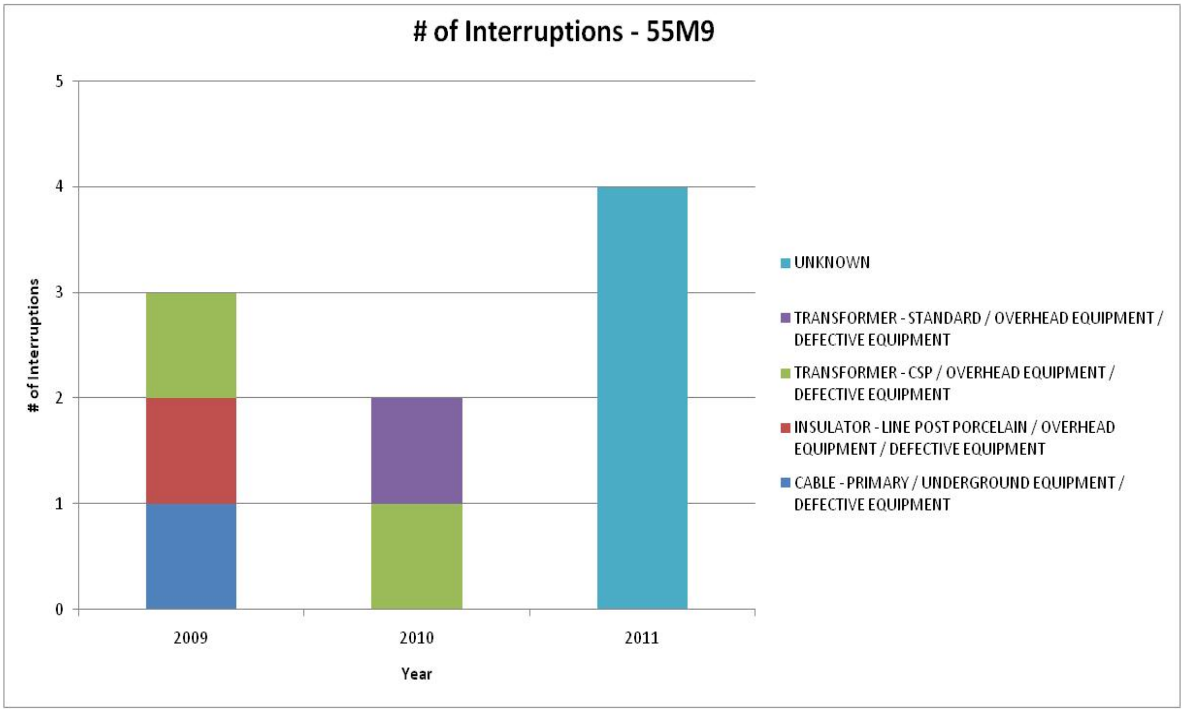



**Figure 80: 55M9 number of interruptions**

### 33.2. Scope of Work

The scope of work is to refurbish the overhead lateral distribution system on feeder NY55M9 by replacing defective poles and non-standard equipment (including insulators, brackets, arrestors), replacing CSP transformers with appropriately sized equivalents and upgrading spans of undersized primary lines (predominantly single-phase) including “open bus” secondary lines identified on the NY55M9.

### 33.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 23089 | W14150 – OH Feeder Rehab – Milvan / Penn | 2014 | $1.02 |
| 23093 | OH Feeder Rehab – Finch / Weston / Toryork | 2014 | $0.64 |
| | | **Total** | **$1.66** |

## 34. Overhead Rebuild and Spot Replacement on NY55M27

### 34.1. Objectives

This job will replace non-standard CSP transformers, porcelain insulators and poles in poor or very poor condition on feeder NY55M27 in the vicinity of the intersection of Finch Avenue West and Islington Avenue in order to improve reliability. The objective of this job is to address areas of this feeder that have experienced outages and could have a high probability of outages in the future. As seen in the chart below, over the last three years the majority of the outages were due to failing equipment and interference on the overhead plant. Replacing end of life and non-standard equipment, which has a high probability of failure and may create a potential safety risk to the public and field crews, will improve the reliability and safety of this feeder.

NY55M27 has sustained four interruptions during the past year. Due to the quantity of end of life components on the feeder, five jobs, separated for reasons of administrative convenience and geography, were developed to rebuild overhead plant over the 2012 -2014 period. In this job package, job W14320 executes spot replacements along Ardwick Drive, job W14326 rebuilds the Nabenby Avenue area, job W14329 rebuilds the Gracedale Boulevard area, job W14333 rebuilds the Aviemore Drive area, job W14334 rebuilds the Duncanwoods Drive and job W14340 rebuilds the feeder along Lindylou Road.

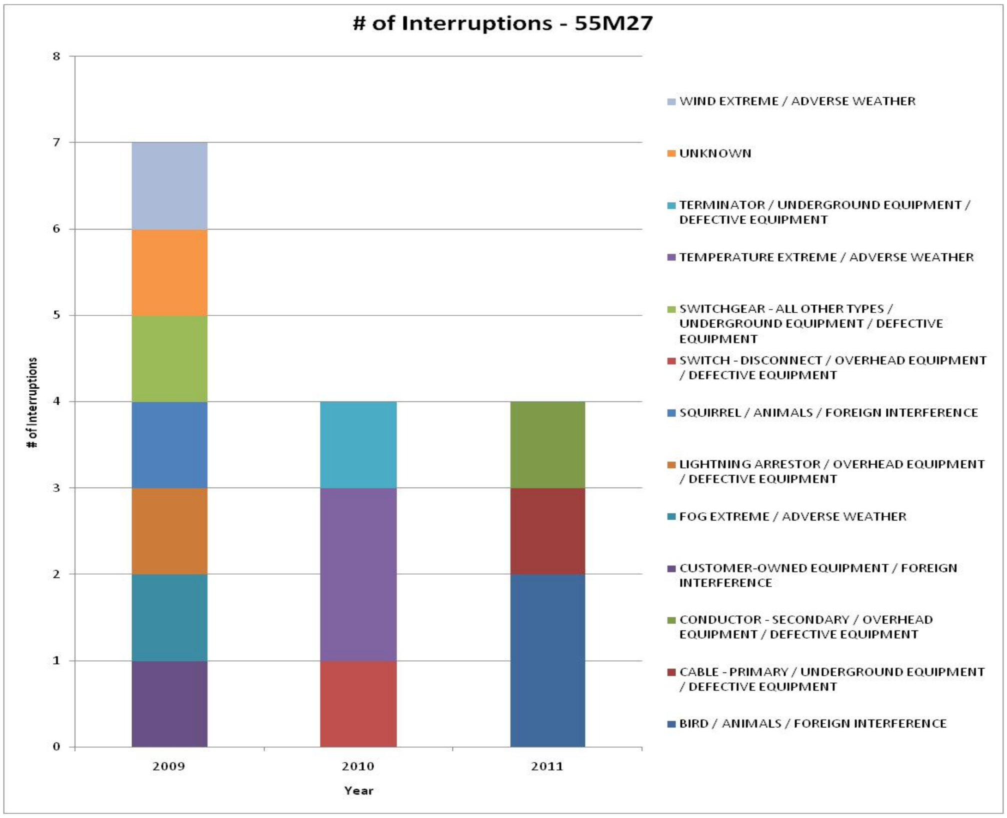



**Figure 81: 55M27 number of interruptions**

### 34.2. Scope of Work

The scope of this work is to replace end-of-life and non-standard assets, considered to have a high probability of failure in the near future. The assets to be replaced include CSP transformers, end of life poles, porcelain insulators, and conductor. Historically, the predominant mode of failure has been due to equipment failure and foreign interference in the overhead plant.

### 34.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 24129 | W14320 – Ardwick Overhead Spot Replacement | 2014 | $0.49 |
| 24166 | W14326 – Nabenby Overhead Rebuild | 2014 | $0.93 |
| 24218 | W14329 – P03 Gracedale Blvd. Overhead Rebuild Finch TS NY55M27 | 2014 | $0.62 |
| 24257 | W14333 – Aviemore Dr. Overhead Rebuild Finch TS | 2014 | $0.60 |
| 24269 | W14334 – Duncanwoods Dr. Overhead Rebuild Finch TS | 2014 | $0.58 |
| 24295 | W14340 – Lindylou Overhead Rebuild | 2014 | $1.12 |
| | | **Total** | **$4.33** |

## 35. Overhead feeder Rehab- Signet, Weston, Fenmar

### 35.1. Objectives

The purpose of this job is to refurbish the OH distribution system by replacing defective poles and non-standard equipment on feeder 55M1 in the area of Steeles Avenue and Weston Road. Interference on the overhead plant has accounted for most of the outages on the feeder since 2009 and has caused the rise in the number of outages from three in 2009 and 2010 to eight in 2011 with two outages already recorded in the first quarter of 2012. This equipment is subject to failure in adverse weather which increases the urgency to rehabilitate the feeder in 2012 so as not to repeat, or worse exceed, the CHI levels (1,358 hours) experienced in 2011.

## 35.2. Scope of Work

As shown in Figure 82, 55M1 had a consistent trend of sustained interruptions with eight outages in 2011. Two outages have already affected this feeder within the first three months of 2012.

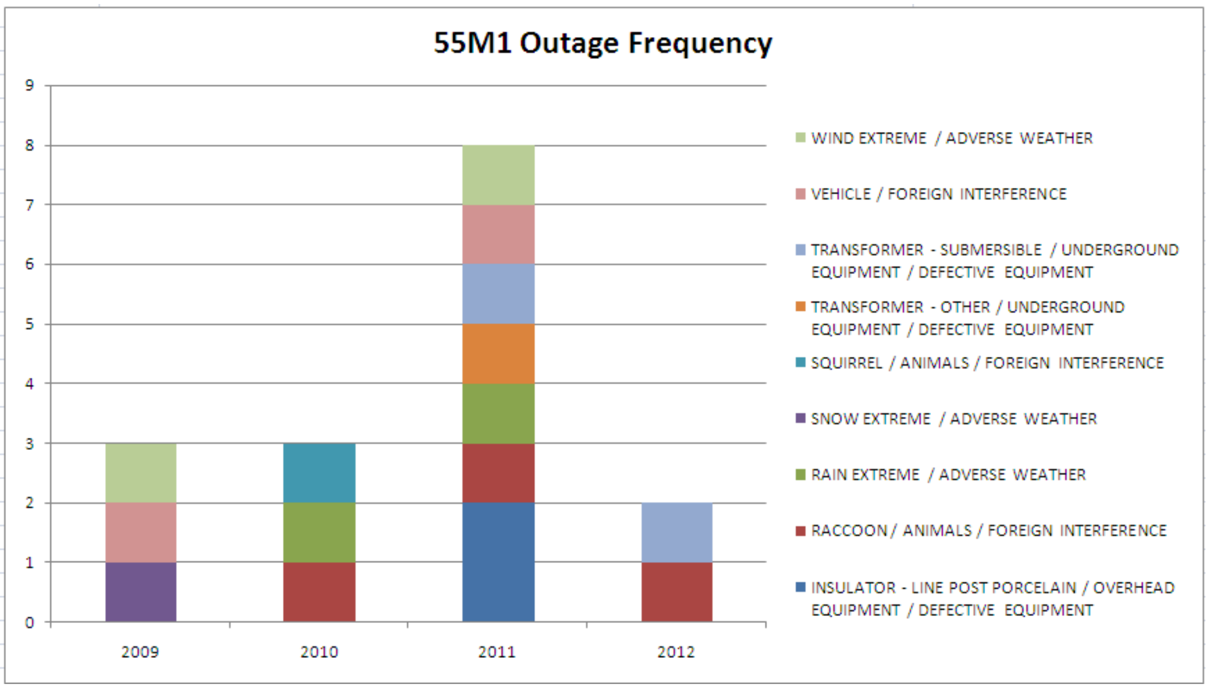



**Figure 82: 55M1 Outage Frequency**

This work will replace defective poles, poor performing CSP transformers and under-sized conductor, as well as install tree poof conductor in tree area. This rehab of overhead infrastructure is intended to mitigate the continuing deterioration of this feeder.

### 35.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 23878 | W14276 OH Feeder Rehab –Signet, Weston, Fenmar (NY55M1) | 2014 | $1.97 |
| | | **Total:** | **$1.97** |

## 36. Voltage Conversion – Westmount MS

### 36.1. Objectives

The objective of these jobs is to convert the distribution infrastructure from Westmount MS to 27.6kV. The distribution and station equipment is old and approaching end-of-life and the switchgear must be replaced. This voltage conversion job will upgrade the system by removing obsolete and aging equipment and thereby allow for the eventual decommissioning of the Westmount MS station once all three feeders that it serves have been converted to 27.6kV.

### 36.2. Scope of Work

The scope of work consists of replacing all the 4KV equipment with standard 27.6KV equipment. All equipment will be transferred over to adjacent 27.6kV primary feeders wherever they exist and new 27.56kV feeders will be extended to customers currently out of reach. There are three jobs each converting a feeder from Westmount MS: RB-F1, RB-F2, and RB-F3. At the completion of these jobs Westmount MS will be decommissioned. By completing the 4kV conversion of the distribution plant, THESL will avoid the need to replace obsolete station equipment in the near future.

### 36.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 24320 | W14343-Voltage Conversion RB-F3 Phase 1 | 2014 | $0.45 |
| 24321 | W14344-Voltage Conversion-Westmount MS RB-F1 | 2014 | $0.60 |
| 24333 | W14345-Voltage Conversion-Westmount MS Phase 1 | 2014 | $0.48 |
| | | **Total:** | **$1.54** |

## 37. Voltage Conversion of Dupont MS

### 37.1. Objectives

The objective of this job is to convert B17DU from a 4kV to 13.8kV. This job is one phase of many to convert the distribution system from Dupont MS to a 13.8kV system. The station and distribution equipment is obsolete and approaching the end of its service life. Conversion of 4kV Dupont MS feeders to 13.8kV system is needed due to the aging station equipment, load growth, and obsolete box-design configuration. Jobs X12152 and X13003, which are in progress for completion by 2013, convert the adjacent and tied backup feeders B4DU and B5DU to 13.8kV. Completion of these jobs will leave feeder B17DU islanded unless it too is converted as proposed in this job. The conversion will also improve safety for work crews and supply reliability to the customers.

### 37.2. Scope of Work

The scope of the job is to convert the 4kV feeder B17DU to the 13.8kV. The circuit is to be re-configured to serve the customers in the area and to integrate with the existing 13.8kV system in the area. All 4kV equipment is to be decommissioned and removed once all customers have been transferred to the new system.

### 37.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 19976 | X13004-Convert 4kV Dupont B71DU to 13.8kV TOB71DU | 2013 | $2.71 |
| | | **Total:** | **$2.71** |

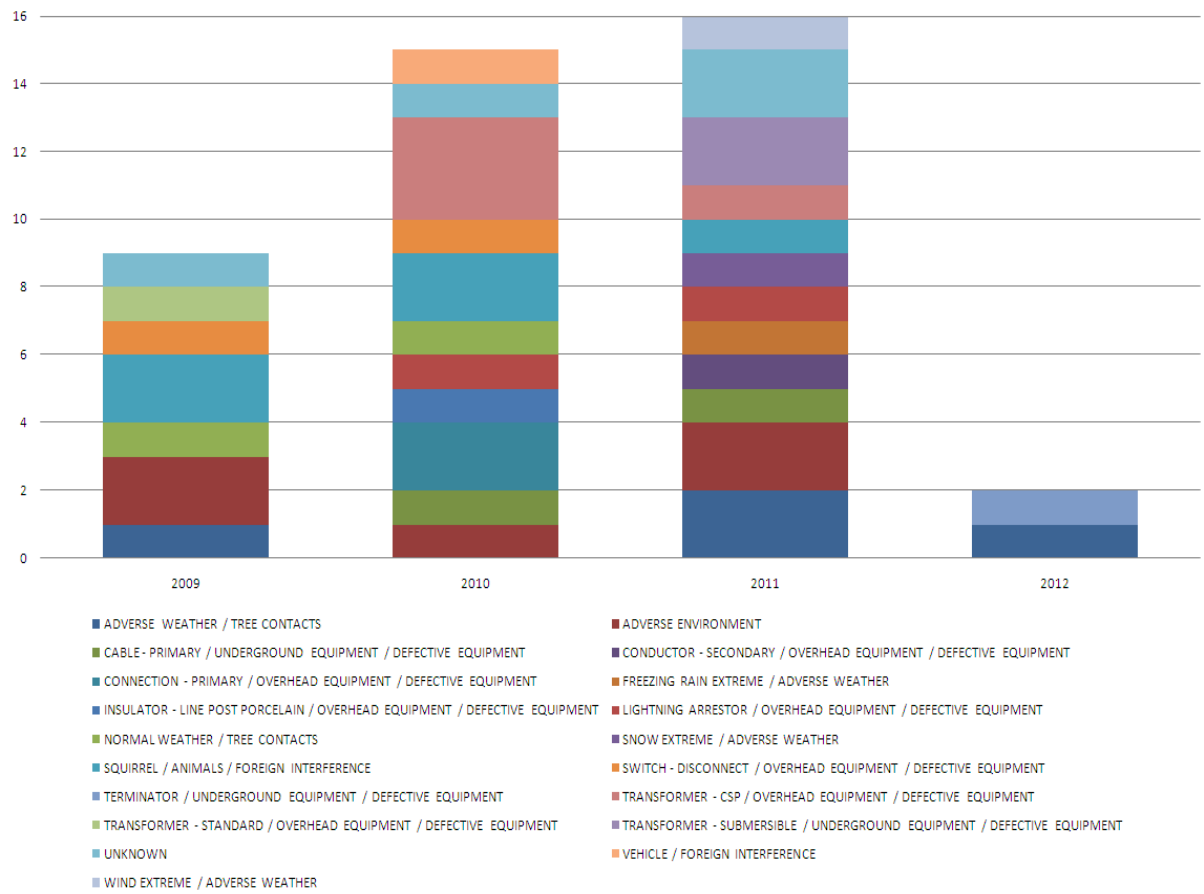
## 38. Overhead Rebuild on NY85M5 and NY55M23

### 38.1. Objectives

The purpose of these jobs is to replace old, poorly performing non-standard overhead distribution equipment and poles in poor condition on feeder NY85M5 and NY55M23. The jobs also involve upgrading undersized conductors on the primary conductor going through Carmichael Avenue, Allard Avenue, and to Wilson Avenue from NY85M25.

### 38.2. Scope of Work

As shown in Figures 83 and Figure 84, NY85M5 and NY55M23 have shown evidence of deteriorating reliability in the past three years. NY85M5 had 15 and 16 outages in 2010 and 2011, respectively, or an average of more than one outage every month. NY55M23 has experienced at least six failures per year over the last three years and has already had three sustained outages within the first three months of 2012.




1 **Figure 83: 85M5 Outage Frequency**

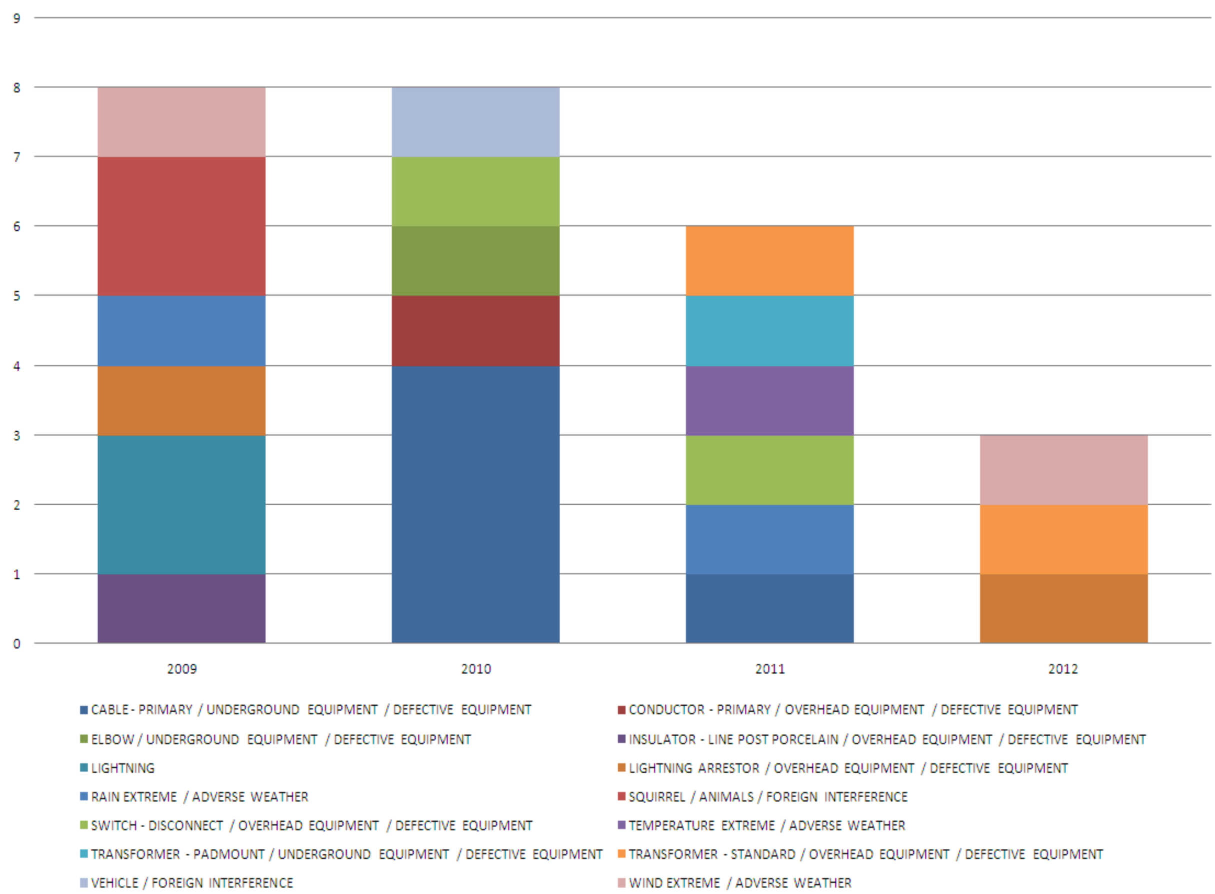



**Figure 84: 55M23 Outage Frequency**

These areas are primarily comprised of poorly performing, non-standard assets including CSP transformers, porcelain insulators and arrestors. The scope of work requires the replacement of end-of-life and non-standard assets. Within the boundaries of this job, all overhead primary conductors, end-of-life poles and CSP transformers will be replaced with current standard equipment. This job replaces poles, switches, insulators, pole-mounted transformers and upgrades the overhead primary conductor to 556.5 kcmil and the replacement of underground XLPE #1 Solid Cable in concrete encased ducts.

More specifically, the primary overhead distribution on McAllister Road, Carmichael Avenue, Pellatt Avenue, and Gary Avenue will be upgraded.

### 38.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 24052 | W14306 - 85M5 - McAllister Rd. Overhead Rebuild | 2014 | $0.30 |
| 24089 | W14315 - 85M5 – Carmichael Ave. OH rebuild and conductor upgrade | 2014 | $0.71 |
| 23979 | W14285 - Pellatt OH and UG lateral Rebuild | 2014 | $0.24 |
| 24007 | W14289 - OH Rebuild off Gary Avenue | 2014 | $0.80 |
| | | **Total** | **$2.06** |

## 39. Overhead Upgrade on feeder ET30M7 and Voltage Conversion on feeder ETRF2

### 39.1. Objectives

The purpose of this job is to upgrade the feeder ET30M7 from Horner TS and partially convert Brown's Line and Burlingame MS from 4kV to 27.6kV. Brown's Line MS and Burlingame MS were originally built in the 1950s and 1960s. They were built to obsolete construction standards and are in deteriorated condition. The assets being replaced by this job are in the area bounded by Thirtieth Street, Valermo Drive, Brown's Line, and Horner Avenue.

### 39.2. Scope of Work

ETRF2 is currently identified as a FESI-4 feeder, with a worst performing feeder rank of 433. The feeder's condition has been deteriorating according to reliability data. A vast majority of the faults were specifically caused by weather and tree contacts. Tree-trimming in this area is scheduled for 2012 and 2013 to address such issues. Further improving the WPF status of ETRF2 and reducing the probability of failure requires replacing assets in poor condition and installing proper fusing.

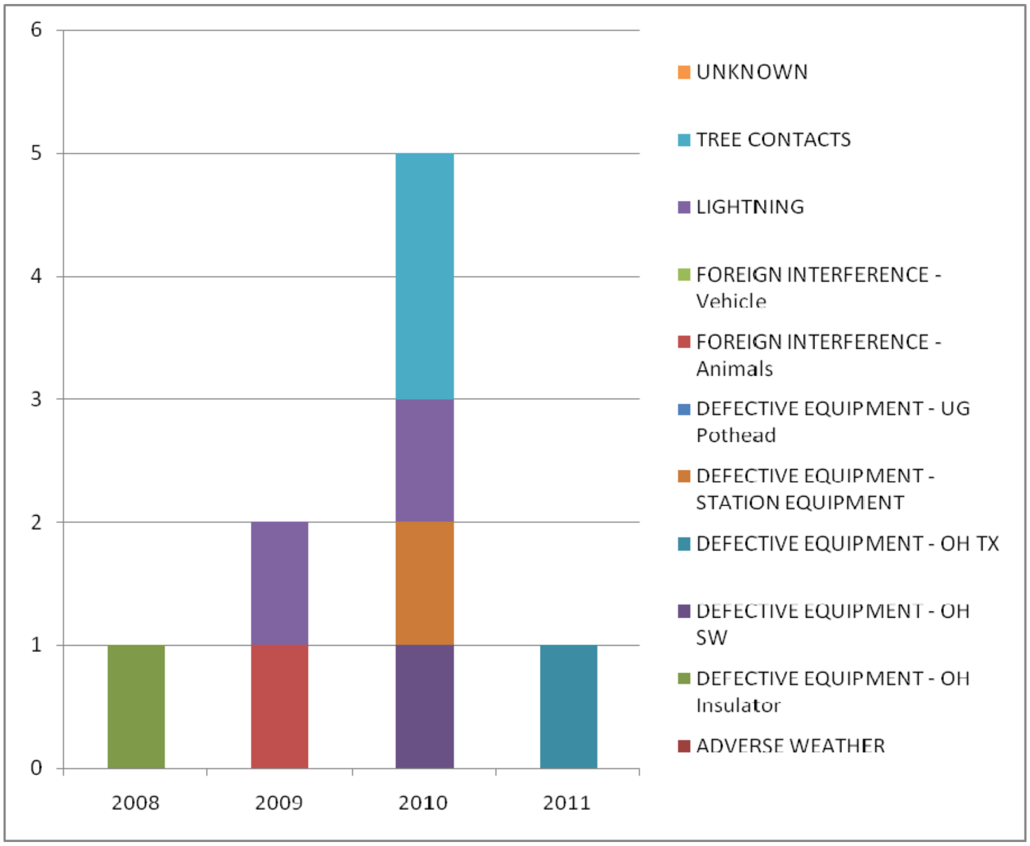



**Figure 85: ETRF2 Outage Frequency**

The scope of work is to install primary and secondary conductor, new poles and transformers to accomplish the upgrade from 4 kV to 27.6 kV.

### 39.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 23361 | 30M7 OH Upgrade and ETRF2 OH VC | 2014 | $2.04 |
| | | **Total:** | **$2.04** |

## 40. Worst Performing Feeder (WPF) Overhead Rebuilds

### 40.1. Objectives

THESL has an ongoing WPF program, which is aimed at improving system reliability and asset performance by addressing those feeders that most impact reliability. The goal of this job is to improve system reliability and asset performance through a complete overhead rebuild of the primary distribution system in the areas listed below, which includes the refurbishment of poor condition poles, transformers, porcelain insulators, lightning arrestors, and the upgrade of conductor. The WPF feeders being addressed in these jobs have shown a trend of deteriorating reliability and have experienced a significant number of outages.

### 40.2. Scope of Work

Toronto Hydro has introduced a Worst Performing Feeder (WPF) program. It is intended to improve system reliability and asset performance by adjusting our planned asset replacement program, with the intent of eventually eliminating these problem feeders from the WPF list. The WPF program covers those feeders which have high numbers of Customer Interruptions (CI) and corresponding Customer Minutes Out (CMO). The top 40 worst performing feeders, as well as FESI-7 and FESI-12, are targeted for improvement.[4] Based on 2007 data, FESI-7 feeders contribute 37 percent of SAIFI and 32 percent of SAIDI. Going forward, as these feeders improve, THESL plans to continue work on adjacent groups of WPF (e.g., FESI-5). The scope of work for the selected jobs below targets the replacement of all aging and non-standard equipment that has a high probability of future failure and poses potential safety risks for the public and field crews. Based on historical reliability statistics these jobs focus on the probability of outages due to foreign interference and include replacing CSP transformers and bare conductor with tree proof conductor at heavily-treed locations.

[4] FESI-X refers to those feeders that have had X or more sustained interruptions (more than one minute) within one year.

### 40.3. W12339 FESI CSP and Conductor Replacement

All overhead primary distribution of YK11M1 and YK11M4 on Grandville Avenue, Greendale Avenue, Guestville Avenue, Dennis Avenue, and part of Astoria Avenue will be upgraded, including the installation of 3/0 tree proof conductor. In addition, an overhead rebuild with 556.5 kcmil tree proof conductor is required on Bayliss Avenue, Lambton Avenue, Astoria Avenue, Guetville Avenue, and York Avenue. Spot replacement of CSP transformers and porcelain insulators will be undertaken on Woolner Avenue, Rockcliffe Boulevard, and Outlook Avenue. As seen in Figure 87 below, the reliability of feeder 11M1 has been deteriorating, predominately due to overhead interference and equipment failure, which will be addressed by this job.

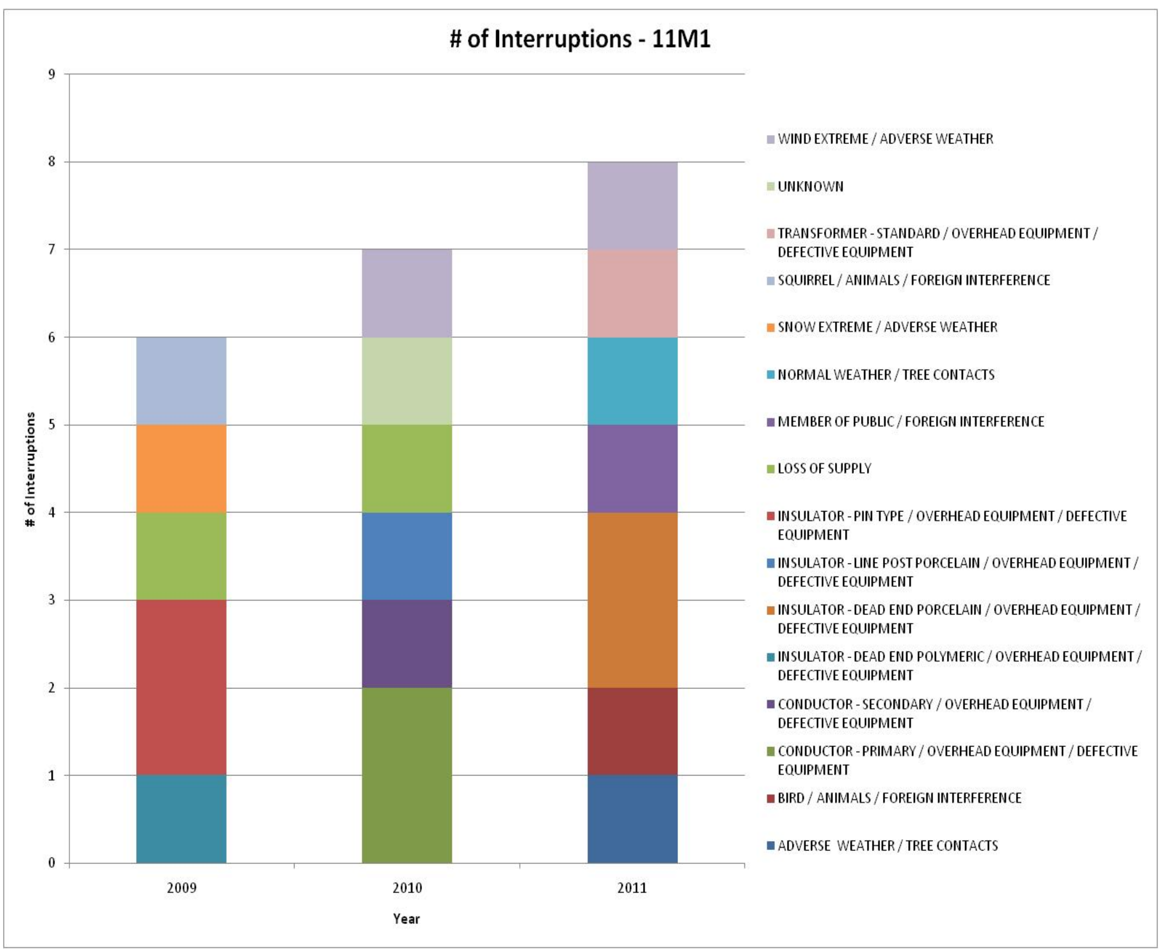



**Figure 86: 11M1 Number of Interruptions**

**40.3.1. W12351 FESI CSP and Conductor Replacement (Multiple Locations)**

This job executes spot replacements of poles, transformers, conductors and animal guards at a total of 127 locations on this feeder distributed among Battersea Crescent, Blandonan Road, Bluebell Gate, Brome Road, Bryn Road, Cleo Road, Circle Ridge, Clubine Avenue, Cirillo Court, Cornelius Parkway, Crioline Road, Delria Drive, Donofree Road, Dorsey Drive, Duval Drive, Erie Stret, Euphrasia drive, Falstaff Avenue, Govedale Avenue, Gracefield Avenue, Haverhill Avenue, Jay Street, Joyce Parkway, Keele Street, Kinkora Drive, Lawrence Avenue West, Macleod Street, Manresa Lane, Maple Leaf Drive, Marianfeld Avenue, North Park Drive Pember Drive, Queens Drive, Quinan Drive, Redberry Parkway, Rollet Drive, Romeo Street, Rustic Road, Sage Road, Treelawn Parkway, Valencia Crescent, Wickford Drive and Wyndale Drive. This feeder had 860 CHI 2011. As shown in Figure 87, this feeder experienced seven outages in 2011. The majority of these outages were due to overhead component failure and interference. It has a high probability of future outages due to aging and non-standard equipment. This job addresses replacement of CSP transformers and upgrades to tree proof conductor in heavily-treed areas.

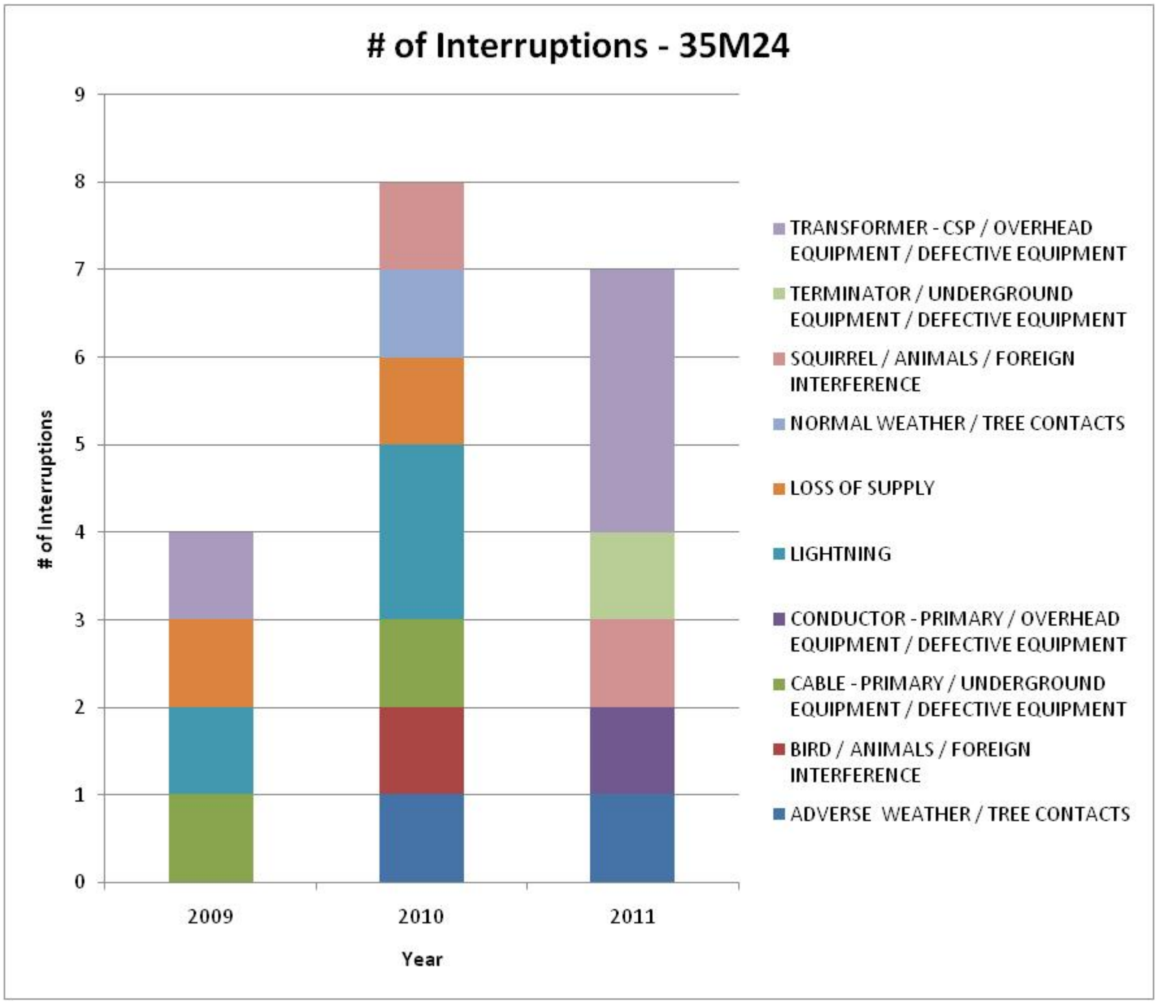



**Figure 87: 35M24 Number of Interruptions**

### 40.3.2. W12284 CSP and Conductor Replacement

This job will undertake overhead rebuild of 11M5 OH primary distribution with 3/0 Tree Proof conductor on Old Mill Drive, Riverview Gardens, Riverside Drive, Traymore Crescent, Halford Avenue, Bridgeview Road, Orchard Cresent Road, Langmuir Crescent, Brumell Avenue, Raymond Avenue, Valleyview Gardens and Thornhill Avenue and replace poles where necessary. This feeder had six outages in 2011 and over the last three years has had high impact outages due to failing equipment and foreign interference on the overhead plant. Figure 88 shows the CMO for this feeder over the last three years. This job addresses these issues by replacing aging and non-standard equipment that are considered a risk for future faults. This job will replace CSP transformers and upgrade conductor to tree proof conductor in heavily treed areas where tree contacts are most likely to occur during periods of adverse weather.

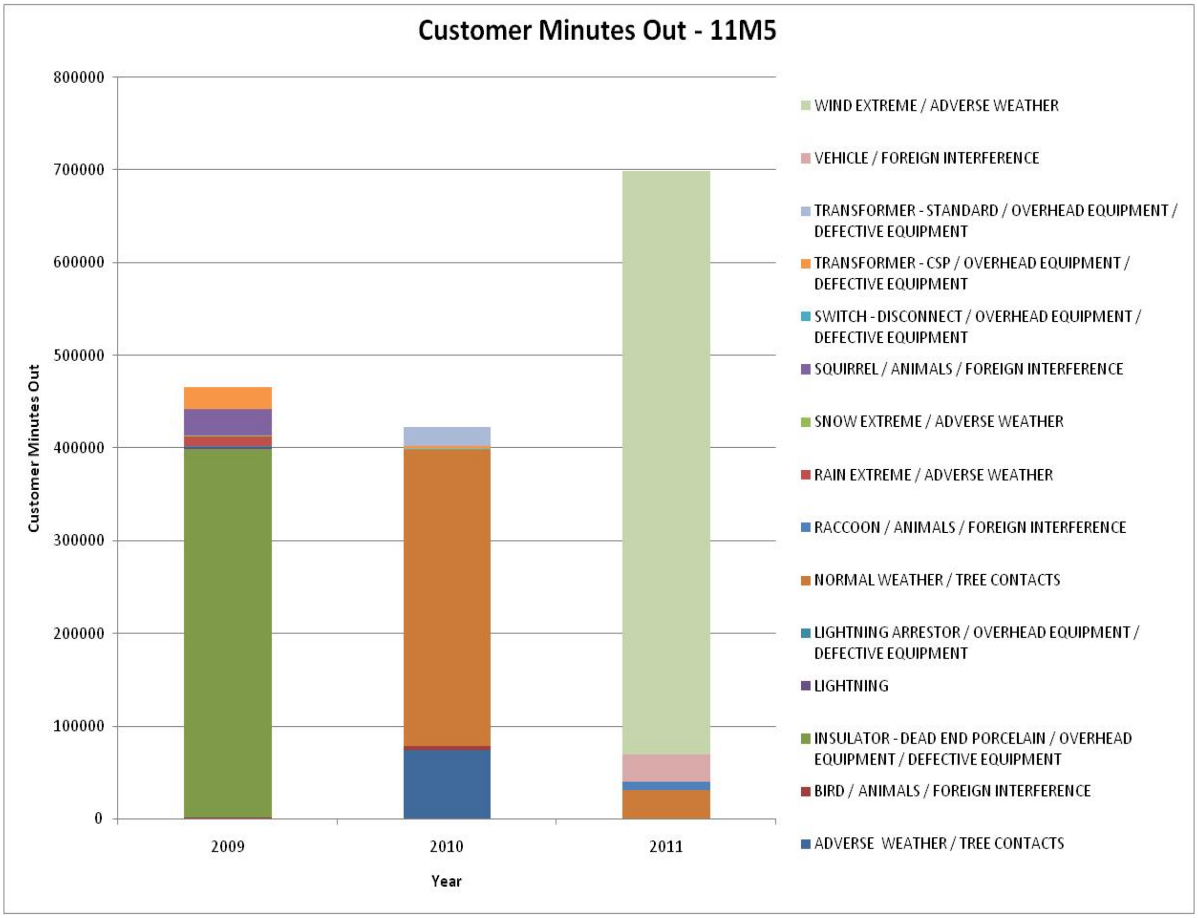



**Figure 88: 11M5 Customers Minutes Out**

### 40.3.3. X12501 O/H Rebuild – Keele St and Milford Ave NY35M12

Feeder 35M12 has become less reliable over the last three years with nine outages in 2011 as shown in Figure 89. The majority of these outages are caused by equipment failure and foreign interference on the overhead plant. This job will target and rebuild the areas of Milford, Densley, and Keele Streets where most of these issues can be addressed. This job will focus on reducing foreign interference by replacing CSP transformers with standard transformers equipped with animal guards and by upgrading conductor with tree proof conductor in heavily-treed areas.

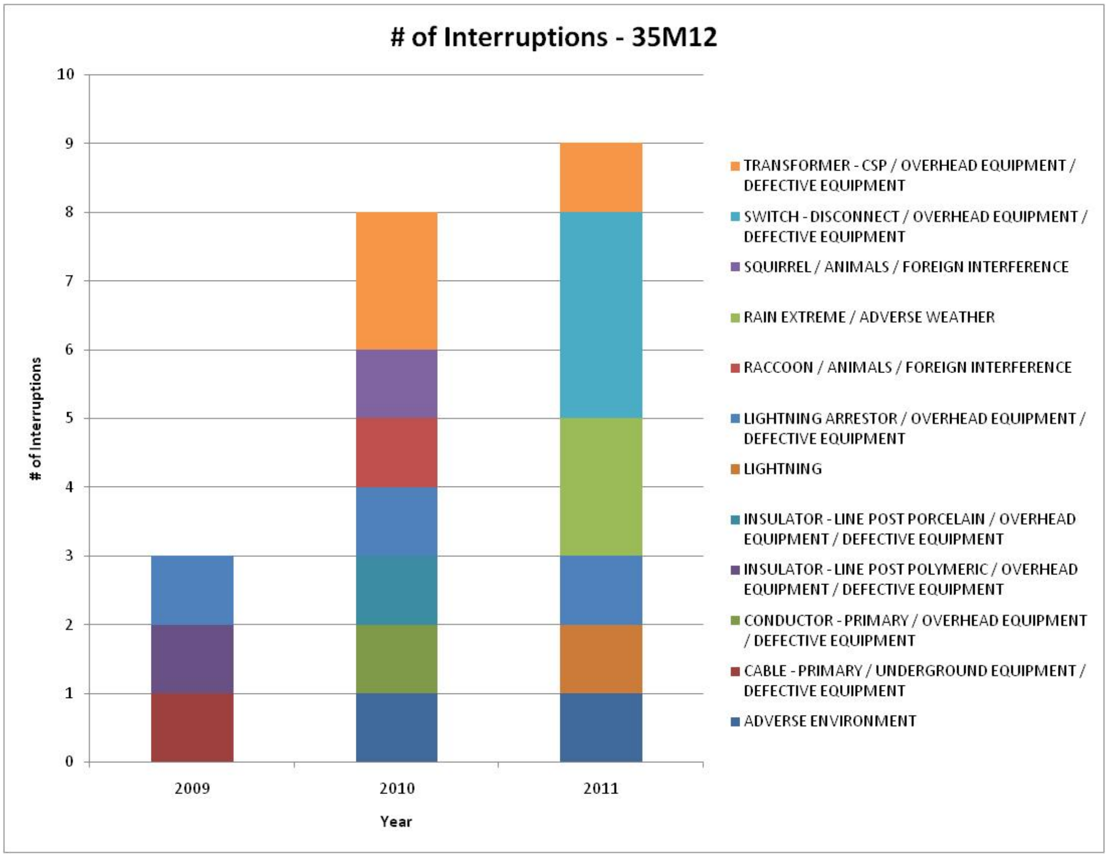



**Figure 89: 35M12 Number of Interruptions**

### 40.3.4. E12104 Chipping Crossburn 53M10 OH Rebuild

Over the last three years there have been several failures concentrated on the OH distribution on Chipping Road, Park Glen Drive and Crossburn Drive that require rehabilitation of Feeder 53M10 to improve the reliability in this area (See Figure 90). This job will replace defective and non-standard equipment on this feeder.

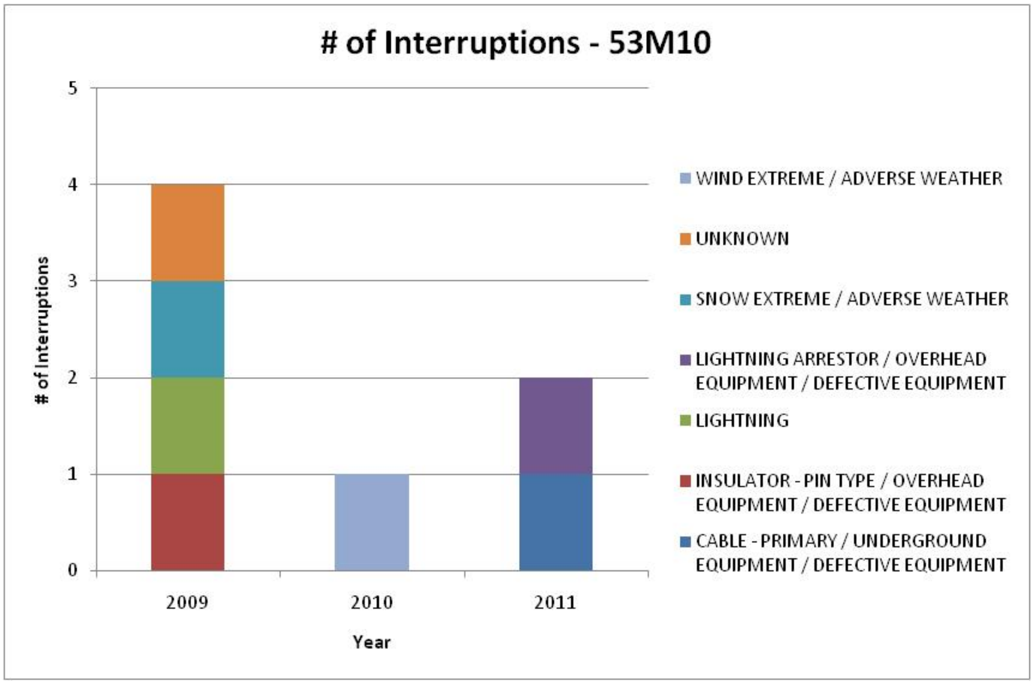



**Figure 90: 53M10 Number of Interruptions**

### 40.4. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20499 | W12339/P03 FESI CSP and Conductor Replacement on YK11M1 off Weston Road and Jane Street | 2012 | $0.85 |
| 20565 | FESI CSP and Conductor Replacement | 2013 | $4.41 |
| 20379 | CSP and Conductor Replacement | 2012 | $1.02 |
| 21025 | O/H Rebuild – Keele St and Milford Ave | 2012 | $1.01 |
| 23677 | Chipping Crossburn 53M10 OH Rebuild | 2012 | $0.30 |
| 20875 | George Andersen and Culford Rd. Overhead Rebuild | 2012 | $1.63 |
| | | **Total:** | **$9.22** |

## 41. Replacement of non-standard equipment and overload transformers

### 41.1. Objectives

The objective of this job is to replace poorly performing assets on Feeder YK35M10. The replacement of CSP transformers, switches, insulators and arresters will be undertaken under this job to improve reliability.

### 41.2. Scope of Work

The scope of work includes the replacement of 131 poles, 7,500m of overhead conductors, 58 CSP transformers, 16 switches, porcelain insulators and arresters in the areas primarily between Genesee Avenue, St. Clair Avenue, Rushton Road and Dufferin Street and then between Oakwood Avenue, Kirknewton Road, Hopewell Avenue and Rogers Road.

### 41.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 19581 | Replacement of non-standard and overloaded transformer on YK35M10 | 2012 | $0.48 |
| 19886 | X12179 - Replacement of CSP transformers | 2013 | $1.29 |
| | | **Total:** | **$1.77** |

## 42. Installation of SCADA Switches

### 42.1. Objectives

The purpose of this job is to replace existing manual switches with SCADA-Mate R2 switches as well as upgrade existing remote switches with fault sensing software in order to improve restoration time as part of the ongoing investment strategy for reducing Customers Hours Interrupted (CHI). These switches are always installed on the main trunk portion of the feeder. Outages on this portion of the feeder impact many customers. Typically, on residential feeders approximately 3,000 customers will experience a sustained outage from a fault on the feeder trunk.

With the installation of remote fault sensing switches, typically three quarters of the customers will have their power restored within a few minutes. Thus, this provides an effective means of restoring customers quickly. Without remote fault sensing switches, crews will need to patrol the feeder until the root cause of the outage is found. Furthermore, a crew will need to operate the manually switches at multiple locations in order to isolate the faulted section of the feeder and re-supply non-affected portions of the feeder from neighbouring tie feeders. The presence of a remote fault sensing switch is expected to provide to major benefits; namely the ability to provide Power System Controllers with fault location information as well as the ability to remotely open and close various switches quickly.

In some cases, THESL does not have control of opening or closing station circuit breakers. With some feeders, this function is controlled by Hydro One Networks. The installation of a remote fault sensing switch close to the egress of the station would allow THESL Power System Controllers to effectively control power supply to the vast majority of the feeder. This shortens the outage duration since co-ordination with Hydro One Network personnel is no longer required.

The locations for switch installations was based upon installing the switches on feeders with poor reliability, those with no remote fault sensing tie points between two feeders, those with many customers or high load between sectionalizing switches, and those where Hydro One networks control the operation of the breaker. Areas that are targeted for this work include distribution feeders in the Fairbanks TS, Bathurst TS, HornerTS, Manby TS, Cavanagh TS, Malvern TS and Scarborough TS areas.

**42.2. Scope of Work**

The scope of work for this job is to replace existing manual switches with SCADA as well as upgrading current SCADA switches on the distribution system. These switches are in multiple locations across the THESL grid.

### 42.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 19785 | X12156 Replacement of the manual tie switches with SCADA 53-M8 | 2012 | $0.30 |
| 19454 | X11524 Replacement manual switch with SCADA, EYA11L | 2012 | $0.07 |
| 19453 | X11525 Replacement manual switch with SCADA, EYA12L | 2012 | $0.07 |
| 19455 | X11526 Replacement manual switch with SCADA, EYA14L | 2012 | $0.08 |
| 19837 | X12163 Replacement of manual tie switches with SCADA 53-M6 | 2012 | $0.52 |
| 19806 | W12089-Remote SCADA Switch Install Bathurst TS | 2012 | $0.09 |
| 19792 | X12158 Replacement of manual tie switches with SCADA 53-M7 | 2012 | $0.51 |
| 19892 | X12176 Replacement of manual tie switches with SCADA 53-M5 | 2012 | $0.35 |
| 19894 | X12182 Replacement of manual tie switches with SCADA 34M5, 34M6 34M7 | 2012 | $0.19 |
| 23354 | W12253 11m7 SWITCH REPLACEMENT JANE/WOOLNER | 2012 | $0.08 |
| 19452 | X10449 Replacement of manual switch with SCADA EYA13L | 2012 | $0.07 |
| 18456 | E11374 SCADA Installation 34M6 | 2012 | $0.20 |
| 17801 | E10387 Bermondsey SCADA | 2012 | $0.33 |
| 20391, 19965 | E11088 North York SCADA 53M10 Area A | 2012 | $0.45 |
| 20416 | X12318 34M1 Scadamates Intallation | 2013 | $0.17 |

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 22598 | W13271 3 Feeder Riser SCADA Switch Installations Hydro Row | 2013 | $0.29 |
| 20659 | W12383-OH Switch Replacements to SCADA Controlled Switches | 2013 | $0.21 |
| 24169 | E14319-New SCADA Switch on 43M24 | 2014 | $0.20 |
| 24139 | E14318-New SCADA Switches on NY51M3 | 2014 | $0.19 |
| 24060 | E12744 - Bell Line Conversion | 2012 | $0.08 |
| | | **Total:** | **$4.48** |

## 43. Overhead Rebuild on feeder NY55M31, NY55M8 and NY55M22

### 43.1. Objectives

The purpose of these jobs is to refurbish, rehabilitate and reconfigure feeders NY55M31, NY55M8 and NY55M22 from Finch TS.

### 43.2. Scope of Work

As shown in Figure 91, feeders 55M8 and 55M31 show a consistent or increasing trend of sustained outages over the past three years. Although 55M22 shows a decrease in outages, the job aims to reconfigure and extend the OH primary for operational flexibility. It is expected to allow for more efficient restoration of adjacent feeders to 55M22.

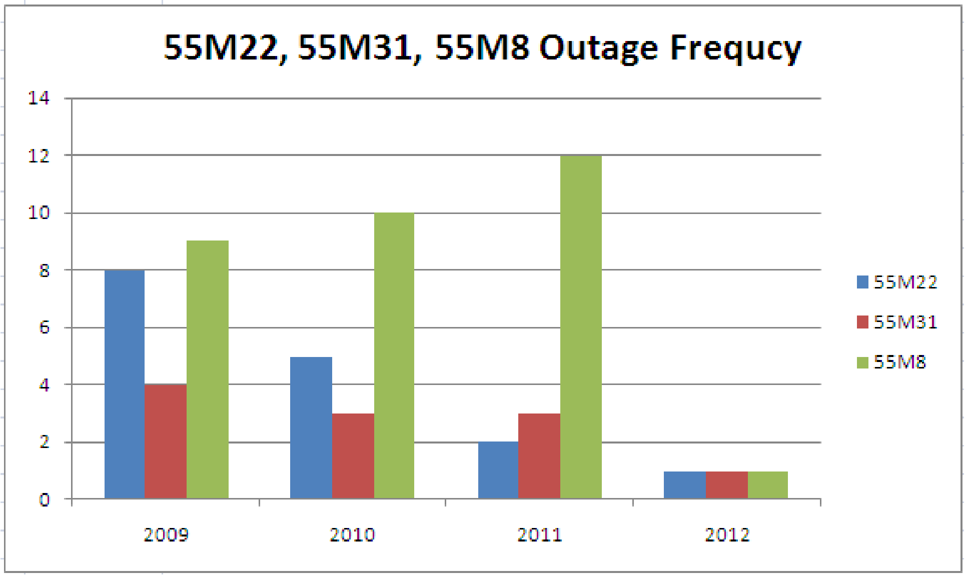



**Figure 91: Outage Frequency on 55M22, 55M31 and 55M8**

The scope of work is to install new poles as well as replacing non-standard overhead CSP transformers and porcelain equipment to reduce the probability of equipment failure. New animal guards are to be installed at the appropriate overhead locations. In addition, a backup will be provided for the overhead loop on the area of Rowntree Mill Road west of Islington Avenue.

### 43.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 22859 | W14073 – 55M31 OH Rebuild at intersection Steels Ave W and Weston RD. | 2014 | $0.80 |
| 20296 | W12270 OH Rebuild Spenvalley Dr and Surrounding Area | 2013 | $0.69 |
| 18523 | W11289 – FESI Rowntree Contingency 55M22 | 2012 | $0.53 |
| | | **Total** | **$2.02** |

## 44. Overhead Feeder Trunk Rehabilitation and Reconfiguration

### 44.1. Objectives

The purpose of this job is to refurbish the overhead distribution system of feeder NY85M4 along Alexdon Road, Chesswood Drive Champagne Drive and Toro Road by replacing defective poles and non-standard equipment.

### 44.2. Scope of Work

The scope of work is to refurbish the overhead lateral distribution system on feeder NY85M4 by replacing defective poles, non standard equipment including CSP transformers, upgrading undersized primary conductor and upgrading "open bus" secondary lines.

Feeder 85M4 has had five outages in the last 12 months. In the last ten years, 55 percent of the sustained outage incidents on the feeder were caused by faults on the overhead system. The asset replacements, fault indicator replacements and system reconfiguration that form this job are needed immediately to improve reliability on the feeder.

### 44.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 23364 | OH Feeder Rehab – Alexdon, Chesswood, Champagne | 2014 | $0.54 |
| | | **Total** | **$0.54** |

## 45. Overhead Rehabilitation on feeder NY55M25 and NY80M2

### 45.1. Objectives

The purpose of these jobs is to replace the non-standard, aged and failing overhead distribution assets to improve the reliability of feeders NY55M25 and NY80M2. This job includes upgrading the undersized primary lines on the feeders and providing adequate backup to Rockford Public School.

Over the past year, there were seven sustained power interruptions on feeder 55M25 and six on feeder 80M2. The available Health Index scores for the 50 percent of the poles evaluated in the job area was as low as 38. Defective and non-standard overhead equipment led to the 20,317 CI experienced on NY55M25 in 2011. In addition, Rockford Public School does not have adequate back-up. The inadequacy of back-up capacity, exacerbated by the undersized primary lines, was responsible for the increase in outage durations (CHI) from 705 in 2010 to 3,534 in 2011. In the event of a failure on the three-phase circuit currently supplying this customer, lengthy outage durations beyond the CHI experienced in 2011 will likely be experienced because restoration will be constrained by the inability to transfer loads to healthy adjacent feeders. The job is expected to improve reliability on these feeders.

### 45.2. Scope of Work

The scope of work for these jobs is to install new poles and replace CSP transformers as well as porcelain insulators along NY55M25 and NY80M2. Some 2,800 m of overhead conductors will be replaced along NY80M2 between Fisherville and Rockford to upgrade the line capacity providing adequacy for load transfer as required during contingencies. A normally open switch located at the intersection of Fisherville Road and Rockford Road will tie feeder NY80M2 to NY85M7 providing the required backup to feeder NY80M2 in the job area.

### 45.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20946 | W12462 – 3 Phase Extension along Rockford | 2012 | $0.27 |
| 20412 | W12306 - FESI NY55M25 OH Feeder Equipment Rehab | 2013 | $0.910 |
| | | **Total** | **$1.18** |

## 46. Overhead Rebuild and Trunk Reconfiguration on NY55M21

### 46.1. Objectives

The purpose of these jobs is to reconfigure the trunk portion of feeder NY55M21 and to rebuild portions of it in the area bounded by Weston Road, Yorkdale Crescent, Aura Lea, and Highbury Road in order to improve reliability. NY55M21 has experienced two sustained power interruptions during the past year. The jobs address aged poles in poor condition, and non-standard, poorly performing assets such as CSP transformers, porcelain insulators, arrestors and overhead conductors.

### 46.2. Scope of Work

The scope work is to replace end-of-life and non-standard assets including all overhead primary conductors, end-of-life poles and CSP transformers. Furthermore, the trunk portion of the feeder will be reconfigured in order to mitigate the impact of potential outages.

### 46.3. Required Capital Costs

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 21999 | W13167 – Clayson/Bartor Trunk Feeder Reconfiguration and Refurbishment | 2013 | $1.10 |
| 22040 | W13169 – Weston Railway – OH Rebuild | 2013 | $1.23 |
| | | **Total** | **$2.33** |

## 47. Voltage Conversion of 4kV Etobicoke System

### 47.1. Objectives

The objective of this job is to convert obsolete and non-standard equipment on the 4kV distribution system to the standard 27.6kV service in the Etobicoke area.

### 47.2. Scope of Work

The 4 kV feeders, EBF1, EF1, EHF1, and KKF2 in the area of Kingsway MS, were selected based on outages (as shown in Figure 92 below) and condition of equipment as observed by field crew. The majority of the equipment on this aging system has reached or is approaching end of life and the substation equipment should be replaced or decommissioned. Furthermore, some of the equipment is becoming difficult to purchase due to obsolescence. These jobs will convert all the 4 kV loads to the 27.6kV system and remove any unnecessary equipment. The long term goal is to convert all the customers on the 4kV station feeders and decommission the station.

The scope of work is to convert all customer loads on the 4kV system to the 27.6kV system usually by a line transfer to an adjacent 27.6kV feeder. In some cases these jobs require additional feeder configuration to accommodate customers that are currently beyond the 27.6kV system. Some trunk lines may be maintained to provide contingency options to 4kV feeders that still serve customers. These lines will be removed when they are no longer necessary and the substation has been decommissioned.

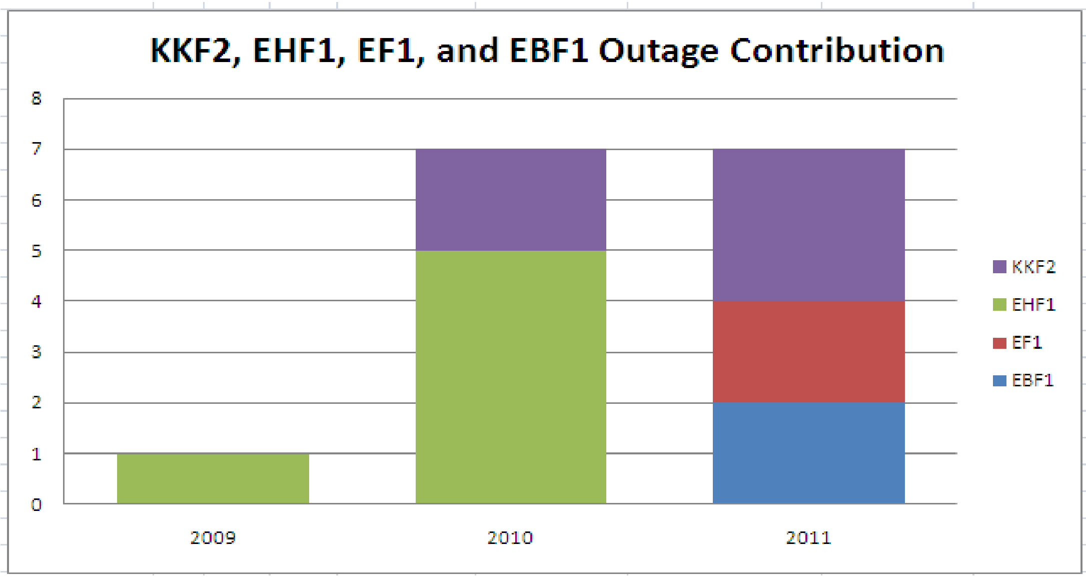



**Figure 92: Outage contribution on KKF2, EHF1, EF1 and EBF1**

### 47.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 23323 | W14181 - Kingsway MS – OH Voltage Conversion (ETEF1) | 2014 | $0.66 |
| | | **Total:** | **$0.66** |

## 48. Overhead Rebuild

### 48.1. Objectives

The objective of these jobs is to replace end of life and non-standard equipment that has a high probability of future failure and could possess a potential safety risk for the public and field crew. These jobs will focus on the replacement of equipment such as poles, porcelain/glass insulators and switches, and CSP transformers. In addition, installing animal guards and insulating drop wires will reduce the probability of outages caused by animal interference at strategic areas providing improved service to the customers. Over the last three years the feeders in question have experienced a number of overhead related faults related to failing equipment and foreign interference.

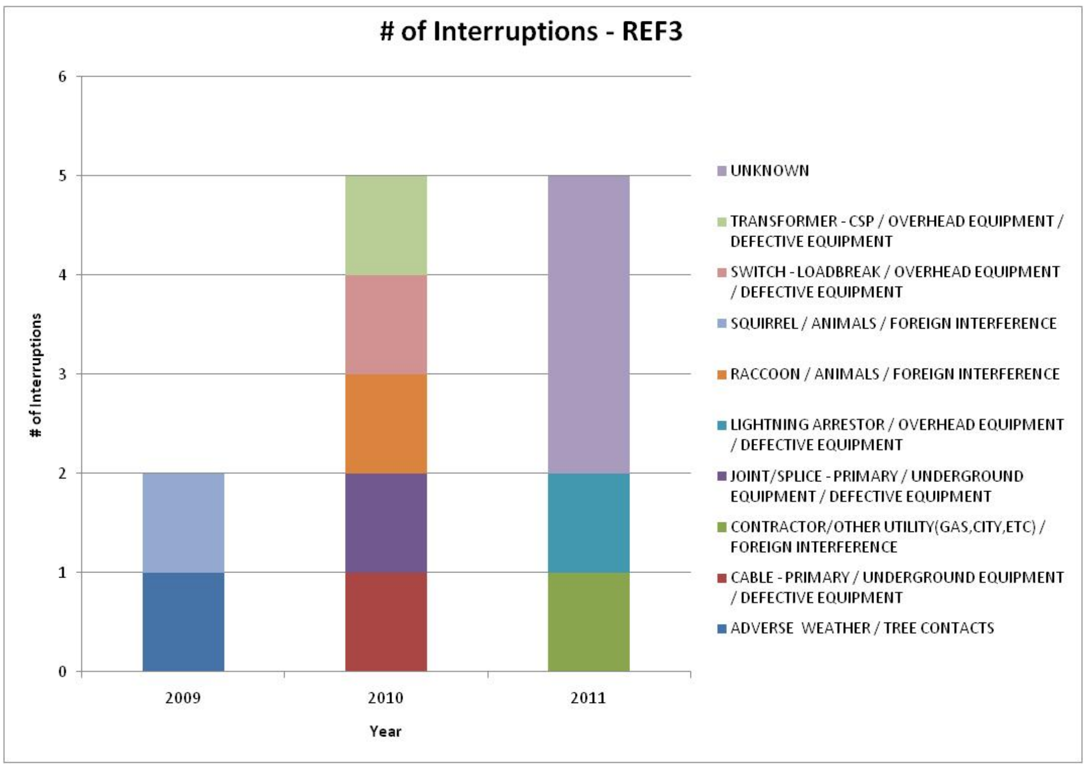
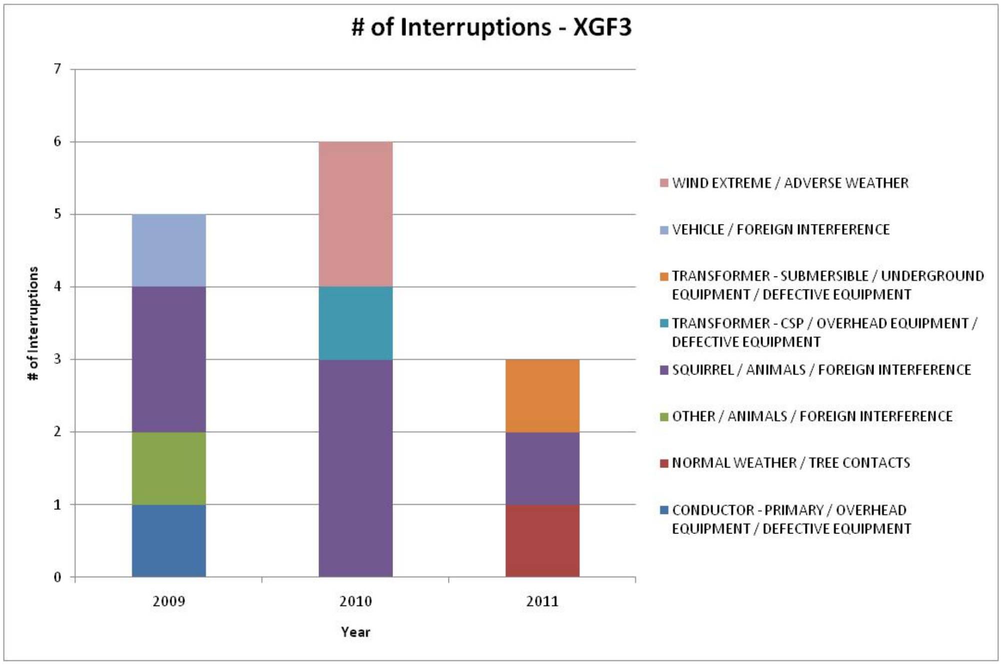
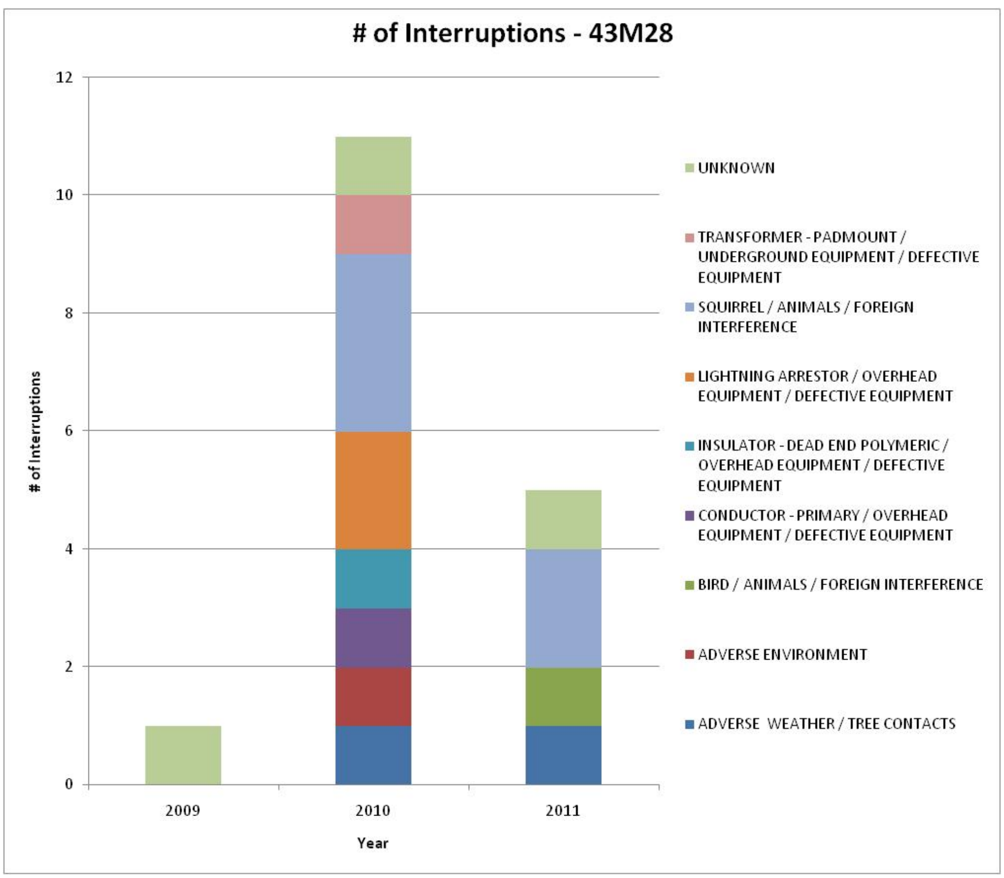



**Figure 93: Number of interruptions on REF3**




1 **Figure 94: Number of interruptions on XGF3**




2 **Figure 95: Number of interruptions on 43M28**

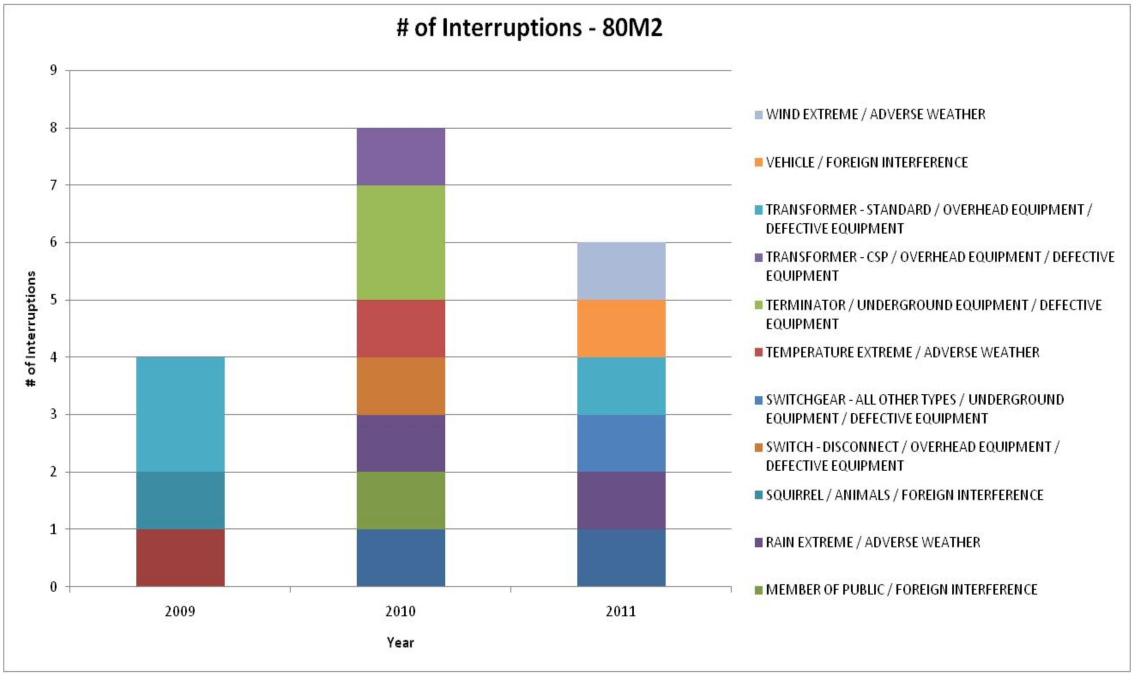



**Figure 96: Number of interruptions on 80M2**

### 48.2. Scope of Work

The scope of this work is to replace all non-standard and aged equipment that can create a fault or a potential safety issue on the listed feeders. This job focuses on the replacement of aging poles, porcelain insulators and switches. Furthermore, this job will install animal guards and insulated drop wires at strategic locations that are expected to reduce the probability of a fault due to animal interference.

### 48.3. Required Capital Costs

| Job Estimate Number | Project Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 22229 | E12574 Overhead Rehabilitation of SCREF3 | 2013 | $0.83 |
| 23312 | E14170 Rouge Park OH Rebuild Phase and VC of 3 SCXGF3 | 2014 | $0.62 |
| 21457 | E13110 NYSS68-F9 OH Rebuild at Pleasant View | 2013 | $0.54 |
| 23134 | E11805 - Fibreglass Secondary Insulation Inspection | 2012 | $0.03 |
| | | **Total:** | **$2.03** |

## 49. Manby-Horner TS Feeder Reconfiguration

### 49.1. Objectives

The objective of this job is to relieve overloaded feeders from the Manby TS east of Kipling Avenue by constructing a new feeder powered out of the Horner TS and slightly modifying the configuration of the existing feeders from both Manby and Horner Transformer Substations.

### 49.2. Scope of Work

The scope of work of this job is to construct a new overhead line at the intersection of Evans Avenue and Kipling Avenue, eastwards to Royal York Road. The new arrangement will result in 25A load from Horner TS feeder 30M1 and 200A load from Manby TS feeder 38M13 transferred to the new feeder 30M12 off buses B of the Horner TS. About 200A load will be transferred off Manby feeder 38M7 to feeder 38M13 resulting in an overall transfer of 250A from Manby TS bus-Q feeder ET38M13 to the new Horner TS feeder ET30M12.

In addition to relieving the overloaded feeders, redistribution of load is expected to improve the effectiveness of the Feeder Automation that will be developed in the area by creating sufficient spare capacity to allow for the automatic backup of adjacent feeders in the event of outages.

This job is related to the job described above in Section 8 as follows. The job in Section 8 builds a new feeder ETR30M12 out of Horner TS to immediately relieve the Manby bus B-Y of 12MVA, thus averting bus overloading by 2012. This job outlined in Section 49 extends the new feeder proposed in Section 8 (ETR30M12) North-East to further relieve the Manby TS of 14.8MVA by reconfiguring the load and structure of the feeders ET38M7, ET38M13, ET38M20 and ETR30M1 averting the forecasted year 2014 overloading of Manby TS bus Q-Z as indicated in Figure 61 above.

### 49.3. Required Capital Costs

| Job Estimate Number | Job Phase | Year | Estimated Cost ($M) |
|---|---|---|---|
| 23430 | P03 Evans Avenue and Royal York Rd, Reconfiguration of Feeders | 2013 | $0.80 |
| | | **Total:** | **$0.80** |

## 50. CSP and Pole replacement on feeder NY80M5

### 50.1. Objective

The objective of this job is to replace poles that have exceeded their useful lives and CSP transformers on feeder NY80M5 out of Fairchild I TS to prevent future outages and potential safety risks due to equipment failure.

### 50.2. Scope of Work

Feeder NY80M5 has been above FESI 7 for most of the last three years and is currently FESI 8 and WPF 53. In addition, this feeder is currently picking up customers from feeder NY51M7, which results in additional customers also experiencing the failures from Fairchild TS and this feeder. A feeder patrol was performed on the feeder, which noted the poor condition of assets.

1 **50.3. Required Capital Costs**

| Job Estimate Number | Job Title | Year | Estimated Cost ($M) |
|---|---|---|---|
| 20881 | E12457 - CSP Transformer and Pole Replacement | 2013 | $0.44 |
| | | **Total:** | **$0.44** |

**Appendix 1**

**Overhead Infrastructure Business Case Evaluation (BCE) Process**

The business case evaluation (BCE) process involves the calculation of the net benefit of a capital job and incorporates quantified estimated risk, which is calculated based upon the assets' probability and impact of failure. The probability of asset failure is determined based upon the asset's age and condition. The impact of asset failure is derived based upon the various direct and indirect cost attributes associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement. The multiplication of the probability and impact of asset failure provides the quantified estimated risk of asset failure.

### 1.1 Life Cycle Cost and Optimal Intervention Timing Results

Calculation of the probability of failure relies on the assets' Hazard Distribution Function ("HDF"), which represents a conditional probability of an asset failing from the remaining population that has survived up till that time. These functions are validated either directly by THESL or through the assistance of asset life studies from third-party consultants. The impacts of failure are then quantified by accounting for the direct costs associated with the materials and labour required to replace an asset upon failure, as well as the indirect costs. These indirect costs would include the costs of customer interruptions, emergency repairs and asset replacements. The final estimated risk cost is produced, which represents the product of a hazard rate function for the given asset and its corresponding impact costs. Lastly, as shown in Figure 1 below, the lifecycle cost is produced, representing the total operating costs for a new asset, taking into account the annualized risk and capital over its entire lifecycle. The optimal intervention time would then be the red circle at which the Equivalent Annualized Cost ("EAC") is at its lowest.


**Figure 1: Typical Example of Optimal Intervention Time (New Assets)**

This EAC value from the lifecycle cost curve would then need to be cross-referenced against the total costs of the existing asset to determine optimal replacement timing, as shown by the green circle in Figure 2. This specific point in time would indicate that the existing asset has reached its economic end-of-life at 47 years of age and requires intervention. Note that for the existing asset, there is no capital cost component, as this is a sunk cost. Therefore, the existing asset costs are comprised exclusively of the estimated risks remaining.

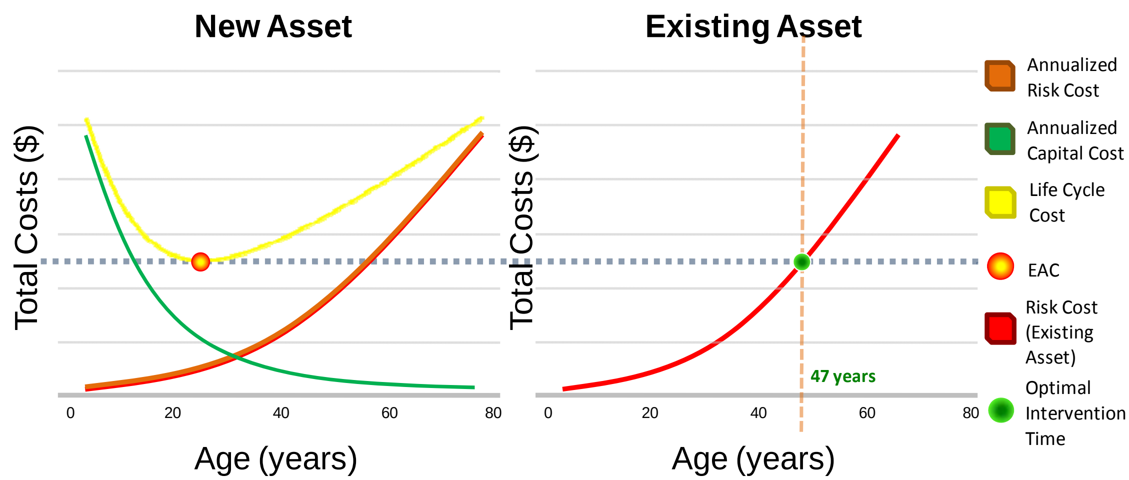



**Figure 2: Typical Example of Optimal Intervention Time (Existing Assets)**

Note that for the example in Figure 2, should the asset be replaced prior to the 47 year optimal intervention time, this would represent sacrificed asset life. Should the asset be replaced after the optimal intervention time, this would represent excess estimated risk.

### 1.2 Project Evaluation Results

The Overhead Infrastructure replacement segment represents an “in-kind” replacement project in which the existing overhead assets are being replaced with new standardized versions of those assets, however the overall configuration associated with this infrastructure remains the same.

In-kind projects are evaluated by calculating the ‘avoided estimated risk cost’ of executing the project immediately in 2012 as opposed to delaying it. Within the ICM application, the deferral time has been set to 2015, as a proxy for the timing of the next Cost of Service EDR application. In order to calculate the avoided estimated risk cost of performing a project in 2012 as opposed to 2015, the various costs and benefits associated with executing a project in a particular year are taken into account.

When a project analysis is undertaken, assets within the project may be before, at, or beyond their optimal replacement time, thus some assets will have sacrificed economic life and others will have incurred excess risk. The cumulative sacrificed life and excess risk of the assets involved becomes a cost against the project, as shown by the red curve in Figure 3. Within the Overhead Infrastructure segment, multiple assets are replaced together as part of a linear job, and therefore there are concurrent intervention benefits that must be weighted against the total costs (cumulative asset excess risk and sacrificed life values) in order to produce an overall project net cost calculation. These benefits would include factors such as equipment rentals, transportation of crew and material, excavations, and road moratoriums. These benefits are illustrated by the green curve in Figure 3. Taking the sum of the costs (cumulative asset excess risk and sacrificed life values) and benefits, year-by-year, provides the Net Project Benefit for the Job-Based Approach, illustrated by the blue curve in Figure 3.

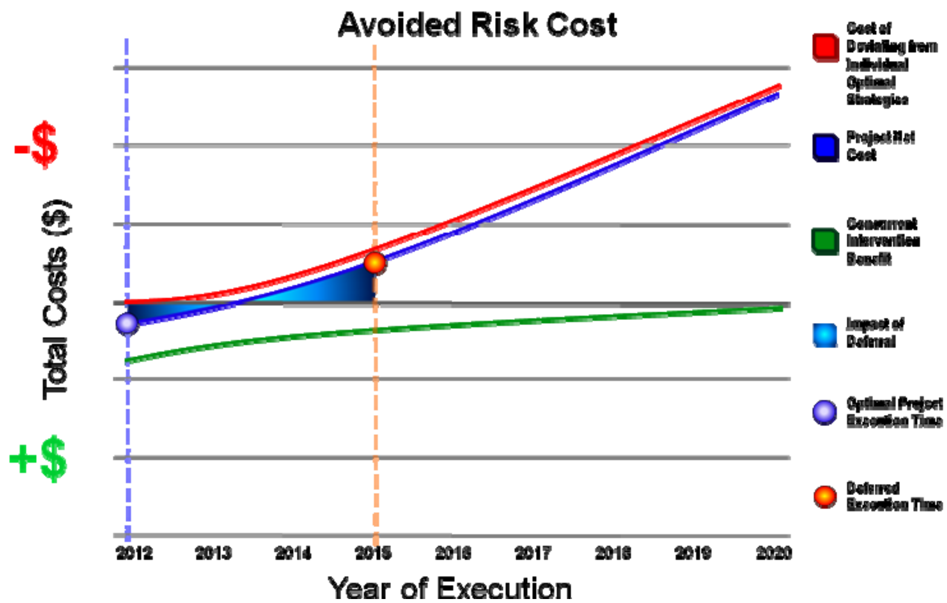
Since the optimal intervention year is the lowest point on the Project Net Cost curve, represented by the blue curve in Figure 3, the estimated risk costs for the project assets in 2015 will exceed the estimated risks that exist today. By performing the work immediately as opposed to waiting until 2015, we can eliminate these estimated risks. Therefore, these avoided costs represent the benefits of the in-kind project execution in 2012 as opposed to 2015.

The formula for this calculation is detailed below:

Avoided Estimated Cost = $PV(PROJECT_{NET\_COST}(2015)) - PROJECT_{NET\_COST}(2012)$

Where:

- $PROJECT_{NET\_COST}(2012)$: Represents the total project net costs in 2012.
- $PV(PROJECT_{NET\_COST}(2015))$: Represents the present value of total project net costs in 2015.




**Avoided Estimated Risk Cost**

**Figure 3: Example of Project Net Benefit Analysis for Job-Based Approach**

Within the Overhead Infrastructure segment, individual optimal intervention timing results were calculated for each of the assets to be replaced, based upon the processes identified in Section 1.1.

Each of these assets may possess an individual sacrificed life and an excess risk value, which collectively produce a year-by-year cost. Each of these assets will also possess a year-by-year concurrent intervention benefit that is produced by comparing the costs of replacing these assets as part of an integrated job as opposed to replacing them individually. Therefore, the individual year-by-year costs and benefits for each asset are aggregated to produce the overall Project Net Cost year-by-year as illustrated in Figure 3.

As noted in the formula above, this Project Net Cost was then calculated for all overhead infrastructure project assets at years 2012 and 2015 respectively as per these two execution approaches. Project Net Costs quantified in 2015 were brought back to a present value and the difference between this value and the Project Net Cost quantified in 2012 was taken as the Avoided Estimated Risk Cost. The final results are provided in Table 1.

1 **Table 1: Avoided Estimated Risk Cost for Overhead Infrastructure Segment**

| Business Case Element | Estimated Cost (in Millions) |
|---|---|
| Present Value of Project Net Cost in 2015 (PV($PROJECT_{NET\_COST}$(2015)) | $ 186 |
| Project Net Cost in 2012 ($PROJECT_{NET\_COST}$(2012)) | $ 111 |
| **Avoided Estimated Risk Cost = (PV($PROJECT_{NET\_COST}$(2015)) – $PROJECT_{NET\_COST}$(2012))** | **$ 75** |

# ICM Project – Overhead Infrastructure and Equipment

## Box Construction Segment

**Toronto Hydro-Electric System Limited (THESL)**

# I EXECUTIVE SUMMARY

## 1. Project Description

Box construction refers to a type of legacy 4kV overhead construction that was previously used in the former City of Toronto and still exists in some areas of the city. The picture below shows a typical box construction installation in the city. There are a number of reliability, safety and load capacity issues associated with box construction (described below), which THESL plans to address through a proactive program to convert these feeders to standard 13.8kV overhead construction. In addition, there are specific issues that necessitate the conversion of box construction 4kV feeders supplied from stations such as Hazelwood MS (municipal station). These issues are described in detail in Section II, 2. The legacy overhead construction will be replaced with 13.8 kV overhead feeders. The estimated total cost of the proposed segment is $58.5 million.

**Typical Box Construction Installation (January 16, 2012)**

Conversion of twenty-seven 4kV box construction feeders identified in the 25 jobs that comprise this segment will allow THESL to decommission the following 4kV stations: College, Hazelwood, Keele and St Clair, Millwood, Merton, and Dufferin. In addition, 4kV box construction feeders B15J, B5J, B8J, B9J, B10J, B11J, B7H, B2DU, B4DU and B6DU will be converted to 13.8kV overhead construction as well as to facilitate the future decommissioning of additional stations.

The specific jobs that will be undertaken to implement this segment are discussed in Section V below. These jobs all involve the replacement of assets required for feeder conversion including poles, switches, transformers and conductor. In addition, to enable the conversion of various feeders, these replacements will remove many obsolete assets from the THESL system. As discussed below in Section V, 2, 2.1, some of these assets create increased safety risks for THESL crews.

## 2. Why the Project is Needed Now

Below is a list of issues associated with Box Construction. The work conducted under this segment is necessary to address these issues.

- Safety to field crews – Several potential safety risks associated with 4kV box construction feeders (see Table-3 below).
- Capacity – Capacity of 4kV box construction feeders is about one-third of 13.8kV overhead feeders and they are not as flexible to accommodate larger customer loads.
- Outage Length – Typical length of outages on 4kV box construction feeders is twice that of 13.8kV overhead feeders. (Refer to Table-4 and Figure 7 for historical outage data.)
- System Efficiency – Line losses experienced on 4kV box construction feeders are about nine times those of 13.8kV overhead feeders.
- Support decommissioning of 4kV stations feeding box construction feeders such as Hazelwood municipal station (MS) – Some stations, such as Hazelwood MS, have assets in need of immediate replacement. Rather than undergo costly ‘like-for-like’ replacement of legacy station assets, it is prudent to convert associated box construction feeders to a higher voltage level and decommission the station.
- Asset condition – Many 4kV box construction feeder assets are past their useful lives and in poor condition.
- Harmonize with other THESL initiatives – Proposed 4kV box construction conversion jobss align with other THESL initiatives, such as the Downtown Station Load Transfer Facilities segment.
- Aesthetics – Poor aesthetics of 4kV box construction feeders.

- Skill set to maintain legacy assets – It is becoming increasingly difficult to maintain 4kV box construction feeders.

## 3. Why the Proposed Project Is the Preferred Alternative

THESL's program to replace obsolete legacy 4 kV box construction with new 13.8 kV feeders will improve safety, reliability and system efficiency as discussed in Section III. THESL evaluated the proposed box construction replacement segment, the preferred alternative, against the alternative of maintaining and replacing the equipment used in box construction, the status quo. Other than replacing box construction or leaving it in place and addressing individual assets as needed, there are no viable options to address the issues that box construction creates.

The status quo would have THESL continue to maintain and repair box construction wherever it is currently found. Due to the high number of assets past their useful lives on these feeders as seen in Table-6, maintaining the status quo will likely result in additional maintenance cost and worse reliability. The safety and operational issues associated with box construction detailed above also will continue. In contrast, THESL's preferred alternative, the planned conversion program, will convert twenty seven outmoded 4kV box construction feeders to modern 13.8kV feeders.

The effectiveness of the box construction segment can be further highlighted by comparing the difference in cost of ownership between the existing box construction asset class that will be replaced and the new standardized overhead asset class that will be installed. This difference in cost includes quantified risks, taking into account the assets' probability of failure, and multiplying this by direct and indirect cost attributes associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement (See Appendix J).

Carrying out immediate work to replace the Box Construction 4kV feeders with 13.8kV feeders as proposed in this segment will result in an estimated net present value for the project of $15.6 million. To calculate this figure, THESL first calculated the cost of ownership of the current state and then subtracted the ownership if the feeders are replaced and the total project cost, as shown in Table-1. Please refer to Appendix J for a further explanation of this calculation.

**Table-1: Business Case Evaluation (BCE) for Box Construction Projects**

| Business Case Element | Cost ($, millions) |
|---|---|
| **Cost of Ownership of Existing Box Construction ($COO_E$)** | |
| Projected risk cost of existing box construction feeders (PV)* | $40.3 |
| Projected risk cost of existing Stations (PV)** | $17.4 |
| Projected non-asset risk cost of existing 4kV overhead (NPV) | $66.0 |
| Stations Maintenance for existing system (PV)*** | $2.4 |
| 4kV line losses relative to 13.8kV feeders (PV) | $10.4 |
| **TOTAL ($COO_E$)** | **$136.5** |
| **Cost of Ownership of New Standardized Overhead Construction ($COO_N$)** | |
| Projected risk cost of converted feeders (PV)**** | -$7.5 |
| Projected non-asset risk cost of new 13.8kV overhead (NPV) | -$54.9 |
| **TOTAL ($COO_N$)** | **-$62.4** |
| **PROJECT COST** | **-$58.5** |
| **PROJECT NPV** | **$15.6** |

Note for *s, please see Table-44 in Appendix J

## II PROJECT DESCRIPTION

### 1. Overview

Box construction refers to a type of legacy 4kV overhead construction that was previously used in the former City of Toronto and still exists in some areas of the city. Figure 1 shows a typical box construction installation in the city. There are a number of reliability, safety and load capacity issues associated with box construction (described below), which THESL plans to address through a proactive program to convert these feeders to standard 13.8kV overhead construction. In addition, there are specific issues which necessitate the conversion of box construction 4kV feeders supplied from stations such as Hazelwood MS (municipal station). These issues are described in detail in Section III.

**Figure 1: Typical Box Construction Installation (January 16, 2012)**

### 2. Project Cost

Table-2 shows the estimated cost of each box conversion job. These jobs are organized based on the specific municipal stations to which they relate in Section V, below.

1 **Table-2: 4kV box construction proposed for conversion to 13.8kV**

| Job Estimate Number | Job Title | Cost Estimate ($ million) | Projected Year of Execution |
|---|---|---|---|
| X11422 | Hazelwood Overhead Conversion (B7HW) | $1.82 | 2012 |
| X12445 | B5HW and B3HW conversion/transfer | $3.42 | 2012 |
| X12325 | B15J conversion to 13.8kV | $3.64 | 2012 |
| X12352 | B7CD conversion to 13.8kV | $1.33 | 2012 |
| X11369 | Keele/St. Clair MS Voltage Conversion from 4kV to 13.8kV System B1KS, B4KS | $3.45 | 2013 |
| X12353 | Voltage Conversion from 4kV to 13.8kV System TOB4CD | $1.63 | 2013 |
| X11452 | Millwood MS: B2MD, Merton MS:B1MR, Partial Voltage Conversion | $2.73 | 2013 |
| X12054 | Voltage Conversion from 4kV to 13.8kV System TOB5DN | $6.03 | 2013 |
| X12506 | Voltage Conversion from 4kV to 13.8kV System Part 2 B4DN | $0.17 | 2013 |
| X13186 | transfer load | $1.18 | 2013 |
| X12193 | X13186 - Load Transfer (3MVA) A200E to new feeder AxxxE | $1.44 | 2013 |
| X13177 | Convert Junction 4kV B8J to 13.8kV | $0.21 | 2013 |
| X13178 | Convert Junction 4kV B9J (south of Bloor) to 13.8kV | $0.73 | 2013 |
| X12129 | Millwood MS: B3MD, Merton MS B2MR Voltage Conversion Millwood(4.16 kV) | $4.84 | 2014 |
| X12055 | Voltage Conversion from 4kV to 13.8kV System TOB3DN | $3.23 | 2014 |
| X12161 | Convert Junction 4kV B11J to 13.8kV | $2.14 | 2014 |
| X12194 | Convert Junction 4kV B10J to 13.8kV | $1.68 | 2014 |

| Job Estimate Number | Job Title | Cost Estimate ($ million) | Projected Year of Execution |
|---|---|---|---|
| X12142 | Convert 4kV Merton Feeder B2MR to 13.8kV System | $0.62 | 2014 |
| X12145 | Convert 4kV Merton Feeder B3MR to 13.8kV System | $1.11 | 2014 |
| X12174 | Convert 4kV Merton Feeder B5MR to 13.8kV System | $3.78 | 2014 |
| X12143 | Convert 4kV Merton Feeder B1MR, B2MR to 13.8kV System | $2.24 | 2014 |
| X13362 | Convert 4kV B7H feeder to 13.8kV system | $2.38 | 2014 |
| X14202 | B3DN Voltage conversion | $2.07 | 2014 |
| X13176 | Convert Dupont 4kV B4DU to 13.8kV | $3.67 | 2014 |
| X13003 | Convert 4kV Dupont B6DU to 13.8kV | $2.96 | 2014 |
| **TOTAL** | | **$58.5** | |

## 3. Project Location

Figure 2 is a map showing the locations of all box construction feeders in the City of Toronto.

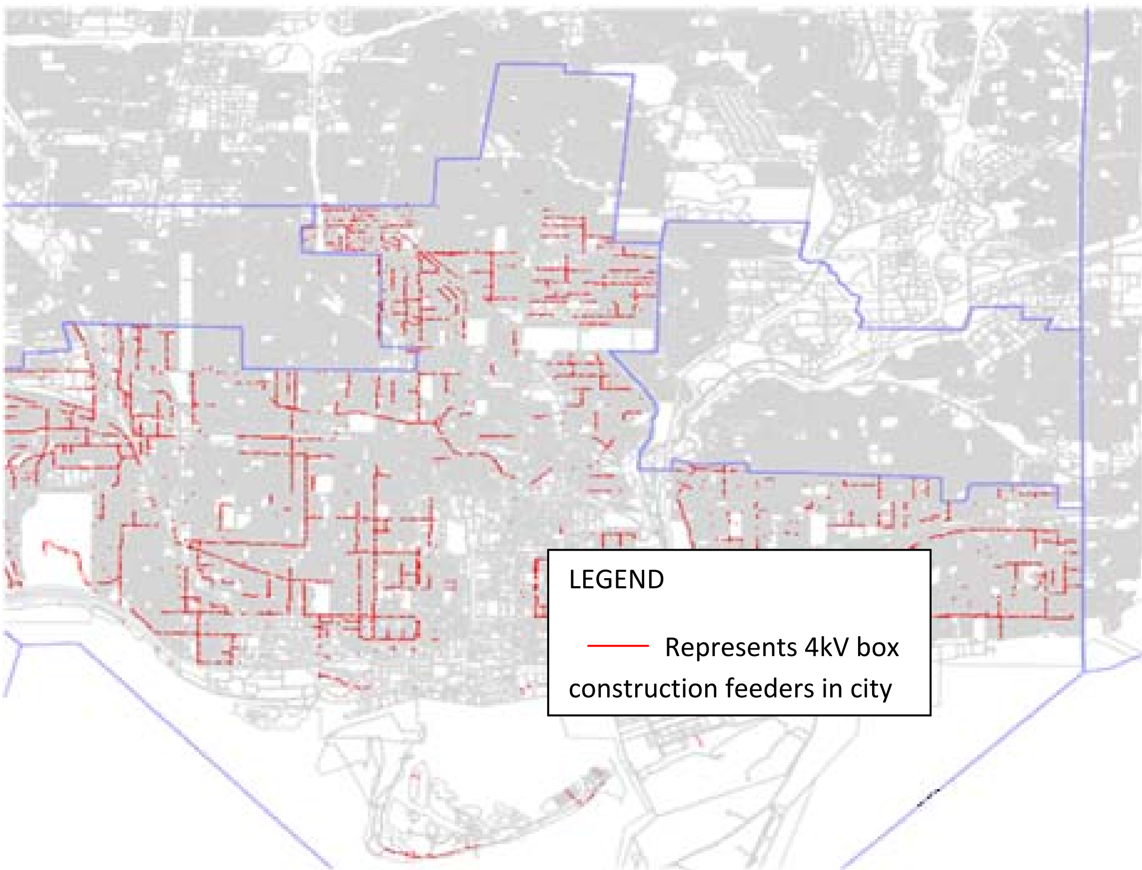



**Figure 2: Map shows locations of all 4kV box construction feeders in the distribution system**

Figure 3 shows the specific box construction feeders.

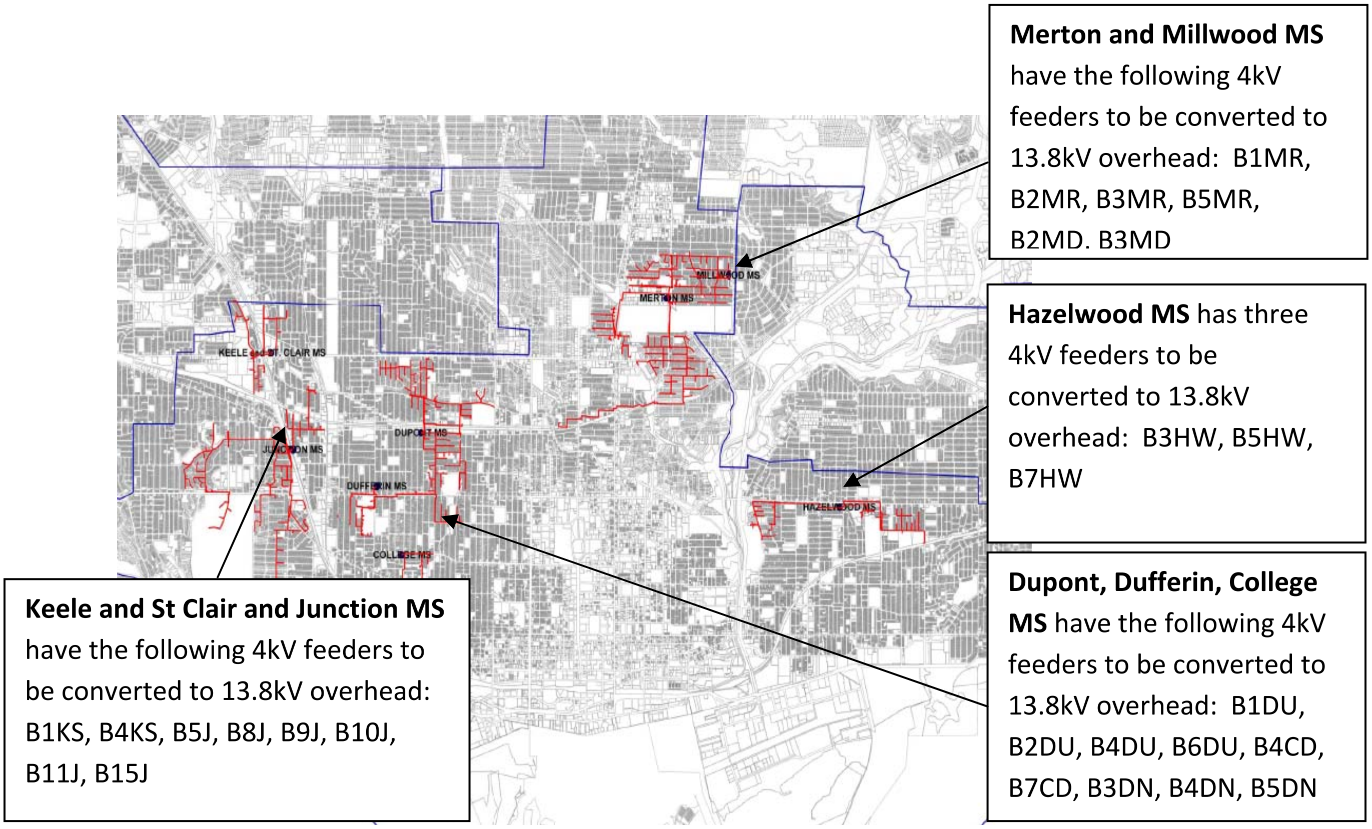



**Figure 3: Map shows locations of 4kV box construction feeders proposed for conversion to 13.8kV in 2012-2014**

## III NEED

This section presents the reasons why THESL must replace box construction now. The specific jobs for 2012, 2013 and 2014 that THESL proposes to accomplish this segment are described in Section V – Description of Work.

### 1. Safety

There are numerous potential safety issues associated with box construction. They are outlined in Table-3.

**Table-3: Safety Issues Associated with Box Construction**

| Safety Issue | Description |
|---|---|
| System Complexity | The conversion of box construction feeders to current 13.8kV overhead construction standards will improve workplace safety for crews by reducing the complexity associated with box construction poles. Box construction poles typically support more circuits compared to standard 13.8kV overhead circuits. High concentration of cables in one spot (the box construction) increases the potential risk of a shock hazard to crews working on it. See Figure 13 and Figure 14 for examples of typical 4kV box construction and 13.8kV overhead feeders. Furthermore, with box construction, some circuits cannot be accessed with bucket trucks due to the physical arrangement of the feeders running through a single box pole, forcing line crews to climb the poles and increasing the potential safety risk for Toronto Hydro employees. |

| Safety Issue | Description |
|---|---|
| EUSR rule 129 | There are situations associated with box construction work where THESL crews working in close proximity to the lines and, in cases, can have difficulty in conforming to the working clearances defined in Electrical Utilities Safety Rules (EUSR) rule 129. More specifically, the required 15 cm air gap between people/tools and energized conductors cannot always be achieved. See Appendix A for the complete text of EUSR Rule 129, K for documented safety concerns from THESL field crews, and Appendix E for the larger clearances (relative to 4kV box construction) between conductors found on a current construction standard 13.8kV overhead feeder (762mm on a 13.8kV overhead feeder vs. 330mm on a 4kV box construction feeder). While THESL takes great care to ensure that worker safety is never compromised, working on box construction increases risks. |
| Legacy Equipment | Some equipment that is directly associated with box construction was designed and installed prior to the adoption of current safe work practices. One such example is 'Positect' switches, an obsolete type of fused switch that is operated by hand, and consequently puts field crews in the flash zone of the switch (arc flash hazard).Current standard disconnect switches are designed to be operated with a 'switch stick' that keeps workers outside of the flash zone. While a stick was developed for 'Positect' switches to reduce the risk to crews, the fact remains that these switches were designed to be operated by hand. See Figure 15 for a photo of this switch type. Another example of obsolete equipment associated with box construction is porcelain insulators, which have been known to fail in ways that have damaged nearby property and create potential risk of injury. For more information, refer to Figure 16 and C for safety bulletin. |

## 2. Loading/Capacity

Load capacity of 4 kV box construction feeders is less than a third of the capacity of 13.8kV overhead feeders (3MVA and 10MVA, respectively). In addition, 4kV feeders are not as flexible when it comes to supplying new large customers. An example of a scenario where a customer could not be accommodated on the existing 4kV feeder can be found in Appendix F, where a 4kV feeder in close proximity to a customer could not be used due to capacity constraints, and a higher voltage/capacity 13.8kV feeder had to be extended into the area as a result.

In addition, delivering electricity at a primary voltage of 4kV (as is the case with box construction) is less energy efficient when compared to 13.8kV feeders. The line losses associated with a 4kV system are approximately nine times higher than those of 13.8kV lines (see H for a detailed calculation). When these line losses are taken into consideration, significant savings can be seen from converting from 4kV to 13.8kV, as seen in Appendix J.

**3. Clearance**

Clearance issues are also prevalent with 4kV overhead box construction feeders. As per CSA and THESL standards, the clearance between overhead feeders and buildings must be greater than three metres, as shown in Electrical Safety Authority (ESA) standard Appendix B. In many cases, as buildings are replaced or rebuilt, they are being located closer to or even right against the lot lines compromising on line clearances previously achievable. In many instances, the three-metre clearance does not exist between lot line and roadway, due to the large area that the box occupies at the top of box construction poles. Extensive planning must then be done to isolate those conductors within three metres and still feed customers in that area. This work can often be avoided with existing 13.8kV overhead construction standards. See Figure 4, Figure 5, and Figure 6 for examples of these clearance issues in Toronto.

Queen and Bathurst area. Feeder was isolated in this area due to work on building at SE corner of intersection, requiring extensive temporary circuit modifications to the area.

**Figure 4: Construction at Queen and Bathurst (January 17, 2012)**

Though not a problem yet, there will be clearance issues in the event that buildings along Tecumseh (south of Queen) need any civil work done.

**Figure 5: Potential Clearance Issue (January 17, 2012)**

Box pole was modified to accommodate construction project (Palmerston, North of Queen on West side). Specialized work becoming more difficult due to lack of experienced overhead line crews.

**Figure 6: Clearance Issue (January 17, 2012)**

## 4. Reliability

Box construction infrastructure, having been installed in the 1950s and 1960s, includes a significant number of assets that are approaching or have past the end of their useful lives. Increasing failures among these assets will cause more frequent outages. Table-6 and Section V presents specific reliability and asset condition analyses and jobs pertaining to the feeders identified for conversion.

Current construction standards also allow for greater operational flexibility and efficiency than that achievable with box construction. This additional flexibility can reduce outage duration. For example, disconnect switches are manually operated on 4kV box construction feeders, but converting to current 13.8kV overhead standards is expected to allow for installation of remotely operated SCADA switches, which will decrease outage times through faster fault identification and reduced switching times. Table-4 shows that the average outage duration on a 4kV box construction feeder is <u>double</u> that of 13.8kV overhead feeders built to current construction standards.

**Table-4: Reliability Performance for 4kV Box Construction vs. Standard 13.8kV O/H Feeders from 2000-2010**

| | **4.16kV Overhead Box Construction** | **13.8kV Overhead construction** |
|---|---|---|
| **Total CI** | 883,673 | 885,956 |
| **Total CHI** | 899,965 | 429,221 |
| **Average Outage Duration** | **61 minutes** | **29 minutes** |

'CI' – customers interrupted and 'CHI' – customer hours interrupted

Furthermore, by examining the frequency of outages per year of 4kV feeders compared to 13.8kV feeders from 2005-2010, it can be seen that there are consistently fewer outages on the 13.8kV feeders (as shown in Figure 7). Though both 4kV and 13.8kV feeders show a downward trend in Figure 7, it should be noted that the number of kilometres of 4kV feeders is decreasing while the number of kilometres of 13.8kV feeders is increasing due to voltage conversion projects in years past.

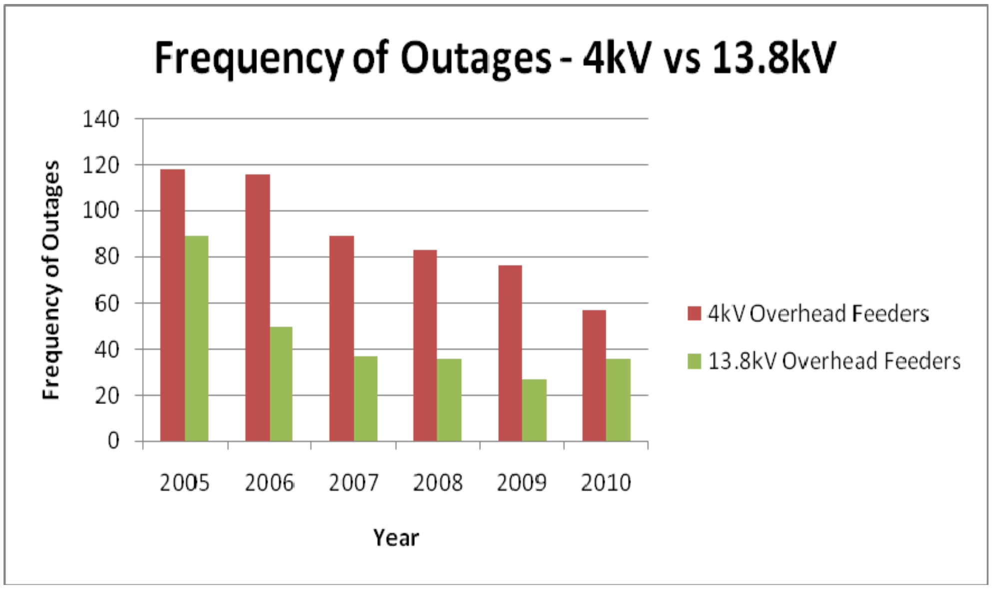



**Figure 7: Frequency of Outages - 4kV vs 13.8kV Overhead feeders**

## 5. Aging 4kV Stations Supplying Box Construction Feeders

Several 4kV stations have been shown to have assets in poor condition that will require action over the 2012-2014 period. This problem can be addressed by either replacing station assets on a 'like-for-like' basis, or by converting all 4kV load served from that station to 13.8kV and decommissioning the station. Hazelwood MS is an example of a station that must be addressed by 2013, as shown in maintenance records in Table-7, Table-8 and Table-9. Dufferin MS (refer to Table-36) and Merton MS (refer to Table-32) also have station equipment that needs to be addressed. Rather than continue to sustain a 4kV legacy system and continue being exposed to the associated safety, clearance and reliability issues, THESL proposes to convert these 4kV box construction feeders, and decommission these legacy stations.

Furthermore, decommissioning 4kV MS stations is expected to result in maintenance cost savings. Eliminating maintenance on these decommissioned stations will reduce THESL's need to hold inventory of obsolete 4kV equipment and maintain this equipment in good working order. It will also eliminate the labour costs incurred when obsolete 4kV station equipment must be replaced (as an example, see Hazelwood MS case study in Section 1.2).

## 6. Other Benefits of Converting Box Construction

Aesthetics of areas with box construction feeders is expected to be improved with conversion to 13.8kV overhead feeders. Figure 13 and Figure 14 below, show the appearance of a typical 4kV box construction feeder and that of a typical 13.8kV feeder.

Working on box construction requires a special set of skills. These skills are difficult to maintain because box construction is no longer standard, but instead is a legacy design with legacy equipment (such as shielded primary cable) found only in certain areas of the city. In the past, when 4kV box construction feeders were the standard design for overhead distribution, crews had extensive continuous experience working on them. Now, because new employees work on 4kV box construction feeders on an infrequent ‘as-needed’ basis and the older generation of employees is retiring, fewer employees have experience working 4kV box construction skills, which increases the difficulty of maintaining and managing this legacy system.

In a similar vein, legacy 4kV box construction replacement equipment has become difficult to procure, due to a limited number of suppliers. In the case of shielded primary cable, only one North American supplier currently manufactures this type of cable. In addition, since this cable is a ‘non-stock non-standard’ item for the supplier, a lengthy 12-week lead time and a minimum order quantity of 3000 m (cannot order lengths of cable smaller than this amount) is required for each order.

Decommissioning 4kV MS associated with the box construction feeders is also expected to allow Toronto Hydro to use MS land for other projects such as feeder ties for station load transfer in the downtown area. See D for an excerpt from the station load transfer (downtown contingency) presentation that lists Hazelwood MS and Dufferin MS as future switching locations. Furthermore, delays in decommissioning Hazelwood MS will delay THESL’s plans for station load transfer capability, further extending THESL’s risk for a significant outage from a station-wide failure, such as was experienced at Dufferin transmission station (TS) in 2009 (see Appendix G for news article regarding this outage). Hazelwood MS is located between Leaside TS and Carlaw TS, and its land could be used to create a link between those stations in the event of a station-wide outage.

## 7. Box Construction Job Sequencing

Converting all 4kV box construction feeders to 13.8kV and decommissioning all associated 4kV substations in a three-year period is not feasible. Rather, the jobs selected for conversion in 2012-2014 are part of a larger long-term (ten- to 15-year) plan to convert all 4kV box construction feeders and decommission associated MSs. There are numerous engineering challenges that require THESL to convert 4kV box construction feeders in a sequential manner:

a) Availability of 13.8kV 4-wire (with neutral) feeders

Three-phase overhead feeders require a fourth neutral cable to accommodate single-phase load (fed from a low-impedance 4-wire bus), but not all 13.8kV feeders are '4-wire' (e.g., underground 13.8kV feeders can be either 3-wire or 4-wire). As a result, only 4kV box construction feeders that have 13.8kV 4-wire feeders or 4-wire bus at a station in their vicinity can be converted to 13.8kV overhead feeders. In addition, these 13.8kV overhead feeders must have sufficient capacity to accommodate the existing 4kV load, which not all of them do. For example, Wiltshire MS 4kV box construction feeders cannot be converted to 13.8kV overhead feeders due to a lack of existing 4-wire overhead feeder capacity. When Keele and St Clair MS is decommissioned, the two 13.8kV 4-wire feeders feeding Keele and St Clair MS will be available to take on Wiltshire MSs 4kV load.

b) Some Hydro One-owned station equipment in THESL transmission stations (TS) require upgrades

Station equipment, such as transformers, switchgear and bus, must be upgraded to accommodate future 4-wire bus for 4kV box construction conversion jobs. For example, Highlevel TS must have its high-impedance 3-wire 13.8kV bus/transformer/ switchgear upgraded to a low-impedance 4-wire bus to accommodate 4kV conversion jobs at Highlevel MS. As a result, stations like Highlevel MS have not been targeted for conversion in the 2012-2014 timeframe.

As more 4kV box construction feeders are converted to 13.8kV, access to 13.8kV overhead feeders increases. As a result, some 4kV feeders that previously could not be converted to 13.8kV may now be candidates for conversion. In addition to the reasons provided above to explain the need for 4kV box construction conversion jobs in 2012-2014, the specific jobs discussed below also were selected because they are located in the vicinity of 13.8kV overhead feeders with adequate capacity.

## IV PREFERRED ALTERNATIVE

THESL's program to replace obsolete legacy 4 kV box construction with new 13.8 kV feeders will improve safety, reliability and system efficiency as discussed extensively above. THESL evaluated the proposed box construction replacement segment, the preferred alternative, against the alternative of maintaining and replacing the equipment used in box construction, the status quo. Other than replacing box construction or leaving it in place and addressing individual assets as needed, there are no viable options to address the issues that box construction creates.

### 1. Maintaining the Status Quo

The status quo would have THESL continue to maintain and repair box construction wherever it is currently found. Due to the high number of assets past their useful lives on these feeders as seen in Table-6, maintaining the status quo will likely result in additional maintenance cost and worse reliability. The safety and operational issues associated with box construction detailed above also will continue. In contrast, THESL's preferred alternative, the planned conversion program, will convert twenty seven outmoded 4kV box construction feeders to modern 13.8kV feeders.

Failure to execute this segment will force THESL to manage the issues described in Section III above in a reactive and less effective manner. It will also delay the decommissioning of some MS and, as a result, reduce the availability of 13.8kV feeders to support modernization of 4kV overhead box construction plant to existing overhead construction standards.

The effectiveness of the box construction segment can be further highlighted by determining the difference in cost of ownership between the existing box construction asset class that will be replaced and the new standardized overhead asset class that will be installed. This difference in costs includes quantified risks, taking into account the assets' probability of failure, and multiplying this by the direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement.

Carrying out the proposed work on this asset class is expected to result in a net present value of $15.6 million, which represents the difference between these cost of ownership values with the total project cost subtracted. This business case evaluation is explained in Appendix J.

### 1.1. Performance Impacts

A list of feeders that will be addressed under this program, along with the job costs and number of assets past their useful life per circuit kilometre is provided in Table 5.

**Table-5: Assets Past their Useful Lives Per Circuit Kilometre on 4kV Feeders to be Converted to 13.8kV**

| Feeder | Estimated Project Cost ($M) | Assets Past Useful Life | Circuit Length (km) | Quantity/km | Projected Year of Execution |
|---|---|---|---|---|---|
| B3HW (X12445) | $3.42 | 39 | 3.80952 | 10.2 | 2012 |
| B5HW (X12445) | | 154 | 3.03309 | 50.8 | |
| B7HW (X11422) | $1.82 | 82 | 2.14393 | 38.2 | 2012 |
| B15J (X12325) | $3.64 | 219 | 6.29048 | 34.8 | 2012 |
| B7CD (X12352) | $1.33 | 78 | 1.4864 | 52.5 | 2012 |
| B4KS (X11369) | $3.45 | 129 | 2.54616 | 50.7 | 2013 |
| B1KS (X11369) | | 45 | 2.42689 | 19.8 | |
| B4CD (X12353) | $1.63 | 0 | 1.11803 | 0.0 | 2013 |
| B2MD, B1MR (X11452) | $2.73 | 63 | 3.83669 | 16.4 | 2013 |
| B5DN (X12054) | $6.03 | 50 | 3.60117 | 13.9 | 2013 |
| B1DU | | 95 | 1.53529 | 61.9 | |

| Feeder | Estimated Project Cost ($M) | Assets Past Useful Life | Circuit Length (km) | Quantity/km | Projected Year of Execution |
|---|---|---|---|---|---|
| (X12054) | | | | | |
| B4DN (X12506) | $0.17 | 35 | 0.61803 | 56.6 | 2013 |
| transfer load (X13186) | $1.18 | 0 | 0 | n/a | 2013 |
| B5J (X12193) | $1.44 | 28 | 1.90018 | 14.7 | 2013 |
| B8J (X13177) | $0.21 | 31 | 0.44607 | 69.5 | 2013 |
| B9J (X13178) | $0.73 | 210 | 4.65797 | 45.1 | 2013 |
| B3MD, B2MR (X12129) | $4.84 | 87 | 3.18416 | 27.3 | 2014 |
| B2DU (X12055) | $3.23 | 228 | 3.87552 | 58.8 | 2014 |
| B11J (X12161) | $2.14 | 149 | 2.74384 | 54.3 | 2014 |
| B10J (X12194) | $1.68 | 89 | 1.63134 | 54.6 | 2014 |
| B2MR (X12142) | $0.62 | 52 | 3.19 | 16.3 | 2014 |
| B3MR (X12145) | $1.11 | 69 | 4.47065 | 15.4 | 2014 |
| B5MR (X12174) | $3.78 | 37 | 3.60165 | 10.3 | 2014 |
| B1MR, B2MR (X12143) | $2.24 | 85 | 3.72 | 22.8 | 2014 |
| B7H (X13362) | $2.38 | 36 | 2.9141 | 12.4 | 2014 |
| B3DN (X14202) | $2.07 | 72 | 1.47931 | 48.7 | 2014 |
| B4DU (X13176) | $3.67 | 194 | 4.55508 | 42.6 | 2014 |

| Feeder | Estimated Project Cost ($M) | Assets Past Useful Life | Circuit Length (km) | Quantity/km | Projected Year of Execution |
|---|---|---|---|---|---|
| B6DU (X13003) | $2.96 | 136 | 4.06301 | 33.5 | 2014 |
| **TOTAL** | **$58.5** | **2,305*** | **78.87** | | |

*Total count is lower than the sum of the individual assets due to shared poles between feeders.

A higher number of assets past their useful lives indicates that the likelihood of outages due to component failures will increase. Execution of the listed jobs will result in the modernization of all assets on these feeders which are past their useful lives.

Table-6 shows the number of assets per feeder that are projected to fail by their respective planned year of conversion. In addition, it shows the quantity of assets past their useful lives per feeder, along with associated estimated 'like-for-like' replacement costs and quantified risk cost.

**Table-6: Failure Projections, Assets past their useful lives and Associated Anticipated 'Like-for-Like' Replacement Costs per Feeder**

| Feeder | Proposed Year of Conversion | Station | Assets Presently Projected to Fail by Year of Conversion (in counts) | Risk Cost of Feeder up to Year of Conversion ($M) | Assets Past Useful Life (in counts) | Estimated Cost of Replacement for Assets Past Useful Life ($M) |
|---|---|---|---|---|---|---|
| B7CD | 2012 | College | 3 | $0.12 | 78 | $1.03 |
| B3HW | 2012 | Hazelwood | 6 | $0.12 | 39 | $0.57 |
| B5HW | 2012 | Hazelwood | 13 | $0.24 | 154 | $1.85 |
| B7HW | 2012 | Hazelwood | 7 | $0.21 | 82 | $1.04 |
| B15J | 2012 | Junction | 12 | $0.45 | 219 | $2.69 |
| B4CD | 2013 | College | 2 | $0.08 | 0 | $0 |

## ICM Project | Box Construction Segment

| Feeder | Proposed Year of Conversion | Station | Assets Presently Projected to Fail by Year of Conversion (in counts) | Risk Cost of Feeder up to Year of Conversion ($M) | Assets Past Useful Life (in counts) | Estimated Cost of Replacement for Assets Past Useful Life ($M) |
|---|---|---|---|---|---|---|
| B5DN | 2013 | Dufferin | 8 | $0.24 | 50 | $0.69 |
| B4DN | 2013 | Dufferin | 2 | $0.03 | 35 | $0.46 |
| B1DU | 2013 | Dupont | 9 | $0.35 | 95 | $1.35 |
| B5J | 2013 | Junction | 4 | $0.16 | 28 | $0.42 |
| B8J | 2013 | Junction | 2 | $0.02 | 31 | $0.37 |
| B9J | 2013 | Junction | 16 | $0.43 | 210 | $2.60 |
| B4KS | 2013 | Keele and St Clair | 13 | $0.65 | 129 | $1.85 |
| B1KS | 2013 | Keele and St Clair | 5 | $0.07 | 48 | $0.60 |
| B2MD | 2013 | Millwood | 6 | $0.12 | 30 | $0.36 |
| B3DN | 2014 | Dufferin | 9 | $0.65 | 72 | $0.96 |
| B2DU | 2014 | Dupont | 28 | $1.98 | 228 | $2.96 |
| B4DU | 2014 | Dupont | 29 | $1.29 | 194 | $2.54 |
| B6DU | 2014 | Dupont | 20 | $0.56 | 136 | $1.65 |
| B7H | 2014 | Highlevel | 17 | $0.40 | 36 | $0.44 |
| B11J | 2014 | Junction | 18 | $0.81 | 149 | $1.96 |
| B10J | 2014 | Junction | 10 | $0.23 | 89 | $1.07 |
| B3MD | 2014 | Millwood | 36 | $1.04 | 35 | $0.42 |
| B2MR | 2014 | Merton | 30 | $0.46 | 52 | $0.66 |
| B3MR | 2014 | Merton | 34 | $0.79 | 69 | $0.77 |
| B5MR | 2014 | Merton | 12 | $0.22 | 37 | $0.51 |
| B1MR | 2014 | Merton | 42 | $0.68 | 33 | $0.386 |
| **TOTAL** | | | **393** | **$12.36**** | **2,305*** | **$29.4*** |

*Total is lower than the sum of the individual assets due to shared poles between feeders

**Cost calculated on 'per feeder' basis. If two feeders share a pole on this list, then the risk of its failure will be double-counted in this calculation.

The quantified risks displayed above are calculated by taking into account the assets' probability of failure, and multiplying this by the various direct and indirect cost attributes associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement, as explained in Appendix J.

Though the estimated replacement cost of assets past their useful lives on feeders in Table 6 is less than the estimated project capital cost shown above in Table-2, it should be noted that all replacements in this "status quo" scenario will be on a 'like-for-like' basis, and thus no modernization of the system will be achieved and the issues associated with box construction will remain. Funds will continue to be invested in an obsolete 4kV design.

From 2007-2011, the proposed feeders for conversion averaged 17,000 customers interruptions (CI) and 23,666 customer hours interrupted (CHI). Many of the outages were caused by defective equipment, animal contacts, and tree contacts. If these feeders are converted to current construction standard 13.8kV overhead feeders (would include animal guards, tree-proof cable where needed, and up-to-date equipment), 15,600 CI and 22,300 CHI would be potentially mitigated.

### 1.2. Decommissioning Hazelwood MS

Hazelwood MS supplies three 4kV box construction feeders: B3HW, B5HW, B7HW. Although they have not failed yet, maintenance reports for transformer and switchgear assets in Hazelwood MS provide compelling evidence that they must be either replaced or decommissioned in the near future, as they are approaching failure. See Table-7, Table-8 and Table-9 for maintenance reports of transformers and switchgear at Hazelwood MS. A proactive conversion of the 4kV box construction load supplied by Hazelwood MS to 13.8kV will mean that the entire station can be decommissioned. This is expected to eliminate the need to replace obsolete 4kV station equipment on a 'like-for-like' basis.

THESL's 2011 ten-year plan includes decommissioning Hazelwood MS by 2013, rather than replace the station assets of concern. In order to decommission the station, all 4kV load fed by this station would have to be converted to 13.8kV and fed from adjacent 13.8kV overhead feeders prior to 2013.

Furthermore, maintenance reports for transformer and switchgear assets in Hazelwood MS provide compelling evidence that they must be either replaced or decommissioned in the near future, as they are approaching failure. Table-7 and Table-8 show partial results from a standard maintenance test known as DGA (Dissolved Gas Analysis), indicating that the insulation inside the transformer is in poor condition.

**Table-7: Transformer TR1 DGA results**

| | June 12, 2010 | July 31, 2008 | Dec 6, 2006 | Feb 15, 2005 |
|---|---|---|---|---|
| CO2 (PPM) | 11,351 | 8,092 | 8,806 | 8,254 |
| CO (PPM) | 617* | 608* | 630* | 609* |

'*' indicates 'condition 3' status, meaning significantly overheated cellulose (transformer insulation degradation, and eventual transformer failure)

**Table-8: Transformer TR2 DGA results**

| | June 21, 2010 | July 31, 2008 |
|---|---|---|
| $CO_2$ (PPM) | 10,526 | 6,972 |
| CO (PPM) | 553* | 588* |

'*' indicates 'condition 2' status, meaning overheated cellulose insulation (transformer insulation degradation, and eventual transformer failure)

Table-9 shows the Health index (HI) for the above station assets, indicating that they should be replaced or decommissioned in the near future. 'Health Index' is based on various conditions specific to the asset in question. As an example, HI of station power transformers takes into consideration conditions such as age, dissolved gas analysis (DGA), oil quality testing, and visible oil leaks. A score below 50 is considered poor.

**Table-9: Health Index (HI) for Hazelwood MS station assets**

| Asset | Health Index |
|---|---|
| TR1 | 46 |
| TR2 | 35 |
| TR3 | 35 |
| TR4 | 35 |
| Switchgear | 42.85 |

In addition to the poor dissolved gas analysis results seen in Table-7 and Table-8, a site inspection of Hazelwood MS revealed problems with the four station transformers, as they were all leaking oil. Figure 8 through Figure 11 show that the transformers are leaking. If the station is not decommissioned, it is estimated that THESL will have to replace $1.73M of station equipment that are past useful lives and incur $0.65M in maintenance costs over the next five years. Note that refurbishing old assets like these station transformers rather than replacing them does not make economic sense when major components like core, windings/insulation and oil have to be replaced, as it is estimated that the refurbishment cost will be close to the replacement cost itself.

A transformer failure could result in an outage for the area supplied by Hazelwood MS. In the event of a catastrophic failure, the lack of firewalls between the station transformers would undoubtedly result in an extended outage for the area serviced by Hazelwood MS, and lead time to replace these transformers would be anywhere from 3.5 days to seven days depending on availability of spare transformers.

**Figure 8: Transformer TR1 with signs of oil leakage (January 16, 2012)**


**Figure 9: Transformer TR2 with more significant oil leakage (January 16, 2012)**


**Figure 10: Transformer TR3 shows significant signs of oil leakage (note the oil saturated mats) (January 16, 2012)**


**Figure 11: Transformer TR4 shows significant signs of oil leakage (note the oil saturated mats) (January 16, 2012)**

Delaying the conversion of 4kV Hazelwood MS feeders to 13.8kV and decommissioning Hazelwood MS will result in a significant risk of major equipment failure.

### 1.3. Consequences of Deferring the 4kV Box Construction Conversion Projects

Should this project be deferred, none of the problems discussed previously in this document will be mitigated and none of the following expected corresponding benefits will be realized:

- Safety improvements for field crews (refer to Table-3 for details)
- Support for decommissioning of Hazelwood MS, such that legacy 4kV station equipment can be removed from service without needing to be replaced on a 'like-for-like' basis
- Replacement of legacy assets past their useful lives, modernizing the system and harmonizing work practices
- Alignment with THESL's Downtown Station Load Transfer Facilities segment, reducing the risk of a large scale station-wide power outage that would have no first contingency backup (refer to D for more details)
- Improved system flexibility to accommodate large loads

- Improved operational flexibility through installation of SCADA switches on 13.8kV overhead
- Reduced line losses resulting from conversion of primary voltage from 4kV to 13.8kV, as shown in BCE found in Appendix J
- Improved aesthetics of THESL plant in the affected areas
- Reduced need for a separate skill set to maintain legacy 4kV box construction

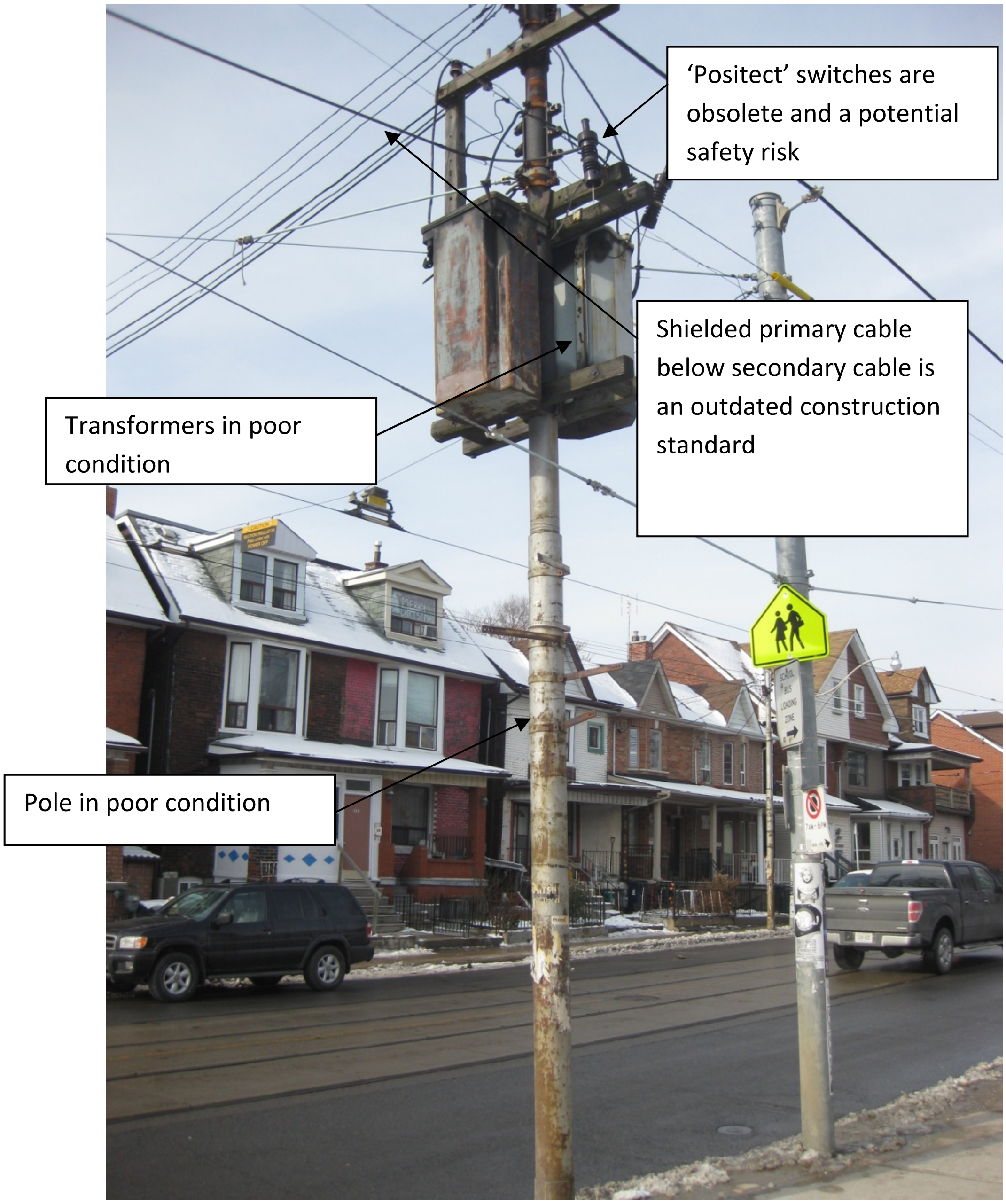
## V DESCRIPTION OF WORK

### 1. Partial Conversion of College MS (X12352, X12353)

#### 1.1. Objective

The objective of these jobs is to prepare College MS for conversion from 4.16kV to 13.8kV. The main objective is to mitigate the safety concerns associated with working around energized box construction which is found on feeders from College MS. The main benefits of completing this work are improved reliability and mitigation of potential safety risks. The equipment that is being replaced is overhead 4kV distribution plant which includes conductor, poles, transformers and switches.

Figure 12 shows an example of obsolete assets on College MS feeder B7CD.




1 **Figure 12: Equipment Condition Issues on B7CD (January 16, 2012)**

## 1.2. Historical Reliability Performance

**Table-10: Historical Reliability - College MS**

| HISTORICAL RELIABILITY PERFORMANCE – COLLEGE MS | | | |
|---|---|---|---|
| **Reliability Metric** | **2008** | **2009** | **2010** |
| Feeder CI | 0 | 0 | 738 |
| Feeder CHI | 0 | 0 | 369 |

## 1.3. Scope of Work

The scope of work in X12352 and X12353 is to convert B7CD and B4CD, respectively from 4.16kV to 13.8kV.

**Table-11: Assets to be Replaced - College MS**

| Assets to be upgraded from 4.16kV to 13.8kV | | | |
|---|---|---|---|
| X12352 | | X12353 | |
| Poles | 76 | Poles | 50 |
| Switches | 8 | Switches | 7 |
| Transformers | 27 | Transformers | 23 |
| Conductor | 1.4864 km | Conductor | 1.11803 km |

## 1.4. Locations

The assets being replaced by this job belong to B4CD and B7CD in the intersection of College Street and Dovercourt Road for B4CD and Dundas Street and Ossington Avenue for B7CD.

### 1.5. Required Capital Costs

**Table-12: Capital Costs - College MS**

| Job Estimate Number | Job Phase | Cost ($, millions) | Projected Year of Execution |
|---|---|---|---|
| 18761 | X12352 – B7CD OH Feeder Voltage Conversion | $1.33 | 2012 |
| 20537 | X12353 – B4CD OH Feeder Voltage Conversion | $1.63 | 2013 |
| **Total:** | | $2.96 | |

### 1.6. Preferred Option for Feeders Supplied by College MS (B7CD, B4CD)

Maintenance reports suggest that station assets in College MS are deteriorating, as shown in Table-13 and Table-14 below.

**Table-13: College MS Transformer TR1 DGA results**

| TR1 | June 16, 2009 | May 11, 2009 | April 8, 2009 |
|---|---|---|---|
| CO (PPM) | 365* | 412* | 359* |

'*' indicates 'condition 2' status, meaning overheated cellulose insulation (transformer insulation degradation, and eventual transformer failure) NOTE: 'PPM' means 'Parts Per Million'

Note that small changes in DGA readings can be attributed to change in solubility of gases into mineral oil based on the oil temperature. For example, solubility of hydrogen into mineral oil can increase up 79% over an oil temperature change from 0C to 80C.

**Table-14: College MS Transformer TR3 DGA results**

| TR3 | December 15, 2009 | April 8, 2009 |
| --- | --- | --- |
| Hydrogen (PPM) | 217* | 1,619** |

'*' indicates 'condition 2' status, and '**' indicates 'condition 3' status meaning partial discharge activity (intermittent conduction between windings, leads to eventual transformer failure)

Note that large changes in DGA readings can be caused by contamination during the oil sampling. Regardless of the large difference in the reading in the above results, the lower value in the more recent reading continues to indicates partial discharge activity is occurring between the transformer windings.

The significant number of assets past their useful lives and assets projected to fail, along with the safety concerns and increased complexity of box construction when compared to 13.8kV overhead construction warrants executing these jobs.

Investing in converting legacy 4kV system to 13.8kV and decommissioning the station is recommended.

## 2. Partial Conversion of Hazelwood MS (X11422, X12445)

### 2.1. Objective

The objective of these jobs is to prepare Hazelwood MS for conversion from 4kV to 13.8kV to mitigate the safety concerns from working around energized box construction, which is found on feeders from Hazelwood MS. The benefits of completing this work are the elimination of safety hazards, improved reliability and, when conversion is complete, reduced line losses. The equipment that is being replaced is overhead 4kV distribution plant which includes conductor, poles, transformers and switches.

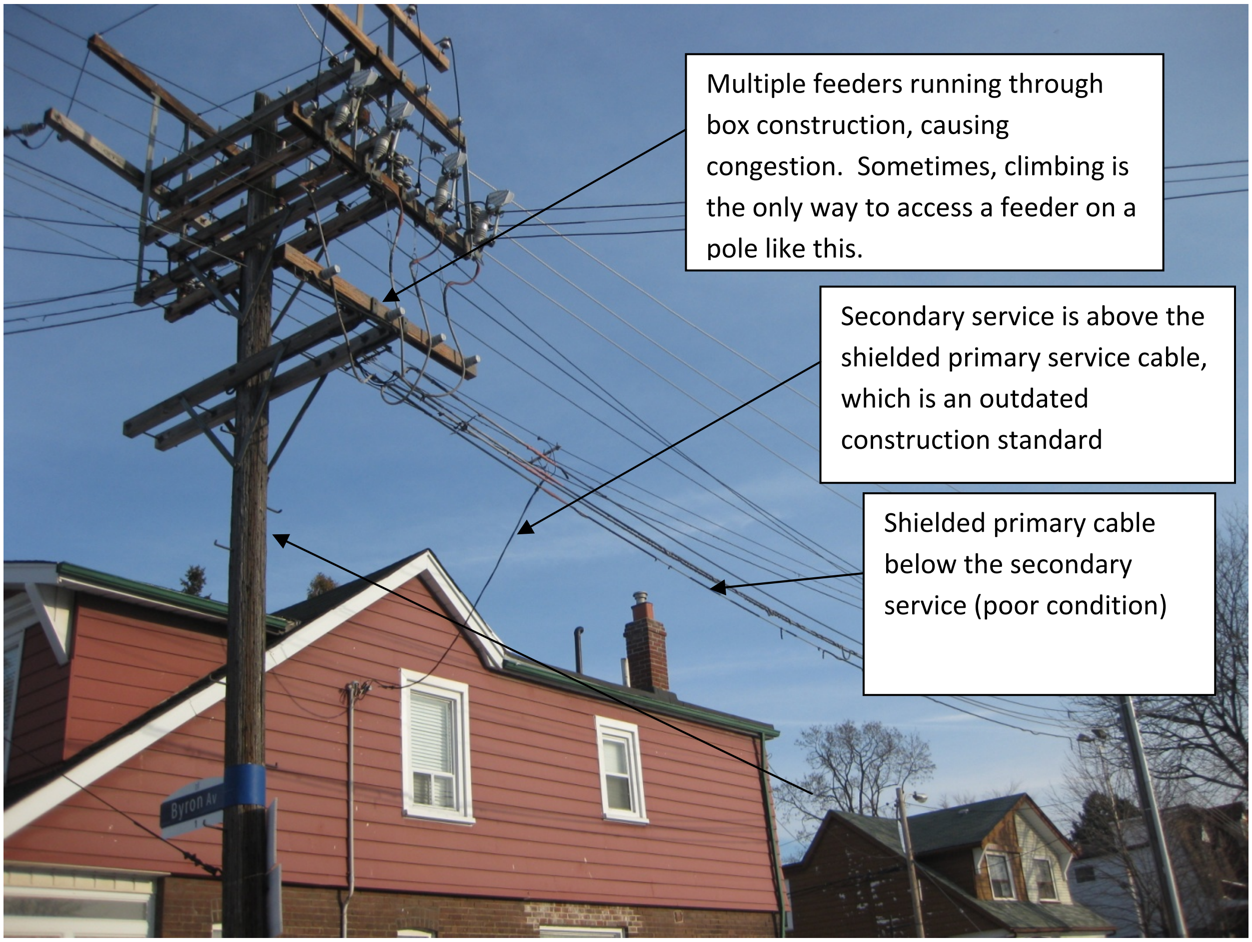



**Figure 13: Typical box construction pole from B3HW (January 16, 2012)**

When compared to 4kV box construction feeders, current construction standards for 13.8kV overhead feeders are much less congested in terms of primary and secondary conductors, and provide a safer work environment for field crews as a result. Figure 14 provides an example of a typical 13.8kV feeder.

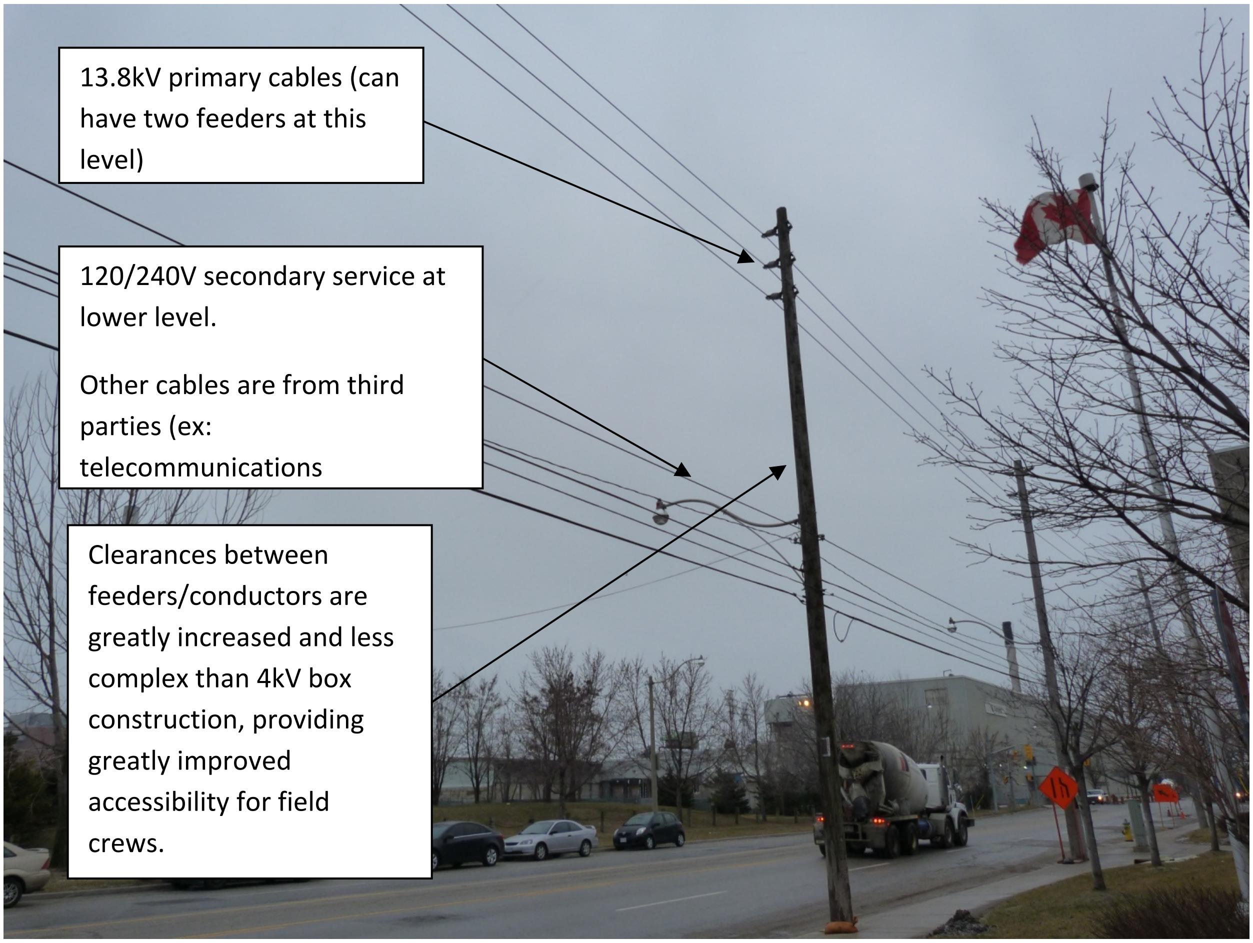



**Figure 14: Typical 13.8kV Overhead Construction (January 24, 2012)**

There are also workplace safety concerns associated with 4kV assets not meeting the current THESL standard, as described above in Table 3. Examples of such assets include porcelain insulators (should be polymer type, see C for safety bulletin), and 'Positect' type switches that present a potential safety risk, as field crews operate the switches while directly in front of them (arc flash hazard). See Figure 15 for an example of a 'Positect' switch.


**Figure 15: 'Positect' Disconnect Switch on B3HW (January 16, 2012)**


1 **Figure 16: Non-Standard Porcelain Insulator on B5HW (January 16, 2012)**


**Figure 17: Obsolete Disconnect Switch on B5HW (January 16, 2012)**

A significant number of assets on all box construction feeders in the city are over 60 years old, and are now past their useful life. Figure 18 and Figure 19 show examples of assets fed from Hazelwood MS which are past useful life.


**Figure 18: Exposed Rebar on B5HW (January 16, 2012)**


**Figure 19: Poor Condition Equipment on B3HW (January 16, 2012)**

## 2.2. Historical Reliability Performance

**Table-15: Historical Reliability - Hazelwood MS**

| HISTORICAL RELIABILITY PERFORMANCE – Hazelwood MS | | | |
|---|---|---|---|
| **Reliability Metric** | **2008** | **2009** | **2010** |
| Feeder CI | 1,764 | 0 | 1,195 |
| Feeder CHI | 1,767 | 0 | 975 |

‘CI’ stands for ‘Customers Interrupted’ and ‘CHI’ stands for ‘Customer Hours Interrupted’

### 2.3. Scope of Work

The scope of work in X11422, X12445 is to convert B7HW, B3HW and B5HW respectively from 4.16kV to 13.8kV.

**Table -16: Assets to be Replaced - Hazelwood MS**

| **Assets to be upgraded from 4.16kV to 13.8kV** | | | |
|---|---|---|---|
| X11422 | | X12445 | |
| Poles | 96 | Poles | 200 |
| Switches | 8 | Switches | 7 |
| Transformers | 27 | Transformers | 23 |
| Conductor | 2.4 km | Conductor | 6.8 km |

### 2.4. Locations

The assets being replaced belong to B3HW, B5HW and B7HW and they are bounded by the area Danforth Ave in the North, Jones Ave in the west, Felsted in the south and Coxwell in the east.

### 2.5. Required Capital Costs

**Table-17: Capital Costs - Hazelwood MS**

| **Job Estimate Number** | **Job Phase** | **Cost ($, millions)** | **Projected Year of Execution** |
|---|---|---|---|
| 18629 | X11422 – B7HW OH Feeder Voltage Conversion | $1.82 | 2012 |
| 20919 | X12445 – B3HW, B5HW OH Feeder Voltage Conversion | $3.42 | 2012 |
| **Total:** | | $5.23 | |

### 2.6. Preferred Option for Feeders Supplied by Hazelwood MS (B3HW, B5HW, B7HW)

Maintenance reports suggest that station assets in Hazelwood MS need to be replaced in the 2013 timeframe, as shown in Table-7, Table-8, and Table-9. It should be noted that these feeders need to be converted prior to 2013 in order to avoid 'like-for-like' replacement of legacy Hazelwood MS equipment by 2013.

Furthermore, the significant number of assets past useful life, along with the potential safety risks and increased complexity of box construction when compared to 13.8kV overhead construction warrants executing these jobs.

Decommissioning Hazelwood MS will also allow THESL to use MS land for other projects in the downtown area. See D for excerpt from a presentation that lists Hazelwood MS as a future switching location.

## 3. Partial Conversion of Junction MS (X12325, X12193, X13177, X13178, X12161 and X12194)

### 3.1. Objectives

The objective of these jobs is to prepare Junction MS for conversion from 4.16kV to 13.8kV to mitigate the safety concerns from working around energized box construction, which is found on feeders from Junction MS. The benefits of completing this work are the mitigation of potential safety risks, improved reliability and, when conversion is complete, reduced line losses. The equipment that is being replaced is overhead 4kV distribution plant which includes conductor, poles, transformers and switches. Figure 20 shows an example of a typical box construction pole from Junction MS.

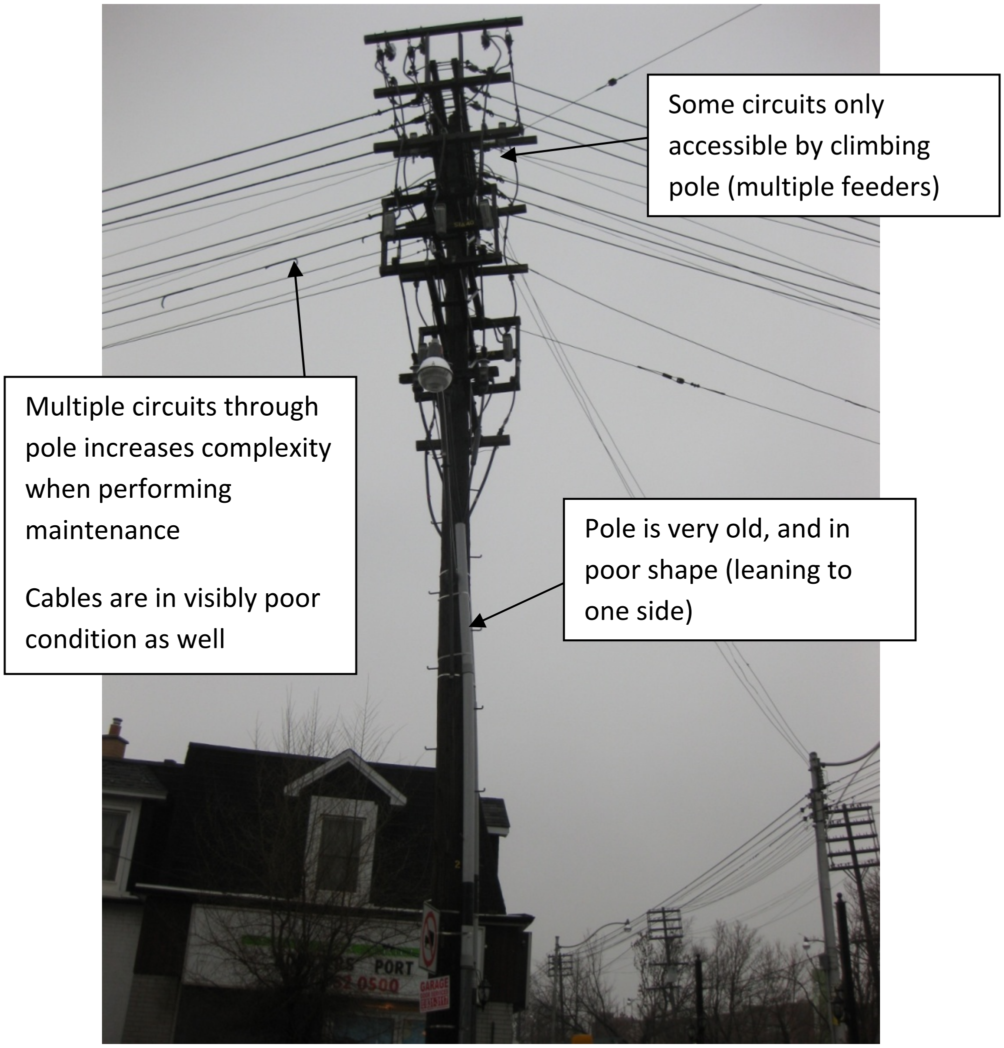



**Figure 20: Pole from Feeder in Junction MS (January 17, 2012)**

### 3.2. Historical Reliability Performance

**Table-18: Historical Reliability - Junction MS**

| HISTORICAL RELIABILITY PERFORMANCE – Junction MS | | | |
|---|---|---|---|
| **Reliability Metric** | **2008** | **2009** | **2010** |
| Feeder CI | 7,827 | 16,015 | 9,478 |
| Feeder CHI | 5,074 | 46,480 | 16,332 |

‘CI’ stands for ‘Customers Interrupted’ and ‘CHI’ stands for ‘Customer Hours Interrupted’

### 3.3. Scope of Work

The scope of work in the following jobs is to convert most of the feeders from Junction MS to 13.8kV voltage.

- X12325: B15J
- X12193: B5J
- X13177: B8J
- X13178: B9J
- X12161: B11J
- X12194: B10J

**Table-19: Assets to be Replaced - Junction MS**

| Assets to be upgraded from 4.16kV to 13.8kV | |
|---|---|
| Information from six conversion jobs | |
| Poles | 586 Poles |
| Conductor | 17.6 km |

### 3.4. Locations

The assets being replaced belong to B5J, B8J, B9J, B10J, B11J and B15J in the general area of Keele and Bloor Street.

### 3.5. Required Capital Costs

**Table-20: Capital Costs - Junction MS**

| Job Estimate Number | Job Phase | Cost ($, millions) | Projected Year of Execution |
|---|---|---|---|
| 20365 | X12325 – B15J OH Feeder Voltage Conversion | $3.64 | 2012 |
| 20368 | X12193 – B5J OH Feeder Voltage Conversion | $1.44 | 2013 |
| 20548 | X13177 – B8J OH Feeder Voltage Conversion | $0.21 | 2013 |
| 20476 | X13178 – B9J OH Feeder Voltage Conversion | $0.73 | 2013 |
| 20369 | X12161 – B11J OH Feeder Voltage Conversion | $2.14 | 2014 |
| 20366 | X12194 – B10J OH Feeder Voltage Conversion | $1.68 | 2014 |
| **Total:** | | **$9.85** | |

### 3.6. Preferred Option for Feeders Supplied by Junction MS (B15J, B5J, B8J, B9J, B10J, B11J)

The significant number of assets past useful life, along with the potential safety risks and increased complexity of box construction when compared to 13.8kV overhead construction (see Table-3 and Table-8) warrants the undertaking of this conversion. Junction MS, which supplies these feeders, is planned to be decommissioned in the future.

## 4. Partial Conversion of Keele and St. Clair MS (X11369)

### 4.1. Objectives

The objective of this work is to prepare Keele and St. Clair MS for conversion from 4.16kV to 13.8kV to mitigate the safety concerns from working around energized box construction which is found on these feeders. The benefits of completing this work are the elimination of safety hazards, improved reliability and, when conversion is complete, reduced line losses. The equipment that is being replaced is overhead 4kV distribution plant which includes conductor, poles, transformers and switches.

### 4.2. Historical Reliability Performance

**Table-21: Historical Reliability - B1KS and B4KS**

| HISTORICAL RELIABILITY PERFORMANCE – B1KS, B4KS | | | |
|---|---|---|---|
| **Reliability Metric** | **2008** | **2009** | **2010** |
| Feeder CI | 1,745 | 2,538 | 1,102 |
| Feeder CHI | 3,241 | 1,743 | 2,931 |

‘CI’ stands for ‘Customers Interrupted’ and ‘CHI’ stands for ‘Customer Hours Interrupted’

### 4.3. Scope of Work

The scope of work in X11369 is to convert B1KS and B4KS from 4.16kV to 13.8kV.

**Table-22: Assets to be Replaced - B1KS and B4KS**

| Assets to be upgraded from 4.16kV to 13.8kV | |
|---|---|
| Poles | 172 |
| Switches | 22 |
| Transformers | 42 |
| Conductor | 5,157 m |

### 4.4. Locations

The assets being replaced belong to B1KS and B4KS in the area bordered by Northland Avenue in the North, Weston Road in the west, Adrian Avenue in the South and Wilshire Avenue in the east.

### 4.5. Required Capital Costs

**Table-23: Capital Costs**

| Job Estimate Number | Job Phase | Cost ($, millions) | Projected Year of Execution |
|---|---|---|---|
| 18740 | X11369 – KS MS Voltage Conversion from 4kV to 13.8kV System. TOB1KS, TOB4KS | $3.45 | 2013 |

### 4.6. Preferred Option for Feeders Supplied by Keele and St. Clair MS (B1KS, B4KS)

The significant number of assets past useful life, along with the potential safety risks and increased complexity of box construction when compared to 13.8kV overhead construction warrants executing these jobs.

Furthermore, the 4-wire 13.8kV feeders currently supplying Keele and St. Clair MS will be available once the station is decommissioned, and will be integral in converting other 4kV box construction feeders to 13.8kV beyond 2014 (specifically 4kV box construction feeders from Wiltshire MS), as 13.8kV 4-wire overhead feeders were not previously there.

### 5. Partial Conversion of Millwood MS (X11452*, X12129*)

#### 5.1. Objectives

The objective of these jobs is to prepare Millwood MS for conversion from 4.16kV to 13.8kV to mitigate the safety concerns from working around energized box construction, which is found on feeders from Millwood MS. The benefits of completing this work are the mitigation of potential safety risks, improved reliability and, when conversion is complete, reduced line losses. The equipment that is being replaced is overhead 4kV distribution plant which includes conductor, poles, transformers and switches.

#### 5.2. Historical Reliability Performance

**Table-24: Historical Reliability - Millwood MS**

| HISTORICAL RELIABILITY PERFORMANCE – B2MD, B3MD | | | |
|---|---|---|---|
| Reliability Metric | 2008 | 2009 | 2010 |
| Feeder CI | 0 | 1,010 | 0 |
| Feeder CHI | 0 | 1,128 | 0 |

‘CI’ stands for ‘Customers Interrupted’ and ‘CHI’ stands for ‘Customer Hours Interrupted’

#### 5.3. Scope of Work

The scope of work of jobs X11452, X12129 includes the conversion of B2MD and B3MD respectively from 4.16kV to 13.8kV. Jobs X11452 and X12129 also involve one or more feeders from Merton station, as discussed below.

**Table-25: Assets to be Replaced - Millwood MS**

| Assets to be upgraded from 4.16kV to 13.8kV | |
|---|---|
| Poles | 253 |
| Switches | 42 |
| Transformers | 61 |
| Conductor | 7,576 m |

## 5.4. Locations

Boundaries for this work are outlined in Table-26.

**Table-26: Project Boundaries for Millwood MS Conversion**

| Project | Feeders | North Boundary | South Boundary | East Boundary | West Boundary |
|---|---|---|---|---|---|
| X11452 | B1MR | Manor Road East | Belsize Drive | Bayview Avenue | Mt. Pleasant Road |
| X12129 | B2MR | Millwood Road | Merton Road | Bayview Avenue | Mt. Pleasant Road |

## 5.5. Required Capital Costs

**Table-27: Capital Costs**

| Job Estimate Number | Job | Cost ($, millions) | Projected Year of Execution |
|---|---|---|---|
| 18738 | X11452 Millwood MS: B2MD, B1MR Partial Voltage Conversion* | $2.73 | 2013 |
| 19632 | X12129 Millwood MS: B3MD, Merton MS B2MR Voltage Conversion* | $4.84 | 2014 |
| **Total** | | $7.57 | |

*Jobs convert feeders in both Merton MS and Millwood MS. Job cost included in Merton MS as well

## 5.6. Preferred Option for Feeders Supplied by Millwood MS (B2MD, B3MD)

The information on the preferred option for Millwood MS is discussed in section 6.6 below in association with the work on feeders from Merton MS.

## 6. Partial Conversion of Merton MS (X11452, X12129, X12142, X12145, X12174, X12143)

### 6.1. Objectives

The objective of these jobs is to prepare Merton MS for conversion from 4.16kV to 13.8kV to mitigate the potential safety risks from working around energized box construction, which is found on feeders from Merton MS. Jobs X11452 and X12129 also involve one or more feeders from Millwood station. The benefits of completing this work are mitigation of potential safety risks, improved reliability and, when conversion is complete, reduced line losses. The equipment that is being replaced is overhead 4kV distribution plant which includes conductor, poles, transformers and switches.

### 6.2. Historical Reliability Performance

**Table-28: Historical Reliability - Merton MS**

| HISTORICAL RELIABILITY PERFORMANCE – B1MR, B2MR, B3MR, B5MR | | | |
|---|---|---|---|
| **Reliability Metric** | **2008** | **2009** | **2010** |
| Feeder CI | 2,910 | 5,158 | 3,099 |
| Feeder CHI | 785 | 5,545 | 4,321 |

### 6.3. Scope of Work

The scope of work for the jobs listed in Table-29 is to convert feeders B1MR, B2MR, B3MR, B5MR from 4.16kV to 13.8kV.

**Table-29: Assets to be Replaced - Merton MS**

| Assets to be upgraded from 4.16kV to 13.8kV | |
|---|---|
| Poles | 637 |
| Switches | 97 |
| Transformers | 132 |
| Conductor | 19,108 m |

### 6.4. Locations

The boundaries for this work are outlined in Table-30.

**Table-30: Project Boundaries for Merton MS Conversion**

| Project | Feeders | North Boundary | South Boundary | East Boundary | West Boundary |
|---|---|---|---|---|---|
| X11452 | B1MR | Manor Road East | Belsize Drive | Bayview Avenue | Mt.Pleasant Road |
| X12129 | B2MR | Millwood Road | Merton Road | Bayview Avenue | Mt.Pleasant Road |
| X12142 | B2MR | Moore Avenue | St.Clair Avenue East | Bayview Avenue | Mt.Pleasant Road |
| X12145 | B3MR | Moore Avenue | Garfield Avenue | Bayview Avenue | Avoca Avenue |
| X12174 | B5MR | Various | | | |
| X12143 | B1MR,B2MR | Manor Road | Davisville Avenue | Mt.Pleasant Road | Yonge Street |

### 6.5. Required Capital Costs

**Table-31: Capital Costs**

| Job Estimate Number | Job | Cost ($, millions) | Projected Year of Execution |
|---|---|---|---|
| 18738 | X11452 Millwood MS: B2MD, B1MR Partial Voltage Conversion* | $2.73 | 2013 |
| 19632 | X12129 Millwood MS: B3MD, Merton MS B2MR Voltage Conversion* | $4.84 | 2014 |
| 19712 | X12142 Convert 4kV Merton Feeder B2MR to 13.8kV System B2MR | $0.62 | 2014 |
| 19711 | X12145 Convert 4kV Merton Feeder B3MR to 13.8kV System B2MR | $1.11 | 2014 |
| 19977 | X12174 Convert 4kV Merton MS Feeder B5MR to 13.8kV System TOB5MR | $3.78 | 2014 |
| 19706 | X12143 Convert 4kV Merton Feeder B1MR, B2MR to 13.8kV System B1MR B2MR | $2.24 | 2014 |
| **Total** | | **$15.31** | |

*Jobs convert feeders in both Merton MS and Millwood MS. Job cost included in Millwood MS as well.

### 6.6. Preferred Option for Feeders Supplied by Millwood MS (B2MD, B3MD) and Merton MS (B1MR, B2MR, B3MR, B5MR)

Maintenance reports suggest that station assets in Merton MS are deteriorating, as shown in Table-32.

**Table-32: Merton MS Transformer TR1 DGA results**

| TR1 | March 5, 2010 |
|---|---|
| CO(PPM) | 361* |

'*' indicates 'condition 2' status, meaning overheated cellulose insulation (transformer insulation degradation, and eventual transformer failure)

The significant number of assets past useful life, along with the safety concerns and increased complexity of box construction when compared to 13.8kV overhead construction warrants executing these jobs.

## 7. Partial Conversion of Dufferin MS (X12054, X12506, X14202)

### 7.1. Objectives

The objective of these jobs is to prepare Dufferin MS for conversion from 4.16kV to 13.8kV to mitigate potential safety risks from working around energized box construction. The expected benefits of completing this work are the mitigation of potential safety risks, improved reliability and, when conversion is complete, reduced line losses. .

## 7.2. Historical Reliability Performance

**Table-33: Historical Reliability - Dufferin MS**

| HISTORICAL RELIABILITY PERFORMANCE – B3DN, B4DN and B5DN | | | |
|---|---|---|---|
| **Reliability Metric** | **2008** | **2009** | **2010** |
| Feeder CI | 0 | 0 | 978 |
| Feeder CHI | 0 | 0 | 56,724 |

## 7.3. Project Scope of Work

The scope of work described in X12054, X12506 and X14202 is to convert the Dufferin MS feeders B-3-DN, B-4-DN and B-5-DN from 4.16kV to 13.8kV system.

**Table-34: Assets to be Replaced - Dufferin MS**

| Assets to be upgraded from 4.16kV to 13.8kV system | | | | | |
|---|---|---|---|---|---|
| X12054 | | X12506 | | X14202 | |
| Poles | 149 | Poles | 45 | Poles | 86 |
| Switches | 17 | Switches | 1 | Switches | 17 |
| Transformers | 28 | Transformers | 6 | Transformers | 12 |
| Conductor | 5.03 km | Conductor | 1.15 km | Conductor | 2.03 km |

## 7.4. Locations

The assets being replaced belong to feeders B-3-DN, B-4-DN and B-5-DN. B-3-DN is bounded by Shanly St in the north, Brock Ave in the west, Sylvan Ave in the south and Dufferin St in the east. B-4-DN is located around the intersection of Margueretta St and Bloor St West. B-5-DN is located around the intersection of Harbord and Shaw Streets.

### 7.5. Required Capital Costs

**Table-35: Capital Costs**

| Job Estimate Number | Job Phase | Cost ($, millions) | Projected Year of Execution |
|---|---|---|---|
| 18758 | X12054 – Voltage Conversion from 4kV to 13.8kV (B5DN) | $6.03 | 2013 |
| 21101 | X12506 – Voltage Conversion from 4kV to 13.8kV (B4DN) | $0.17 | 2013 |
| 23358 | X14202 – Voltage Conversion from 4kV to 13.8kV (B3DN) | $2.07 | 2014 |
| **Total:** | | **$8.27** | |

### 7.6. Preferred Option for Feeders Supplied by Dufferin MS (B3DN, B4DN, B5DN)

Maintenance reports suggest that station assets in Dufferin MS are deteriorating, as shown in Table-36.

**Table-36: Dufferin MS Transformer TR1 DGA results**

| TR1 | April 8, 2009 | March 23, 2006 |
|---|---|---|
| CO(PPM) | 386* | 398* |

'*' indicates 'condition 2' status, meaning overheated cellulose insulation (transformer insulation degradation, and eventual transformer failure)

Note that small changes in DGA readings can be caused by changes in solubility of gases into mineral oil based on the oil temperature. For example, solubility of hydrogen into mineral oil can increase up 79% over an oil temperature change from 0C to 80C.

The significant number of assets past their useful lives and assets projected to fail, along with the potential safety risks and increased complexity of box construction when compared to 13.8kV overhead construction warrants executing these jobs.

Decommissioning Dufferin MS will also allow THESL to use MS land for other projects in the downtown area. See D for excerpt from a presentation that lists Dufferin MS as a future switching location.

## 8. Partial Conversion of Dupont MS (X12055, X13176, X13003)

### 8.1. Project Objectives

The objective of these jobs is to prepare Dupont MS for conversion from 4.16kV to 13.8kV system to mitigate potential safety risks from working around energized box construction. The benefits of completing this work are the mitigation of safety risks, improved reliability and, when conversion is complete, reduced line losses.

### 8.2. Historical Reliability Performance

**Table-37: Historical Reliability - Dupont MS**

| HISTORICAL RELIABILITY PERFORMANCE – B2DU, B4DU and B6DU | | | |
|---|---|---|---|
| **Reliability Metric** | **2008** | **2009** | **2010** |
| Feeder CI | 2,604 | 1,806 | 835 |
| Feeder CHI | 79,190 | 272,672 | 51,770 |

### 8.3. Scope of Work

The scope of work described in X12055, X13176 and X13003 is to convert the Dupont MS feeders B-2-DU, B-4-DU and B-6-DU from 4.16kV to 13.8kV system.

**Table-38: Assets to be Replaced - Dupont MS**

| Assets to be upgraded from 4.16kV to 13.8kV system | | | | | |
|---|---|---|---|---|---|
| X12055 | | X13176 | | X13003 | |
| Poles | 226 | Poles | 228 | Poles | 208 |
| Switches | 31 | Switches | 28 | Switches | 21 |
| Transformers | 38 | Transformers | 46 | Transformers | 39 |
| Conductor | 4.08 km | Conductor | 5.12 km | Conductor | 4.66 km |

### 8.4. Locations

The assets being replaced belong to feeders B-2-DU, B-4-DU and B-6-DU. B-2-DU is located around the intersection of Garnet Ave and Shaw Street. B-4-DU is located around the intersection of Davenport Rd and Ossington Avenue. B-6-DU is bounded by the area of Rosemount Ave in the north, Westmount Avenue in the west, Davenport Rd in the south and Winona Dr in the east.

### 8.5. Required Capital Costs

**Table-39: Capital Costs**

| Job Estimate Number | Job Phase | Cost ($, millions) | Projected Year of Execution |
|---|---|---|---|
| 20992 | X12055 – Voltage Conversion from 4kV to 13.8kV (B2DU) | $3.23 | 2014 |
| 19966 | X13176 – Voltage Conversion from 4kV to 13.8kV (B4DU) | $3.67 | 2014 |
| 19984 | X13003 – Voltage Conversion from 4kV to 13.8kV (B6DU) | $2.96 | 2014 |
| | **Total:** | **$9.87** | |

### 8.6. Preferred Option for Feeders Supplied by Dupont MS (B-2-DU, B-4-DU and B-6-DU)

The significant number of assets past useful life, along with the safety concerns and increased complexity of box construction when compared to 13.8kV overhead construction warrants the undertaking of this conversion. Stations supplying these feeders (Dupont MS) are planned to be decommissioned going forward.

## 9. Partial Conversion of High Level MS (X13362)

### 9.1. Objectives

The objective of this work is to convert this feeder from 4.16kV to 13.8kV. Merton MS cannot be decommissioned before this Highlevel MS feeder is converted to 13.8kV, as B4MR from Merton MS is the standby feeder for B7H. This job will also mitigate the potential safety risks from working around energized box construction. The expected benefits of completing this work are the mitigation of safety risks, improved reliability and, when conversion is complete, reduced line losses.

### 9.2. Historical Reliability Performance

**Table-40: Historical Reliability - High Level MS**

| HISTORICAL RELIABILITY PERFORMANCE – B-7-H | | | |
|---|---|---|---|
| **Reliability Metric** | **2008** | **2009** | **2010** |
| Feeder CI | 1,196 | 1,794 | 598 |
| Feeder CHI | 26,312 | 88,504 | 29,900 |

### 9.3. Scope of Work

The scope of work described in X13362 is to completely convert the High Level feeder B-7-H from 4.16kV to 13.8kV.

**Table-41: Assets to be Replaced - High Level MS**

| **Assets to be upgraded from 4.16kV to 13.8kV system** | |
|---|---|
| X13362 | |
| Poles | 87 |
| Switches | 10 |
| Transformers | 25 (1-Phase), 1 (3-Phase) |
| Conductor | 1.581 km (1-Phase), 1.315 km (3-Phase) |

### 9.4. Locations

The assets being replaced belong to feeder B-7-H. The overhead section of this feeder is located the intersection of Inglewood Drive and Maclennan Avenue. There is an underground portion to feeder B7H that runs from Highlevel MS (MacPherson Avenue and Rathnelly Avenue) east along Cottingham Street/Shaftesbury Avenue/Summerhill Avenue to a riser at the intersection of Summerhill Avenue and MacLennan Avenue. Because the load on this feeder will be taken on by 13.8kV feeders in the vicinity (A22L and A360CS), this underground portion will be removed.

### 9.5. Required Capital Costs

**Table-42: Capital Costs**

| **Job Estimate Number** | **Job Phase** | **Cost ($, millions)** | **Projected Year of Execution** |
|---|---|---|---|
| 24076 | X13362 – Convert 4kV B7H feeder to 13.8kV system (TOB7H) | $2.38 | 2014 |
| **Total:** | | **$2.38** | |

### 9.6. Preferred Option for Feeder Supplied by High Level MS (B-7-H)

The significant number of assets past useful life, along with the potential safety risks and increased complexity of box construction when compared to 13.8kV overhead construction warrants the undertaking of this conversion. High Level MS supplying this feeder is planned to be decommissioned going forward.

## V APPENDICES

Appendix A: EUSR Rule 129

Appendix B: ESA building clearance standard

Appendix C: Safety Bulletin for Porcelain Insulators

Appendix D: Excerpt from downtown contingency presentation

Appendix E: Clearances between conductors on overhead 13.8kV (latest construction standards)

Appendix F: Example of feeder request where no capacity was available

Appendix G: News report regarding extensive outage at Dufferin TS in 2009

Appendix H: Calculation of Efficiency of 13.8kV feeders vs. 4kV feeders

Appendix I: *4kV vs. 13.8kV System Losses* by Romano Sironi

Appendix J: Box Construction Business Case Evaluation (BCE) Process

Appendix K: Joint Health and Safety Committee Notes, page 8

## Appendix A

## EUSR Rule 129

Toronto Hydro-Electric System Limited
EB-2012-0064
Tab 4, Schedule B5, Appendix A
ORIGINAL (6 pages)

b) the equipment is physically removed from the immediate vicinity of any source of electrical, dynamic or potential energy, has no ready means of connection, and has had all stored energy discharged.

## 129 Safe Limits of Approach

1. The limits specified in the following tables are the minimum requirements. To obtain the safest work environment, ***workers*** must maintain maximum clearance, and use equipment and procedures adequate to protect against electrical shock or burns.

<table>
<tr><th colspan="7">LIMITS OF APPROACH<br>Maintain Maximum Clearances and Install Barriers Where Practical</th></tr>
<tr><th colspan="4">Personnel Zones</th><th colspan="3">Mobile Work Equipment</th></tr>
<tr><th>Voltages</th><th>OHSA Minimum</th><th>Authorized Worker</th><th>Restricted Zone</th><th>OHSA</th><th>Non-Insulated Booms</th><th>Certified Insulated A.D.</th></tr>
<tr><td>750V to 15kV</td><td rowspan="4">>3.0m (10 ft.)</td><td rowspan="2">>0.9m (3 ft.)</td><td>0.9m to 0.3m (3 ft. to 1ft.)</td><td rowspan="4">>3.0m (10 ft.)</td><td rowspan="2">>0.9m (3 ft.)</td><td>>0.3m (1 ft.)</td></tr>
<tr><td>>15kV to 35kV</td><td>0.9m to 0.45m (3 ft. to 1.5 ft.)</td><td rowspan="2">>0.45m (1.5 ft.)</td></tr>
<tr><td>>35kV to 50kV</td><td>>1.2m (4 ft.)</td><td>1.2m to 0.6m (4 ft. to 2 ft.)</td><td>>1.2m (4 ft.)</td></tr>
<tr><td>>50kV to 150kV</td><td>>1.5m (5 ft.)</td><td>1.5m to 0.9m ( 5 ft. to 3 ft.)</td><td>>2.4m (8 ft.)</td><td>>0.9m (3 ft.)</td></tr>
<tr><td>>150kV to 250kV</td><td>>4.5m (15 ft.)</td><td>>2.1m (7 ft.)</td><td>2.1m to 1.2m (7 ft. to 4 ft.)</td><td>>4.5m (15 ft.)</td><td>>3.0m (10 ft.)</td><td>>1.2m (4 ft.)</td></tr>
<tr><td>>250kV to 550kV</td><td>>6.0m (20 ft.)</td><td>>3.7m (12 ft.)</td><td>3.7m to 2.75m (12 ft. to 9 ft.)</td><td>>6.0m (20 ft.)</td><td>>4.6m (15 ft.)</td><td>>2.75m (9 ft.)</td></tr>
<tr><td colspan="4">SYMBOLS ≤ less than or equal to<br>> greater than<br>< less than</td><td>cranes, power shovels, back hoes, mech. brush cutter</td><td>RBD, aerial ladder, work platform, uncertified aerial device</td><td>certified and tested by certified laboratory</td></tr>
</table>

**For Authorized Workers:**

- Only ***authorized workers*** or ***workers*** under the continuous direction of an ***authorized worker*** may approach, work or allow material or conductive tools to approach exposed ***energized*** electrical ***apparatus*** to limits stated.
- In planning the task to be performed, consideration must be given to the ***worker***'s position in relation to the exposed ***energized apparatus*** such that movements of the ***worker***'s body or conductive tools, material or vegetation will not result in any encroachment upon these limits.

<table>
<tr><th colspan="7">LIMITS OF APPROACH<br>Maintain Maximum Clearances and Install Barriers Where Practical</th></tr>
<tr><th colspan="4">Personnel Zones</th><th colspan="3">Mobile Work Equipment</th></tr>
<tr><th>Voltages</th><th>OHSA Minimum</th><th>Authorized Worker</th><th>Restricted Zone</th><th>OHSA</th><th>Non-Insulated Booms</th><th>Certified Insulated A.D.</th></tr>
<tr><td>750V to 15kV</td><td rowspan="4">>3.0m (10 ft.)</td><td rowspan="2">>0.9m (3 ft.)</td><td>0.9m to 0.3m (3 ft. to 1ft.)</td><td rowspan="4">>3.0m (10 ft.)</td><td rowspan="2">>0.9m (3 ft.)</td><td>>0.3m (1 ft.)</td></tr>
<tr><td>>15kV to 35kV</td><td>0.9m to 0.45m (3 ft. to 1.5 ft.)</td><td rowspan="2">>0.45m (1.5 ft.)</td></tr>
<tr><td>>35kV to 50kV</td><td>>1.2m (4 ft.)</td><td>1.2m to 0.6m (4 ft. to 2 ft.)</td><td>>1.2m (4 ft.)</td></tr>
<tr><td>>50kV to 150kV</td><td>>1.5m (5 ft.)</td><td>1.5m to 0.9m ( 5 ft. to 3 ft.)</td><td>>2.4m (8 ft.)</td><td>>0.9m (3 ft.)</td></tr>
<tr><td>>150kV to 250kV</td><td>>4.5m (15 ft.)</td><td>>2.1m (7 ft.)</td><td>2.1m to 1.2m (7 ft. to 4 ft.)</td><td>>4.5m (15 ft.)</td><td>>3.0m (10 ft.)</td><td>>1.2m (4 ft.)</td></tr>
<tr><td>>250kV to 550kV</td><td>>6.0m (20 ft.)</td><td>>3.7m (12 ft.)</td><td>3.7m to 2.75m (12 ft. to 9 ft.)</td><td>>6.0m (20 ft.)</td><td>>4.6m (15 ft.)</td><td>>2.75m (9 ft.)</td></tr>
<tr><td colspan="4">SYMBOLS ≤ less than or equal to<br>> greater than<br>< less than</td><td>cranes, power shovels, back hoes, mech. brush cutter</td><td>RBD, aerial ladder, work platform, uncertified aerial device</td><td>certified and tested by certified laboratory</td></tr>
</table>

**For Work in the Restricted Zone:**
The Minimum Clearances provided in the Restricted Zone for ***authorized workers*** may only be reduced when ***authorized workers*** are performing ***approved*** live line procedures, or when ***approved*** cover-up (rated for the voltage being worked on) has been applied. The ***worker*** and equipment must maintain a minimum distance of 15 cm (6 inches) from the installed, ***approved*** barrier(s).

***Authorized workers*** or a ***worker(s)*** in training under the continuous direction of an ***authorized worker*** may approach or allow material or conductive tools to approach exposed ***energized*** electrical ***apparatusas*** stated in the Restricted Zone section, only when the following conditions are adhered to:

- for all work up to 50 kV, appropriate rubber gloves must be worn while in the Restricted Zone;
- barriers and/or cover-up must be installed where practical to minimize exposure to ***energized*** electrical apparatus and all ***second points of contact***;
- a ***dedicated observer*** must be in place, who is competent in the task being performed and has no other duties while monitoring the work continuously;
- either the ***worker*** performing the work or the dedicated ***observer*** must have successfully completed the 4th year of a formal Powerline Technician Apprenticeship training program or equivalent; and
- the ***worker's*** position in relation to the exposed energized electrical ***apparatus*** shall be such that movements of the ***worker***'s body or conductive tools, material or vegetation will not result in any encroachment.

| LIMITS OF APPROACH<br>Maintain Maximum Clearances and Install Barriers Where Practical | | | | | | |
|---|---|---|---|---|---|---|
| Personnel Zones | | | | Mobile Work Equipment | | |
| **Voltages** | **OHSA Minimum** | **Authorized Worker** | **Restricted Zone** | **OHSA** | **Non-Insulated Booms** | **Certified Insulated A.D.** |
| 750V to 15kV | >3.0m (10 ft.) | >0.9m (3 ft.) | 0.9m to 0.3m (3 ft. to 1ft.) | >3.0m (10 ft.) | >0.9m (3 ft.) | >0.3m (1 ft.) |
| >15kV to 35kV | | | 0.9m to 0.45m (3 ft. to 1.5 ft.) | | | >0.45m (1.5 ft.) |
| >35kV to 50kV | | >1.2m (4 ft.) | 1.2m to 0.6m (4 ft. to 2 ft.) | | >1.2m (4 ft.) | |
| >50kV to 150kV | | >1.5m (5 ft.) | 1.5m to 0.9m ( 5 ft. to 3 ft.) | | >2.4m (8 ft.) | >0.9m (3 ft.) |
| >150kV to 250kV | >4.5m (15 ft.) | >2.1m (7 ft.) | 2.1m to 1.2m (7 ft. to 4 ft.) | >4.5m (15 ft.) | >3.0m (10 ft.) | >1.2m (4 ft.) |
| >250kV to 550kV | >6.0m (20 ft.) | >3.7m (12 ft.) | 3.7m to 2.75m (12 ft. to 9 ft.) | >6.0m (20 ft.) | >4.6m (15 ft.) | >2.75m (9 ft.) |
| **SYMBOLS** **≤ less than or equal to**<br>**> greater than**<br>**< less than** | | | | cranes, power shovels, back hoes, mech. brush cutter | RBD, aerial ladder, work platform, uncertified aerial device | certified and tested by ***certified laboratory*** |

**Non-Insulated Booms and Non-Insulated Portion of Aerial Devices:**

- Only ***authorized workers*** or ***workers*** under the continuous direction of an ***authorized worker***, are permitted to operate ***non-insulated booms or non-insulated portion of aerial devices*** in ***proximity*** to exposed ***energized apparatus***.
- The distances stated must be strictly followed for all parts of the equipment, including the booms, hoisting cables and any part of the load being hoisted. Additional clearance must allow for any change in boom angle, swing of the hoisting cable and load while it is being moved.
- For hoisting and rigging operations in the ***proximity*** of ***energized*** electrical ***apparatus*** a dedicated signal person must be used.

<table>
<tr><th colspan="7">LIMITS OF APPROACH<br>Maintain Maximum Clearances and Install Barriers Where Practical</th></tr>
<tr><th></th><th colspan="3">Personnel Zones</th><th colspan="3">Mobile Work Equipment</th></tr>
<tr><th>Voltages</th><th>OHSA Minimum</th><th>Authorized Worker</th><th>Restricted Zone</th><th>OHSA</th><th>Non-Insulated Booms</th><th>Certified Insulated A.D.</th></tr>
<tr><td>750V to 15kV</td><td rowspan="4">>3.0m (10 ft.)</td><td rowspan="2">>0.9m (3 ft.)</td><td>0.9m to 0.3m (3 ft. to 1ft.)</td><td rowspan="4">>3.0m (10 ft.)</td><td rowspan="2">>0.9m (3 ft.)</td><td>>0.3m (1 ft.)</td></tr>
<tr><td>>15kV to 35kV</td><td>0.9m to 0.45m (3 ft. to 1.5 ft.)</td><td rowspan="2">>0.45m (1.5 ft.)</td></tr>
<tr><td>>35kV to 50kV</td><td>>1.2m (4 ft.)</td><td>1.2m to 0.6m (4 ft. to 2 ft.)</td><td>>1.2m (4 ft.)</td></tr>
<tr><td>>50kV to 150kV</td><td>>1.5m (5 ft.)</td><td>1.5m to 0.9m ( 5 ft. to 3 ft.)</td><td>>2.4m (8 ft.)</td><td>>0.9m (3 ft.)</td></tr>
<tr><td>>150kV to 250kV</td><td>>4.5m (15 ft.)</td><td>>2.1m (7 ft.)</td><td>2.1m to 1.2m (7 ft. to 4 ft.)</td><td>>4.5m (15 ft.)</td><td>>3.0m (10 ft.)</td><td>>1.2m (4 ft.)</td></tr>
<tr><td>>250kV to 550kV</td><td>>6.0m (20 ft.)</td><td>>3.7m (12 ft.)</td><td>3.7m to 2.75m (12 ft. to 9 ft.)</td><td>>6.0m (20 ft.)</td><td>>4.6m (15 ft.)</td><td>>2.75m (9 ft.)</td></tr>
<tr><td colspan="4">SYMBOLS ≤ less than or equal to<br>> greater than<br>< less than</td><td>cranes, power shovels, back hoes, mech. brush cutter</td><td>RBD, aerial ladder, work platform, uncertified aerial device</td><td>certified and tested by certified laboratory</td></tr>
</table>

**Certified Insulated Aerial Devices:**

- Only ***authorized workers*** or ***workers*** in training under the continuous direction of an ***authorized worker*** are permitted to operate ***certified insulated aerial devices*** in ***proximity*** to exposed ***energized apparatusas*** per the distances specified.
- For voltages up to and including 50 kV, ***approved*** barriers and/or cover-up must be installed when the minimum clearance stated in this table cannot be maintained.
- For voltages where there are no ***approved*** barriers, the stated limits in this table must never be reduced.
- For hoisting and rigging operations in the ***proximity*** of energized electrical ***apparatus*** a dedicated signal person must be used.

<table>
<tr><th colspan="7">LIMITS OF APPROACH<br>Maintain Maximum Clearances and Install Barriers Where Practical</th></tr>
<tr><th colspan="4">Personnel Zones</th><th colspan="3">Mobile Work Equipment</th></tr>
<tr><th>Voltages</th><th>OHSA Minimum</th><th>Authorized Worker</th><th>Restricted Zone</th><th>OHSA</th><th>Non-Insulated Booms</th><th>Certified Insulated A.D.</th></tr>
<tr><td>750V to 15kV</td><td rowspan="4">>3.0m (10 ft.)</td><td rowspan="2">>0.9m (3 ft.)</td><td>0.9m to 0.3m (3 ft. to 1ft.)</td><td rowspan="4">>3.0m (10 ft.)</td><td rowspan="2">>0.9m (3 ft.)</td><td>>0.3m (1 ft.)</td></tr>
<tr><td>>15kV to 35kV</td><td>0.9m to 0.45m (3 ft. to 1.5 ft.)</td><td rowspan="2">>0.45m (1.5 ft.)</td></tr>
<tr><td>>35kV to 50kV</td><td>>1.2m (4 ft.)</td><td>1.2m to 0.6m (4 ft. to 2 ft.)</td><td>>1.2m (4 ft.)</td></tr>
<tr><td>>50kV to 150kV</td><td>>1.5m (5 ft.)</td><td>1.5m to 0.9m ( 5 ft. to 3 ft.)</td><td>>2.4m (8 ft.)</td><td>>0.9m (3 ft.)</td></tr>
<tr><td>>150kV to 250kV</td><td>>4.5m (15 ft.)</td><td>>2.1m (7 ft.)</td><td>2.1m to 1.2m (7 ft. to 4 ft.)</td><td>>4.5m (15 ft.)</td><td>>3.0m (10 ft.)</td><td>>1.2m (4 ft.)</td></tr>
<tr><td>>250kV to 550kV</td><td>>6.0m (20 ft.)</td><td>>3.7m (12 ft.)</td><td>3.7m to 2.75m (12 ft. to 9 ft.)</td><td>>6.0m (20 ft.)</td><td>>4.6m (15 ft.)</td><td>>2.75m (9 ft.)</td></tr>
<tr><td colspan="4">SYMBOLS ≤ less than or equal to<br>> greater than<br>< less than</td><td>cranes, power shovels, back hoes, mech. brush cutter</td><td>RBD, aerial ladder, work platform, uncertified aerial device</td><td>certified and tested by certified laboratory</td></tr>
</table>

## Appendix B

## ESA building clearance standard

(4) Conductors of a secondary line shall have a minimum 6.*1* m measured vertically between the conductors under maximum sag conditions and the ground.

(5) Notwithstanding Subrule (1) for high and low voltage line installations on public right of ways, for the purpose of roadway lighting systems or traffic control systems, CSA 22.3 No.1-06, Overhead systems or the Ontario Provincial Standards shall be permitted.

**75-708 Clearances of conductors from buildings**

(1) An overhead primary line conductor shall be kept at least 3 m at maximum conductor swing measured horizontally from a building.

(2) Primary line conductors shall not be installed over buildings unless the installation is lawful under Rule 2-030, and work shall not begin until the plans and specifications for the work are approved in accordance with Rule 2-010.

(3) No building, mobile home or structure shall be placed or constructed within at least 3 m at maximum conductor swing measured horizontally from the nearest conductor of an overhead primary line.

(4) Where the conductor swing is not known, a distance of 1.8 m shall be used.

(5) An overhead secondary line conductor shall be kept at least 1 m measured horizontally from any building except where necessary to connect to the electrical wiring of a building.

**75-710 Clearances for other structures**

(1) Notwithstanding Rule 36-110, conductors of a primary line shall
- (a) not be located closer than 12 m measured horizontally from silos to the closest conductors, with the conductor at rest;
- (b) not be located over wells from which pump rods may be lifted and come in contact with the conductors;
- (c) have sufficient clearance from free-standing poles that support flood or area lighting, flagpoles, antennae, or other similar structures so as to permit the structure to fall in an arc, without touching the conductors at rest;
- (d) not be located within 6 m, measured horizontally from wind-mills or similar structures to the closest conductor, with the conductor at rest; and
- (e) have a minimum vertical clearance of 3.1 m above fencing at maximum sag.

(2) Conductors of a secondary line shall not be installed closer than 1 m measured horizontally from structures.

(3) The poles and equipment associated with a primary or secondary line shall be located and suitably protected so as to avoid the possibility of damage from contact with vehicles.

**75-712 Tree trimming**

## Appendix C

## Safety Bulletin for Porcelain Insulators

# Bulletin EH&S 2006

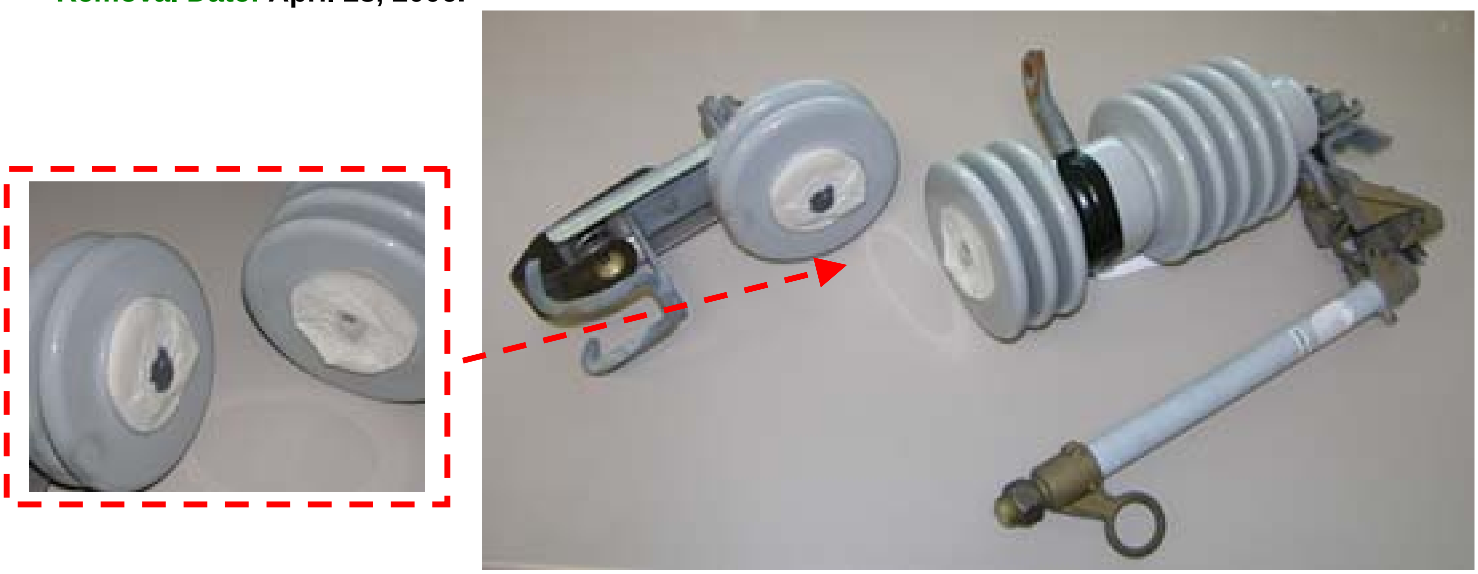
toronto hydro corporation

**"Environmental, Health and Safety Bulletins"** are intended for immediate notification of potential workplace hazards, accidents, injuries, near misses, environmental issues and important information relative to accident prevention.

The information may not be complete initially but the updates shall be made available as progress is made.

***EH&S ISSUE:*** **☐ PROCEDURE ☑ TOOLS/EQUIPMENT ☐ ENVIRONMENTAL ☐ NEAR MISS INCIDENT ☐ ACCIDENT**
***FROM:*** **☐ DISTRIBUTION SERVICES ☐ CUSTOMER SERVICES ☑ CORPORATE EHS ☐ WORKFORCE DEVELOPMENT**

**Posting Date: March 28, 2006.**
**Removal Date: April 28, 2006.**



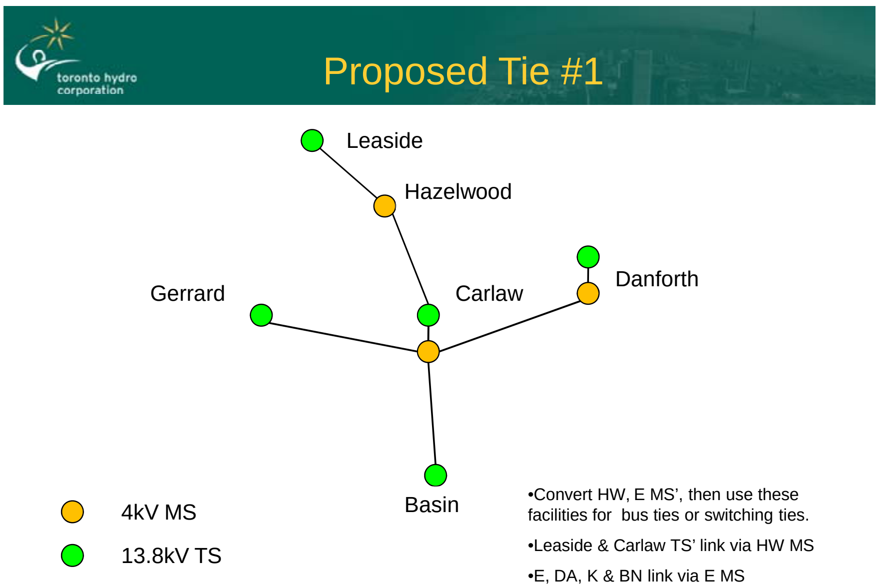
John Boag (ICR High Voltage) has reported that recently there have been a number of failures of the fused porcelain cut out style of switch pictured above. This single-phase switch is bracket-mounted and used to isolate and fuse distribution equipment, in the case of this failure a single-phase standard overhead transformer. The majority of these recent failures have been taken place in the former East York area on 27.6kV circuits. The weak point where the fractures are occurring appears to be where the pin ends inside the glass insulator. Most of these failures haven't occurred during a switching operation.
The Policy and Standards Department is investigating these failures to determine if a pattern is developing with specific equipment. Crews can greatly assist the failure analysis process by indicating the equipment manufacturer in System Response Reports.
When operating high voltage electrical equipment it is critical to remember the importance of obeying the safe limits of approach, use approved safe work procedures, visually inspect equipment for defects before operation and use all required Personal Protective Equipment.

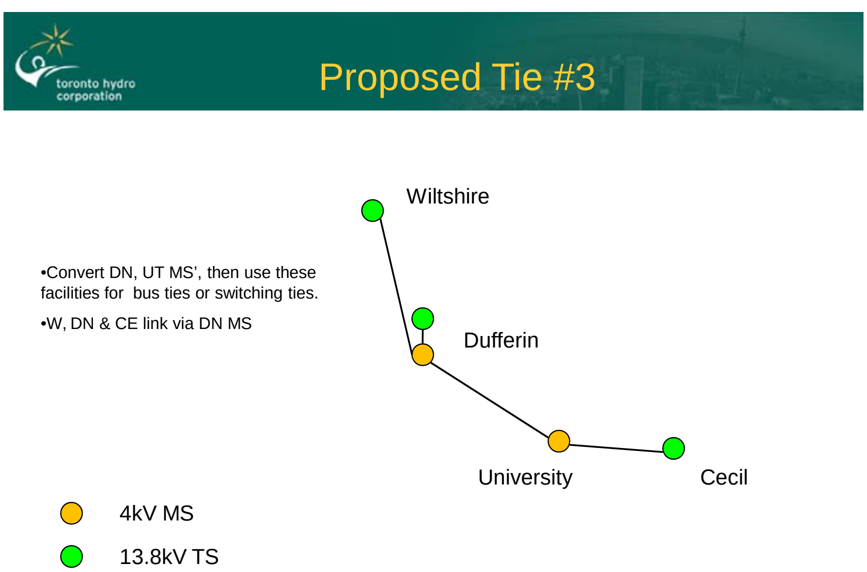
***REMEMBER THE 3 A's OF SAFETY ⬩ AWARENESS ⬩ ATTITUDE ⬩ ACTION***
***ENSURE THAT YOU LIVE AND WORK SAFELY TO PREVENT ACCIDENTS!!!***

## Appendix D

## Excerpt from downtown contingency presentation

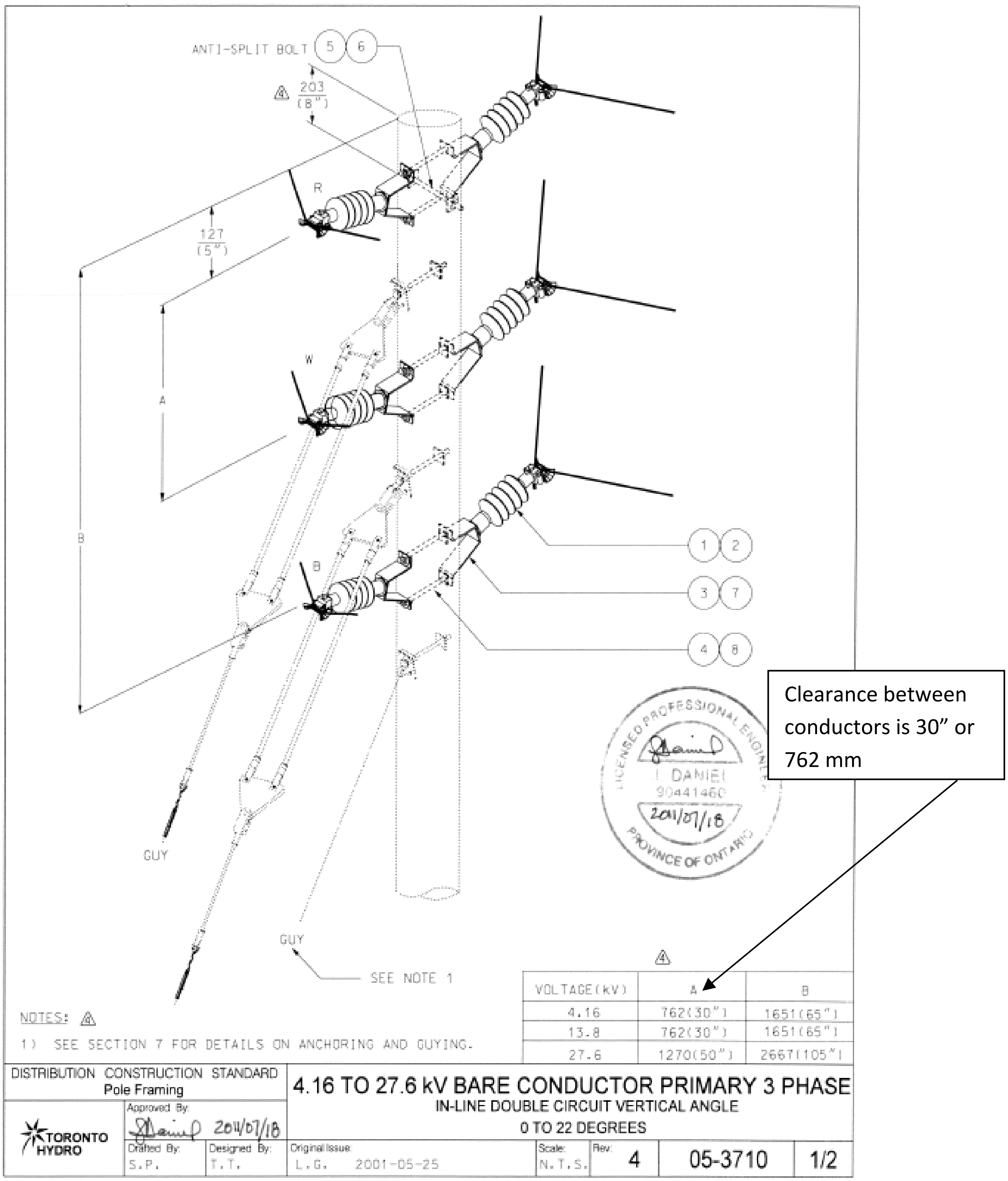
Appendix D shows that Hazelwood MS and Dufferin MS are proposed stations to be decommissioned, whose land shall be used for switching station



**Appendix E**

**Clearances between conductors on overhead 13.8kV (latest construction standards)**



**Appendix F**

**Example of feeder request where no capacity was available**

---

Appendix F shows a customer feeder request that was asking to connect to a 4kV box construction feeder for 750kVA of load.  No capacity was available, and a 13.8kV overhead feeder now has to be extended into the area to accommodate the customer.

# ICM Project | Box Construction Segment



## Feeder Request Form

Investment Planning Department

Date: 2/22/2012

To: DAVID BADREGON Ext. 32203 Dept: Planning Investme

From: JYO HARDUAR Ext. 28046 Dept: CFDC E

Ellipse #

Supply Method: OH (Overhead)

Is Civil Work Required: Yes No

Feeder Request #: 2012-55

Previous FR #:

| Current Status | Date | Changed by: |
|---|---|---|
| APPROVED | 3/9/2012 | PETER COONI |

Energized:

Cancelled:

Deferred to:

**Customer Data:**

Name: URBANCORP CURZON ( District: TORONTO

Street #: 50 Street Name: CURZON ST

**Intersection:**

Street1: QUEEN ST E Street2: DUNDAS ST E

Service Status: Permanent / Temporary In Service: 7/26/2012 Disconnected:

Capital Project in Area:

Exist.Service Size (A): 0

Prop.Service Size (A): 0

Exist. Supply Voltage: 0 V

Prop. Supply Voltage: 0 V

Class: Class 3 (50-999kW

| | Existing (kVA) | Additional (kVA) | Total (kVA) |
|---|---|---|---|
| Winter | 0 | 750 | 750 |
| Summer | 0 | 750 | 750 |

**Transformer Data:**

Type: Pole / Padmount / Vault / Customer Substation

Location: CUSTOMER District: TO

Pole #: Street: CURZON ST

Phase(s): R W B

Size (kVA) Existing:

Proposed: 750

New: 750

Preferred Feeder: B8E Other Feeders:

Comment: PROPOSED CUSTOMER OWNED SUBSTATION 750 KVA - 208V- VOLTAGE FRONTING SITE ONLY 4KV?

Notes: 1. Feeder Check is Valid for one year from approval date.
2. Advise System Planning of any customer info change (load in service date, address)

Planner ___________ JYO HARDUAR Supervisor ___________ DAVE GRAHAM

**Assigned Feeder Information**

| | | | | New |
|---|---|---|---|---|
| Feeder(s) | TOA62E | TOA67E | | |
| Bus: | A8A9 | A8A9 | | |
| Station: | CARLAW TS | CARLAW TS | | |
| District | TO | TO | | TO |
| System Type | UGR | UGR | | |
| Phase(s) | R W B | R W B | R W B | R W B |

Load Transfer Required Feeder Capacity Available: Yes No Vault Cost Sharing

Comments: 750KVA LOAD EXCEEDS MAXIMUM CUSTOMER CONNECTION SIZE ON 4KV FEEDERS SUCH AS PROPOSED B8E FEEDER (WOULD EXCEED CAPACITY OF B8E ANYWAY), AND 13.8KV FEEDER MUST BE USED AS A RESULT. CONSIDER USING A67E AS NORMAL AND A62E AS STANDBY, AS THERE IS CAPACITY ON THOSE FEEDERS

Note that in the 'comments' section, the 4kV feeder in close proximity to customer did not have adequate capacity.

## Appendix G

## News report regarding extensive outage at Dufferin TS in 2009

This article can be found at:

http://toronto.cityguide.ca/dufferin-flood-toronto-blackout-engulfs-half-of-city-toronto-hydro-028444.php

Toronto Hydro-Electric System Limited
EB-2012-0064
Tab 4
Schedule B5, Appendix G
ORIGINAL (4 pages)

# Dufferin Flood: Toronto Blackout Engulfs Half of City – Toronto Hydro?

Yikes! As of 11PM this evening, approximately half of Toronto has gone dark. Details are still very sketchy as to the cause or when power is expected to return. Many people are using their smartphones to access the internet in hopes of getting more information from Toronto Hydro. But still no news as yet.

Within minutes of the lights going out, Twitter users adopted the hash tag #darkTO and are blogging their blackout experience and locations. To get the most updated information, check out Twitter!

More as we hear it...

UPDATE: News is breaking that the power outage is being caused by flooding at the Dufferin & Bloor power station. Here's a pic of the situation, click here.

> As a result, electricity was expected to be off for 18-to-24 hours (in an area bordered by St. Clair Ave., Queen St., Spadina Ave., and Jane St.).
>
> Affected residents were advised to seek shelter with a friend or relative because of the cold and to ensure taps and electronics were turned off.
>
> The outage has forced a shutdown of east-west subway service through the affected area (from the Jane to Bathurst stations). About 40 shuttle buses were expected to carry passengers through the morning rush.

We've also received word of numerous Toronto District School Board and Catholic Board school closures as a result of the power outage which is still ongoing. Here is a list of schools that are *closed* for today.

Alexander Muir/Gladstone Ave J&S PS
Annette Street J&S PS (same complex as High Park Alt School JR)
Bickford Centre (same complex as West End Alt SS)
Bloor CI
Brock JPS
Brockton HS
Central Technical School
Dewson Street JPS
Dovercourt JPS

A blogging guide to the city of Toronto, Ontario.

send tips/stories to tips@cityguide.ca
contact us click here.

LANGUAGE
En Français

SYNDICATION
All feeds: click here.

DAILYPIXEL NETWORK
2010Vancouver.ca
Airport.ca
Archive.ca
BallPimp.ca
CityGuide.ca/CALGARY
Canuck.ca
Dailypixel.ca
Dial.ca
Engagements.ca
FluPandemic.ca
Footblog.ca
Forks.ca
Gadget.ca
Gimme.ca
Greetings.ca
Hell.ca
Hugg.ca
CityGuide.ca/KELOWNA
Lease.ca
Meme.ca
Naturopath.ca
PrimeMinister.ca
Profit.ca
RRSPS.ca
SearchEngine.ca
Stare.ca
Stylish.ca
Superwoman.ca
CityGuide.ca/TORONTO
Video.ca
VirtualReality.ca
Wager.ca

TAGS
Tag Cloud

SYNDICATION FEEDS
RSS 2.0
Bloglines
MY YAHOO!
newsgator
MyFeedster
add to kinja



SEARCH
Go

Fern Avenue PS
Garden Avenue JPS
Harbord CI
Howard JPS
Kent SPS (same complex as Alpha II Alt School)
Montrose PS
Oakwood CI
Old Orchard JPS
Ossington/Old Orchard JPS
Palmerston Avenue PS
Pauline PS (complex shared with St Sebastian Catholic Sch)
Perth Avenue PS (complex shared with St Luigi Catholic Sch)
Regal Road JPS
Shirley Street School (same complex as City View Alt School SR)
West Toronto CI
Transportation will also be cancelled for all these schools.

Catholic Board schools that are closed:

James Culnan
St. Pius
St. Cecilia
Pope Paul VI
St. Josaphat
St. Rita
St.Luigi
Bishop Marrocco/Thomas Merton
St. Vincent De Paul
Loretto College
St. Mary of the Angels
St. Mary - Portugal Square
St.Helen
St. Anthony
St. Sebastian
Senhor Santo Cristo
St. Luke
St. Francis of Assisi
Former St. David
Msgr. Faser
Msgr Fraser Orientation Centre
Bishop Allen
St. Raymond
St. Peter Campus
St. Bruno
Link Program - Park Place

More news on the subway closure situation...

> TTC confirms that the Bloor Danforth line between St. George and Islington stations is closed as a result of the outage and shuttle buses are in place until approximately 1:30 a.m. when the blue night all-night buses will begin service. Further information from TTC will follow early in the morning as to whether or not subway service will resume in the morning on that stretch of subway.

The City of Toronto has now designated several 'reception' points for residents who do not have power or heat and need to seek shelter. Here is a list of these open reception areas:

Metro Hall, 55 John Street
York Civic Centre, 2700 Eglinton Avenue West
JJ Piccininni Community Centre, 1369 St. Clair Avenue West
Castelview Wychwood Long Term Care, 351 Christie Street
Memorial Community Centre, 44 Montgomery Road

Harrison Pool, 15 Stephanie Street
Trinity Community Recreation Centre, 15 Crawford Street

Emergency Management Ontario has some great tips on what you should or shouldn't be doing during a blackout:

- Open blinds, curtains and drapes during the day on the sunny side of your home to let sunlight and its heat during the sunny days, and close during the night. Otherwise keep them closed to keep the heat in. You may also want to use window insulation kits or plastic sheeting to add extra insulation to keep the heat in.
- If you have an elderly or disabled neighbour be a good Samaritan and check on them and if you need assistance, contact your neighbours for help.
- Listen to local radio for emergency information.
- Do not use 911 to report a power outage.
- Use caution when traveling because traffic lights may not operate.
- Use proper candle holders, never leave candles unattended and keep away from combustible materials.
- Turn off all tools, appliances and electrical equipment including tools and computers so that when power is restored there is not a heavy load on the electric system.
- Don't open your freezer or fridge unless it is absolutely necessary. A full freezer can keep food frozen for 24 to 36 hours if the door remains closed.
- Don't use charcoal, gas barbeques or home generators indoors. They give off carbon monoxide.
- Leave one light on so you know when power is restored.
- Listen for further instructions from local public authorities.

After the power returns

- If the main electric switch was turned off, check to ensure appliances, air conditioning systems, TVs, microwave ovens and home electronics are unplugged to prevent damage from a power surge when the power is restored.
- Switch on the main electric switch.
- Give the electrical system a chance to stabilize before reconnecting tools and appliances. Wait 10 to 15 minutes before reconnecting all the tools and appliances.
- Check food supplies in fridge, freezers and cupboards for signs of spoilage.

For more details and tips of how to deal with a blackout, please refer to this PDF document from the Government of Canada.

Update: Power is beginning to come back online for many, but there are still pockets of the west end that are still offline. Streetcar service appears to be running normally again.

Update: Toronto Hydro is still saying that power will be out for some residents until late this evening. However, people can call 416-542-8000 to get updates on effected areas.

Related News:
Flooded power station in Toronto cuts electricity to about 22000
Schools closed and subway service affected by power outage
Toronto power outage could last 24 hours
Progress made in T.O. power restoration battle

image: aussiegall

TAGS: BLACKOUT, DUFFERIN, ELECTRICITY, HYDRO, SUBWAY

SHARE

( Add your comments )

Recent Entries:

- [Ontario Place makeover, major renovation on the way]
- [NFL in Toronto: Bills vs. Jets December 3rd]
- [43rd Annual Cavalcade of Lights kicks off]

## [ READER COMMENTS ]

### Add your comments...

We kindly ask that you keep your comments relevant to this blog entry. Abusive or inappropriate comments or comments that are specifically promotional in nature may be removed.

Your Name: (required)

Your Email Address: (required, will be kept private)

Your Website's URL: (optional)

Would you like us to remember your info for next time?

Yes No

Your Comments:

Preview **Add It!**

**Appendix H**

**Calculation of Efficiency of 13.8kV feeders vs. 4kV feeders**

Energy losses are defined by:

$E = I^2R$,

where
E is energy, I is current, and R is resistance of the conductor.

For an equivalent load, current on 4kV lines will be higher than 13.8kV by a factor of:
13.8kV/4.16kV = 3.1

Assuming the resistance of a typical 4kV conductor is the same as that of a 13.8kV conductor, energy losses will be directly proportional the square of current through the conductor. Since the current will be ~3 times higher in 4kV circuits, losses will be $3^2$ = ~9 times.

In 1990, total losses on the 4kV system were approximately $6 million for the year.

## Appendix I

## Toronto Hydro 4kV conversion plan from 1990

April 5, 1988

# 4 KV VERSUS 13.8 KV

# SYSTEM LOSSES

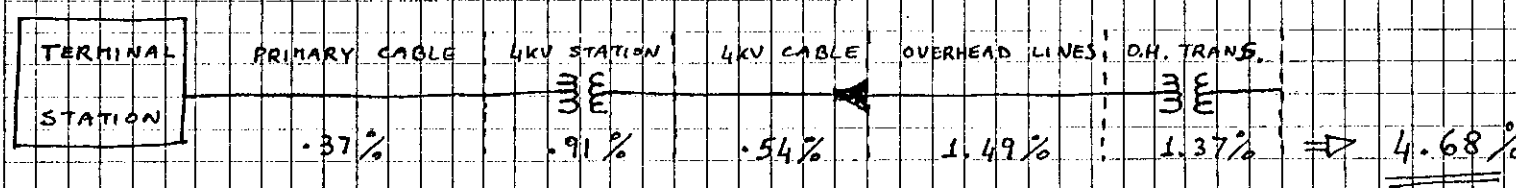
prepared by

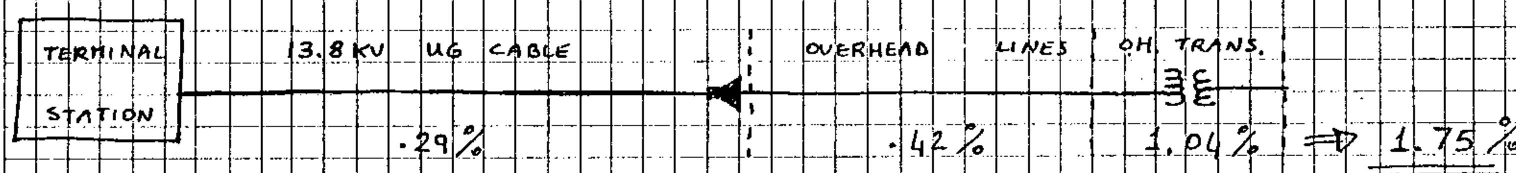
R. SIRONI

This paper is part of the 13.8 KV conversion alternative study and specifically addresses and compare the system losses between the existing 4KV system and the proposed 13.8 KV overhead distribution system.

## Summary

The total losses of the 4KV system is 4.68%, and
" " " " " 13.8KV " " 1.75%
of the total capacity as summarize below




| | PEAK | TOTAL LOSSES | ANNUAL OPERATING COST | ANNUAL COST/KVA |
|---|---|---|---|---|
| 4KV SYSTEM | 520,000 KVA | 23,300 KW | \$ 5,921,000.00 | \$ 11.39 |
| 13.8 KV SYSTEM | 520,000 KVA | 9,100 KW | \$ 2,214,000.00 | \$ 4.26 |
| CONVERSION SAVINGS DUE TO IMPROVEMENT IN LOSSES | | 14,200 KW | \$ 3,707,000.00 | \$ 7.13 |

## CONCLUSION

The annual savings of \$ 7.13 per KVA is only 1.8% of the conversion cost (estimated at \$ 400.00 per KVA)
The conversion program cannot be economically justified by solely considering the savings due to the improvement in losses.

The annual operating cost (charge for losses) "A" has been determined utilizing the following simple formula:

$$A = K \left( 8760 \times C_{KWH} \times L \times Peak \times LF + C_{KW} \times L \times Peak \right)$$

where

$$K = \frac{\text{Average Monthly System Peak}}{\text{Maximum Monthly Peak}} = \frac{1424 \text{ MW}}{1544 \text{ MW}} = 92.23\%$$

Note: the actual K factor in the 4KV system is lower.

8760 = Number of hours in 1 year.

$C_{KWH}$ = Cost per KWH (dollars) of system energy purchased from Ontario Hydro = \$ 0.0205

Peak = 520,000 KW of existing 4KV system.

LF = Loss Factor obtained as an average between a few feeder daily load profiles (78% load factor) – See Drawing DS-III-13 = 68%

$C_{KW}$ = Cost per Kilowatt per Annum = \$ 141.69 (142.92) excluding switchgear cost

L = Losses express in percent of the total capacity as summarized on the line diagram of page 1

4KV SYSTEM

$$A_{4KV} = 92.23\% \left( 8760 \times 0.0205 \times 4.68\% \times 520{,}000 \times 68\% + 141.69 \times 4.68\% \times 520{,}000 \right) = \$ 5{,}921{,}114.30$$

13.8 KV SYSTEM

$$A_{13.8KV} = A_{4KV} \times \frac{L_{13.8KV}}{L_{4KV}} = 5{,}921{,}114.30 \times \frac{1.75\%}{4.68\%} = \$ 2{,}214{,}049.10$$

# INDEX SUMMARY

## 4KV SYSTEM



## 13.8 KV SYSTEM



---

## APPENDIX I



## APPENDIX II



## APPENDIX III



## APPENDIX IV

PRIMARY CABLE LOSSES

# 4kV, 550V AND TRACTION STATIONS PEAK LOADS

FOR THE MONTH OF FEBRUARY 1987

OK

1

Received June 26/87
[illegible]

Loads as given are in kVA, except where noted in KW

| Station | Peak Load February 1987 | Cable Length | Cable Size | Cable Losses [kW] | Firm Rating | Nominal Rating | Unit Overload Rating | No. of ~~Units~~ Cables |
|---|---|---|---|---|---|---|---|---|
| Bulwer 550V (WR) | 590 (I) | | | | 2,400 | 3,000 | 1,200 | 3 |
| Carlaw 4kV (K) 7-8 EK 9-10 EK | (-) (CH)<br>37,200 (OH) | 4618' | (.0186)<br>1000 P.I.C | 78.0 | * 43,200 | 36,000 | 14,400 | 4×2 |
| Carlaw Railway E | 1,056 kW | | | | 1,875 | 2,500 | 1,875 | 2 |
| Chaplin 4kV (a') (DX) | 13,300 (CH-1) | 5517' | (.0383)<br>350 [illegible] | 65.4 | 15,300 (W) | 15,000 | 7,650 | 3 |
| Cherry 550V (BN) | 460 (I) | | | | 1,250 | 3,000<br>1,000 | 3,900<br>1,250 | 1<br>1 |
| College 4kV (DN) | 25,000 (CH-1) | 5370' | (.03285)<br>350<br>500 HT | 144.8 | 25,050 | 20,000 | 8,350 | 4 |
| Commissioners 4kV (BN) | 8,200 (CH-1) | 2000' | 350 H | 9.0 | 9,400 | 9,000 | 4,700 | 3 |
| Danforth 4kV (MN) | 20,600 (MP) | 2085' | 350 B | 22.2 | 25,050 | 20,000 | 8,350 | 4×2 |
| Danforth Railway (MN) | 1,872 kW | | | | 1,875 | 2,500 | 1,875 | 2 |
| Defoe 4kV (T) | 16,200 (CH) | 4458' | (.0531)<br>250 B | 81.6 | 19,500 | 16,200<br>5,000 | 6,500<br>8,350 | 3<br>1 |
| Defoe 550V (T) | 530 (Ms) | | | | 1,200 | 2,000 | 1,200 | 2 |

Note:
* Carlaw Station Firm Capacity f _kVA by 13.8kV Supply cables to Bus A4-5E.

Peak Loads for the
Month of FEBRUARY 1987

| Station | | Peak Load February 1987 | Peak Load February 1986 | Cable Length | Cable Size | Cable Losses [kW] | Nominal Rating | Unit Overload Rating | No. of ~~Units~~ Cables |
|---|---|---|---|---|---|---|---|---|---|
| Dickens 550V | (E) | 1,100 (Ms) | 1,200 (Ms) | | | | 4,500 | 1,800 | 3 |
| Dufferin 4kV | (DN) | 12,700 (Ms) | 11,700 (Ms) | 100' | (.0166) 1500 kcm | .4 | 15,000 | 8,350 | 3 |
| Duncan Railway | (WR) | 3,696 kW | 3,293 kW | | | | 5,000 | 1,875 | 4 |
| Dupont 4kV | | 22,400 (CH) | 20,300 (CH) | 4887' | 350 B | 123.3 | 20,000 | 8,350 | 4 |
| Dupont 550V | | 1,200 (TMs) | 1,200 (TMs) | | | | 3,000 | 1,500 | 2 |
| Eglinton 4kV (d) | (DX) | (-) (CH) 16,400 (Ms) | 16,900 (CH-1) | 116' | 350 B | 1.6 | 20,000 | 7,900 | 4 |
| Forman 4kV | (L) | (-) (Ms) 6,600 (TMs) | 6,200 (Ms) | 10547' | (350) 1000 (0.0276) | 33.3 | 10,000 | 8,350 | 2 |
| George & Duke 4kV | (GD) X | 13,700 (CH-1) | 14,600 (CH-1) | 2423' | 1000 Pilc | 5.7 | 15,000 | 9,400 | ~~3~~ 4×2 |
| George & Duke 550V | (GD) | 830 (I) | 1,100 (I) | | | | 4,500 | 1,800 | 3 |
| Glengrove 4kV | (GL) | 28,200 (Mp) | 29,100 (Mp) | 100' | 350 | 3.3 | 25,000 | 8,350 | 5 |
| Hammersmith 4kV (a') | (MN) | 22,100 (CH) | 20,200 (CH) | 6032' | 350 B | 148.2 | 20,000 | 7,467 | 4 |
| Hazelwood 4kV | (E) | 22,700 (Ms) | 20,700 (TMs) (-) (Ms) | 5981' | 1000 B | 75.3 | 20,000 | 8,350 | 4 |
| High Level 4kV | (H) | (-) (CH) 37,200 (OH) | 33,900 (CH) 35,100 (OH) | 1471' | 1500 HS | 19.2 | 36,000 | 14,400 | 4×2 |

*Note: High Level Firm capacity for WINTER limited to 40,000 kVA by Ontario Hydro Transformers.

Peak Loa[d] for the
Month of FEBRUARY 1987

3

| Station | | Peak Load February 1987 | Peak Load February 1986 | Cable Length | Cable size | [kW] Cable Losses | Nominal Rating | Unit Overload Rating | No. of ~~Units~~ Cables |
|---|---|---|---|---|---|---|---|---|---|
| Island 4kV | (T) | 1,200 (TMs) | 1,600 (I) | 7504' | (.0684) 2/0 H - 350 H | 1.8 | 5,400 | 3,375 | 2 |
| Jefferson 550V (c) | (T) | 810 (I) | (-) (I) | | | | 3,000 | 1,875 | 2 |
| Junction 4kV | (J) | 27,100 (CH) | 25,200 (CH) | 100' | 1000 | 1.2 | 25,800 | 6,000 | 6 |
| Keele & St. Clair 4kV (c) | (W) | 12,600 (Mp) | 11,000 (Mp) | 8368' | 350 HS | 89.1 | 15,000 | 7,350 | 3 |
| Kingsway 4kV | (M BY) | 2,200 (CH) | 2,700 (CH) | 19672' | 3/0 | 7.5 | 3,000 | 3,750 | 1 |
| Merton 4kV (a') | (GL) | 13,600 (CH-1) | 13,700 (Ms) (-) (CH-1) | 11540' | 350 | 143.1 | 15,000 | 7,875 | 3 |
| Millwood 4kV | (L) | 4,600 (TMs) (-) (Ms) | 4,000 (Ms) | 5800' | 1000 | 6.0 | 10,000 | 8,350 | 2 |
| Mowat 550V | (T) | 610 (I) | 750 (I) | | | | 3,000 | 1,800 | 2 |
| Ontario 4kV (b) | (GD) | 13,400 (Ms) | 12,400 (Ms) | 3262' | (.0457) 250 Kcm 350 " | 35.1 | 13,400 | 4,300 | 4 |

*Note: Each Ontario 4kV feeder on its own Bank. ...nited by the rating of the
four Ontario 4kV feeders and stand-by fe... rated at 3,350kVA.

Peak Loads for the
Month of FEBRUARY 1987



| Station | Peak Load February 1987 | Peak Load February 1986 | Cable Length | Cable Size | Cable Losses [kW] | Nominal Rating | Unit Overload Rating | No. of ~~Units~~ cables |
|---|---|---|---|---|---|---|---|---|
| Ontario 550V (d) (GD) | 1,100 (I) | 1,600 (I) | — | | | 5,400 | 3,375 | 2 |
| Ossington Railway (B) | 912 kW | 816 kW | — | | | 2,500 | 1,875 | 2 |
| Overdale 4kV (DX FNK) | 6,600 (MS) | 6,500 (MS) | 8196'<br>4918' | 350<br>3/0 | 18.0<br>4.2 | 11,580 | 7,750 | 2 < 1 1 |
| Parkdale 4kV (T) | 25,100 (CH) | 24,400 (CH) | 10722' | 250 B | 376.8 | 27,000 | 6,500 | 5 |
| Portland 550V (d) (WR) | 1,800 (I) | 1,700 (I) | — | | | 4,500 | 1,875<br>2,350 | 1<br>2 |
| Queensway 4kV (MBY) | 2,200 (CH) | 2,300 (CH) | 24 000 | 3/0 | 9.3 | 3,375 | 4,220 | 1 |
| Rennie Park 4kV (MBY) | 4,700 (CH) | 4,600 (CH) | 22 900 | 3/0 | 39.6 | 6,000 | 7,500 | 1 |
| Runnymede 4kV (W)(a') | 11,300 (TMS)<br>13,500 (CH-1) | 12,300 (TMS)<br>14,400 (CH-1) | 10413' | 350 | 127.2 | 15,000 | 7,450 | 3 |
| Sherbourne 4kV (K) | 15,400 (CH) | 14,200 (CH) | 8321' | 350 HT | 132.3 | 15,000 | 8,350 | 3 |
| Sorauren 550V (e) (W) | 340 (I) | 390 (I) | — | | | 2,000 | 1,500 | 2 |
| Spadina 4kV<br>B3 Bus (FNX)<br>B1 Bus (DX) | <br>2,800 (MS)<br>4,600 (CH-1) | <br>2,900 (MS)<br>(-) (CH-1) | <br>13114'<br>9210' | <br>3/0<br>{500 350} (.0328 | <br>8.1<br>33.6 | <br>5,000<br>5,400 | <br>8,350<br>7,500 | <br>TR#1<br>TR#2 |

Transformer #1 feeds B3 Bus only, and Transformer #2 feeds B1 Bus only.

Peak Loads For the
Month of FEBRUARY 1987

| Station | Peak Load February 1987 | Peak Load February | Cable Length | Cable Size | Cable Losses [kW] | Nominal Rating | Unit Overload Rating | No of ~~Uni~~ Cab |
|---|---|---|---|---|---|---|---|---|
| Sterling Road 550V (b) (W) | 1,000 (I) | 1,000 (I | — | | | 5,400 | 3,375 | 2 |
| Strachan 4kV (b) (T) | 12,100 (Ms) | 12,600 (M | 100' | 350 | 1.0 | 16,200 | 8,350 | 3 |
| Tecumseth 550V (e) (T) | 530 (I) | 520 (I | — | | | 3,000 | 1,800 | 2 |
| Terauley 4kV (A) | 7,400 (Ms) | 7,400 (Ms | 100' | 350 | .4 | 9,000 | 4,700 | 3 |
| (CE) University 4kV (CE) | 19,600 (TMs) | 17,700 (CH | 2667' | 500 350 | 44.1 | 20,000 | 8,350 | 4 |
| Wellesley Hospital 550V (d) (K) | 1,800 kW | 2,100 kW | — | | | 5,400 | 3,375 | 2 |
| Wiltshire 4kV (W) | 18,100 (Mp) 19,800 (CH-1) | 17,700 (Mp 18,200 (CH | 100' | 350 | 2.0 | 16,200 5,400 | 6,500 8,450 | 3 1 |
| 4KV SYSTEM PEAK | 511,000* KVA | | | | 1891.7 | | | |

$$\% \text{ CABLE LOSSES} = \frac{\text{Total Cable Losses [kW]}}{\text{4KV SYSTEM PEAK [kVA]}} = \frac{1891.7}{511{,}000} = \boxed{0.37\%}$$

* The 550 V and the Railway Station are not included (20,236 kVA)

The primary cable losses were calculated with the following formula:

$$L_{cable} = \left(\frac{\text{Station Peak [kVA]}}{\sqrt{3} \times 13.8 \times \text{No Cables}}\right)^2 \times \frac{\text{Cable Length [feet]}}{1000} \times \text{Resistance } [\Omega/1000'] \times \text{No of phases}$$

# TYPICAL TRANSFORMER LOSSES

0.91% AVERAGE

5 MVA/6.67 MVA 13.2 kV - 4160 V

## OLD TRANSFORMERS (1950's)

0.89%

NO LOAD LOSSES 12300 W
FULL LOAD LOSSES 32000 W

Approx 5% Z (99% Eff) on Full Load

These XFMRS would be at CD, GD, HZ, GL

## NEW TRANSFORMERS (1980's)

0.94%

NO LOAD LOSSES 9000 W
FULL LOAD LOSSES 38000 W

Approx 5% Z (99% Eff) on Full Load

These XFMRS were spares to be used when failures occurred and are spread out around the system.

## NEWLY ORDERED UNITS (1988)

SPECIAL SOUND LEVEL REQUIREMENTS (58 dB as opposed to 65 dB

NO LOAD LOSSES 6000 W
FULL LOAD LOSSES 27200 W

Approx 5% Z

(99% Eff on Full Load)

We will order XFMRS with the new sound level requirement now due to noise complaints from residential neighbourhoods. Note that low sound level also brings losses down

# 4KV FEEDER CABLE LOSSES

The 4KV feeder cable losses were calculated utilizing the following formula:

$$\text{Feeder Losses}/_{\text{per phase}} = \text{Resistance}\,[\Omega/_{1000'}] \times \frac{\text{Cable Length}}{1000} \times \frac{\text{Current}}{1000}$$

Where

$$\text{Resistance} = 0.023\ [\Omega/_{1000'}] \text{ for 600 kcmil Cu 4kV Cable}$$

$$\text{TOTAL Feeder Losses} = \text{Total Feeder Losses}/_{\text{phase}} \times 3 =$$

$$= 924.1^{*} \times 3 = 2{,}772 \text{ kW}$$

$$\%\ \text{4KV cable Losses} = \frac{\text{Total Feeder Losses}}{\text{4KV system Peak}} = \frac{2772}{511{,}000} = \boxed{0.54\%}$$

* 924.1 kW = Total (see attached for details)

## TERAULEY

.3 1) B-2-A - 6200 ft - (48)

10.3 2) B-4-A - 2200 ft - (450)

5.4 3) B-5-A - 2600 ft - (300)

5.6 4) B-7-A - 4600 ft. - (230)

21.6

## COLLEGE

13.2 1) B-1-CD - 2300 ft - (500)

.3 2) B-2-CD - 300 ft - (224)

11.3 3) B-3-CD - 2100 ft - (484)

.1 4) B-4-CD - 300 ft - (130)

1.1 5) B-6-CD - 200 ft - (488)

7.2 6) B-7-CD - 1700 ft - (428)

16.5 7) B-81/82-CD - 3650 ft - (444)

49.7

## COMMISSIONERS

.3 1) B-1-CM - 250 ft - (212)

.4 2) B-2-CM - 250 ft - (256)

.9 3) B-3-CM - 500 ft - (274)

1.0 4) B-4-CM - 700 ft - (248)

2.6

## CHAPLIN

.4 1) B-1-CP - 150 ft - (340)

.6 2) B-2-CP - 200 ft - (370)

.2 3) B-3-CP - 1450 - (67)

4.9 4) B-4-CP - 1250 - (414)

.3 5) B-51/52-CP - 800 - (118)

7.3 6) B-6-CP - 1900 - (410

13.7

## DANFORTH

— 1) B-1-DA (ON POTL)

.3 2) B-2-DA - 2100 - (80)

17.2 3) B-3-DA - 3800 - (444)

24.1 4) B-4-DA - 4700 - (472)

6.3 5) B-5-DA - 3600 - (276)

— 6) B-6-DA - GONE TO 13.8 KV

11.0 7) B-7-DA - 3650 - (362)

4.1 8) B-8-DA - 1800 - (316)

.8 9) B-9-DA - 300 - (536)

63.8

$$\text{FEEDER LOSSES}/\phi = 0.023 \times \frac{\text{Feet}}{1000} \times \frac{I^2}{1000} \quad [\text{KW}/\phi]$$

## DEFOE

1) B-2-DF - 200 ft - (398) .7
2) B-3-DF - 1400 ft - (176) 1.0
3) B-4-DF - 700 ft - (158) .4
4) B-5-DF (Con potential) /
5) B-6-DF (Standby) /
6) B-7-DF - 1400 ft - (386) 4.8
7) B-8-DF - 600 ft - (430) 2.6
8) B-9-DF - 600 ft - (404) 2.3
9) Bs-1-DF - 600 ft - (130) .2

12.0

## DUFFERIN

1) B-1-DN - 900 ft - (388) 3.1
2) B-3-DN - 1600 ft - (288) 3.1
3) B-4-DN - 1700 ft. - (366) 5.2
4) B-5-DN - 2700 ft (204) 2.6
5) B-6-DN - 4100 ft (428) 17.3

31.3

## DUPONT

1) B-1-DU - 2400 ft - (80) .4
2) B-2-DU - 500 ft - (396) 1.8
3) B-31/32-DU - 1300 ft - (343) 3.5
4) B-4-DU - 3800 ft - (458) 18.3
5) B-6-DU - 2200 ft - (484) 11.9
6) B-7-DU - 2500 ft. - (468) 12.6
7) B-8-DU - 6200 ft - (510) 37.1

85.6

## CARLAW

1) B-1-E - 300 ft - (390) 1.1
2) B-2-E - 1200 ft - (336) 3.1
3) B-4-E - 2600 ft - (388) 9.0
4) B-5-E - 800 ft - (398) 2.9
5) B-6-E - 2000 ft - (364) 6.1
6) B-7-E - 1500 ft - (416) 6.0
7) B-8-E - 3200 ft - (426) 13.4
8) B-9-E - 1200 ft - (414) 4.7
9) B-10-E - 600 ft - (452) 2.8
10) B-11-E - 600 ft - (436) 2.6
11) B-12-E - 900 ft - (316) 2.1
12) B-13-E - 3100 ft - (422) 12.7
13) B-15-E (Standby)

66.5

## EGLINTON

1) B-1-EG – 2500 ft – (244) 3.4
2) B-2-EG – 2400 ft – (298) 4.9
3) B-3-EG – 2300 ft – (228) 2.8
4) B-4-EG – 650 ft – (376) 2.1
5) B-5-EG – 1800 ft – (200) 1.7
6) B-6-EG – 200 ft – (408) .8
7) B-7-EG – 2200 ft – (392) 7.8

23.5

## FORMAN

1) B-1-FN – 300 ft – (50) .0
2) B-2-FN – 300 ft – (354) .9
3) B-3-FN – 1300 ft – (364) 4.0

4.9

## GEORGE & DUKE

1) B-1-GD – 900 ft. – (390) 3.2
2) B-2-GD – 3800 ft – (283) 7.0
3) B-3-GD – 500 ft – (340) 1.3
4) B-4-GD – 3100 ft – (227) 3.7
5) B-5-GD – 300 ft – (303) .6
6) B-6-GD – (Standby) /
7) B-7-GD – 300 ft – (247) .4

16.2

## GLENGROVE

1) B-1-GL – 700 ft – (362) 2.1
2) B-2-GL – 1500 ft – (250) 2.2
3) B-3-GL – (Standby) /
4) B-4-GL – 2200 ft – (374) 7.1
5) B-5-GL – 600 ft – (146) .3
6) B-6-GL – 600 ft – (388) 2.1
7) B-7-GL – 2200 ft – (408) 8.4
8) B-8-GL – 4100 ft – (416) 16.3
9) B-9-GL – 100 ft – (396) .4
10) B-10-GL – 4100 ft – (456) 19.6
11) B-11-GL – 4000 ft – (422) 16.4

74.9

## HIGH LEVEL

1) B-1-H – 1300 ft – (446) 5.9
2) B-2-H – 4400 ft – (394) 15.7
3) B-3-H – 1600 ft – (114) .5
4) B-4-H – (On potential)
5) B-6-H – 600 ft – (440) 2.7
6) B-7-H – 4300 ft – (414) 17.0
7) B-8-H – (On potential)
8) B-9-H – (Standby)
9) B-10-H – 800 ft – (312 1.8
10) B-11-H – 900 ft – (432 3.
11) B-12-H – 4300 ft – (358 12.
12) B-13-H – 1800 ft – (346 5.0
13) B-14-H – 2500 ft – (324 6.
14) B-15-H – 800 ft – (332 2.
15) B-16-H – 2500 ft – (396 9.
16) B-17-H – 800 ft – (386 2.7

84.

## HAMMERSMITH

1) B-1-HS-1300ft-(414) 5.1
2) B-2-HS-400ft-(356) 1.2
3) B-31/32-HS-1700ft-(256) 2.6
4) B-41/42-HS-2800ft-(360) 8.3
5) B-5-HS-1600ft.-(368) 5.0
6) B-61/62-HS-(standby) /
7) B-7-HS-4200ft-(342) 11.3

33.5

## HAZELWOOD

1) B-1-HW-5300ft-(316) 12.2
2) B-2-HW-3000ft-(394) 10.7
3) B-31/32 (3)-HW-800ft-(434) 3.5
4) B-4-HW-(standby) /
5) B-5 HW-3000ft-(418) 12.1
6) B-6-HW-1200ft-(442) 5.4
7) B-7-HW-4100ft-(442) 18.4
8) B-8-HW-1500ft-(432) 6.4

68.7

## ISLAND

1) B-1-I-100ft-(33) .0
2) B-2-I-100ft-(143) .0

.0

## JUNCTION

1) B-1-J-100ft-(290) .2
2) B-2-J-900ft-(384) 3.1
3) B-3-J-900ft-(446) 4.1
4) B-5-J-2500ft-(296) 5.0
5) B-8 J-400ft-(102) .1
6) B-9-J-400ft-(374) 1.3
7) B-10-J-3500ft-(396) 12.6
8) B-11-J-100ft-(460) .5
9) B-14-J-400ft-(400) 1.5
10) B-15-J-900ft-(428) 3.8

32.2

## KEELE & ST. CLAIR

1) B-1-KS-100ft-(312) .2
2) B-2-KS-600ft-(406) 2.3
3) B-3-KS-1200ft-(238) 1.6
4) B-4-KS-1200ft-(324) 2.9
5) B-5-KS-160ft-(112) .0

7.0

## KINGSWAY

1) B-1-KY-50ft-(208) .1
2) B-2-KY-(Standby) /
3) B-3-KY-50ft-(163) .0

.1

## MILLWOOD

1) B-1-MD-(Standby) /
2) B-2-MD-800ft-(340) 2.1
3) B-3-MD-800ft-(368) 2.5

4.6

## MERTON

1) B-1-MR-1600ft-(354) 4.6
2) B-2-MR-400ft-(320) .9
3) B-3-MR-2700ft-(354) 7.8
4) B-4-MR-3400ft-(300) 7.0
5) B-5-MR-400ft-(382) 1.3

21.6

## ONTARIO

1) B-1-ON-200ft-(410) .8
2) B-2-ON-200ft-(457) 1.0
3) B-3-ON-1300ft-(456) 6.2
4) B-4-ON-1300ft-(456) 6.2

14.2

## OVERDALE

1) B-1-OV - 200 ft - (416) .8
2) B-2-OV - 200 ft - (84) .0
3) B-3-OV - (Standby)
4) B-4-OV - (Standby)
5) B-5-OV - 200 ft - (261) .3
6) B-6-OV - 200 ft - (107) .1

1.2

## PARKDALE

1) B-1-PQ - 1000ft - (344) 2.7
2) B-2-PQ - 1300ft - (400) 4.8
3) B-3-PQ - 2200ft - (426) 9.2
4) B-4-PQ - 1800ft - (408) 6.9
5) B-5-PQ - 2300ft - (376) 7.5
6) B-6-PQ - 400ft - (436) 1.7
7) B-7-PQ - 3000ft - (288) 5.7
8) B-8-PQ - 900 ft - (384) 3.1
9) B-9-PQ - 1800ft - (392) 6.4
10) B-10-PQ - (Standby)

48.0

## QUEENSWAY

1) B-1-QU - 100ft - (167) .1
2) B-2-QU - 100ft - (193) .1

.2

## RUNNYMEDE

1) B-1-RD - 100ft - (376) .3
2) B-2-RD - 100ft - (322) .2
3) B-3-RD - (Standby)
4) B-4-RD - 500 ft - (208) .5
5) B-5-RD - 500ft - (326) 1.2
6) B-6-RD - 2600ft - (396) 9.4

11.6

## RENNIE PARK

1) B-1-RK - 200ft - (380) .7
2) B-2-RK - 300ft - (302) .6

1.3

## SPADINA

1) B-1-SA - 200ft - (368) .6
2) B-2-SA - 400ft - (274) .7
3) B-3-SA - 900ft - (356) 2.6
4) B-4-SA - (Standby)

3.9

## SHERBOURNE

1) B-1-SE - 3700 ft - (288) 7.1
2) B-2-SE - 3100ft - (436) 13.6
3) B-3-SE - 1200ft - (416) 4.8
4) B-4-SE - 2400ft - (258) 3.7
5) B-5-SE - 1000ft - (348) 2.9
6) B-6-SE - 2400ft - (300) 5.0

37.1

## STRACHAN

1) B-2-T - 1500ft - (394) 5.
2) B-4-T - 200ft - (192) .
3) B-9-T - 2000 ft - (324) 4.
4) B-11-T - 1500ft - (394) 5.

15.

## UNIVERSITY

1) B-1-UT - 2100ft - (376) 6.8
2) B-21-UT - (Standby)
3) B-31/32-UT - ~~6000~~ 3600ft - (724/2) 10.8
4) B-4-UT - 1000ft - (346) 2.8
5) B-5-UT - 1700ft - (442) 7.6
6) B-6-UT - 400ft - (178) .3
7) B-7-UT - 2700ft - (458) 13.0
8) B-8-UT - 3200ft - (336) 8.3

49.6

## WILTSHIRE

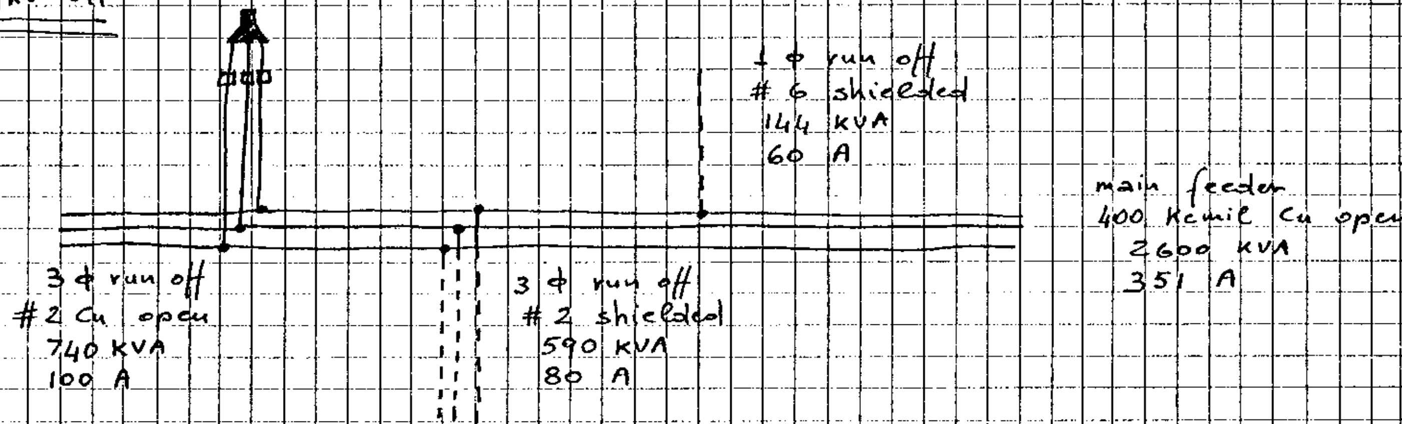
1) B-1-W - 1200ft - (274) 2.
2) B-2-W - 2300ft - (386) 7.
3) B-3-W - 700ft - (316) 1.
4) B-4-W - 1200ft - (230) 1.
5) B-5-W - 2200ft - (278) 3.
6) B-6-W - 1500ft - (392) 5.

22.

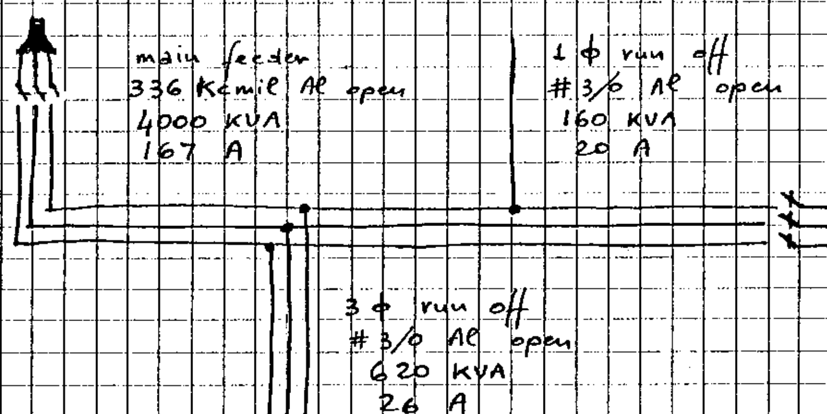
## OVERHEAD PRIMARY LINE LOSSES

In order to symplify the losses calculation for the primary overhead distribution system the layouts of the 4KV and the 13.8 KV feeders have been reduced to the following diagram

4KV OH




13.8 KV OH




Feeder number

4KV In addition the the 190 4KV feeders presently carrying load another 10 were included to take into account the street lights feeders and the 550 V substation.

13.8 KV Assuming that each 13.8 KV overhead loop is expected to be loaded at 80 % of its maximum capacity of 10 MVA during first contingency, each 13.8 KV feeder capacity is 4 MVA

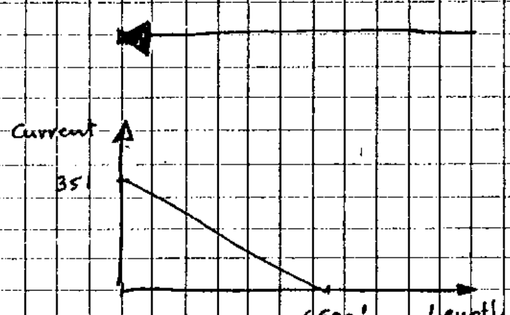
$$\frac{520\ MW}{4\ MW} = 130 \text{ feeders will be required}$$

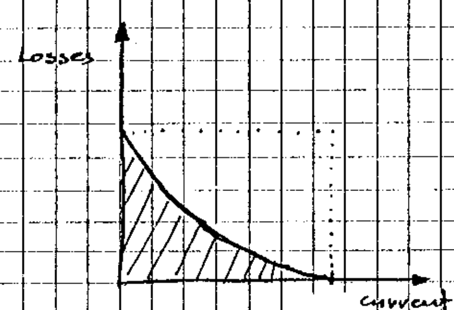
| | Number of Feeders | Average Current/feeder [A] | Average Pri feeder length of street | Line Length | Line Size | Line Current [A] | Resist/1000' | Line Losses [KW] | System Losses [kW] |
|---|---|---|---|---|---|---|---|---|---|
| 4 kV | 200 | 351 | 16,400' | 6500' 3ϕ | 400 Kcmil Cu | 351 | 0.0281 | 22.50 | |
| | | | | 1700' 3ϕ | #2 Cu | 100 | 0.16 | 2.72 | |
| | | | | 1600' 3ϕ | #2 shielded | 80 | 0.7 | 7.16 | |
| | | | | 6600' 1ϕ | #6 shielded | 60 | 0.8 | 6.33 | 7742 |
| | | | | | | | | 38.71 | |
| 13.8 kV | 130 | 167 | 25,500' | 11,500' 3ϕ | 336 Kcmil Al | 167 | 0.0513 | 16.45 | |
| | | | | 2,500' 3ϕ | 3/0 Al | 26 | 0.1025 | 0.17 | |
| | | | | 11,500' 1ϕ | 3/0 Al | 20 | 0.1025 | 0.16 | |
| | | | | | | | | 16.78 | 2181 |

The "Line Losses" was calculated using the following formula

$$\frac{1}{3}\left(\text{Resistance} \times \frac{\text{Line Length}}{1000} \times \text{Current}^2 \times \text{No of phases}\right)$$

The $\frac{1}{3}$ factor is an approximation based on the consideration that the current is directly proportional to the line length (i.e. maximum at the riser and zero at the end of line) and the losses varies with the square of the current




$$\int i^2\,di = \frac{i^3}{3} \Rightarrow \frac{1}{3}\left(I^2 \times L\right)$$

## 4KV OVERHEAD TRANSFORMER LOSSES (BY TX. SIZE)

| KVA | 3-5-7 | 10 | 15 | 25 | 37 | 50 | 75 | 100 | 167 | 200 | 540 | 112 | 150 | 225 | 300 | TOTA |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No | 188 | 230 | 604 | 7219 | 2107 | 1401 | 528 | 1773 | 186 | 120 | 6 | 50 | 64 | 72 | 4 | 14,55 |
| TOT KVA | 1,316 | 2,300 | 9,060 | 180,475 | 77,959 | 70,050 | 39,600 | 177,300 | 31,062 | 24,000 | 3,240 | 5,600 | 9,600 | 16,200 | 1,200 | 648,9 |
| $L_1$ | 35 | 45 | 64 | 102 | 149 | 163 | 250 | 273 | 403 | 460 | 1150 | 433 | 525 | 665 | 805 | |
| $L_2$ | 100 | 140 | 200 | 301 | 437 | 516 | 680 | 809 | 1404 | 1660 | 4250 | 1400 | 1495 | 2025 | 2515 | |
| L | 135 | 185 | 264 | 403 | 586 | 679 | 930 | 1082 | 1807 | 2120 | 5400 | 1833 | 2020 | 2690 | 3320 | |
| %L | 1.93 | 1.85 | 1.76 | 1.61 | 1.58 | 1.36 | 1.24 | 1.08 | 1.08 | 1.06 | 1.00 | 1.64 | 1.35 | 1.20 | 1.11 | |
| TOT L | 20 | 34 | 128 | 2,325 | 985 | 762 | 393 | 1532 | 268 | 204 | 26 | 73 | 104 | 156 | 11 | 7021 |

The total losses were calculated utilizing the following simplified formula:

$$\text{TOT } L = K \times \%L \times \text{TOT KVA}$$

where

$$K = \text{utilization factor} = \frac{\text{4KV system Peak}}{\text{Total KVA Installed}} = \frac{520{,}000}{648{,}962} = 80\%$$

$$\%L = \text{percent Losses} = \frac{L}{KVA} = \frac{L_1 + L_2}{KVA}$$

$L_1$ = Transformer core loss (kW)

$L_2$ = Transformer copper loss (kW) at full load

% OH TRANSF. LOSSES

$$= \frac{\text{TOTAL TX LOSSES}}{\text{4KV SYSTEM PEAK}} = \frac{7021}{511{,}000} = \boxed{1.3}$$

## 13.8 KV FEEDER CABLE LOSSES

The 13.8 KV feeder cable losses were calculated utilizing the following formula

$$L_{CABLE} = \text{No. of Feeders} \times \left(\frac{\text{Average Current}}{\text{Feeder}}\right)^2 \times \frac{\text{Feeder Length}}{1000} \times \text{Resistance} \times 3$$

where

$$\text{No. of Feeders} = \frac{520\ MW}{4\ MW} = 130$$

$$\frac{\text{Average Current}}{\text{Feeder}} = \frac{520{,}000}{130 \times \sqrt{3} \times 13.8} = 167.4\ A$$

Average Feeder Length = 5020 feet (see attached list of existing 13.8 KV feeder)

Resistance = 0.0274 for **500** kcmil Cu 15KV cable

3 = number of phases

$$L_{cable} = 130 \times (167.4)^2 \times \frac{5020}{1000} \times 0.0274 \times 3 = 1{,}503\ kW$$

$$\%\ \text{Losses} = \frac{L_{cable}}{\text{oH System Peak}} = \frac{1503}{520{,}000} = \boxed{0.29\%}$$

MARCH 30, 1988

# 13.8 KV. FEEDER

| STATION | FEEDER | DISTANCE | CABLE SIZE |
|---|---|---|---|
| BRIDGEMAN | A-231-B | 302 m | 500 KCMIL, 3C, 15KV PILC |
| | A-232-B | 194 | 500 KCMIL, 3C, 15KV PILC |
| BASIN | A-201-B | 624 | 500 KCMIL, 3C, 15KV, PILC |
| | A-202-B | 600 | 500 KCMIL, 3C, 15KV PILC |
| CARLAW | A-200-E | 1735 | 500, SC, 83, 7769 |
| | A-201-E | 3497 | [illegible] |
| DUFFERIN | A-250-DN | 2604 | 500, SC, 84-7959 |
| | A-251-DN | 2005 | 500, SC, [illegible]-7959 |
| | A-252-DN | 2212 | 500, SC, 84-8049 |
| | A-253-DN | 3443 | 500, SC, 85-7179 |
| | A-255-DN | 1089 | 500, SC, 82-7334 |
| | A-256-DN | 1112 | 500, SC, 82-7334 |
| DUPLEX | A-230-DX | 1493 | HJ-85-7246<br>500, SC, 85-7246 |
| | A-240-DX | 1431 | HJ-85-7246<br>500, SC, 85-7246 |
| MAIN | A-241-MN | 1729 | 500, SC, HJ, 86-7385 |
| | A-242-MN | 424 | 500, SC, HJ 86-7385 |

TOTAL 24494 m ÷ 16 = 1531 m [AVERAGE FEEDER LENGTH]
(5020 feet)

APPENDIX I

toronto hydro

March 16, 1988

TO: Mr. D.K. Abram

Copy to: Mr. D.H. Corker

RE: Statistics Canada Information on Distribution Transformers

Attached please find the following information on distribution transformers requested by Statistics Canada:

1. For single phase pole mounted up thru 167 KVA;

2. For three phase padmounted transformers up thru 500 KVA;

3. For three phase URD up thru 500 KVA;

4. Our approach to no load and load losses evaluation.

INFORMATION COPY
ORIGINAL SIGNED BY
T. L. BELL

T.L. Bell
Director of Engineering
Planning/Chief Engineer

JS/cm
1931G
Attach.

POLE MOUNTED TRANSF. TYPICAL ①

| EM | QUANTITY | IMPEDANCE | UNIT PRICE | LOSSES N.L. | LOSSES L.L. | N.L. @ |
|---|---|---|---|---|---|---|
| **8000-120/240 V** | | | | | | |
| 10 KVA W/Taps | — | | | | | |
| 10 KVA N/Taps | — | | | | | |
| 25 KVA W/Taps | — | | | | | |
| 25 KVA N/Taps | — | | | | | |
| 50 KVA W/Taps | 16 | 1.5% | $1,036.00 | 142 | 491 | $\frac{633 \times 100}{50000} = 1.27\%$ |
| 50 KVA N/Taps | — | | | | | |
| 75 KVA W/Taps | — | | | | | |
| 75 KVA N/Taps | — | | | | | |
| 100 KVA W/Taps | 151 | 1.6% | $1860.00 | 229 | 815 | $\frac{1044 \times 100}{100000} = 1.04\%$ |
| 167 KVA W/TAPS | 7 | 1.6% | $2565.00 | 360 | 1160 | $\frac{1520 \times 100}{167000} = 0.91\%$ |
| **14,400-120/240 V** | | | | | | |
| 10 KVA W/Taps | — | | | | | |
| 10 KVA N/Taps | — | | | | | |
| 25 KVA W/Taps | — | | | | | |
| 25 KVA N/Taps | — | | | | | |
| 50 KVA W/Taps | — | | | | | |
| 50 KVA N/Taps | — | | | | | |
| 75 KVA W/Taps | — | | | | | |
| 75 KVA N/Taps | — | | | | | |
| 100 KVA N/Taps | — | | | | | |
| | | | | | | |

POLE MOUNTED TRANSF. (2)

| ITEM | QUANTITY | IMPEDANCE | UNIT PRICE | LOSSES N.L. | LOSSES L.L. | N |
|---|---|---|---|---|---|---|
| 8000 ~~7200~~-600/347 | | | | | | |
| 19. 10 KVA W/Taps | — | | | | | |
| 20. 25 KVA W/Taps | — | | | | | |
| 21. 50 KVA W/Taps | 61 | 1.7% | $986.00 | 130 | 558 | $\frac{688 \times 100}{50000} = 1.38\%$ |
| 22. 75 KVA W/Taps | — | | | | | |
| 100KVA W/TAPS | 60 | | $1,540.00 | 253 | 851 | $\frac{1104 \times 100}{100000} = 1.1\%$ |
| 167KVA W/TAPS | 19 | 1.5% | $2,600.00 | 325 | 1070 | $\frac{1395 \times 100}{167000} = 0.84\%$ |
| 14400-600/347 | | | | | | |
| 23. 10 KVA W/Taps | — | | | | | |
| 24. 25 KVA W/Taps | — | | | | | |
| 25. 50 KVA W/Taps | — | | | | | |
| 26. 75 KVA W/Taps | — | | | | | |
| 14400/7200-120/240 | | | | | | |
| 27. 10 KVA N/Taps | — | | | | | |
| 28. 25 KVA N/Taps | — | | | | | |
| 29. 50 KVA N/Taps | — | | | | | |
| 30. 75 KVA N/Taps | — | | | | | |
| 7200/2400 - 120/240 | | | | | | |
| 31. 10 KVA ~~W~~ N/Taps | — | | | | | |
| 32. 25 KVA ~~W~~ N/Taps | — | | | | | |
| 33. 50 KVA ~~W~~ N/Taps | — | | | | | |

(3)

DATE: ~~MARCH 14~~/88

PADMOUNTED TRANSFORMERS

| PHASE | KVA | VOLTAGE RATING | QUANTITY PURCH. 1987 | TYPICAL IMPEDANCE | TYPICAL UNIT PRICE + TAX | TYPICAL LOSSES N.L. WATTS | TYPICAL LOSSES L.L. WATTS | |
|---|---|---|---|---|---|---|---|---|
| 3P | 112 | 4160V DELTA - 208Y/120V | 4 | 3.0% | $7,929.00 | 433 | 1400 | 1.64% |
| 3P | 150 | 4160V DELTA - 208Y/120V | 8 | 2.1% | $8364.00 | 525 | 1495 | 1.35% |
| 3P | 225 | 4160V DELTA - 208Y/120V | 4 | 2.8% | $9625.00 | 665 | 2025 | |
| 3P | 300 | 4160V DELTA - 208Y/120V | 6 | 3.6% | $9,780.00 | 805 | 2515 | |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |

DATE: ~~MARCH 11/88~~

PADMOUNTED TRANSFORMERS

| PHASE | KVA | VOLTAGE RATING | QUANTITY PURCH. 1987 | TYPICAL IMPEDANCE | UNIT PRICE + TAX | LOSSES N.L. WATTS | LOSSES L.L. WATTS |
|---|---|---|---|---|---|---|---|
| 3P | 112 | 13,800V DELTA - 216Y/125V | 0 | 3.0% | $5,015.00 | 350 | 1900 |
| 3P | 150 | 13,800V DELTA - 216Y/125V | 2 | 2.9% | $7,109.00 | 358 | 1907 |
| 3P | 225 | 13,800V DELTA - 216Y/125V | 1 | 3.0% | $8585.00 | 655 | 1800 |
| 3P | 300 | 13,800V DELTA - 216Y/125V | 4 | 3.5% | $9,147.00 | 790 | 2575 |
| 3P | 500 | 13,800V DELTA - 216Y/125V | 4 | 4.3% | $10,960.00 | 1175 | 3910 |

DATE: ~~MARCH 14~~/88

PADMOUNTED TRANSFORMERS

TYPICAL

| PHASE | KVA | VOLTAGE RATING | QUANTITY PURCH. 1987 | IMPEDANCE | UNIT PRICE + TAX | LOSSES N.L. WATTS | LOSSES L.L. WATTS |
|---|---|---|---|---|---|---|---|
| 3P | 150 | 13,800V DELTA-600Y/347V | 2 | 3.2% | 7,150.00 | 510 | 2085 |
| 3P | 300 | 13,800V DELTA - 600Y/347V | 2 | 3.5% | 8,905.00 | 815 | 3465 |
| 3P | 500 | 13,800V DELTA - 600Y/347V | 4 | 3.4% | 9,965.00 | 1103 | 3985 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |

| | QUANTITY PURCH 1987 | IMPEDANCE | UNIT PRICE + TAX. | LOSSES N.L. WATTS | LOSSES L.L. WATTS |
|---|---|---|---|---|---|
| OO KVA 13,800-600Y/347V. SUBWAY | 12 | 4% min | $16,760.00 | 1175 | 3950 |
| OO KVA 13,800-216Y/125V. NETWORK | 10 | 6.44% | $18,290.00 | 1100 | 5275 |
| 225 KVA 13,800-216Y/125V. SUBWAY | 2 | 4% min | $14,500.00 | 600 | 2150 |
| 300 " " " | 8 | 4% min | $15,836.00 | 690 | 2760 |
| 500 " " " " | 8 | 4% min | $16,760.00 | 900 | 4600 |

M Knox

⑥

March 9, 1988

# TORONTO HYDRO
## APPROACH TO NO LOAD AND LOAD LOSSES FOR DISTRIBUTION TRANSFORMERS

Toronto Hydro uses four formulas to calculate the cost of no load and load losses. For 1988, these formulas are:

| | |
|---|---|
| 120/208 V Network: | 5.57N + 1.91L |
| 240/416 V Network: | 5.57N + 2.44L |
| 4kV and 13.8kV Overhead: | 5.57N + 3.13L |
| 13.8kV Subway: | 5.57N + 2.78L |

where N = no load losses in watts
L = load loses in watts

The formulas give the present value of losses over the life of the transformer, which is assumed to be 30 years.

The cost of the losses is calculated, then added to the purchase price. The tenders are compared on the basis of price plus the cost of losses, with the contract being awarded to the lowest total price. For manufacturers who do not meet their guaranteed losses, the penalty is calculated using the same formulas.

JS/cm
1908G

7

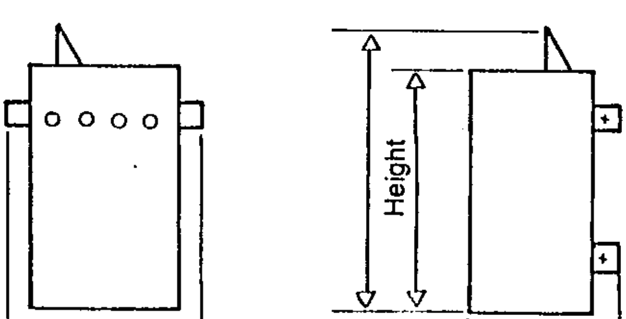
# DISTRIBUTION TRANSFORMER DATA SHEET 42-16460

8

MANUFACTURER: WESTINGHOUSE CANADA INC DATE APRIL 15, 1987

| ITEM | | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|
| KVA | | 100 | 167 | 25 | 50 | 75 | 100 |
| PRIMARY VOLTAGE | | 2400 | 2400 | 2400 | 2400 | 2400 | 2400 |
| SECONDARY VOLTAGE | | 120/240 | 120/240 | 600 | 600 | 600 | 600 |
| DRY OR OIL | | Oil | Oil | Oil | Oil | Oil | Oil |
| TEMPERATURE RISE °C | | 65 | 65 | 65 | 65 | 65 | 65 |
| SOUND LEVEL | d.b. | 51 | 55 | 48 | 48 | 51 | 51 |
| CORE LOSS | WATTS | 240 | 485 | 96 | 160 | 230 | 240 |
| LOAD LOSS | WATTS | 680 | 1415 | 214 | 415 | 520 | 680 |
| TOTAL LOSS | WATTS | 920 | 1900 | 310 | 575 | 750 | 920 |
| % EXCITING CURRENT @ 100% V. | | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| @ 110% V. | | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 |
| % IMPEDANCE @ °C | | 1.7 | 2.0 | 1.5 | 1.6 | 1.5 | 1.7 |
| TOTAL WEIGHT KG | | 560 | 640 | 195 | 250 | 420 | 560 |
| LITRES-OIL | | 200 | 180 | 70 | 80 | 145 | 180 |
| DIMENSIONS | Height | 1142 | 1060 | 760 | 880 | 1005 | 1142 |
| | Width | 900 | 960 | 815 | 815 | 850 | 900 |
| | Depth | 800 | 880 | 610 | 610 | 740 | 800 |
| TAPS | V.<br>V. | 2520)<br>2460)<br>2400)<br>2340)<br>2280) | Ditto | Ditto | Ditto | Ditto | Ditto |

Item #7 - same as Item #2

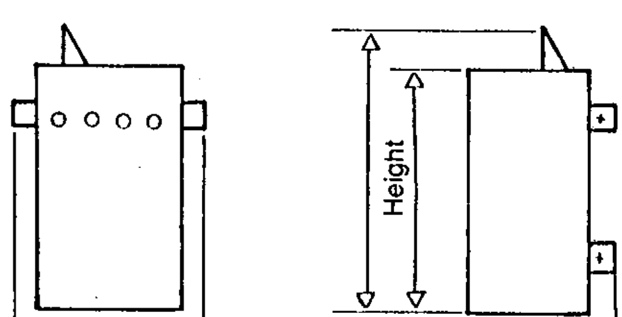


9

# DISTRIBUTION TRANSFORMER DATA SHEET

MANUFACTURER Carte International Ltd. DATE April 15, 1987.

| ITEM | | 1. | 2. | 3. | 4. | 5. | 6. |
|---|---|---|---|---|---|---|---|
| KVA | | 100 | 167 | 25 | 50 | 75 | 100 |
| PRIMARY VOLTAGE | | 2400 | 2400 | 2400 | 2400 | 2400 | 2400 |
| SECONDARY VOLTAGE | | 120/240 | 120/240 | 600 | 600 | 600 | 600 |
| DRY OR OIL | | oil | oil | oil | oil | oil | oil |
| TEMPERATURE RISE °C | | 65 | 65 | 65 | 65 | 65 | 65 |
| SOUND LEVEL | d.b. | 51 | 55 | 48 | 48 | 51 | 51 |
| CORE LOSS | WATTS | 292 | 402 | 88 | 141 | 206 | 292 |
| LOAD LOSS | WATTS | 845 | 1723 | 313 | 516 | 680 | 855 |
| TOTAL LOSS | WATTS | 1137 | 2125 | 401 | 657 | 886 | 1147 |
| % EXCITING CURRENT | | | | | | | |
| @ 100% V. | | 1.0 | 1.0 | 1.5 | 1.5 | 1.5 | 1.0 |
| @ 110% V. | | 2.0 | 2.0 | 3.0 | 3.0 | 3.0 | 2.0 |
| % IMPEDANCE @ 85°C | | 2.45 | 2.4 | 1.9 | 2.0 | 2.0 | 2.1 |
| TOTAL WEIGHT KG | | | | | | | |
| LITRES-OIL | | | | | | | |
| DIMENSIONS | Height | Drawings will be supplied upon receipt of order. | | | | | |
| | Width | | | | | | |
| | Depth | | | | | | |
| TAPS - | V. | std. | std. | std. | std. | std. | std. |
| | V. | | | | | | |

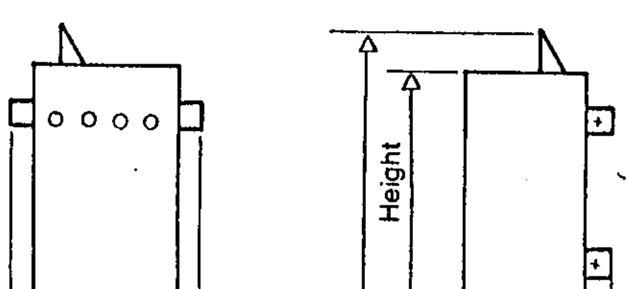


(10

# DISTRIBUTION TRANSFORMER DATA SHEET

MANUFACTURER Carte International Ltd. DATE April 15, 1987.

| ITEM | | 7. | | | | | |
|---|---|---|---|---|---|---|---|
| KVA | | 167 | | | | | |
| PRIMARY VOLTAGE | | 2400 | | | | | |
| SECONDARY VOLTAGE | | 600 | | | | | |
| DRY OR OIL | | oil | | | | | |
| TEMPERATURE RISE °C | | 65 | | | | | |
| SOUND LEVEL | d.b. | 55 | | | | | |
| CORE LOSS | WATTS | 402 | | | | | |
| LOAD LOSS | WATTS | 1532 | | | | | |
| TOTAL LOSS | WATTS | 1934 | | | | | |
| % EXCITING CURRENT | | | | | | | |
| @ 100% V. | | 1.0 | | | | | |
| @ 110% V. | | 2.0 | | | | | |
| % IMPEDANCE @ 85 °C | | 2.1 | | | | | |
| TOTAL WEIGHT KG | | | | | | | |
| LITRES-OIL | | Drawings will be supplied upon receipt of order. | | | | | |
| DIMENSIONS | Height | End connections of secondary windings are aluminum. The bushings themselves are a copper based material. We use a proper non cold flow connection utilizing a belleville spring washer. | | | | | |
| | Width | | | | | | |
| | Depth | Items 1,3-6 secondary terminal connections to be eyebolts the same as your P.O. E41160. Items 2,7 secondary terminal connections to be connectors the same as your P.O. E38524. | | | | | |
| TAPS - | V. | std. | | | | | |
| | V. | | | | | | |

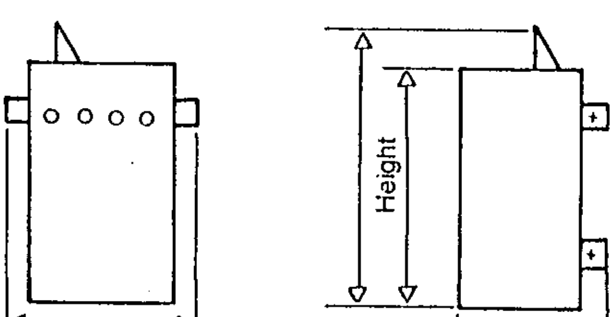


# DISTRIBUTION TRANSFORMER DATA SHEET

MANUFACTURER MOLONEY ELECTRIC CORPORATION DATE April 14, 1987

MOLONEY NEG. NO. T-28431

| ITEM | | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|
| KVA | | 100 | 167 | 25 | 50 | 75 | 100 |
| PRIMARY VOLTAGE | | 2400 | 2400 | 2400 | 2400 | 2400 | 2400 |
| SECONDARY VOLTAGE | | 120/240 | 120/260 | 600 | 600 | 600 | 600 |
| DRY OR OIL | | OIL | OIL | OIL | OIL | OIL | OIL |
| TEMPERATURE RISE °C | | 65 | 65 | 65 | 65 | 65 | 65 |
| SOUND LEVEL | d.b. | 50 | 51.1 | 41.5 | 47.6 | - | 50 |
| CORE LOSS | WATTS | 250 | 415 | 122 | 185 | 230 | 270 |
| LOAD LOSS | WATTS | 900 | 1380 | 272 | 525 | 670 | 727 |
| TOTAL LOSS @85°C | WATTS | 1150 | 1795 | 394 | 710 | 900 | 997 |
| % EXCITING CURRENT | | | | | | | |
| @ 100% V. | | 1.0 | 1.0 | 1.5 | 1.0 | 1.0 | 1.0 |
| @ 110% V. | | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| % IMPEDANCE @ 85°C | | 1.7 | 1.7 | 1.5 | 1.3 | 1.7 | 1.3 |
| TOTAL WEIGHT KG | | 480 | 650 | 175 | 304 | 425 | 480 |
| LITRES-OIL | | 141 | 200 | 46 | 80 | 145 | 141 |
| DIMENSIONS | Height | 1050 | 1170 | 740 | 850 | 1050 | 1050 |
| | Width | 875 | 950 | 745 | 815 | 875 | 875 |
| | Depth | 780 | 870 | 590 | 725 | 780 | 780 |
| TAPS - | V. / V. | Four 2½% taps, 2 full capacity above and 2 reduced capacity below normal voltage. | | | | | |



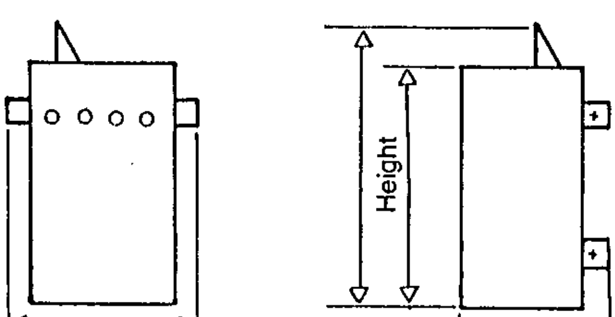

Typical Drawing 79929-B attached

# DISTRIBUTION TRANSFORMER DATA SHEET

MANUFACTURER MOLONEY ELECTRIC CORPORATION DATE April 14, 1987

MOLONEY NEG. NO. T-28431

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| ITEM | | 7 | | | | | |
| KVA | | 167 | | | | | |
| PRIMARY VOLTAGE | | 2400 | | | | | |
| SECONDARY VOLTAGE | | 600 | | | | | |
| DRY OR OIL | | OIL | | | | | |
| TEMPERATURE RISE °C | | 65 | | | | | |
| SOUND LEVEL | d.b. | 51.1 | | | | | |
| CORE LOSS | WATTS | 415 | | | | | |
| LOAD LOSS | WATTS | 1375 | | | | | |
| TOTAL LOSS | WATTS | 1790 | | | | | |
| % EXCITING CURRENT | | | | | | | |
| @ 100% V. | | 1.0 | | | | | |
| @ 110% V. | | 5.0 | | | | | |
| % IMPEDANCE @ 85°C | | 1.7 | | | | | |
| TOTAL WEIGHT KG | | 650 | | | | | |
| LITRES-OIL | | 200 | | | | | |
| DIMENSIONS | Height | 1170 | | | | | |
| | Width | 950 | | | | | |
| | Depth | 870 | | | | | |
| TAPS - | V. | 4-2½% Taps, | | | | | |
| | V. | 2 FCAN and 2 RCBN. | | | | | |

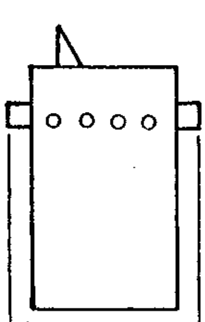


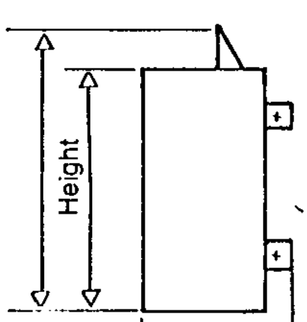

Typical Drawing No. 79929-B attached.

# DISTRIBUTION TRANSFORMER DATA SHEET

MANUFACTURER Federal Pioneer Limited DATE April 13, 1987

| ITEM | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| KVA | 100 | 167 | 25 | 50 | 75 | 100 |
| PRIMARY VOLTAGE | 2400 | 2400 | 2400 | 2400 | 2400 | 2400 |
| SECONDARY VOLTAGE | 120/240 | 120/240 | 600 | 600 | 600 | 600 |
| DRY OR OIL | oil | oil | oil | oil | oil | oil |
| TEMPERATURE RISE °C | 65 | 65 | 65 | 65 | 65 | 65 |
| SOUND LEVEL d.b. | 51 | 55 | 48 | 48 | 51 | 51 |
| CORE LOSS WATTS | 264 | 333 | 102 | 175 | 207 | 283 |
| LOAD LOSS WATTS | 706 | 1418 | 246 | 420 | 638 | 762 |
| TOTAL LOSS WATTS | 970 | 1751 | 348 | 595 | 845 | 1045 |
| % EXCITING CURRENT | | | | | | |
| @ 100% V. | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| @ 110% V. | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 |
| % IMPEDANCE @ °C approximate | 1.5 | 2.3 | 1.7 | 1.6 | 1.7 | 1.3 |
| TOTAL WEIGHT KG | 423 | 660 | 177 | 293 | 389 | 423 |
| LITRES-OIL | 167 | 258 | 50 | 68 | 127 | 167 |
| DIMENSIONS mm Height | 863 | 965 | 673 | 826 | 838 | 863 |
| Width | 889 | 991 | 780 | 813 | 813 | 889 |
| Depth | 782 | 993 | 535 | 635 | 635 | 782 |
| TAPS - V. | 2½ | 2½ | 2½ | 2½ | 2½ | 2½ |
| V. | 2½ | 2½ | 2½ | 2½ | 2½ | 2½ |

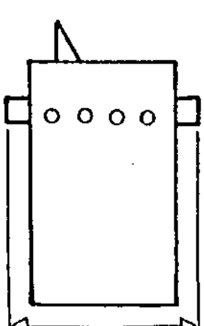


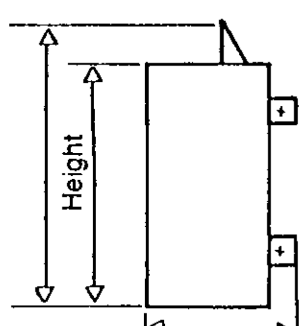


# DISTRIBUTION TRANSFORMER DATA SHEET

MANUFACTURER Federal Pioneer Ltd DATE April 13, 1987

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| ITEM | 7 | | | | | | |
| KVA | 167 | | | | | | |
| PRIMARY VOLTAGE | 2400 | | | | | | |
| SECONDARY VOLTAGE | 600 | | | | | | |
| DRY OR OIL | oil | | | | | | |
| TEMPERATURE RISE °C | 65 | | | | | | |
| SOUND LEVEL d.b. | 55 | | | | | | |
| CORE LOSS WATTS | 407 | | | | | | |
| LOAD LOSS WATTS | 1225 | | | | | | |
| TOTAL LOSS WATTS | 1632 | | | | | | |
| % EXCITING CURRENT | | | | | | | |
| @ 100% V. | 1.5 | | | | | | |
| @ 110% V. | 3.0 | | | | | | |
| % IMPEDANCE @ °C | 1.4 | | | | | | |
| TOTAL WEIGHT KG | 660 | | | | | | |
| LITRES-OIL | 259 | | | | | | |
| DIMENSIONS Height | 965 | | | | | | |
| Width | 991 | | | | | | |
| Depth | 993 | | | | | | |
| TAPS - V. | 2½ | | | | | | |
| V. | 2½ | | | | | | |





OCT./74 (15)

E-84526

FERRANTI- PACKARD LIMITED.

ONAN 167 60 2400-600

6 [illegible] 2-151069 TO 072, 075, 076

| | [illegible] | Core Loss | Total Loss at 85°C. | Impedance @85°C. |
|---|---|---|---|---|
| [illegible] | .538 | 435 | 1880 | 1.41 |
| [illegible] | 1.0 | 475 | 2050 | 1.4 |

| Serial No. | [illegible] | [illegible] |
|---|---|---|
| 2-130817 | 50°C | 63°C |
| Guarantee | 65°C | 65°C |

[illegible]

| Serial No. | Sound Level |
|---|---|
| 2-133999 | 48 db |
| 2-134000 | 47.7 db |
| Guarantee | 56 db |

[illegible]

H.V. to L.V. and Grd. 19KV 1MIN

L.V. to H.V. and Grd. 10KV 1MIN

Induced 2 X NORMAL 7200 CYCLES

POLARITY ADDITIVE TAPS: 4-2½% 2520 VOLTS

2460 "

2400 "

2340 "

2280 "

[illegible] Name plate A101 375 326 Outline A101 245 043

[illegible] Height 42¼ Weight 1339 lbs.

Width 32" Oil 39.5 Gals.

Depth 30"

1U2 ) ) MOLONEY ELECTRIC

ONAN 100 60 2400-600 VOLT

6 261700-261705 incl.

| | [illegible] | [illegible] | [illegible] | [illegible] | Impedance @ [illegible] |
|---|---|---|---|---|---|
| | •41% | •94% | 271 | 1173 | 3.08% |
| | 1.5% | 4.0% | 325 | 1295 | 3.0% |

| | | |
|---|---|---|
| 261703 | 54.1°C | 64°C |
| | 65°C | 65°C |
| | 261701 | 44db |
| | | 50db |

H.V. to L.V. and Gnd. 19KV - 1min.

L.V. to H.V. and Gnd. 10KV - 1min.

Induced 2 x NORMAL - 400 cycles - 18 secs.

POLARITY Additive TAPS: 4 x 2½% - 2520 VOLTS

2460 VOLTS

2400 VOLTS

2340 VOLTS

2280 VOLTS

DRAWINGS: Nameplate 66371-B Rev 2. Outline 72610-B-Rev 0.

Height 37" Weight 1110 lbs.

33" Oil 21 Gals.

Depth 27½"

J. Anderson

JUNE/72 (17)

[illegible] 77865 [illegible] F.P.E - PIONEER ELECT LTD.

[illegible] O.N.A.N [illegible] 75 [illegible] 60 [illegible] 2400-600 VOLT.

[illegible] 3 [illegible] 4923-1, -2 & -3.

| | [illegible] | | [illegible] | [illegible] | Impedance @ [illegible] |
|---|---|---|---|---|---|
| [illegible] | ·87% | 3·55% | 259 | 1022 | 2·5% |
| | 2.0% | 6.0% | 272 | 1022 | 2·5% |

| [illegible] | [illegible] | [illegible] | Winding Temp. Rise. |
|---|---|---|---|
| Conducted on Order E 73357 | T4804-3 | 57°C | 63·9°C |
| | | | |
| | [illegible] | 65°C | 65°C. |

| SOUND TESTS: | [illegible] | Sound Level. |
|---|---|---|
| Conducted on Order E 73357 | T4804-3 | 48db |
| | | |
| | | 50db. |

INSULATION TESTS: [illegible]

H.V. to L.V. and Grd. 19KV - 1min

L.V. to H.V. and Grd. 10KV - 1min.

Induced 2x Normal - 120 cycles 1min.

POLARITY Additive TAPS: 4 × 2½% - 2520 VOLTS

2460 VOLTS

2400 VOLTS

2340 VOLTS

2280 VOLTS

DRAWINGS: Nameplate M2102A0359-T4923 Outline M1103B0755-7-T4923

WEIGHTS AND DIMENSIONS: Height 41½" Weight 890 lbs.

Width 33" Oil 35 Galn.

Depth 31½"

J Anderson

(18)

JAN/72

76025 F.P.E - PIONEER

O.N.A.N. 50 60 2400 - 600 VOLT

[illegible] 6 [illegible] 4794-1, -2, -3, -4, -5 & -6.

| | [illegible] | [illegible] | [illegible] | [illegible] Losses @ 85°C. | Impedance @ 85°C. |
|---|---|---|---|---|---|
| [illegible] | ·693% | 2·51% | 180 W | 682 W | 2.68% |
| [illegible] | 1·5% | 3.0% | 194 W | 746 W | 2·5% |

[illegible]

| [illegible] | [illegible] | Winding Temp. Rise. |
|---|---|---|
| 4794-5 | 50.6°C | 59·8°C |
| 4794-4 | 50 ° C | 59·3°C |
| Guaranteed | 65°C | 65°C |

SOUND LEVEL

| [illegible] | Sound Level. |
|---|---|
| 4794 -1 | 44·37 db |
| 4794 - 3 | 45·1 db. |
| Guaranteed: | 50 db |

INSULATION DETAIL

H.V. to L.V. and Grd. 19 KV - 1 min.

L.V. to H.V. and Grd. 10 KV - 1 min.

Induced 2 x NORMAL - 400 cycles - 18 secs.

POLARITY Additive

TAPS: 4 x 2½% - 2520 VOLTS

2460 VOLTS

2400 VOLTS

2340 VOLTS

2280 VOLTS

DRAWINGS: Nameplate M2102A0359-4794 Outline M1103B0755-6-4794

WEIGHTS AND DIMENSIONS: Height 34½" Weight 634 Lbs.

Width 31" Oil 19·2 Gals.

Depth 29¼"

J Anderson

(19)

SEPT. /73

81893 Ferranti - Packard Ltd

C.N.A.N. 167 60 2400-120/240 volt

9 2-142960 to 2-142968 incl.

| | | | | |
|---|---|---|---|---|
| .585% | 1.62% | 437W | 1968W | 1.784% |
| 1.0% | 2.6% | 475W | 2275W | 1.8% |

2-138131 54°C 57°C

65°C 65°C

2-142962 50.5db

56 db

19KV - 1min

10KV - 1min

2 x NORMAL

Additive 4 x 2½% - 2520 VOLTS

2460 VOLTS

2400 VOLTS

2340 VOLTS

2280 VOLTS

DRAWINGS: Nameplate A101 375 236 Outline A101 245 028

Height 42¼" Weight 1365 lbs.

34" 33 gals.

33"

J. Anderson

JUNE /71 (20)

73385 CANADIAN GENERAL ELECTRIC

ENAN 100 60 2400 - 120/240 VOLTS

6 782389, -91, -94, 784210, -21 & -06

| | | | | |
|---|---|---|---|---|
| ·634 | 2.13 | 311·6 | 1242.35 | 2.10% |
| 1·5 | 5.0 | 325 | 1295 | 2.20% |

| | | |
|---|---|---|
| 746293 | 61°C | 63·2°C |
| 746294 | 61°C | 63·2°C |
| | 65°C | 65°C |

Conducted at Stores by Transformer Test Section - Nov 4/71

782391 49.0 db

50.0 db.

19KV - 1min

10KV - 1min.

2x NORMAL

POLARITY: Additive 4x2½% : 2520 VOLTS

2460 VOLTS

2400 VOLTS

2340 VOLTS

2280 VOLTS

DRAWINGS: Nameplate 231726 Outline 188A7283 SHEET #2A.

WEIGHTS AND DIMENSIONS: Height 38½" Weight 915 lbs.

Width 32¼" Oil 23 Gals.

Depth 28"

J Henderson

DEC. /71 (21)

73385 CANADIAN GENERAL ELECTRIC

O.N.AN 75 60 2400-120/240 VOLTS

6 784566, -67, -69, -70, -71 & -72.

| | | | | |
|---|---|---|---|---|
| ·73 | 2.22 | 262.83 | 1021.84 | 2.09 |
| 1·5 | 5.0 | ~~325.0~~ 272 per J.G. | 1022.0 | 2.2 |

HEAT RISE TEST CONDUCTED ON ORDER E69536 { 744076 56.9°C 60.9°C

744077 57.2°C 62.5°C

65°C 65°C

Conducted at Stores by Transformer Test Section - Nov 4/71 JA 784569 49.6 db

50 db.

60 KV - 1 min.

30 KV - 1 min.

2x NORMAL

POLARITY Additive 4×2½% : 2520 VOLTS

2460 VOLTS

2400 VOLTS

2340 VOLTS

2280 VOLTS

DRAWINGS: Nameplate 231726 Outline 188A7283 SHEET #2A.

38½" Weight 825 Lbs.

32¼" Oil 24 Gals.

28"

J Anderson.

March /72. (22)

76241 Moloney Electric

ONAN 50 60 2400-120/240 VOLT.

11 259424, -30, -31, -32, -34, -35, -36, -37, -38, -39, -40.

| | | | | Total Losses at 85°C. | Impedance @ 85°C. |
|---|---|---|---|---|---|
| | .65% | 2.27% | 168 | 697 | 1.60% |
| | 1.5% | 4.0% | 194 | 746 | 1.50% |

| | | Winding Temp. Rise |
|---|---|---|
| See Order 249397 | 49.1°C | 57.1 |
| E67972 | | |
| | 65.0°C | 65°C |

| | | Sound Level. |
|---|---|---|
| See Order #E67972. | 249399 | 43.1db. |
| | | 50db. |

INSULATION TESTS: H.V. to L.V. and Grd. 19KV - 1min.

L.V. to H.V. and Grd. 10KV - 1min.

Induced 2x normal - 7200 cycles.

POLARITY Additive. TAPS: 4 x 2½% - 2520 VOLTS

2460 VOLTS

2400 VOLTS

2340 VOLTS.

2280 VOLTS.

DRAWINGS: Nameplate 59970-B. Rev 5 Outline 72610-B. Rev O.

WEIGHTS AND DIMENSIONS: Height 37" Weight 650 Lbs.

Width 31½" Oil 19 Gals.

Depth 26"

J Anderson

(23)

JUNE /71

78512 FERRANTI- PACKARD ELECT LTD.

ONAN 37 60 2400-120/240 VOLT.

12 2-135845, -847, -849, -850, -851, -852, -853, -854, -855, -856, -858 & -859.

| | | | Total Losses | Impedance |
|---|---|---|---|---|
| 1.2% | 4.75% | 149 W | 586.4 W | 1.89% |
| 1.4% | 3.20% | 155 W | 615 W. | 1.93% |

Test conducted on Order E67326

| | | |
|---|---|---|
| 2-122690 | 50 °C | 64°C |
| 2-122693 | 49.5°C | 60.7°C |
| Guarantee: | 65°C | 65°C |

Conducted on Order # E67326 { 2-122688 Sound Level. 43.37 db

Guarantee: 50 db.

H.V. to L.V. and Grd. 19KV - 1 min.

L.V. to H.V. and Grd. 10KV - 1 min.

Induced 2x NORMAL

POLARITY ADDITIVE TAPS: 4 x $2\frac{1}{2}$% - 2280 VOLTS

2340 VOLTS

2400 VOLTS

2460 VOLTS

2520 VOLTS

DRAWINGS: Nameplate A-101 375 014 Rev.7 Outline A101 225 001

WEIGHTS AND DIMENSIONS: Height $32\frac{1}{4}$" Weight 535 Lbs.

Width $29\frac{1}{4}$" Oil 18 Gals.

Depth $24\frac{3}{4}$"

J Anderson

SEPT./74 (24)

WESTINGHOUSE CANADA LTD.

E-83891

ONAN 25 60 2400-120/240

870781, 782, 790, 794, 795, 861246, 247, 255, 256, 258, 276, 279, 280, 284, 285, 874451, 468, 481, 489, 492, 500, 501, 502, 504

24

| | | | |
|---|---|---|---|
| .84 | 102 | 403 | 1.725 |
| 1.0 | 114 | 442 | 1.5 |

48.3°C (H.V.)

861255

65°C 65°C

(BY THES) 870794 45.25 db

(BY WESTINGHOUSE) — 47.6 db

50db

19 KV - 1 MIN.

10 KV - 1 MIN.

2X RATED VOLTAGE AT 180HZ FOR 7200 CYCLES

ADDITIVE 4-2½% 2520 VOLTS

2460 "

2400 "

2340 "

2280 "

DRAWINGS: Nameplate 145P671 Outline 784B774

Height 31" Weight 350 lbs.

Width 28" Oil 10 Gals.

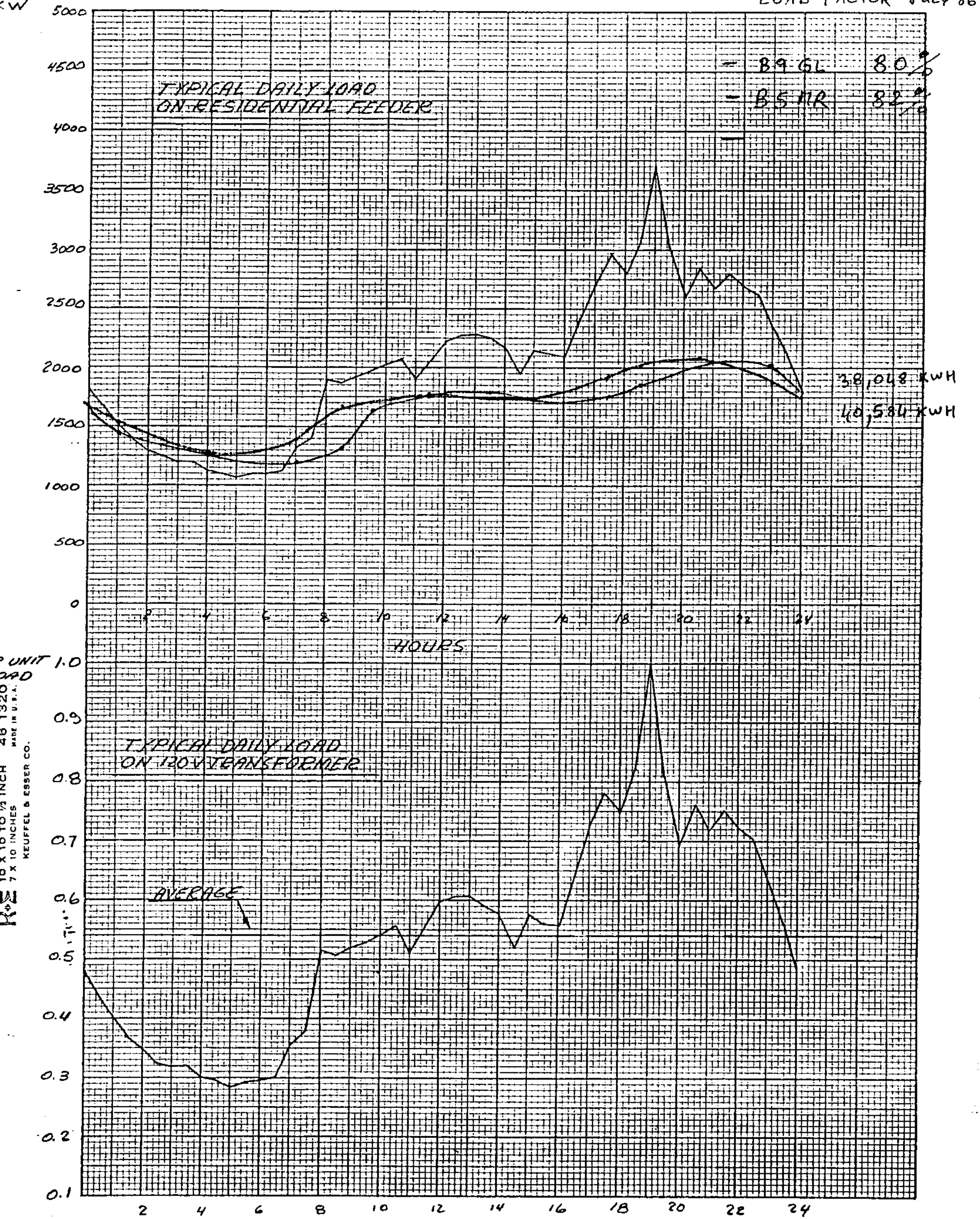
23"

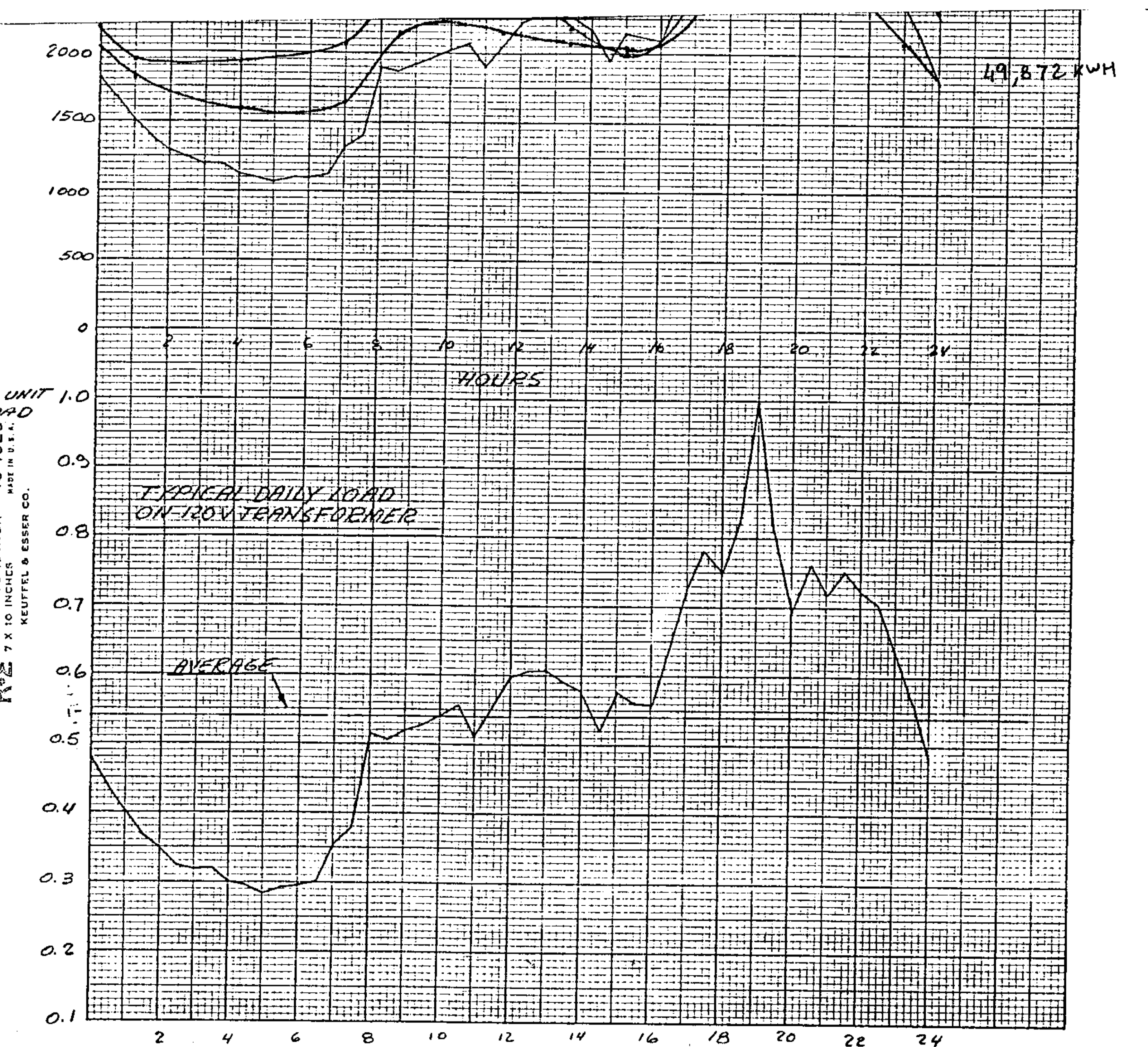
# 1987 System Peaks

| | | |
|---|---|---|
| Jan | 1433 | MW |
| Feb | 1494 | " |
| March | 1381 | " |
| April | 1294 | " |
| May | 1432 | " |
| June | 1458 | " |
| July | 1522 | " |
| Aug | 1501 | " |
| Sept | 1346 | " |
| Oct | 1278 | " |
| Nov | 1405 | " |
| Dec | 1544 | " Maximum Monthly Peak |

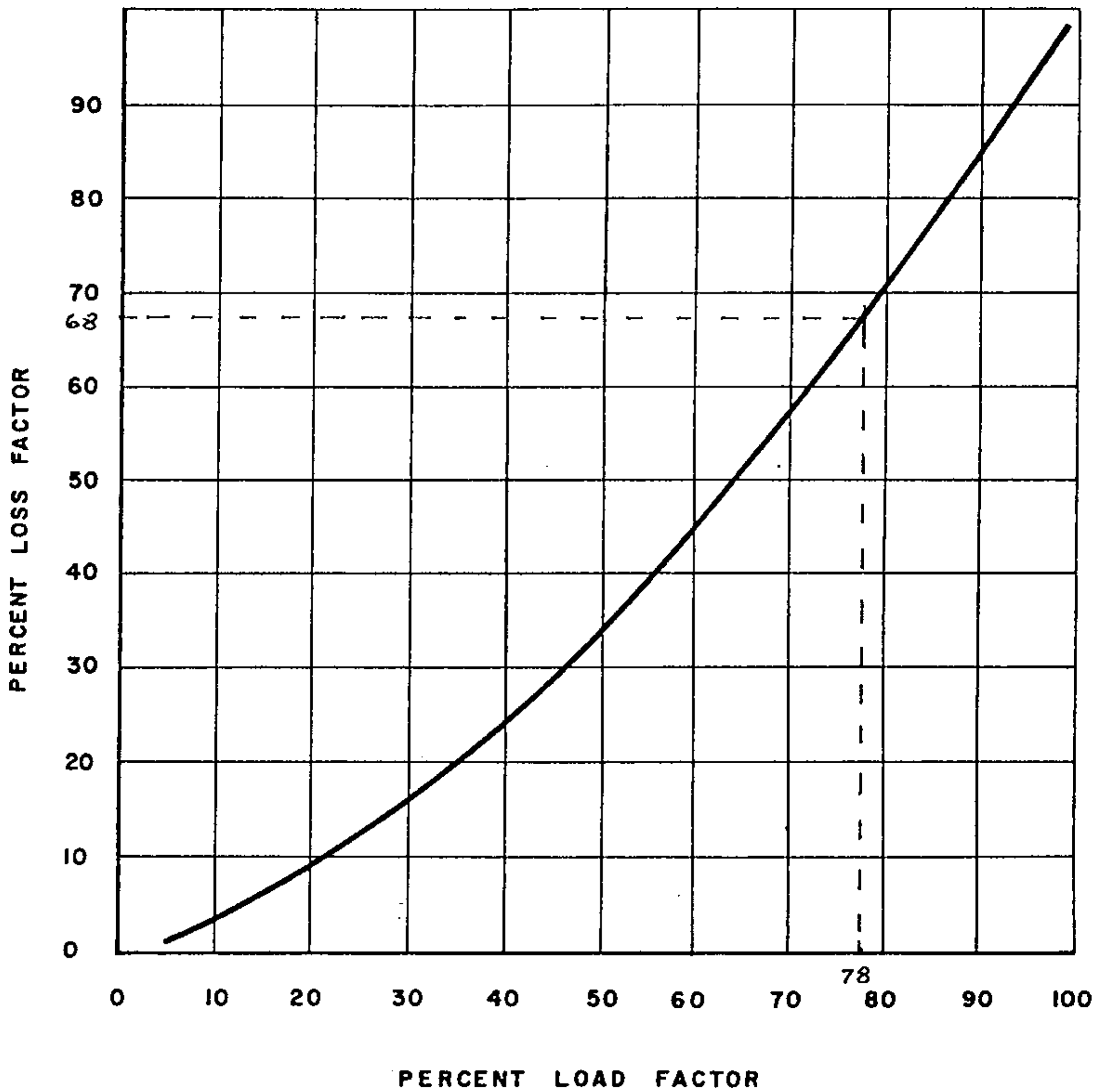
17,088 ÷ 12 = 1424 Average Monthly System Peak

LOAD FACTOR JULY 86




49,872 KWH
2000
1500
1000
500
0
2 4 6 8 10 12 14 16 18 20 22 24
HOURS
UNIT LOAD
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
TYPICAL DAILY LOAD ON 120V TRANSFORMER
AVERAGE
2 4 6 8 10 12 14 16 18 20 22 24
7 X 10 INCHES
KEUFFEL & ESSER CO.
MADE IN U.S.A.

# MSS - 84
# DS - III - 13




## LOSS FACTOR

# UNDERGROUND CABLE CHARACTERISTICS  April 13th, 195[illegible]

## ZERO SEQUENCE, RESISTANCE, REACTANCE AND IMPEDANCE

ms / 1000 ft. with 75°C copper temperature (for currents flowing through ground and sheath  500 metre ohms effective resistivity of earth.)

| VOLTAGE Cond. Formation | Cond. Size | 25 CYCLE R | 25 CYCLE X | 25 CYCLE Z | 60 CYCLE R | 60 CYCLE X | 60 CYCLE Z |
|---|---|---|---|---|---|---|---|
| 13,200 3.C.S. ☆ See sketch (a) | 500 | 0.211 | 0.199 | 0.292∠43.0 | 0.339 | 0.187 | 0.386∠29.0 |
| | 350 | 0.218 | 0.227 | 0.314∠46.0 | 0.382 | 0.254 | 0.[illegible]75∠[illegible] |
| | 250 | 0.212 | 0.236 | 0.318∠48.0 | 0.424 | 0.312 | 0.532∠36.0 |
| | 3/0 | 0.237 | 0.246 | 0.340∠46.0 | 0.452 | 0.333 | 0.567∠[illegible] |
| | 2/0 | 0.254 | 0.263 | 0.365∠46.0 | 0.492 | 0.386 | 0.628∠38.0 |
| 13,200 1.S.R. ☆ See sketch (b) | 1500 | 0.133 | 0.0669 | 0.149∠26.7 | 0.168 | 0.0500 | 0.175∠26.6 |
| | 1000 | 0.146 | 0.0852 | 0.169∠30.2 | 0.198 | 0.0682 | 0.207∠[illegible] |
| | 750 | 0.163 | 0.104 | 0.193∠32.6 | 0.230 | 0.0890 | 0.246∠21.[illegible] |
| | 350 | 0.209 | 0.134 | 0.248∠32.7 | 0.287 | 0.116 | 0.31[illegible]∠[illegible] |
| | 2/0 | 0.256 | 0.191 | 0.319∠36.7 | 0.424 | 0.216 | 0.475∠[illegible] |
| 13,200 1.S.R. ☆ See sketch (c) | 1000 | 0.146 | 0.0845 | 0.169∠30.1 | 0.197 | 0.0682 | 0.209∠[illegible] |
| | 750 | 0.159 | 0.104 | 0.189∠33.2 | 0.230 | 0.0893 | 0.247∠[illegible] |
| | 350 | 0.206 | 0.133 | 0.245∠32.9 | 0.286 | 0.1228 | 0.[illegible]∠[illegible] |
| | 2/0 | 0.250 | 0.188 | 0.312∠37.0 | 0.417 | 0.2240 | 0.473∠[illegible] |
| 13,200 1.S.R. ☆ See sketch (d) | 1500 | 0.129 | 0.0630 | 0.144∠26.0 | 0.167 | 0.0550 | 0.[illegible]∠[illegible] |
| | 1000 | 0.144 | 0.0832 | 0.166∠30.0 | 0.196 | 0.0702 | 0.208∠[illegible] |
| | 750 | 0.157 | 0.105 | 0.189∠33.8 | 0.229 | 0.0915 | 0.24[illegible]∠[illegible] |
| | 350 | 0.203 | 0.133 | 0.242∠33.2 | 0.286 | 0.125 | 0.312∠23.6 |
| | 2/0 | 0.248 | 0.187 | 0.314∠37.1 | 0.414 | 0.225 | 0.[illegible]72∠25.0 |
| 4,150 3.C.S. ☆ See sketch (a) | 750 | 0.181 | 0.175 | 0.252∠44.0 | 0.330 | 0.176 | 0.372∠[illegible] |
| | 600 | 0.187 | 0.187 | 0.263∠45.0 | 0.351 | 0.197 | 0.403∠[illegible] |
| | 250 | 0.209 | 0.243 | 0.320∠49.3 | 0.472 | 0.284 | 0.550∠[illegible] |
| | #0 | 0.266 | 0.290 | 0.394∠47.5 | 0.619 | 0.405 | 0.760∠[illegible] |
| | #4 | 0.451 | 0.302 | 0.541∠33.8 | 0.714 | 0.543 | 0.900∠[illegible] |

☆ 3.C.S. = 3 cond. sector
1.S.R. = 1 cond. round

"R" is the series resistance in ohms/1,000 ft. to zero sequence currents flowing through both ground and sheath.

"X" is the series reactance in ohms/1,000 ft. to zero sequence currents flowing through both ground and sheath.

Account has been taken of mutual effects between the cables and return paths.

September 2, 1954.

## UNDERGROUND CABLE CHARACTERISTICS

### POSITIVE AND NEGATIVE SEQUENCE, RESISTANCE, REACTANCE AND IMPEDANCE OHMS/1,000 FEET WITH 75°C COPPER TEMPERATURE

| …TAGE … Formation | Cond. Size | INSULATION Cond (Mils) | Belt (Mils) | Lead Sheath (Mils) | 25 CYCLE R (Resistance) | X (Reactance) | Z (Impedance) | 60 CYCLE R (Resistance) | X (Reactance) | Z Impedance) |
|---|---|---|---|---|---|---|---|---|---|---|
| | 750 | | | | | | | | | |
| … | 500 | 155 | 155 | 135 | 0.0263 | 0.0113 | 0.0286 /23.3 | 0.0274 | 0.0272 | 0.0386/44.8 |
| | 350 | 155 | 155 | 125 | 0.0374 | 0.0118 | 0.0392/17.5 | 0.0383 | 0.0282 | 0.0476/36.4 |
| | 250 | 155 | 155 | 115 | 0.0524 | 0.0123 | 0.0538/13.2 | 0.0531 | 0.0295 | 0.0607/29.1 |
| …d Sector | 3/0 | 155 | 155 | 110 | 0.0781 | 0.0131 | 0.0793/9.5 | 0.0785 | 0.0314 | 0.0845/21.9 |
| …etch (a) | 2/0 | 155 | 155 | 110 | 0.0986 | 0.0135 | 0.0995/7.8 | 0.0986 | 0.0324 | 0.104/18.2 |
| | 1500 | 235 | | 115 | 0.00962 | 0.0178 | 0.0202/61.6 | 0.0144 | 0.0420 | 0.0443/71.1 |
| …00 | 1000 | 235 | | 110 | 0.0139 | 0.0204 | 0.0247/55.8 | 0.0186 | 0.0482 | 0.0516/68.9 |
| | 750 | 235 | | 100 | 0.0181 | 0.0211 | 0.0278/49.5 | 0.0231 | 0.0501 | 0.0552/65.2 |
| …le Cond.round | 350 | 235 | | 95 | 0.0375 | 0.0248 | 0.0449/33.5 | 0.0417 | 0.0590 | 0.0721/54.7 |
| sketch (b) | 2/0 | 235 | | 85 | 0.0975 | 0.0296 | 0.1019/16.9 | 0.101 | 0.0705 | 0.123/34.9 |
| | 1000 | 235 | | 110 | 0.0145 | 0.0248 | 0.0287/59.7 | 0.0223 | 0.0581 | 0.0623/69.1 |
| …00 | 750 | 235 | | 100 | 0.0187 | 0.0255 | 0.0316/53.7 | 0.0254 | 0.0602 | 0.0653/67.1 |
| …le Cond.round | 350 | 235 | | 95 | 0.0380 | 0.0292 | 0.0478/37.6 | 0.0445 | 0.0693 | 0.0824/57.3 |
| sketch (c) | 2/0 | 235 | | 85 | 0.0979 | 0.0341 | 0.104/19.2 | 0.102 | 0.0811 | 0.130/38.3 |
| | 1500 | 235 | | 115 | 0.0107 | 0.0238 | 0.0261/66.0 | 0.0203 | 0.0550 | 0.0586/69.7 |
| …00 | 1000 | 235 | | 110 | 0.0149 | 0.0265 | 0.0304/60.7 | 0.0240 | 0.0617 | 0.0662/68.7 |
| …le Cond.round | 750 | 235 | | 100 | 0.0190 | 0.0273 | 0.0333/55.2 | 0.0289 | 0.0639 | 0.0700/65.7 |
| sketch (d) | 350 | 235 | | 95 | 0.0382 | 0.0308 | 0.0491/39.0 | 0.0458 | 0.0732 | 0.0862/57.9 |
| | 2/0 | 235 | | 85 | 0.0980 | 0.0358 | 0.104/20.1 | 0.104 | 0.0851 | 0.134/39.3 |
| | 750 | 95 | 65 | 125 | 0.0175 | 0.00996 | 0.0202/29.7 | 0.0188 | 0.0239 | 0.0304/51.8 |
| …0 | 500 | 95 | 65 | 125 | 0.0219 | 0.0102 | 0.0242/24.9 | 0.0230 | 0.0245 | 0.0336/46.7 |
| … Sector | 250 | 95 | 65 | 110 | 0.0524 | 0.0110 | 0.0535/11.9 | 0.0531 | 0.0264 | 0.0593/26.4 |
| sketch (a) | 1/0 | 95 | 65 | 95 | 0.124 | 0.0133 | 0.125/6.2 | 0.124 | 0.0319 | 0.128/14.5 |
| | 4 | 95 | 65 | 85 | 0.315 | 0.0155 | 0.315/2.8 | 0.315 | 0.0371 | 0.317/6.7 |

30

| ...TAGE ... Formation | Cond. Size | INSULATION Cond. (Mils) | Belt (Mils) | Lead Sheath (Mils) | 25 CYCLE R (Resistance) | X (Reactance) | Z (Impedance) | 60 CYCLE R (Resist. ance) | X (React-ance) | Z (Impedance) |
|---|---|---|---|---|---|---|---|---|---|---|
| .../208-600 ...gle conductor | 1500 | 95 | | 110 | 0.0104 | 0.0223 | 0.0246/65.0 | 0.0183 | 0.0519 | 0.0551/70.6 |
| ... sketch (c) ... | 1000 | 80 | | 100 | 0.0145 | 0.0248 | 0.0288/59.7 | 0.0215 | 0.0584 | 0.0622/69.8 |
| | 2000 | | | | | | | 0.0163 | 0.0484 | 0.0514 /71.4 |
| .../208-600 ...cond. round ...etch (d). | 1500 | 95 | | 110 | 0.0107 | 0.0239 | 0.0262/66.0 | 0.0197 | 0.0556 | 0.0591/70.5 |
| | 1000 | 85 | | 100 | 0.0148 | 0.0266 | 0.0304/60.9 | 0.0230 | 0.0622 | 0.0664/69.7 |
| .../2..3-600 cables in one ...ct. | 500 | 95 | | 95 | 0.0259 | 0.0128 | 0.0289/26.3 | 0.0270 | 0.0303 | 0.0406/48.3 |
| | 250 | 95 | | 85 | 0.0515 | 0.0138 | 0.0533/15.0 | 0.0523 | 0.0328 | 0.0618/32.1 |

...g Conductor Cable = 2/5

0.0986 0.0360

... the A.C. series resistance of one conductor in ohms/1,000 feet at 75°C, and is the D.C. resistance of an equivalent cross-section solid copper bar, with allowance for stranding, skin effect and cabling.

... the equivalent series reactance of one conductor in ohms/1,000 feet, assuming balanced load and taking into account the mutual effect between phases.

...gle Conductor Cable.

...s the equivalent A.C. series resistance of one conductor in ohms/1,000 feet at 75°C assuming perfect transposition and bonding of the sheaths and is the D.C. resistance of an equivalent cross-section solid copper bar with allowance for stranding, skin effect and sheath losses.

...s the equivalent series reactance of one conductor in ohms/1,000 feet at 75°C assuming perfect transposition and bonding of the sheaths and with allowances for sheath losses. The mutual effect between phases has been taken into account.

-----

...formulae used were derived from those in the 1950 Edition of the Electrical Transmission and Distribution Reference Book.

...e constants used apply to typical conditions on the Toronto Hydro-Electric System.

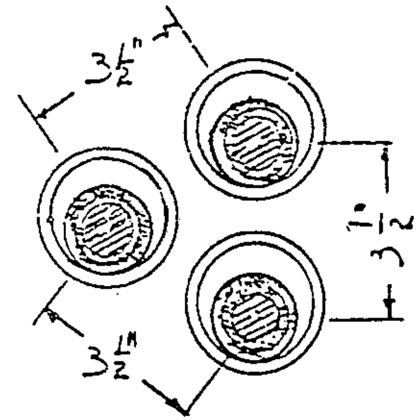
0.0330 0.0678 0.0..3

## UNDERGRO ABLE CHARACTERISTICS

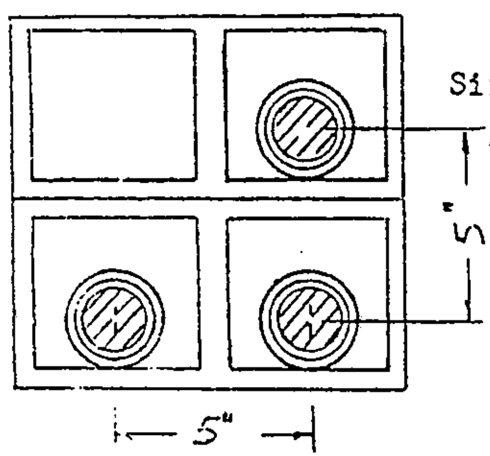
## THREE PHASE CONDUCTOR FORMATIONS

Sketch A 3 Conductor Cable
Paper insulated, compound filled, lead sheathed with sector shaped conductors

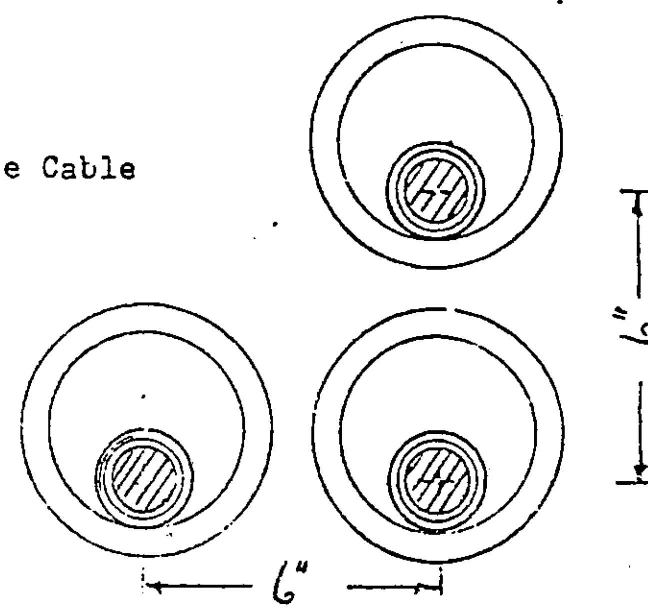

Sketch B Single Conductor Cable
Lead sheathed, in ducts with 3½" equilateral spacing.




Sketch C Single Conductor Cable
Lead Sheathed in tile ducts 5" Spacing.



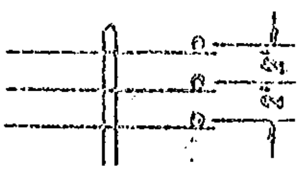
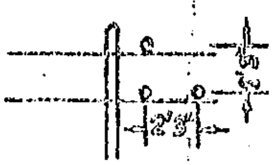
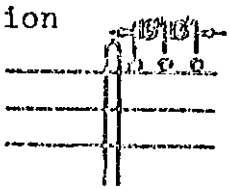

Sketch D Single Conductor Cable
Lead Sheathed in ducts 6" spacing.



# OVERHEAD LINE CHARACTERISTICS

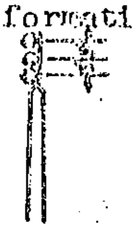
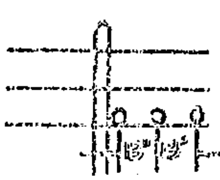
Three Phase lines, Positive and Negative Sequence only, with no reference to Neutral

Medium Hard Drawn 97.3% Conductivity Copper at 25°C.
Values in ohms/1000 feet.

| Voltage and Spacing | Wire Size | Strand | 25 CYCLE R (Resistance) | 25 CYCLE X (Reactance) | 60 CYCLE R (Resistance) | 60 CYCLE X (Reactance) |
|---|---|---|---|---|---|---|
| 3,200 Volt | #4 | 1 | 0.260 | 0.0569 | 0.260 | 0.137 |
| ft. Vertical Formation | #2 | 1 | 0.164 | 0.0547 | 0.164 | 0.131 |
|  | 1/0 | 7 | 0.105 | 0.0519 | 0.105 | 0.125 |
| | 3/0 | 19 | 0.0661 | 0.0490 | 0.0662 | 0.118 |
| | 350 | 19 | 0.0316 | 0.0456 | 0.0320 | 0.109 |
| 3,200 Volt | #4 | 1 | 0.260 | 0.0569 | 0.260 | 0.137 |
| ft. 3 inches | #2 | 1 | 0.164 | 0.0547 | 0.164 | 0.131 |
| riangular formation | 1/0 | 7 | 0.105 | 0.0519 | 0.105 | 0.125 |
|  | 3/0 | 19 | 0.0661 | 0.0490 | 0.0662 | 0.118 |
| | 350 | 19 | 0.0316 | 0.0456 | 0.0320 | 0.109 |
| ,400 - 4,150 Volt | #4 | 1 | 0.260 | 0.0510 | 0.260 | 0.122 |
| inches horizontal | #2 | 1 | 0.164 | 0.0488 | 0.164 | 0.117 |
| ormation | 1/0 | 7 | 0.105 | 0.0461 | 0.105 | 0.111 |
|  | 3/0 | 19 | 0.0661 | 0.0431 | 0.0662 | 0.104 |
| | 400 | 19 | 0.0277 | 0.0391 | 0.0281 | 0.0939 |

## OVERHEAD LINE CHARACTERISTICS

### Three Phase Lines (continued).

| Voltage and Spacing | Wire Size | Strand | 25 CYCLE R (Resistance) | 25 CYCLE X (Reactance) | 60 CYCLE R (Resistance) | 60 CYCLE X (Reactance) |
|---|---|---|---|---|---|---|
| 00 volt Concrete Pole op rack construction riangular formation. | #6 | 1 | 0.413 | 0.0515 | 0.413 | 0.124 |
| | #4 | 1 | 0.260 | 0.0493 | 0.260 | 0.118 |
| | #2 | 1 | 0.164 | 0.0471 | 0.164 | 0.113 |
|  | 1/0 | 7 | 0.105 | 0.0443 | 0.105 | 0.106 |
| | 3/0 | 19 | 0.0661 | 0.0414 | 0.0662 | 0.0993 |
| | 300 | 19 | 0.0369 | 0.0388 | 0.0372 | 0.0931 |
| | 500 | 37 | 0.0222 | 0.0362 | 0.0227 | 0.0868 |
| | 1000 | 61 | 0.0111 | 0.0328 | 0.0120 | 0.0787 |
| 00 volt Concrete Pole xtension arm onstruction ertical formation. | #6 | 1 | 0.413 | 0.0441 | 0.413 | 0.106 |
| | #4 | 1 | 0.260 | 0.0419 | 0.260 | 0.101 |
| | #2 | 1 | 0.164 | 0.0397 | 0.164 | 0.0952 |
| | 1/0 | 7 | 0.105 | 0.0369 | 0.105 | 0.0886 |
|  | 3/0 | 19 | 0.0661 | 0.0340 | 0.0662 | 0.0816 |
| | 300 | 19 | 0.0369 | 0.0314 | 0.0372 | 0.0753 |
| | 500 | 37 | 0.0222 | 0.0288 | 0.0227 | 0.0691 |
| | 1000 | 61 | 0.0111 | 0.0254 | 0.0120 | 0.0609 |
| 00 volt Concrete Pole L" arms construction ectangular formation. | #6 | 1 | 0.413 | 0.0541 | 0.413 | 0.130 |
| | #4 | 1 | 0.260 | 0.519 | 0.260 | 0.125 |
| | #2 | 1 | 0.164 | 0.0497 | 0.164 | 0.119 |
|  | 1/0 | 7 | 0.105 | 0.0469 | 0.105 | 0.113 |
| | 2/0 | 19 | 0.0661 | 0.0440 | 0.0662 | 0.106 |
| | 300 | 19 | 0.0369 | 0.0414 | 0.0372 | 0.0994 |
| | 500 | 37 | 0.0222 | 0.0388 | 0.0227 | 0.0932 |
| | 1000 | 61 | 0.0111 | 0.0354 | 0.0120 | 0.0850 |
| 00 volt 3 inches horizontal ormation. | #6 | 1 | 0.413 | 0.0532 | 0.413 | 0.128 |
| | #4 | 1 | 0.260 | 0.0510 | 0.260 | 0.122 |
| | #2 | 1 | 0.164 | 0.0488 | 0.164 | 0.117 |
| | 1/0 | 7 | 0.105 | 0.0461 | 0.105 | 0.111 |
|  | 2/0 | 19 | 0.0661 | 0.0431 | 0.0662 | 0.104 |
| | 300 | 19 | 0.0369 | 0.0405 | 0.0372 | 0.0973 |
| | 500 | 37 | 0.0222 | 0.0379 | 0.0227 | 0.0910 |
| | 1000 | 61 | 0.0111 | 0.0345 | 0.0120 | 0.0829 |

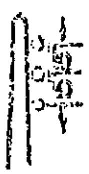
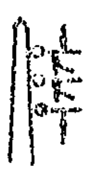
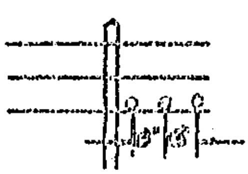
"R" is the resistance/conductor in ohms/1000 feet at 25°C and is the D.C. resistance of an equivalent cross-section solid copper bar with allowance for stranding (2%) and skin effect (a variable factor).

"X" is the reactance/conductor in ohms/1000 feet, with the mutual effect of the other phases taken into account.

## OVERHEAD LINE CHARACTERISTICS

Single Phase, Low Voltage Lines - Resistance and Reactance/Conductor. No reference to Neutral.

Medium Hard Drawn 97.3% conductivity copper at 25°C

| Voltage and Spacing | Wire Size | Strand | 25 CYCLE R (Resistance) | 25 CYCLE X (Reactance) | 60 CYCLE R (Resistance) | 60 CYCLE X (Reactance) |
|---|---|---|---|---|---|---|
| 120/240 Volt Concrete Pole, 15 inch Spacing Vertical formation. | 6 | 1 | 0.413 | 0.0590 | 0.413 | 0.142 |
| | 4 | 1 | 0.260 | 0.0568 | 0.260 | 0.136 |
| | 2 | 1 | 0.164 | 0.0546 | 0.164 | 0.131 |
| | 1/0 | 7 | 0.105 | 0.0518 | 0.105 | 0.124 |
|  | 3/0 | 19 | 0.0661 | 0.0489 | 0.0662 | 0.117 |
| | 300 | 19 | 0.0369 | 0.0463 | 0.0372 | 0.111 |
| | 500 | 37 | 0.0222 | 0.0437 | 0.0227 | 0.105 |
| | 1000 | 61 | 0.0111 | 0.0403 | 0.0120 | 0.0968 |
| 120/240 Volt Concrete Pole, 7 inch Spacing Vertical formation. | 6 | 1 | 0.413 | 0.0517 | 0.413 | 0.124 |
| | 4 | 1 | 0.260 | 0.0495 | 0.260 | 0.119 |
| | 2 | 1 | 0.164 | 0.0473 | 0.164 | 0.114 |
| | 1/0 | 7 | 0.105 | 0.0446 | 0.105 | 0.107 |
|  | 3/0 | 19 | 0.0661 | 0.0416 | 0.0662 | 0.0999 |
| | 300 | 19 | 0.0369 | 0.0390 | 0.0372 | 0.0937 |
| | 500 | 37 | 0.0222 | 0.0364 | 0.0227 | 0.0874 |
| | 1000 | 61 | 0.0111 | 0.0330 | 0.0120 | 0.0793 |
| 120/240 Volt 13 inch Spacing Horizontal formation | 6 | 1 | 0.413 | 0.0577 | 0.413 | 0.138 |
| | 4 | 1 | 0.260 | 0.0555 | 0.260 | 0.133 |
| | 2 | 1 | 0.164 | 0.0533 | 0.164 | 0.128 |
| | 1/0 | 7 | 0.105 | 0.0505 | 0.105 | 0.121 |
|  | 3/0 | 19 | 0.0661 | 0.0476 | 0.0662 | 0.114 |
| | 300 | 19 | 0.0369 | 0.0450 | 0.0372 | 0.108 |
| | 500 | 37 | 0.0222 | 0.0424 | 0.0227 | 0.102 |
| | 1000 | 61 | 0.0111 | 0.0390 | 0.0120 | 0.0935 |

"R" is the resistance conductor in ohms/1000 feet at 25°C and is the D.C. resistance of an equivalent cross-section solid copper bar with allowance for stranding (2%) and skin effect (a variable factor).

"X" is the reactance/conductor in ohms/1000 feet.

No reference is made to the Neutral.

The values are derived from data in the 1950 Edition of the Electrical Transmission and Distribution Reference Book.

# ALUMINUM STRANDED

## Physical Characteristics

BARE STRANDED ALUMINUM

PHYSICAL CHARAC-TERISTICS

### SIZES 6 AWG TO 1,590 MCM

| Size AWG or MCM | No. of Wires | Code Word | Rated Ultimate Tensile Strength Lb. | d-c Resistance at 20°C Ohms per Mile | Area Square Inches | Stranding | | Approx. Cond'r. Diam. Inch. | Net Weight Lb. per 1000 Ft. |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | No. of Wires | Wire Diam. Inch. | | |
| 6 | 7 | Peachbell | 560 | 3.492 | .0206 | 7 | .0612 | .184 | 24.4 |
| 4 | 7 | Rose | 915 | 2.174 | .0328 | 7 | .0772 | .232 | 38.8 |
| 3 | 7 | Lily | 1,135 | 1.725 | .0413 | 7 | .0867 | .260 | 48.9 |
| 2 | 7 | Iris | 1,405 | 1.368 | .0521 | 7 | .0974 | .292 | 61.7 |
| 1 | 7 | Pansy | 1,705 | 1.084 | .0657 | 7 | .1093 | .328 | 77.8 |
| 1/0 | 7 | Poppy | 2,070 | .859 | .0829 | 7 | .1228 | .368 | 98.2 |
| 1/0 | 19 | Geranium | 2,320 | .859 | .0829 | 19 | .0745 | .372 | 98.2 |
| 2/0 | 7 | Aster | 2,610 | .682 | .1045 | 7 | .1379 | .414 | 123.8 |
| 2/0 | 19 | Buttercup | 2,870 | .682 | .1045 | 19 | .0837 | .419 | 123.8 |
| 3/0 | 7 | Phlox | 3,160 | .541 | .1318 | 7 | .1548 | .464 | 156.1 |
| 3/0 | 19 | Primrose | 3,560 | .543 | .1318 | 19 | .0940 | .470 | 156.8 |
| 4/0 | 7 | Oxlip | 3,990 | .429 | .1662 | 7 | .1739 | .522 | 196.8 |
| 4/0 | 19 | Sunflower | 4,320 | .431 | .1662 | 19 | .1055 | .528 | 197.8 |
| 266.8 | 7 | Daisy | 5,025 | .340 | .2095 | 7 | .1952 | .586 | 248 |
| 266.8 | 19 | Laurel | 5,340 | .341 | .2095 | 19 | .1185 | .592 | 249 |
| 300. | 19 | Peony | 5,890 | .304 | .2356 | 19 | .1257 | .629 | 280 |
| 336.4 | 19 | Tulip | 6,605 | .271 | .2642 | 19 | .1331 | .666 | 314 |
| 397.5 | 19 | Canna | 7,650 | .229 | .3122 | 19 | .1446 | .723 | 372 |
| 477. | 19 | Cosmos | 8,990 | .191 | .3746 | 19 | .1584 | .792 | 446 |
| 500 | 19 | Zinnia | 9,425 | .182 | .3927 | 19 | .1622 | .811 | 467 |
| 556.5 | 19 | Dahlia | 10,490 | .164 | .4371 | 19 | .1711 | .856 | 520 |
| 636. | 37 | Orchid | 12,490 | .144 | .4995 | 37 | .1311 | .918 | 597 |
| 715.5 | 37 | Violet | 14,050 | .128 | .5620 | 37 | .1391 | .974 | 672 |
| 750. | 37 | Petunia | 14,430 | .122 | .5890 | 37 | .1424 | .997 | 704 |
| 795. | 37 | Arbutus | 15,300 | .115 | .6244 | 37 | .1466 | 1.026 | 747 |
| 874.5 | 37 | Anemone | 16,480 | .105 | .6868 | 37 | .1537 | 1.076 | 821 |
| 954. | 37 | Magnolia | 17,980 | .0961 | .7493 | 37 | .1606 | 1.124 | 896 |
| 1,033.5 | 37 | Bluebell | 19,480 | .0887 | .8117 | 37 | .1671 | 1.170 | 971 |
| 1,113. | 61 | Marigold | 21,850 | .0825 | .8741 | 61 | .1351 | 1.216 | 1,048 |
| 1,192.5 | 61 | Hawthorn | 23,400 | .0770 | .9366 | 61 | .1398 | 1.258 | 1,122 |
| 1,272. | 61 | Narcissus | 24,450 | .0722 | .9990 | 61 | .1444 | 1.300 | 1,197 |
| 1,351.5 | 61 | Columbine | 26,000 | .0680 | 1.0615 | 61 | .1488 | 1.339 | 1,272 |
| 1,431. | 61 | Carnation | 26,950 | .0642 | 1.1239 | 61 | .1532 | 1.379 | 1,347 |
| 1,510.5 | 61 | Gladiolus | 28,450 | .0608 | 1.1863 | 61 | .1574 | 1.417 | 1,422 |
| 1,590. | 61 | Coreopsis | 29,950 | .0578 | 1.2488 | 61 | .1614 | 1.453 | 1,496 |

*Note: The above conductors meet the requirements of CSA specification C49-1957*

**POLYETH SMOOTH BODY ALUMINUM**

# POLYETHYLENE WEATHER-RESISTANT

## Smooth Body

*See Charts Pages 30 and 31*

| Size AWG or MCM | No. of Wires | Code Word | Rated Ultimate Strength Lbs. | d-c Resistance Ohms per 1000 Ft. at 20°C | Insulation Thickness Inches | Diameter Inches | | Weight Lb. per 1000′ | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Bare | Total | Alum. | Total |
| 6 | 7 | Bay | 560 | .6551 | 2/64 | .167 | .230 | 24.4 | 33 |
| 4 | 7 | Hop | 870 | .4118 | 2/64 | .213 | .276 | 38.8 | 49 |
| 2 | 7 | Sloe | 1330 | .2591 | 3/64 | .268 | .362 | 61.7 | 81 |
| 1 | 7 | Alder | 1620 | .2053 | 3/64 | .299 | .393 | 77.8 | 99 |
| 1/0 | 7 | Aspen | 1960 | .1626 | 4/64 | .337 | .462 | 98.2 | 131 |
| 2/0 | 7 | Thorn | 2480 | .1292 | 4/64 | .377 | .502 | 123.8 | 160 |
| 3/0 | 7 | Barwood | 3000 | .1023 | 4/64 | .424 | .549 | 156.1 | 197 |
| 3/0 | 18 | Camwood | 3380 | .1028 | 4/64 | .424 | .549 | 156.8 | 198 |
| 4/0 | 7 | Dogwood | 3790 | .0811 | 4/64 | .475 | .600 | 196.8 | 242 |
| 4/0 | 18 | Oakwood | 4100 | .0816 | 4/64 | .476 | .601 | 197.8 | 243 |
| 266.8 | 7 | Redwood | 4770 | .0643 | 4/64 | .534 | .659 | 248 | 299 |
| 266.8 | 18 | Corkwood | 5070 | .0646 | 4/64 | .535 | .660 | 249 | 300 |
| 300.0 | 18 | Hornbeam | 5590 | .0576 | 4/64 | .567 | .692 | 280 | 334 |
| 336.4 | 18 | Ironwood | 6270 | .0512 | 4/64 | .600 | .725 | 314 | 372 |
| 397.5 | 18 | Beechwood | 7260 | .0434 | 5/64 | .652 | .808 | 372 | 448 |
| 477.0 | 18 | Buttonwood | 8540 | .0361 | 5/64 | .714 | .870 | 446 | 532 |

NOTE: 1) *Weights of Covered Conductors are approximate and subject to normal manufacturing tolerance.*

2) *The rated ultimate strength of polyethylene covered Aluminum is shown as 95% of the strength specified for the bare conductor.*

## Appendix J

## Box Construction Business Case Evaluation (BCE) Process

The business case evaluation (BCE) process involves the calculation of the net benefit of a capital project which requires comparing the ongoing annualized cost of an asset against the quantified risk cost associated with its failure, which is calculated based upon the assets' probability of failure and the impact of their failure.

Calculation of the probability of failure relies on the assets' Hazard Distribution Function ("HDF"), which represents a conditional probability of an asset failing from the remaining population that has survived up until that time. These functions are validated either directly by THESL or through the assistance of asset life studies from third-party consultants. The impacts of failure are then quantified by accounting for the direct costs associated with the materials and labour required to replace an asset upon failure, as well as the indirect costs. These indirect costs would include the costs of customer interruptions, emergency repairs and asset replacements. The final estimated risk cost produced, represents the product of a hazard rate function for the given asset and its corresponding impact costs. Lastly, as shown in Figure 1, the lifecycle cost is produced, representing the total operating costs for a new asset, taking into account the annualized risk and capital over its entire lifecycle. The optimal intervention time would then be the red marker at which the Equivalent Annualized Cost ("EAC") is at its lowest.

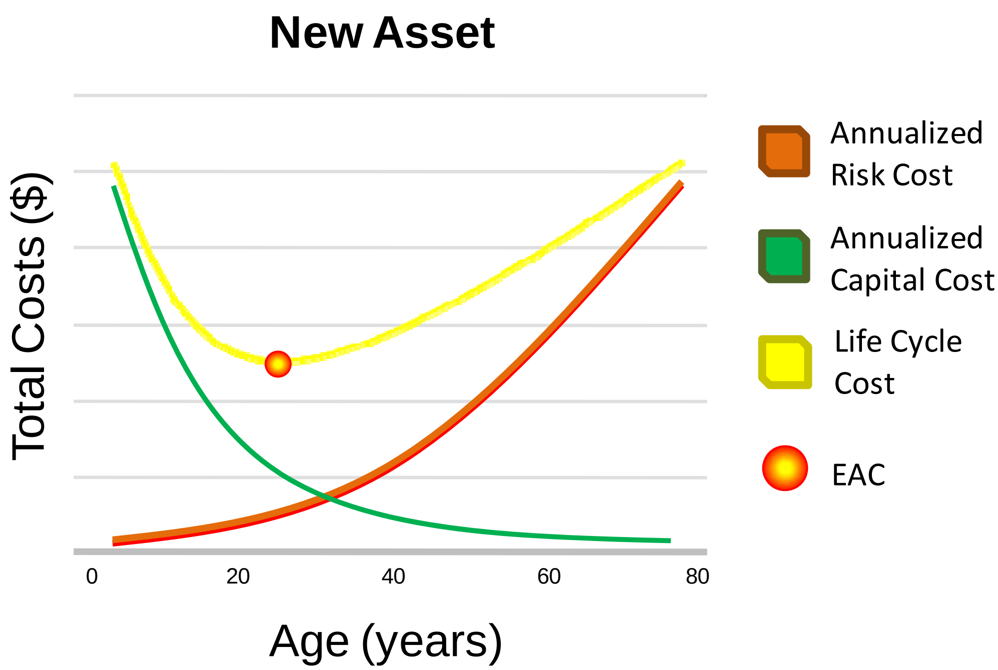



**Figure 1: Typical Example of Optimal Intervention Time (New Assets)**

This EAC value from the lifecycle cost curve would then need to be cross-referenced against the total costs of the existing asset to determine optimal replacement timing, as shown by the green marker in Figure 2. This specific point in time would indicate that the existing asset has reached its economic end-of-life at 47 years of age and requires intervention. Note that for the existing asset, there is no capital cost component, as this is a sunk cost. Therefore, the existing asset costs are comprised exclusively of the estimated risks that are remaining.

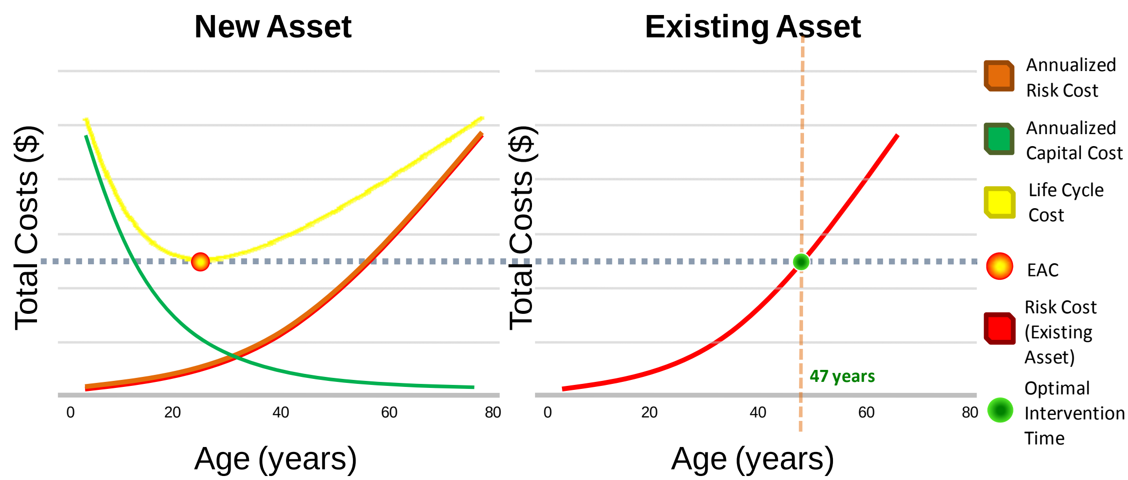



**Figure 2: Typical Example of Optimal Intervention Time (Existing Assets)**

Note that for the example in Figure 2, should the asset be replaced prior to the 47 year optimal intervention time, this would represent a sacrificed life to the asset. Should the asset be replaced after the optimal intervention time, this would represent an excess estimated risk.

4kV Box Construction conversion falls under the "non-in-kind project" category, in which existing 4kV Box Construction overhead feeders are removed from the system (existing state) and new 13.8kV overhead distribution assets are installed as part of the current construction standard (new state).

Non-in-kind projects are evaluated based on the 'cost of ownership' between the existing state and new state. In order to establish the 'cost of ownership' of a single asset, the estimated annualized risk for the existing asset is plotted along with its 'Equivalent Annual Cost' (EAC), as shown in Figure 3. The EAC defines the cost that is incurred every year, for the ownership of the asset, in a specific design for all future years. For the existing asset, only the risk is taken into account since the replacement cost is a sunk cost. As such, the asset follows its risk cost curve until it reaches its optimal replacement timing, at which point it should be replaced and thus, begins to follow the EAC line. The net present value of these costs from the current age onwards, over a 100-year period, represents the asset-related 'Cost of Ownership' of an asset in a particular design. The cost of ownership is represented by the region shaded blue in Figure 3.

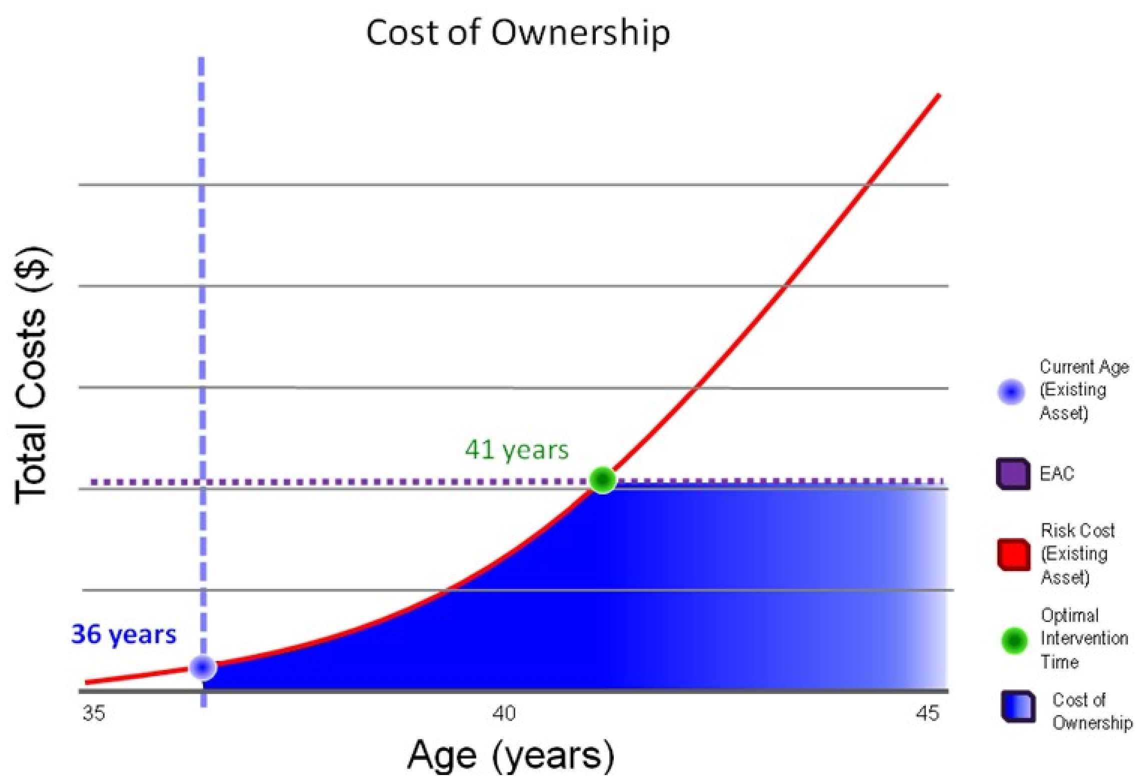



**Figure 3: Typical Example of the Cost of Ownership of the Existing Asset**

## 5.1 Data Collection - Procedure

For the 4kV Box Construction conversion project, the cost of ownership must be calculated for both the existing 4kV Box Construction assets as well as the new 13.8kV overhead distribution to be installed. Each 4kV Box Construction asset must be replaced with a 13.8kV overhead asset counterpart. For example, each 4kV overhead transformer is replaced with an equivalent 13.8kV overhead transformer, while a wood pole would be replaced with another wood pole. In addition to the distribution assets, the cost of ownership for the 4kV station assets needs to be calculated as well. In the case of 4kV station assets however, the removal of the 4kV system means that these 4kV station assets will no longer be required, so the cost of ownership of the 4kV station assets for the new case will be zero. Asset-related risks are calculated for both the existing 4kV Box Construction infrastructure as well as the new 13.8kV overhead distribution infrastructure as part of the cost of ownership determination.

## 5.2 Non Asset Risk - Procedure

Non-Asset Risks are risks incurred due to any factor that may lead to an outage on the system that is not directly tied to the assets' age and condition, including animal contact, lightning, adverse weather, and human elements.

These risks are based upon historical failures that were identified to be caused by factors that are considered to be non-asset related. The information regarding the historical failures is attained from 10 years worth of historical outage data.

Information regarding the number of outages, customer interruptions (CI) and customer hours interrupted (CHI) are captured at the feeder level from this historical outage data. This information is then normalized over the total length of the feeder, such that this historical non-asset-related information is calculated on a per meter basis for that given feeder. This normalized value is then multiplied by the length of the area of study in order to project this historical non-asset risk information to the area of study.

This information can then be translated into a quantified Non-Asset Risk (NAR) by accounting for the customer interruption costs as well as the installed load within the area of study, measured in kVA, which will be impacted should any of these non-asset-related events take place.

These costs are used as part of a net present value calculation to produce the final quantified non-asset risks (NAR) associated with the area of study. Therefore, it is assumed that these non-asset risks will continue to exist over the entire life cycle of each asset.

The 4kV Box Construction distribution and the new 13.8kV standard overhead distribution are both overhead systems and as such will both exhibit non-asset related outages. The NAR sources that impact the overhead distribution system include storms, tree contacts, adverse environments (e.g., salt spray), animal/bird contacts, human elements, extreme temperature, and vehicles. As stated within the document, the outage durations for box construction is double that of the standard 13.8kV overhead distribution and as such there are distinct NAR benefits to the Box Construction Conversion Project. This benefit is captured within this business case evaluation by assuming that the event cost will be the same, while the duration cost for the NAR will decrease with the conversion to 13.8kV standard overhead distribution.

**5.2 Ongoing Costs - Procedure**

Ongoing costs are any additional costs that are associated with a specific system configuration, which are included in the cost of ownership for the existing case. For the 4kV distribution system, this would mainly include 4kV station maintenance costs and distribution line losses.

The 4kV station maintenance costs were obtained by using a 10-year maintenance projection to obtain a yearly average based on projected costs for 2012-2021. This cost was projected out indefinitely (100 years was used) and taken back to the present value. For 4kV line losses, the difference between 4kV line losses relative to 13.8kV feeders (PV) represents savings that will be observed if 4kV feeders are replaced with 13.8kV feeders, thus this benefit needs to be captured within the business case.

The calculation looks at bus loading of 4kV MS being converted in kVA (peak loading), and using the parameters as shown in the table below, the losses are then projected out indefinitely using the 6.06% corporate discount rate which assumes the existing case will remain into the future (100 years was used).

**Table-1: Inputs used for the calculation of Line Losses**

| Input | Value Used |
|---|---|
| Power Factor | 0.95 |
| 4kV Total Losses* | 4.68% |
| 13.8kV Total Losses* | 1.75% |
| Cost of Electricity | $0.0897/kWh |
| Load Factor (as system will not be operating at peak load at all times) | 0.65 |

*Appendix I

## 5.3 Project Net Benefit (NPV) Calculation - Procedure

As previously described, the cost of ownership represents the net present value of the various costs associated with the respective existing assets across their life cycles (100-year period). Both asset-related and non-asset-related risk costs are considered as part of this cost of ownership calculation. This would also include any ongoing costs that are encountered within the existing state that would no longer be applicable in the new state.

As previously mentioned, asset-related risks include the direct and indirect costs associated with asset replacement and resulting outage impacts to customers, while non-asset risks include the indirect costs associated with outage impacts due to weather, animal and human-related events. Cost of ownership was calculated for each "state" of the assets – the existing 4kV Overhead Box Construction assets as well as the new 13.8kV overhead distribution assets. The individual cost of ownership values for each asset are totalled up to represent these respective states.

By comparing the cost of ownership of a proposed future state against the current state, benefits of establishing the future state are determined.

Cost of ownership was calculated for each "state" of the assets (existing overhead box construction and new standardized overhead asset states respectively) as per the formulas provided below:

Cost of Ownership for Existing Assets ($COO_E$) = (NPV1 + NAR1 + Ongoing Costs)

Cost of Ownership for New Assets ($COO_N$) = (NPV2 + NAR2)

Where:

- NPV1 represents cost of ownership of the existing overhead 4kV box construction assets (including station assets) to be replaced or removed, accounting for the assets' probability of failure multiplied with their impacts of failure which include direct and indirect cost attributes associated with in-service asset failures, costs of customer interruptions, emergency repairs and replacement.

- NPV2 represents cost of ownership of the 13.8 kV assets to be installed, accounting for the assets' probability of failure multiplied with their impacts of failure which include direct and indirect cost attributes associated with in-service asset failures, costs of customer interruptions, emergency repairs and replacement.
- Ongoing Costs represents any additional ongoing (maintenance, etc) or additional costs (specific risks) associated with an existing state.
- NAR1 represents the NPV calculation of non-asset risks associated with the existing overhead 4kV box construction plant selected for conversion, including animal-related, weather-related and human-related impacts taking place over the life cycle of this infrastructure.
- NAR2 represents the NPV calculation of non-asset risks associated with the new 13.8kV overhead plant, which would be taking place over the life cycle of this infrastructure.

The overall project net present value is calculated as per the following formula shown below:

- Project NPV = $(COO_E – COO_N)$ – Project Cost

Thus, the Project NPV value reflects the difference in the cost of ownership between the existing construction and new construction, with the total cost of the project subtracted.

## 5.4 Project Net Benefit (NPV) Calculation – Numerical Calculation

The breakdown of costs associated with the Box Construction Business Case Evaluation is noted in Table-2.

**Table-2: Business Case Evaluation Shows Costs of Maintaining Status Quo Exceed Capital Projects Cost**

| Business Case Element | Cost (in Millions) |
|---|---|
| Cost of Ownership of Existing Box Construction ($COO_E$) | |
| Projected risk cost of existing box construction feeders (PV)* | $40.3M |
| Projected risk cost of existing Stations (PV)** | $17.4M |
| Projected non-asset risk cost of existing 4kV overhead (PV) | $66.0M |
| Stations Maintenance for existing system (PV)*** | $2.4M |
| 4kV line losses relative to 13.8kV feeders (PV) | $10.4M |
| **TOTAL ($COO_E$)** | **$136.5M** |
| Cost of Ownership of New Standardized Overhead Construction ($COO_N$) | |
| Projected risk cost of converted feeders (PV)**** | -$7.5M |
| Projected non-asset risk cost of new 13.8kV overhead (PV) | -$54.9M |
| **TOTAL ($COO_N$)** | **-$62.4M** |
| **PROJECT COST** | **-$58.5M** |
| **PROJECT NPV** | **$15.6M** |

*'Projected risk cost of existing construction feeders (PV)' represents FIM analysis of relevant existing 4kV box construction feeders, or cost of ownership of those feeder assets.

**'Stations (NPV)' represents FIM analysis of relevant 4kV MS's, or cost of ownership of those assets. The cost of ownership of the replacement is $0 (4kV load from MS being taken on by existing 13.8kV stations, not new stations), so that value was used in the business case.

***'Stations Maintenance for existing system (PV)' represents the average annual cost of maintenance for each relevant MS (average based on projected costs for 2012-2021), and then projected out indefinitely which assumes the existing case will remain (100 years was used).

****'Projected risk cost of converted feeders (PV)' represents FIM analysis of the converted 13.8kV feeders, or cost of ownership of those new feeder assets.

## Appendix K

## Joint Health and Safety Committee Notes, page 8

10) Dale
11) John/Sean
12) Darren

**Due Dates:**

1) May 1, 2009 Closed
2) March 5, 2010 Closed
3) July 9, 2010 Closed
4) July 9, 2010 Closed
5) June 4, 2010 Closed
6) December 3, 2010 Closed
7) November 5, 2010 Closed
8) May 13, 2011 Closed
9) June 3, 2011 Closed
10) September 2, 2011 Closed
11) November 4, 2011 Closed
12) January 13, 2012 Open

**Status of the Minute: Open.**

---

**OH Minute #214 – Rule #129 Safe Limits of Approach** **Date:** May 7, 2010

**Minute Description:** Application of Rule #129 when working in box construction.

**Minute Discussion:** The Committee discussed the encroachment made when working within box construction.
**Update: November 5, 2010.** John and Sean to draft a written work procedure or other mitigation when the SLOA situations are encountered in box construction. EHS involvement required.
**Update: January 12, 2011.** No updates to report at this meeting.
**Update: March 4, 2011.** Rulebook Committee meeting scheduled for March 23, 2011.
**Update: April 1, 2011**.
**Update: July 8, 2011:** Committee decided to look at performing a risk analysis in lieu of need for Written Work Procedure at this time.
**Update: November 4, 2011:** Sean reported that he has met with Duncan Kerr and will work with him to complete a risk analysis.
**Update: December 9, 2011:** John met with Duncan to discuss this issue mid November. Duncan indicated he would canvas other utilities with box construction to see how they were coping with this issue and report back to Sean and John.

**Action:**

1) Present to the Rules Committee and communicate to Operations to make sure the CCL notifies the supervisor of this condition and it is documented on the tailboard conference form.
2) When available, advise staff to complete a "Procedure for Requesting a Change, Interpretation or Creation of a Rule" form (This form is presently in draft form.) **Update:** Raised and discussed. No further action required as Action #3 to cover this.
3) Convene a team to identify specific situations and risk mitigations in the form of a Written Work Procedure.
4) Look at doing a risk analysis with the assistance of EHS
5) Canvas other utilities with Box Construction to determine how they deal with this issue

**DRP:**
1) John B.
2) John B/Sean
3) John
4) John B/Sean
5) John B/Sean

**Due Date:**
1) December 3, 2010 Closed
2) November 5, 2010 Closed
3) February 3, 2012 Open
4) February 3, 2012 Open
5) February 3, 2012 Open

**Minute Status: Open**

---

**<u>OH Minute #222</u> – Outstanding Safety Concerns** **Date:** February 11, 2011

**Minute Description:** The committee audited the outstanding open Safety Concerns and all are currently past due, some by a significant amount of time.

**Minute Discussion:** The committee is requesting the EHS Manager to follow-up with the identified Managers responsible for the outstanding items and updates and resolutions.

**Update: March 4, 2011.** EHS Manager has met with staff to direct them to ensure updates are reflected accurately in the Safety Concern tracking process. Weekly meetings are scheduled to deal with outstanding concerns. Committee discussed Safety Concern #11901 and how it may have been prematurely closed before fully

# ICM Project – Overhead Infrastructure and Equipment

## Rear Lot Construction Segment



**Toronto Hydro-Electric System Limited (THESL)**

# ICM Project | Rear Lot Construction Segment

## Contents

# I EXECUTIVE SUMMARY

## 1. Project Description

THESL is requesting approximately $66.14 million in ICM funding to finance non-discretionary civil and infrastructure jobs related to rear lot conversion between 2012 to 2014. This amount is broken into discrete jobs, totalling approximately $34.37 million in 2012, $20.73 million in 2013 and $11.03 million in 2014. A detailed description of all the jobs, by year, is provided in Part V below.

The rear lot conversion segment responds to the critical need to move the distribution service currently located in backyards to the street, for reasons of safety, reliability and cost.

Rear lot service was implemented in certain Toronto neighbourhoods in the 1950s and 1960s. The equipment providing rear lot service is past its useful life and difficult to access and repair. As a result of its age and condition, THESL expects that this equipment will continue to fail at an increasing rate and when it does, efforts to repair it create safety, equipment availability and cost issues.

This segment will remove rear lot service in targeted areas that currently pose potential safety risks, greater reliability concerns and higher repair costs. It will be replaced with standard underground service constructed to current specifications. The result of the move to standard service will be reduced safety risks, improved reliability, and reduced costs to repair.
The work to be undertaken in each year covered by this application has been selected based on two factors:

(a) The priority associated with each specific rear lot conversion job; the need to undertake work in a logical sequence that reflects good planning, distribution contingencies and the local impacts of construction; and
(b) The amount of work THESL can complete in a given year.

Each year's funding request represents THESL's current plans for rear lot conversions in that year and the funding approved will be used for this purpose. These jobs represent incremental capital spending that is above and beyond that anticipated when current rates were approved.

## 2. Why the Project is Needed Now

THESL believes that the rear lot conversion work is non-discretionary for the reasons that follow.

If no action is taken, outages, safety risks, and costs resulting from rear lot equipment will likely accelerate to unacceptable levels. In addition to the acceleration in failure rates of the rear lot equipment, studies have shown that underground assets are more reliable and reduce maintenance costs compared to their overhead counterparts.[1] Typical outage restoration times for rear lot plant outages are more than twice those of front lot outages. Thus, customers supplied via the rear lot may experience outage durations that are much longer than normal. Additionally, the likelihood of an outage occurring is significantly higher. The graph below presents the levels of the typical outages of overhead (OH) construction versus underground (UG) construction.

[1] Fenrick, S.A., and Lullit Getachew. "Cost and Reliability Comparisons of Underground and Overhead Power Lines". *Utilities Policy*, Volume 20, Issue 1, March 2012, pages 31-37.

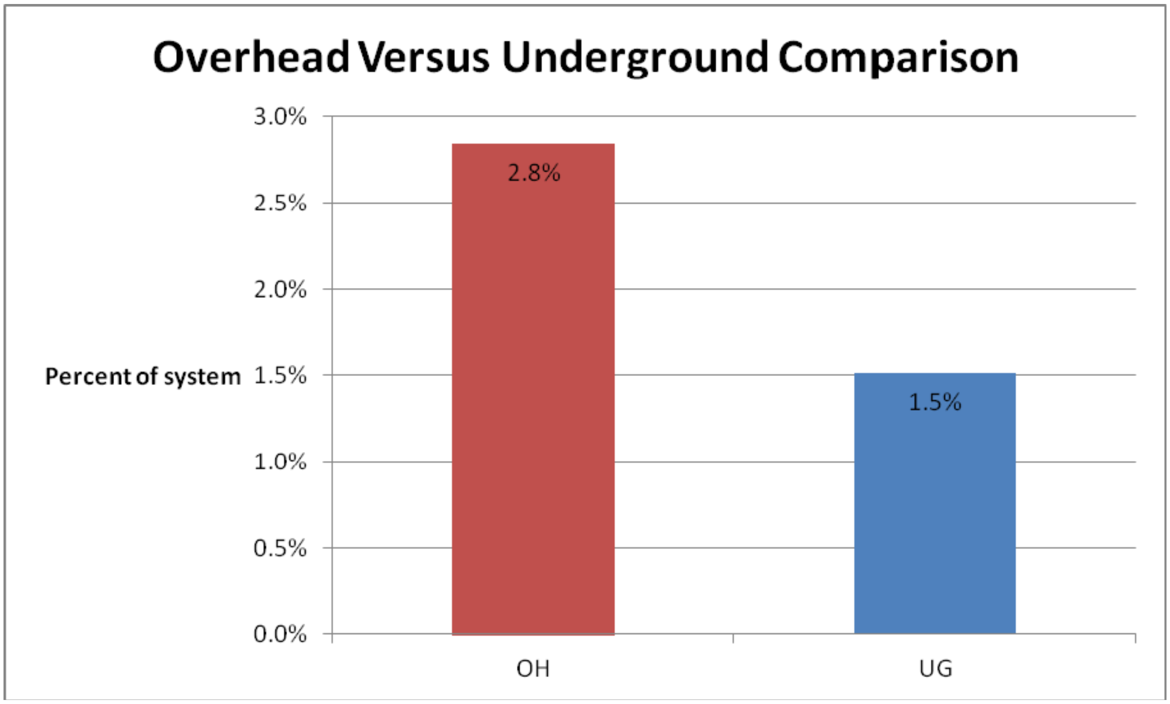



**Figure 1: Typical outages of overhead construction versus underground construction**

This segment is necessary to address the many critical issues inherent in rear lot service due to its location, and the age and condition of the equipment providing this service. The nature of these issues requires that they be addressed immediately or they will continue to pose potential safety risks to THESL crews and the public. Failure to address rear lot construction would also perpetuate ongoing cost and reliability issues, as THESL will be required to undertake expensive and time-consuming repairs on equipment that is past its useful life and difficult to access and maintain.

The specific reasons that require this segment to be undertaken now are:

- Operational constraints – THESL field crews are constantly challenged to access customers' rear lot plant due to physical inability to use the machinery typically employed for distribution system repairs (e.g., bucket trucks, cranes and drilling machines). As a result, crews are at times required to hand-carry heavy assets such as poles and transformers to effect repairs. This increases potential physical risks to the crews, particularly at night and in winter, and extends the time necessary to repair and replace failed equipment. Additional evidence on the operational constraints related to rear lot service can be found in Part III, Section 2 below.

- Asset condition - there are many rear lot distribution assets which are past their useful service lives, in very poor condition and surrounded by heavy vegetation which is challenging and expensive to manage.[2] Additional evidence on the asset condition and vegetation issues concerns related to rear lot service can be found in Part III, Sections 1 and 3 below.
- Crew safety risks – THESL crews at times have to work on poles that have rotted at the bases, making them unstable and imposing potential safety risks. Securing these poles, to the extent possible, delays restoration. Additional evidence regarding crew safety risk can be found in Part II, Section 2 below.
- Public safety risks – energized conductors and poles with associated equipment are in close proximity to residential structures and back yard activities imposing potential contact risk to the public. Additional evidence regarding public safety risk can be found in Part III, Section 4 below.
- Lengthy power restoration times – due to operational constraints, it is estimated that it takes two and a half times longer to restore power to customers compared to a typical front lot outage; during 2010 and 2011, the average CAIDI for THESL overall was 48 minutes. For a sample of rear lot related outages, the average CAIDI for these outages was 109 minutes. Additional information regarding the reliability and customer service concerns related to rear lot service can be found in Part III, Section 5 below.

### 3. Why the Proposed Project is the Preferred Alternative

Four options were evaluated to address existing rear lot risks:

(a) Option 1: Remediation – only repair/replace aged rear lot assets on an as-needed basis.

(b) Option 2: Rebuild – construct new rear lot distribution so that facilities meet current safety regulations.

[2] The same constraints that make it difficult to use heavy equipment such as bucket trucks for repairs often limit the access for the machinery typically used in pruning such as bucket trucks and chippers.

(c) Option 3: Overhead Replacement – construct new overhead front lot distribution assets to replace rear lot construction.

(d) Option 4: Underground Replacement – construct new underground front lot distribution assets to replace rear lot construction.

Option 1, remediation, would not address the issues mentioned above. The equipment providing rear lot service would continue to be beyond its useful service life and in poor condition. The cost, risks and time necessary for repair would also continue as would the potential risk to public safety. Customers served via rear lot service would continue to be exposed to long outages, as fully explained below in Section III-5, and THESL will continue to spend money repairing and maintaining assets that are poorly located and beyond their useful lives.

THESL has assessed Option 2, rebuild, as infeasible. The challenges and cost to reconstruct back yard service would be impossible to justify, given that the end result would be to perpetuate the current problems with access for repair and maintenance and proximity to houses, backyard structures and activities. Moreover, the access issues for re-construction would be even greater than those for repair and is expected to require large amounts of work to be undertaken by hand. Finally, such reconstruction activity would likely significantly disrupt customers use and enjoyment of their backyards.

Option 3, replacement of rear lot service with front lot overhead service, while possible in theory, cannot be practically implemented. Front lot overhead service would not be acceptable to customers who purchased homes without electrical poles, wires and other equipment placed in front of them and the customers would mobilize to block it. Municipal representatives and officials would be enlisted to this cause. Time and money would be expended attempting to implement a solution that, as experience has shown, ultimately would likely be rejected. A specific example of this instance is the Whitebirch rear lot conversion job, in which the planned approach was to convert the existing rear lot infrastructure to an overhead front lot design. This approach was met with extreme opposition from city councillors, and was ultimately rejected by the councillors and residents. In addition, many of the areas with rear lot service are heavily treed so installing front lot service would necessitate ongoing maintenance expenditures for tree trimming and eliminate the potential reliability gains from moving service underground in these areas.

Option 4, underground replacement, is the prudent alternative; it is the only option that offers a practical solution to the issues associated with rear lot construction. While this option has higher initial installation costs, it provides increased reliability by eliminating failures due to external events such as weather, animal and tree contacts, and also reduces the maintenance and repair costs associated with overhead facilities.

Options 1, 2 and 4 were evaluated as part of the business case, as shown below. As further explained in the Appendix, Option 3, replacement of existing rear-lot construction with front-lot overhead construction, would ultimately be rejected as a project, and therefore was not evaluated for this reason. The business case results of the remaining options are summarized in the table below.

**Table 1: Summarization of business case results**

| Business Case Element | Cost (in Millions) |
|---|---|
| **Option 1: Status Quo (Remediation on a As-Needed Basis)**<br>Cost of Ownership of Existing Rear Lot Construction **[COO$_E$]** | $92.68 |
| | |
| **Option 2: Like-for-Like Replacement of Existing O/H Rear Lot with New O/H Rear Lot**<br>Cost of Ownership of New O/H Rear Lot **[COO$_{RL}$]** | $87.09 |
| | |
| **Option 4: Replacement of Existing O/H Rear Lot with New U/G Front Lot** Cost of Ownership of New U/G Front Lot **[COO$_{UG}$]** | $11.97 |
| | |
| Upfront Project Cost (Option 1) **[COST$_E$]** | $0 |
| Upfront Project Cost (Option 2) **[COST$_{RL}$]** | $7.36 |
| Upfront Project Cost (Option 4) **[COST$_{UG}$]** | $66.14 |
| | |
| **Option 2 versus Option 1 NPV [(COO$_E$ – COO$_{RL}$) – COST$_{RL}$]** | **-$1.77** |
| **Option 4 versus Option 1 NPV [(COO$_E$ – COO$_{UG}$) – COST$_{UG}$]** | **$14.57** |
| **Non-quantified benefits of Option 4 include: Increased employee and public safety and enhanced property values** | |

From the Table above, Option 4 has the highest NPV and is the economically preferable and most prudent option. The estimated value of the project is higher than Options 1, 2, and 4. Option 4 provides an NPV of $14.57 million, which represents the difference between the current (existing rear lot) and future (new underground front lot) costs of ownership values reduced by the total project cost of $66.14M. This Option provides the most distinct economic benefits to executing this work immediately. These results, as well as the business case evaluation process, are further explained within the Appendix section. Additional benefits are difficult to quantify, such as increased safety and property values. However, while these benefits were not monetized in the NPV calculations, they are real benefits to the project. By funding Option 4, economic value to ratepayers is expected to increase, public and employee safety enhanced, and the property values of affected customers are likely to increase.

## II DESCRIPTION OF CURRENT SITUATION

### 1. History and Extent of Rear Lot Service

In the 1950's and 1960's, customers were frequently provided service from the rear of their lots rather than from the street. This method was used to reduce cost (compared to front lot underground service) while improving the aesthetics of the neighbourhood streetscape by avoiding poles and wires along the street. For rear lot plant, the electrical distribution was installed on easements between rear property lines of residential customers. As the rear lot plant aged across the city, it has become increasingly apparent that it created many issues affecting both customers (safety and reliability) and THESL crews (safety and operational constraints). Increased maintenance costs have also been associated with rear lot construction.

THESL estimates that approximately 12,000 customers are currently supplied from rear lot distribution equipment and over 1,000 circuit kilometres of rear lot plant currently exist across the THESL distribution system. A portion of over 400 specific feeders supply customers via a rear lot service. The rear lot plant is primarily concentrated in the west end of Toronto.

While there are some portions of rear lot distribution circuits that are underground, most rear lot service is overhead. The majority of rear lot facilities proposed for replacement for this ICM Segment are overheard. These facilities consist of cable, poles, transformers, switches and overhead conductors. The system also consists of minor components, such as non-standard porcelain arrestors and insulators. Rear lot conversion may also be required due to the need to replace 4kV feeders that are connected to aging stations, which are being decommissioned. Table 2 provides a summary of the total quantity of assets that can be found in the rear lot.

**Table 2: Rear lot assets**

| Asset Class | Quantity of Rear Lot Assets |
|---|---|
| Cable (m) | 505,608 |
| Poles | 6,532 |
| Transformers | 1,688 |
| Switches | 660 |
| Conductor (m) | 525,251 |

Figure 2, below, shows the high concentration of rear lot plant in the west end of the city. In these areas, rear lot conversion jobs are complex since multiple feeders provide rear lot service. These feeders are all dependent on one another for load transfers and outage contingency purposes. These interconnections necessitate the staging of conversion jobs over several years.


**Figure 2: Rear lot plant across City of Toronto**

## 2. Issues Associated with the Ongoing Provision of Rear Lot Service

Restricted access to the rear lot plant is the major factor contributing to operational and safety factors for THESL crews. Specifically, because the poles and other facilities cannot be accessed from the street, crews cannot use standard equipment, such as bucket trucks for overhead service and backhoes and other large mechanized digging equipment for underground service.

Instead, crews must manually carry and operate equipment, often in tight and confined areas. Limited access becomes especially concerning during night-time and winter month restorations when visibility and footing, respectively, are poor. This ultimately results in a higher potential of injury to THESL crews due to slips, trips, falls, and muscle strain. Injuries due to such incidents in rear lots have been reported in recent years. Restoration time is also negatively impacted by these factors (refer to Figure 3 for historical Customer Hours Interrupted due to rear lot impacts).

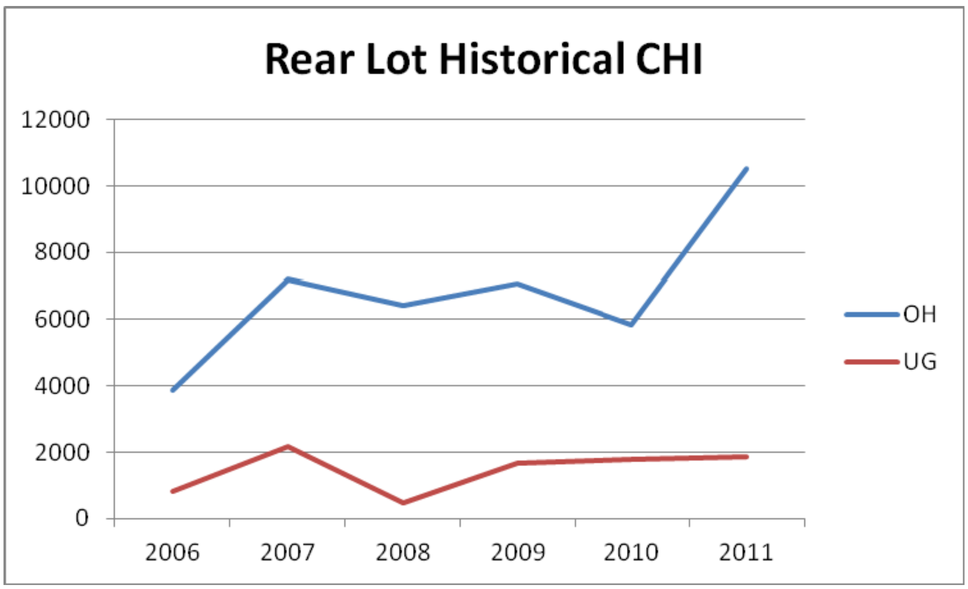



**Figure 3: Historical CHI from rear lot impacts during 2006-2011**

The proximity of rear lot plants to customers' backyards and homes presents a potential safety risk. Poles, energized cable, conductors, switches, and transformers can all be in close proximity to outdoor features and activities on customer property. Examples include sheds, eaves, trampolines, clotheslines, and pools.

In addition, there are characteristics of rear lot plant that tend to lead to increased outages. Due to the great number of mature trees in rear lot areas, animal and tree contact are frequent cause of outages.

Ultimately, the costs associated with rear lot plants are expected to continue to rise. This is mainly due to the lengthy duration of outages (due to inaccessibility), potential risks to crew safety (arising from non-standard work practices such as excessive lifting and carrying, and climbing), public safety (due to proximity of energized equipment to property), and the continued aging and deterioration of the rear lot assets.

## III WHY THE PROJECT IS NEEDED NOW

### 1. Assets Past Their Useful Lives

The following is an overview of the issues experienced by THESL as a result of the age of its rear lot assets:

- Over one-third of critical assets, such as transformers and switches in rear lots, are past their useful service lives. The vast majority of cable is direct buried and beyond its expected end-of-life.
- Over 54 kilometres of direct buried cable are past the end of their useful lives.
- Over 600 transformers and 200 switches are past their useful lives.
- The majority of poles have rot at the top and show signs of feathering (a dominant factor in determining the condition of a pole) as shown in Figures 4 and 5 below.[3] It is evident from these Figures that critical assets on the pole, such as switches and transformers, are not adequately supported due to the extensive cracking. A sample of Health Index data reviewed for rear lot areas, which recently experienced outages in excess of 15 hours, indicates that approximately 10% of the poles are in poor condition and approximately 60% are in very poor condition.
- Non-standard facilities, such as porcelain arrestors and insulators predominate.

[3] Pole top feathering de-rates the condition of the pole significantly. Furthermore, the difficulty in accessing rear lot poles creates difficulties in scheduling routine maintenance to address these issues.

1 **Figure 4: Rear lot pole in poor condition**

**Figure 5: Aging and poor condition plant in the Rexdale Colony, Forest Hill, and Thorncrest rear lot area (photo taken in 2012)**

**2. Operational Constraints**

By far, the most challenging issue for the operation and maintenance of the rear lot distribution system is that THESL vehicles and mechanized equipment (e.g., bucket trucks, cranes, and drilling machines) cannot access rear lots to perform their typical functions. As shown in Figures 6 and 7, below, the lack of road access, and the fact that pathways are often narrow and obstructed by gates, vehicles, and other customer property (e.g., pools, patios, and sheds) require that many tasks be carried out manually.

**Figure 6: Space limitations cause access restrictions to rear lot plant (photo taken in 2012)**

For example, to replace a pole in a rear lot, the new pole usually is carried to the site on a series of rope slings. Typically, a crew of six to eight is required to manoeuvre the pole into position. In turn, this leads to lengthy customer outages. Further, transformers often must be drained of oil to reduce their weight to allow them to be carried up poles; once installed onto the pole-top, they must be refilled using a pump.

Figure 7, below, illustrates a very difficult access location for an overhead transformer, a critical part of the distribution infrastructure. Examples of lengthy outages associated with the repair of rear lot facilities are described in further detail in the customer service and reliability section of this evidence.

**Figure 7: Limited access to critical THESL asset –transformer (photo taken in 2012)**

Another maintenance challenge is the existence of non-standard T-splices in the existing underground plant in rear lot areas. A T-splice is a connection made between two cables; namely, the connection between the end of one cable to the middle portion of another cable. When T-splices are present, there are no means of isolating the faulted cable and so both cables must be de-energized. This results in additional customers being exposed to the outage.

Non-standard, hand-operated Positect switches are commonly found in rear lot construction. These switches are known to cause arc flash hazards. As a result, THESL crews often are required to operate the next upstream load-break switch and then open the Positect switches after they are confirmed to be de-energized. This leads to additional customers experiencing an unplanned outage and increases outage duration. A non-standard Positect switching equipment is shown in Figure 8.

**Figure 8: Non-standard Positect switches in the Rexdale Colony rear lot area (photo taken in 2012)**

Figure 9, below, illustrates a non-standard pole top extension with porcelain insulators. Evident from the Figure is the encroachment of vegetation on overhead critical assets, such as transformers.

**Figure 9: Example of Non-standard Assets in the Rexdale Colony Rear Lot Area (photo taken in 2012)**

### 3. Vegetation Management

Mature trees and plants in rear lot areas often adversely impact THESL facilities, as shown in Figure 10 below. As backyard trees and plants grow over time, they come into direct contact with the rear lot assets, causing unnecessary outages. Tree trimming is an ongoing issue due to restricted access to rear lots, as well as limited space available for tree trimming efforts. Further, many trees in rear lot locations require extensive trimming, potentially causing issues relating to tree health and aesthetics. Tree contacts, and animal contacts facilitated by the proximity of trees, with an energized bare conductor may also pose a fire hazard.

**Figure 10: Excessive vegetation in close proximity to rear lot distribution assets**

Figure 11, below, shows areas in which vegetation has encroached the pole, to such an extent, that THESL crews would be challenged to efficiently and safely climb it. As a result, to respond to an outage, the crew first must trim the trees and then conduct repairs to restore service.

**Figure 11: Vegetation encroaching on THESL assets in the Forest Hill, Banbury-Larkfield-Charnwood, Livingston Guildwood, and Leslie-Lawrence rear lot area (photos taken in 2012)**

## 4. Public Safety

When poles lose their structural integrity, the probability of their failure increases substantially. These failures can cause property damage and pose potential safety hazards as rear lot poles are often in close proximity to houses, pools, out buildings and patios.

On poles in some rear lot areas, energized cable rises from underground to supply an overhead rear lot distribution. At these pole locations, although the cable is enclosed and protected by a cable guard, there have been occurrences where the guard may have rusted or cracked. As a result, an exposed energized cable may now be in close proximity to customer property. Further, in order to supply other nearby streets, an energized cable will 'dip' from the overhead to an underground supply in order to traverse the customer property. This cycle is repeated when the underground cable once again rises along a rear lot pole to feed another rear lot area in the vicinity.

Where rear lots service is located close to homes and other structures, home owners or contractors using ladders may violate electric clearances and expose themselves to energized conductors. As well, customers have used THESL poles situated in the rear lot to attach items such as clothes lines. This provides further potential for injury.

Figures 12a and 12b illustrate situations where the eavestroughs of the houses are very close to the pole and other THESL facilities. A customer using a ladder to clean them would be at risk. Figure 13 illustrates the safety hazard to the public due to the close proximity of the fence to the THESL pole (THESL Standard 03-2400). This represents a particular safety hazard because of the presence of a 4kV energized primary cable rising at this pole location and a high voltage 2,400 V cable (not a 120 V service line). In addition, were one of the poles, shown in the aforementioned Figures, required to be replaced, the close proximity to customer buildings and fences would restrict the amount of space available for THESL crews to work.

**Figure 12a: Example of a rear lot pole close to an eavestrough (photo taken in 2012)**

**Figure 12b: Example of customer premises in close proximity to rear lot facilities**

**Figure 13: Example of customer-owned fence installed too close to a THESL pole (photo taken in 2012)**

Figure 14 shows a clothes line attached to a rear lot pole.

**Figure 14: Clothes Line Attached to a Rear Lot Pole (photo taken in 2012)**

Customer recreational equipment located near THESL rear lot facilities also pose safety hazards. There was a concern that the trampoline in Figure 15 posed a potential safety hazard if it was to be located in close proximity to THESL rear lot plant. THESL contacted the customer to express the serious concern, and the client informed THESL that the trampoline has been moved away from the vicinity of the THESL equipment.


**Figure 15: Example of a Public Safety Issue (photo taken in 2012)**

## 5. Reliability and Customer Service

Typical outage restoration times for rear lot plant are more than twice those of front lot outages. Thus, customers supplied via the rear lot may experience outage durations much longer than normal. During the past five years, an average of three extremely lengthy outages have occurred that were attributable to rear lot distribution. The following is a summary of outages, during the past five years, attributable to rear lot distribution:

Fourteen outages occurred, each lasting over 15 hours in duration. The following is additional information on these outages:

- The average duration of these 14 outages was 29 hours;
- Ten of these outages lasted over 20 hours;
- Three outages had a duration of between 40 and 50 hours;
- One outage lasted over 60 hours;

- 12 occurred during adverse weather conditions; and
- Four resulted from tree contacts.

Rear lot configuration causes inconvenience to customers, due to potential interference with certain aspects of their properties, such as landscape, fences, gates, sheds, and pools. Work on rear lot facilities also may require people to confine their pets.

Obtaining new easements from customers is also difficult. New easements the require consent of customers. They are often very reluctant to provide their consent, since customers typically do not want poles and other facilities on their property.

In many cases, critical portions (of the primary trunk) of 4kV feeders are situated in the rear lot distribution plant. Therefore, an outage that occurs on the trunk potion of a feeder will disrupt service to all customers on that feeder. Rear lot jobs are also driven by the short-term need to convert 4kV feeders supplied by stations that are reaching the end of their serviceable lives and need to be decommissioned.

Since highly complex rear lot conversion jobs are lengthy, some jobs are already in the middle of multi-year phases. Many stakeholders must be committed from start-to-finish to these jobs. These stakeholders include other utilities, such as Bell and Rogers, the City of Toronto (road reconstruction), and area residents, who are subjected to disruptions and construction impacts for extended periods of time.

Figure 16 illustrates an already completed civil phase of a job awaiting electrical installation. In anticipation of funding for rear lot conversion, the civil construction for some of the rear lot jobs was initiated in 2011. Should Option 1 (Refer to Section IV: Alternatives for Addressing Rear Lot Construction) be selected and the proposed conversion activities postponed, THESL will have to return to these areas in 2015 (the anticipated next re-basing year) to complete the conversion work. This will result in further customer disruptions three years from now.

**Figure 16: Civil work that has been completed in the Rexdale Colony rear lot area, awaiting electrical installation (photo taken in 2012)**

Since most of these jobs take two to four years to complete (in phases), the failure to complete existing jobs between 2012-2014 means that these jobs may not be completed before 2016. This would likely turn a two-year job into a five-year job for residents of these neighbourhoods and result in new customer disruptions and dissatisfaction. As well, in these instances, THESL crews and the public likely would continue to be exposed to all the risks previously discussed. Thus, in the case of completed civil construction, it is particularly important to complete the electrical portion of the jobs and remove all rear lot assets. Doing so is expected to both increase system reliability and improve the safety of THESL's crews and the owners of properties served by rear lot construction.

### 6. Conclusions Regarding Need

The jobs proposed in for 2012, 2013 and 2014 (Refer to Section V: Detailed Description of the Work) represent the work that must be undertaken in those years based on the considerations with respect to need, as discussed above. Should the rear lot conversion work be deferred to

2015, these assets will continue aging beyond their useful service lives and their condition will continue to deteriorate. As a result, there will be a corresponding increase in the probability of high-impact outages in the areas with rear lot service. Reliability in these neighbourhoods will continue to decrease and maintenance and repair costs will continue increasing.

Rear lot conversion is targeted to neighbourhoods with the least reliable, oldest and worst condition rear lot distribution plants. The existing rear lot overhead feeders are mostly 4 kV and are often fed by direct-buried underground links. The rear lot areas designated for immediate conversion have experienced excessive outage durations, typically lasting between four to eight hours. Nine of the feeders being addressed in these rear lot areas have experienced at least one outage over 15 hours in duration during the last five years.

It is important to note that rear lot conversion jobs are typically multiphase initiatives, spread over two to four years. Due to this fact and the nature of the antiquated rear lot design, multiple feeders will require decommissioning in order to adequately reconfigure a front lot design. Further, 4kV tie point assessments will be required, which further complicate and lengthen the time required to complete rear lot conversions. For these reasons, once the rebuild of a 4kV area with rear lot service commences, it is prudent to convert all of the remaining rear lot supply in the area in a timely manner.

## IV ALTERNATIVES FOR ADDRESSING REAR LOT CONSTRUCTION

### 1. Alternatives Considered

THESL has considered four alternatives to address the issues associated with rear lot service:

- Option 1, remediation where aged rear lot facilities are repaired/replaced on an as-needed basis;
- Option 2, rebuild rear lot distribution to ensure poles and assets meet current safety regulations;
- Option 3, replace overhead rear lot distribution assets with overhead front lot distribution assets; and
- Option 4, replace overhead rear lot distribution assets with underground front lot distribution assets.

Table 4 provides a summary of each of these four options.

**Table 4: Summary of rear lot conversion options considered by THESL**

| Option | Summary of Procedure |
|---|---|
| Option 1<br>Remediation, where only aged assets are repaired/replaced aged assets on an as-needed basis | ▪ All poles, transformers and assets remain as is<br>▪ Repairs are done on an as-needed basis to the defective assets |

| Option | Summary of Procedure |
|---|---|
| Option 2<br>Rebuild rear lot distribution | ▪ Trench property owners' backyards to upgrade the underground cables passing through their yards<br>▪ Remove existing poles and transformers<br>▪ Perform necessary tree-trimming<br>▪ Install new poles, cable covers to protect the cables going into the risers<br>▪ Install new transformers<br>▪ Backfill the trench, re-sod the yard<br>▪ Restore power to the customers |
| Option 3<br>Replace overhead rear lot distribution assets with overhead front lot distribution assets | ▪ Transformers, primary cable, secondary bus installed overhead on poles<br>▪ Secondary services supplied from poles/mid-span taps |
| Option 4<br>Replace overhead rear lot distribution assets with underground front lot distribution assets | ▪ Primary and secondary bus installed in concrete-encased ducts within city road allowance<br>▪ Above grade low-profile or below grade submersible transformers to be installed<br>▪ Secondary services on private property to be installed in underground direct buried duct to existing meter base locations<br>▪ Meter bases to be changed from overhead to underground where required |

Options 1 and 2 do not address or resolve the underlying safety and reliability issues associated with rear lot service. These Options would perpetuate the safety, cost, reliability and customer service issues described in Section III. They would also require continuing intrusion into the affected backyards, disrupting customers' use and enjoyment. If the remediation or rebuild were to occur in the winter, crew access would become more challenging. If carried out in the summer, homeowners would lose the use of their backyards, a time when they most want to enjoy them.

Further, these intrusions will provide little lasting benefit. As soon as an animal contact occurs, or a serious storm takes place, resulting in an unplanned outage, homeowners will be inconvenienced, once again, by crews accessing their properties. In the meantime, the safety risks for THESL's crews and customers remain.

With regard to Option 3, replacement of overhead rear lot distribution assets with overhead front lot distribution assets, Table 5 provides an overview developed by THESL's Standard Design Practice Team regarding the challenges involved in installing overhead service.

**Table 5: Overview of THESL Standard Design Practice Team's considerations for overhead distribution design**

| Challenge | Reason |
|---|---|
| Customer acceptance<br>Customers will be reluctant to accept a new pole line in front of their property for the enumerated reasons | ▪ Streetscape aesthetics will be negatively impacted with the installation of poles, pole-mounted transformers, overhead primary and secondary cables, and serviced cables<br>▪ Customer acceptance of a pole installation in front of their property will be difficult to obtain, in most cases<br>▪ Customers may view this installation as decreasing the value of their properties |
| City approval<br>Obtaining City approval will be challenging | ▪ Negative impact on streetscape aesthetics<br>▪ Increased customer complaints<br>▪ Any 'above ground' utility installation is met with a higher level of City scrutiny. For example, Ward 2 in Etobicoke required a site meeting with the Councillor prior to any new/relocated down guy installation |
| Tree Trimming | ▪ This option will continue all the problems associated with overhead plant<br>▪ Existing areas have mature trees which will require extensive tree trimming to accommodate clearances for installation of poles, primary and secondary bus, secondary services and transformers. Relative to the undergrounding option, this will increase operating costs due to increased tree trimming required<br>▪ Negative impact on neighbourhood aesthetics |
| Toronto Hydro Corporate Communications | ▪ Increased resources required to deal with an extensive community outreach initiative<br>▪ Delays are expected to occur in situations where customers reject the overhead design option and mobilize to oppose it |

| Challenge | Reason |
|---|---|
| Scheduling | ▪ In the event the overhead option is ultimately rejected due to customers' complaints and THESL is required to install underground service, delays of six months to a year to redesign and obtain approvals can be expected |
| Foreign Attachments | ▪ There may be instances where foreign attachments (Bell, Rogers) remain on the existing rear lot pole line. Customers will be reluctant to accept pole lines in both the rear and the front of their property |

Table 6 provides a summary comparison of Option 3 (replacement with overhead front lot distribution assets) and Option 4 (replacement with underground front lot distribution assets), the two options considered for conversion of rear lot plant.

**Table 6: Summary of the two rear lot conversion options**

| Criteria | Option 3 OH | Option 4 UG |
|---|---|---|
| **Safety** | Favourable | Highly Favourable |
| **Customer Service Initiative** | Least Favourable | Highly Favourable |
| **Corporate Communications** | Least Favourable | Highly Favourable |
| **Customer Acceptance** | Least Favourable | Highly Favourable |
| **City Approvals** | Least Favourable | Favourable |
| **Reliability** | Least Favourable | Highly Favourable |
| **Tree Trimming** | Least Favourable | Favourable |
| **Construction Cost (Initial)** | Highly Favourable | Least Favourable |
| **Service Connections** | Least Favourable | Favourable |
| **Scheduling** | Least Favourable | Favourable |

As is evident from Table 6, Option 4 (replacement with underground front lot distribution assets) is the more favourable option on every dimension, except initial construction cost. This Option's higher initial construction cost is expected to be overcome, however, by the lower overall cost of ownership including lower maintenance, community engagement, and customer outage cost. When comparing the overhead and underground front lot options, the underground solution provides a cost of ownership that is approximately $47.97M less when compared to the overhead solution. This difference in cost of ownership is due to the reduced risks associated with the underground plant when compared to the overhead plant, when accounting for risks pertaining to asset failure as well as non-asset-related risks associated with weather, animal and human-related events, which are directly associated to the overhead system. As Option 4 is expected to be the most favourable option from the customers' perspective, it is recommended.

**2. Economic Benefits of the Preferred Alternative**

The effectiveness of the rear lot segment can be further highlighted by determining the difference in cost of ownership between the current overhead rear lot asset class and the future underground front lot asset class proposed to be installed. The cost of ownership for each state, current and future, includes quantified risk cost, which is the product of the assets' probability of failure and the various direct and customer costs associated with asset failures. The costs considered include those related to customer interruptions, emergency repairs and replacement. In addition, risks that are unrelated to asset age and condition, such as animal-related, human-related and weather-related events, are also considered.

Carrying out immediate work on this asset class will result in a net present value of approximately $14.57M, which represents the difference between the current and future costs of ownership values reduced by the total segment cost of $66.13M. Thus, there are quantifiable social and economic benefits expected from executing this work immediately. These results, as well as the business case evaluation process, are further explained in the Appendix in Section VI below.

In the following table, the NPV of Options 2 and 4 are shown relative to the remediation alternative (Option 1). These estimates demonstrate the economic value of Option 4 relative to Option 1 and Option 2. The details and assumptions behind these figures are shown in the Appendix in Section VI.

**Table 7: NPV of each Option relative to Option 1**

| Alternatives* | NPV (in Millions) |
|---|---|
| Option 2 vs. Option 1 (Like-for-Like Replacement of Rear Lot) | -$1.77 |
| Option 4 vs. Option 1 (Replace Rear Lot with Front Lot U/G) | $14.57 |

*Option 3 was not considered as part of this quantitative analysis, as it was determined not to be a feasible solution for the reasons noted in the Appendix.

## V DESCRIPTION OF WORK

### 1. Listing of All Jobs

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **21138** | X12113 Forest Hill Rear Lot Voltage Conversion Phase 4 – electrical | 2012 | $5.60 |
| **24342** | X11293 Forest Hill Rear Lot Voltage Conversion Phase 5 – civil | 2012 | $4.18 |
| **20012** | X12114 Forest Hill Rear Lot Voltage Conversion Phase 5 – electrical | 2012 | $3.05 |
| **21034** | W12561 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 1 | 2012 | $0.86 |
| **21250** | W12562 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 2 | 2012 | $0.07 |
| **21251** | W12563 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 3 | 2012 | $0.26 |
| **21155** | W12564 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 4 | 2012 | $1.18 |
| **21248** | W12565 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 5 | 2012 | $1.03 |
| **21252** | W12566 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 6 | 2012 | $0.09 |
| **21320** | W12567 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 7 | 2012 | $0.17 |
| **21315** | W13195 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 8 | 2012 | $1.24 |
| **22607** | E12615 Banbury Larkfield RL Rebuild UG VC SS37F2_F4 Ph 2-Electrical | 2012 | $1.51 |

## ICM Project | Rear Lot Construction Segment

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **19501** | E12076 Banbury Larkfield RL Rebuild - Ph 1 – Elec | 2012 | $2.55 |
| **18580** | E11382 Livingston Guildwood VC Rear Lot Rebuild SCGGF1 | 2012 | $5.33 |
| **24854** | E11383 Livingston Guildwood Part 2 OH VC SCGGF1 | 2012 | $0.94 |
| **20677** | W11219 Rathburn SAF1 Rear Lot Conversion | 2012 | $2.69 |
| **21321** | W11168 Albion F1 Silverstone Rear Lot Conversion | 2012 | $1.87 |
| **19755** | X12184 S/E Lawrence/Leslie P1 Electrical | 2012 | $0.19 |
| **19757** | X12185 S/E Lawrence/Leslie P2 Electrical | 2012 | $0.97 |
| **19759** | X12186 S/E Lawrence/Leslie P3 Electrical | 2012 | $0.58 |
| **2012 Total** | | | **$34.37** |
| **20662** | W12381 Rear Lot #011 Civil Infrastructure Ph#1 | 2013 | $3.24 |
| **20726** | W13017 Rear Lot #011 Ph#1 Electrical VC | 2013 | $1.45 |
| **20714** | W12401 Rear Lot #011 Civil Infrastructure Ph#2 | 2013 | $2.22 |
| **20808** | W13019 Rear Lot #011 Ph#2 Electrical VC | 2013 | $1.08 |
| **21211** | W13067 Thorncrest (#011) RL VC Ph#3 Civil/Elec | 2013 | $0.92 |
| **21213** | W13068 Thorncrest (#011) RL VC Ph#4 Civil/Elec | 2013 | $0.64 |
| **21185** | W13142 Thorncrest (#011) RL VC Ph#5 Civil | 2013 | $8.76 |
| **21186** | W13020 Thorncrest (#011) RL VC Ph#5 Electrical | 2013 | $2.43 |
| **2013 Total** | | | **$20.73** |
| **21484** | W11726 Markland Woods Rear Lot VC phase 1 Civil | 2014 | $5.63 |

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **24945** | W11726 Markland Woods Rear Lot VC phase 1 Electrical | 2014 | $5.40 |
| **2014 Total** | | | **$11.03** |
| **2012 – 2014 Total** | | | **$66.13** |

## 2. Forest Hill Rear Lot (X12113, X11293, X12114)

### 2.1 Objectives

The purpose of this job is to improve reliability in the Forest Hill area by converting the rear lot electrical equipment from the following 4kV feeders to front lot underground: B72EG from Eglinton MS, B1CP from Chaplin MS, and B1OV and B5OV from Overdale MS. As discussed above, converting rear lot service is also expected to reduce safety risks for THESL crews and area residents and reduces outage time by eliminating access issues. Indeed, during 2010, a crew member suffered a knee injury in this area due to a slip, trip, and fall incident.

This job should be constructed in 2012 since the area residents in the Forest Hill area already have experienced construction disruptions for four years. This job represents the final phases for conversion of the area. As such, further delays to job completion would negatively impact the area residents. Further, half of the area proposed for this job already has civil construction completed. The rear lot plant is still likely to pose safety risks, however as discussed above in Section III, until THESL assets are relocated to the street.

Residents in this area have been subject to long duration outages and remain susceptible to them. For instance, in 2007, area residents experienced a sustained outage that lasted over 19 hours and, in 2010, area residents experienced a sustained outage that lasted over 12 hours.

### 2.2 Scope of Work

This job will replace both overhead and underground rear lot facilities by installing new 28kV aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts. Poles are required to be installed along major streets in order to accommodate the proposed 27.6kV conductors supplying this area.

| Asset Type | | Assets Installed | |
|---|---|---|---|
| | | Non-Linear Asset Count | Linear Asset Count (m) |
| Pole | | 21 | |
| Switch | | | |
| Transformer | Dry | | |
| | Network | | |
| | Padmount | | |
| | Polemount | | |
| | Submersible | 31 | |
| | Vault | | |
| Conductor | | | 1,065 |
| Cable | | | 17,000 |
| Underground-Civil work | | | 5,400 |

### 2.3 Locations

The assets being replaced by this job are located in the vicinity of the intersection of Eglinton Avenue West and Allen Road.

### 2.4 Required Capital Costs

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **21138** | X12113 Forest Hill Rear Lot Voltage Conversion Phase 4 - electrical | 2012 | $5.60 |
| **24342** | X11293 Forest Hill Rear Lot Voltage Conversion Phase 5 – civil | 2012 | $4.18 |
| **20012** | X12114 Forest Hill Rear Lot Voltage Conversion Phase 5 - electrical | 2012 | $3.05 |
| | | **Total** | **$12.83** |

### 3. Rexdale Colony Park OH Rear Lot (W12561, W12562, W12563, W12564, W12565, W12566, W12567, W13195)

#### 3.1 Background

The Rexdale Colony, located in the western part of Toronto, exemplifies many of the issues facing rear lot areas across the city. Figure 16 illustrates the current configuration overlaid upon a satellite view of the same area:

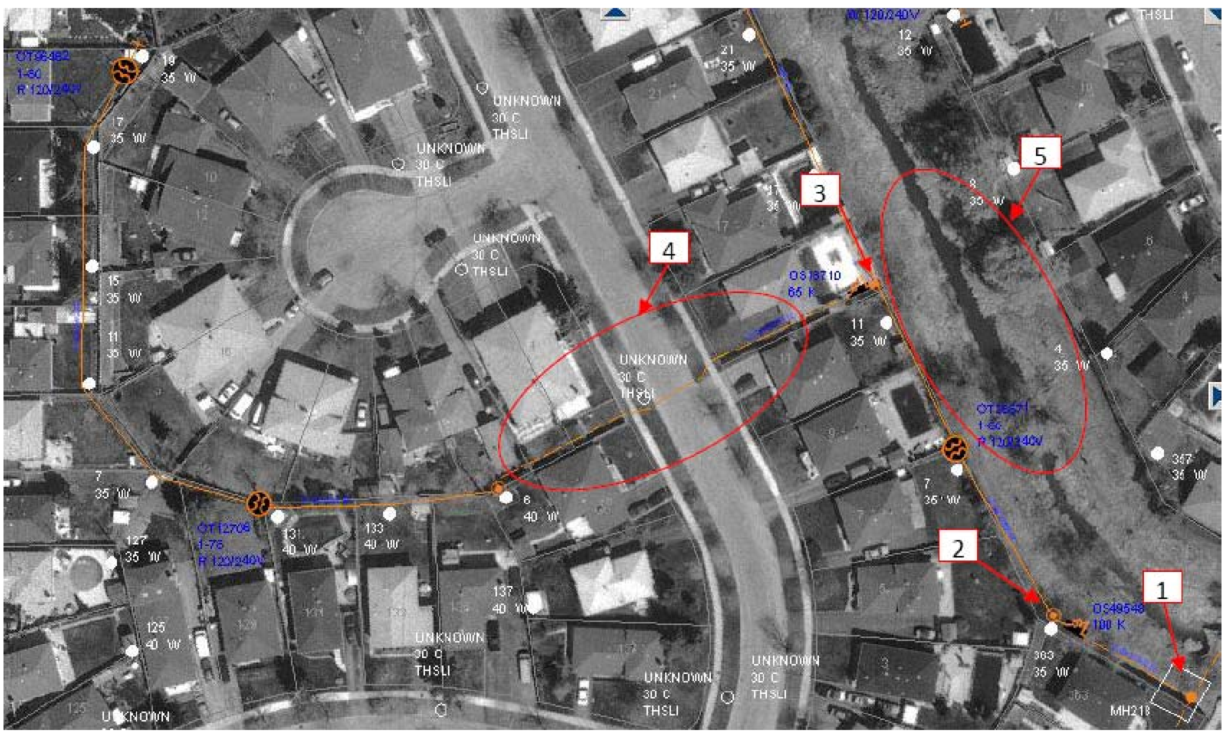



**Figure 17: Current configuration of the Rexdale Colony overlaid upon a satellite view**

Figure 17 illustrates several operational and safety issues present in the rear lot. Item #1 illustrates the direct buried cables supplying the rear lot plant. This cable is over 40 years old. Should an outage occur on a direct buried cable situated like this one, the restoration time would be quite long.

Item #2 illustrates a 4kV cable rising up a pole to supply the overhead rear lot plant. Although the cable is enclosed and protected by a cable guard, in some instances, the guard may rust or even be cracked, inadvertently, by area residents when performing normal daily backyard activities (lawn care, construction due to property additions such as sheds, etc). As a result, the cable will be directly exposed to even more mechanical damage. In cases where a 4kV cable is exposed to water (via rainwater or regular backyard watering), the conductor is subject to corrosion that can damage the component and lead to failure, as well as accelerated deterioration of the insulation component. Further, the cable could become a shock hazard given its close proximity to area residents' backyards. Finally, should an outage occur on this cable, lengthy restoration will likely result due to the inaccessibility of the rear lot.

Item #3 illustrates a 4kV dip down a rear lot pole. This dip is used to traverse to another rear lot area in the vicinity and resupply that area. Similar to item #2, this presents a potential safety risk and will result in lengthy outage should there be a fault of the cable.

Item #4 illustrates a direct buried cable traversing between customer premises. Should an outage occur on this portion of the cable, a lengthy restoration time can be expected due to difficulties in tracing the cable and locating the fault. Disruption to customer property is also likely result.

Item #5 illustrates a heavily treed ravine area parallel to the overhead rear lot plant. The ravine further restricts accessibility in the event of an outage.

Table 8 provides a summary of the issues pertaining to the Rexdale Colony rear lot area.

**Table 8: Summary of the issues pertaining to the Rexdale Colony rear lot area**

| Number | Issue |
|---|---|
| 1 | Supply point to rear lot |
| 2 | Rise overhead to supply rear lot area |
| 3 | Dip underground |
| 4 | DB between house, Concrete Encased under road |
| 5 | Heavily treed ravine |

### 3.2 Objectives

The purpose of this job is to improve service reliability in the Rexdale Colony Park area by converting the rear lot electrical equipment from the following 4kV feeders to front lot underground: ARF4 from Royalcrest MS and PFF1 andPFF2 from Delamere MS.

This work should be constructed in 2012 since the area residents in the Rexdale Colony area already have experienced construction disruptions. These jobs represent the final phases for conversion of the area. As such, further delays in completion would adversely impact area residents. Further, all of the area proposed for this job already has civil construction completed. However, the rear lot plant may still pose safety risks, as discussed above in Section III, until THESL assets are relocated to the street. In addition, area residents remain susceptible to long-duration outages.

### 3.3 Scope of Work

This job will replace both overhead and underground rear lot facilities by installing new 28kV aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts.

| **Asset Type** | | **Assets Installed** | |
|---|---|---|---|
| | | Non-Linear Asset Count | Linear Asset Count (m) |
| Pole | | | |
| Switch | | 2 | |
| Transformer | Dry | | |
| | Network | | |
| | Padmount | | |
| | Polemount | | |
| | Submersible | 68 | |
| | Vault | | |
| Conductor | | | |
| Cable | | | 12,668 |
| Underground-Civil work | | | |

### 3.4 Locations

The assets being replaced by this job are located in the vicinity of the intersection of Martin Grove Road and Albion Road.

### 3.5 Required Capital Costs

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **21034** | W12561 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 1 | 2012 | $0.86 |
| **21250** | W12562 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 2 | 2012 | $0.07 |
| **21251** | W12563 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 3 | 2012 | $0.26 |
| **21155** | W12564 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 4 | 2012 | $1.18 |
| **21248** | W12565 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 5 | 2012 | $1.03 |
| **21252** | W12566 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 6 | 2012 | $0.09 |
| **21320** | W12567 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 7 | 2012 | $0.17 |
| **21315** | W13195 Rexdale Colony Park OH Rear Lot to UG front lot conversion phase 8 | 2012 | $1.24 |
| | | **Total** | **$4.90** |

## 4. Banbury - Larkfield – Charnwood Rear Lot (E12615, E12076)

### 4.1 Objectives

The purpose of this job is to improve reliability in the Banbury – Larkfield – Charnwood area by converting the rear lot electrical equipment from the following 4kV feeders to front lot underground: SS46F1 and SS46F2 from Lesmill MS and SS37F2 and SS37F4 from Don Mills West MS. This job should be constructed in 2012 since the area residents in the Banbury – Larkfield - Charnwood area already have experienced construction disruptions. These jobs represent the final phases for conversion of the area. As such, further delays to job completion would negatively impact area residents. Further, all of the area proposed for this job already has civil construction completed. However, the rear lot plant will still pose the safety risks, as discussed above in Section III, to both THESL crew and area residents until THESL assets are relocated to the street.

Residents in this area have been subject to long duration outages. During 2007, 2008, and during 2009, area residents experienced three sustained outages that lasted over 20 hours. In 2010 and 2011, area residents experienced two sustained outage that lasted over ten hours. There were also six additional outages lasting between two to five hours.

This job will also alleviate the overloading of existing 4 kV circuits in the surrounding area. A recent irreparable failure within Lesmill MS required THESL to re-supply area residents from the neighbouring municipal substations: Northdale MS, Winfield MS and Don Mills West. This led to some feeders from these stations becoming overloaded.

### 4.2 Scope of Work

This job will replace both overhead and underground rear lot facilities by installing new 28kV aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts.

| Asset Type | | Assets Installed: Non-Linear Asset Count | Assets Installed: Linear Asset Count (m) |
|---|---|---|---|
| Pole | | | |
| Switch | | | |
| Transformer | Dry | | |
| | Network | | |
| | Padmount | | |
| | Polemount | | |
| | Submersible | 57 | |
| | Vault | | |
| Conductor | | | |
| Cable | | | 7,000 |
| Underground-Civil work | | | |

### 4.3 Locations

The assets being replaced by this job are located in the vicinity of the intersection of Leslie Street and Banbury Road.

### 4.4 Required Capital Costs

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **22607** | E12615 Banbury Larkfield RL Rebuild UG VC SS37F2_F4 Ph 2-Electrical | 2012 | $1.51 |
| **19501** | E12076 Banbury Larkfield RL Rebuild - Ph 1 - Elec | 2012 | $2.55 |
| | | **Total** | **$4.06** |

## 5. Livingston Guildwood Rear Lot (E11382, E11383)

### 5.1 Objectives

The purpose of this job is to improve service reliability in the Guildwood Livingston rear lot area by converting both overhead and underground rear lot electrical equipment from the following 4kV feeders to front lot underground: GGF1 from Livingston Guildwood MS and GEF2 from Galloway Dearhamwoods MS. This job should be constructed in 2012 since the area residents in the Livingston Guildwood area already have experienced construction disruptions for four years. These jobs represent the final phases for conversion of the area. As such, further delays to job completion would adversely impact the area residents. Further, all of the area proposed for this job already has civil construction completed. However, the rear lot plant will still pose the safety risks, as discussed above in Section III, to both THESL crew and area residents until THESL assets are relocated to the street.

Residents in this area remain susceptible to long duration outages. During the past year there has been one extended outage in this area, with more than 500 customers losing power for over two hours.

### 5.2 Scope of Work

This job will replace both overhead and underground rear lot facilities by installing new 28kV aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts. Poles are required to be installed along major streets in order to accommodate the proposed 27.6kV conductors supplying this area.

| Asset Type | | Assets Installed | |
|---|---|---|---|
| | | Non-Linear Asset Count | Linear Asset Count (m) |
| Pole | | 75 | |
| Switch | | 1 | |
| Transformer | Dry | | |
| | Network | | |
| | Padmount | | |
| | Polemount | | |
| | Submersible | 30 | |
| | Vault | | |
| Conductor | | | 2,870 |
| Cable | | | 3,900 |
| Underground-Civil work | | | |

### 5.3 Locations

The assets being replaced by this job are located in the vicinity of the intersection of Livingston Road and Guildwood Parkway.

### 5.4 Required Capital Costs

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **18580** | E11382 Livingston Guild VC Rear Lot Rebuild SCGGF1 | 2012 | $5.33 |
| **24854** | E11383 Livingston Guildwood Part 2 OH VC SCGGF1 | 2012 | $0.94 |
| | | **Total** | **$6.27** |

## 6. Rathburn SAF1 Rear Lot (W11219)

### 6.1 Objectives

The purpose of this job is to improve reliability in an area of Etobicoke by converting the rear lot electrical equipment from the following 4kV feeders to front lot underground: SAF1 and WBF3 This job should be constructed in 2012 since the area residents in this area already have experienced construction disruptions. This job represents the final phase for conversion of the area. As such, further delays to job completion would negatively impact area residents. Further, all of the area proposed for this job already has civil construction completed.

In addition, the MS transformers supplying this area have been in service since 1955. Recent DGA testing shows the paper strength to be only 30%(TR#1) and 50%(TR#2). The acid number and moisture levels for both transformers are high as well, especially for TR#1. Further, the circuit breakers are 1955 and 1966 vintages, respectively. As such, conversion of this area will avoid the need for expensive station asset replacement costs.

### 6.2 Scope of Work

This job will replace both overhead and underground rear lot facilities by installing new 28kV aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts.

| Asset Type | | Assets Installed | |
|---|---|---|---|
| | | Non-Linear Asset Count | Linear Asset Count (m) |
| Pole | | | |
| Switch | | | |
| Transformer | Dry | | |
| | Network | | |
| | Padmount | | |
| | Polemount | | |
| | Submersible | 18 | |
| | Vault | | |
| Conductor | | | |
| Cable | | | 5,600 |
| Underground-Civil work | | | |

### 6.3 Locations

The assets being replaced by this job are located in the vicinity of the area of Eglinton Avenue West, Rathburn Road, and The East Mall.

### 6.4 Required Capital Costs

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **20677** | W11219 Rathburn SAF1 Rear Lot Conversion | 2012 | $2.69 |
| | | **Total** | **$2.69** |

## 7. Albion F1 Silverstone Conversion Rear Lot (W11168)

### 7.1 Objectives

The purpose of this job is to improve service reliability in the Silverstone area by converting the rear lot electrical equipment from the following 4kV feeder to front lot underground: MGF1 from Albion MS. This job should be constructed in 2012 since the area residents in the Albion Silverstone area already have experienced construction disruptions. This job represents the final phase for conversion of the area. As such, further delays to job completion would negatively impact area residents. Further, all of the area proposed for this job already has civil construction completed.

However, rear lot plant will still pose the safety risks, as discussed above in Section III, to both THESL crew and area residents until THESL assets are relocated to the street. During 2010, a crew member suffered a knee injury in this area due to a slip, trip, and fall incident. In addition, until this work is completed, area residents remain susceptible to long duration outages.

### 7.2 Scope of Work

This job will replace both overhead and underground rear lot facilities by installing new 28kV aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts.

| Asset Type | | Assets Installed | |
|---|---|---|---|
| | | Non-Linear Asset Count | Linear Asset Count (m) |
| Pole | | 1 | |
| Switch | | | |
| Transformer | Dry | | |
| | Network | | |
| | Padmount | | |
| | Polemount | | |
| | Submersible | 17 | |
| | Vault | | |
| Conductor | | | |
| Cable | | | 5,567 |
| Underground-Civil work | | | |

### 7.3 Locations

The assets being replaced by this job are located in the vicinity of the intersection of Martin Grove Road and Albion Road.

### 7.4 Required Capital Costs

| Job Estimate Number | Job Title | Job Year | Cost Estimate ($M) |
|---|---|---|---|
| **21321** | W11168 Albion F1 Silverstone Rear Lot Conversion | 2012 | $1.87 |
| | | **Total:** | **$1.87** |

## 8. Lawrence Leslie Rear Lot (X12184, X12185, X12186)

### 8.1 Objectives

The purpose of this job is to improve service reliability in the Lawrence and Leslie area by converting the rear lot electrical equipment from the 4kV feeder 37F2 to front lot underground. This job should be constructed in 2012 since residents in the Lawrence Leslie area already have experienced construction disruptions. These jobs represent the final phases for conversion of the area. As such, further delays to job completion would negatively impact area residents. Further, all of the area proposed for this job already has civil construction completed.

Residents in this area have been subject to long-duration outages and remain susceptible to them. During 2007, area residents experienced two sustained outages; one lasted over 40 hours and one lasted over 60 hours. Also, during the past year, area residents experienced a sustained outage that lasted 15 hours and three more lasting over two hours each.

### 8.2 Scope of Work

This job will replace both overhead and underground rear lot facilities by installing new 28kV aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts. Poles are required to be installed along major streets in order to accommodate the proposed 27.6kV conductors supplying this area.

| Asset Type | | Assets Installed | |
|---|---|---|---|
| | | Non-Linear Asset Count | Linear Asset Count (m) |
| Pole | | 21 | |
| Switch | | 5 | |
| Transformer | Dry | | |
| | Network | | |
| | Padmount | | |
| | Polemount | | |
| | Submersible | 19 | |
| | Vault | | |
| Conductor | | | |
| Cable | | | 4,650 |
| Underground-Civil work | | | |

### 8.3 Locations

The assets being replaced by this job are located in the vicinity of the intersection of Lawrence Avenue East and Leslie Street.

### 8.4 Required Capital Costs

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **19755** | X12184 S/E Lawrence/Leslie P1 Electrical | 2012 | $0.19 |
| **19757** | X12185 S/E Lawrence/Leslie P2 Electrical | 2012 | $0.97 |
| **19759** | X12186 S/E Lawrence/Leslie P3 Electrical | 2012 | $0.58 |
| | | **Total** | **$1.74** |

## 9. Thorncrest Area Rear Lot (W12381, W13017, W12401, W13019, W13067, W13068, W13142, W13020)

### 9.1 Objectives

The purpose of this job is to improve reliability in the Thorncrest area by replacing and converting the rear lot electrical equipment from the following 4kV feeders to front lot underground: SBF1, BHF2, and RAF2. This job should be constructed in 2013 since the area residents in the Thorncrest area have experienced long duration outages and remain susceptible to them. During 2009, area residents experienced two sustained outages: one lasted over 25 hours, and the other lasted over 40 hours. During 2011, area residents experienced two sustained outages, which lasted between 12 and 15 hours.

### 9.2 Scope of Work

This job will replace both overhead and underground rear lot facilities by installing new 28kV aluminum TRXLPE-insulated cable in new concrete-encased front lot ducts and associated equipment. Poles are required to be installed along Rathburn Rd and Kipling Ave in order to accommodate the proposed 27.6kV conductors supplying this area.

| Asset Type | | Assets Installed | |
|---|---|---|---|
| | | Non-Linear Asset Count | Linear Asset Count (m) |
| Pole | | 78 | |
| Switch | | | |
| Transformer | Dry | | |
| | Network | | |
| | Padmount | | |
| | Polemount | 7 | |
| | Submersible | 20 | |
| | Vault | 10 | |
| Conductor | | | 6,500 |
| Cable | | | 19,210 |
| Underground-Civil work | | | 18,118 |

### 9.3 Locations

The assets being replaced by this job are located in the vicinity of the intersection of Rathburn Road and Islington Avenue.

### 9.4 Required Capital Costs

| Project Estimate Number | Project Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **20662** | W12381 Rear Lot #011 Civil Infrastructure Ph#1 | 2013 | $3.24 |
| **20726** | W13017 Rear Lot #011 Ph#1 Electrical VC | 2013 | $1.45 |
| **20714** | W12401 Rear Lot #011 Civil Infrastructure Ph#2 | 2013 | $2.22 |
| **20808** | W13019 Rear Lot #011 Ph#2 Electrical VC | 2013 | $1.08 |
| **21211** | W13067 Thorncrest (#011) RL VC Ph#3 Civil/Elec | 2013 | $0.92 |
| **21213** | W13068 Thorncrest (#011) RL VC Ph#4 Civil/Elec | 2013 | $0.64 |
| **21185** | W13142 Thorncrest (#011) RL VC Ph#5 Civil | 2013 | $8.76 |
| **21186** | W13020 Thorncrest (#011) RL VC Ph#5 Civil | 2013 | $2.43 |
| | | **Total** | **$20.73** |

## 10. Markland Woods Rear Lot (W11726)

### 10.1 Objectives

The purpose of this job is to improve reliability in the Markland Woods area by converting the rear lot electrical equipment from the following 4kV feeders to front lot underground: ETLFF1, ETLFF4, ETBAF4, ETLFF3, ETBAF1, and ETLFF2 from Mill MS and Neilson MS. This job should be constructed in 2014 since the area residents in the Markland Woods area have experienced long-duration outages and remain susceptible to them. Since 2009, area residents have sustained a total of 17 outages of varying durations. Specifically, during 2009, area residents experienced three sustained outages; two lasted over ten hours and one lasted over 40 hours. During 2010, area residents experienced a sustained outage that lasted over 25 hours. Finally, during this past year, area residents experienced one sustained outage that lasted over ten hours.

### 10.2 Scope of Work

This job will begin to replace both overhead and underground rear lot facilities by installing new concrete-encased front lot ducts.

| Asset Type | | Assets Installed | |
|---|---|---|---|
| | | Non-Linear Asset Count | Linear Asset Count (m) |
| Pole | | 2 | |
| Switch | | 7 | |
| Transformer | Dry | | |
| | Network | | |
| | Padmount | 18 | |
| | Polemount | | |
| | Submersible | | |
| | Vault | | |
| Conductor | | | |
| Cable | | 12,000 | |
| Underground-Civil work | | | 5,979 |

### 10.3 Locations

The assets being replaced by this job are located in the vicinity of the intersection of Mill Road and Burnhamthorpe Road.

## 10.4 Required Capital Costs

| Job Estimate Number | Job Title | Year | Cost Estimate ($M) |
|---|---|---|---|
| **21484** | W11726 Markland Woods Rear Lot VC phase 1 Civil | 2014 | $5.63 |
| **24945** | W11726 Markland Woods Rear Lot VC phase 1 Electrical | 2014 | $5.40 |
| | | **Total** | **$11.03** |

# VI APPENDIX A: NPV Calculations and BCE Overview

**Rear Lot Business Case Evaluation (BCE) Process**

The business case evaluation (BCE) process involves the calculation of the net benefit of a capital project. This requires comparing the ongoing annualized cost of an asset against the quantified risk cost associated with its failure, which is calculated based upon the assets' probability of failure and the impact of their failure.

The calculation of the probability of failure relies on the assets' Hazard Distribution Function ("HDF"), which represents a conditional probability of an asset failing from the remaining population that has survived up until that time. These functions are validated either directly by THESL or through the assistance of asset life studies from third-party consultants. The impacts of failure are then quantified by accounting for the direct costs associated with the materials and labour required to replace an asset upon failure, as well as the indirect costs. These indirect costs would include the costs of customer interruptions, emergency repairs and asset replacements. The final estimated risk cost is produced, which represents the product of a hazard rate function for the given asset and its corresponding impact costs. Lastly, as shown in Figure A1, the lifecycle cost is produced, representing the total operating costs for a new asset, taking into account the annualized risk and capital over its entire lifecycle. The optimal intervention time would then be the red mark at which the Equivalent Annualized Cost ("EAC") is at its lowest.


**Figure A1: Typical Example of Optimal Intervention Time (New Assets)**

This EAC value from the lifecycle cost curve would then need to be cross-referenced against the total costs of the existing asset to determine optimal replacement timing, as shown by the green marker in Figure A2. This specific point in time would indicate that the existing asset has reached its economic end-of-life at 47 years of age and requires intervention. Note that for the existing asset, there is no capital cost component, as this is a sunk cost. Therefore, the existing asset costs are comprised exclusively of the estimated risks that are remaining.

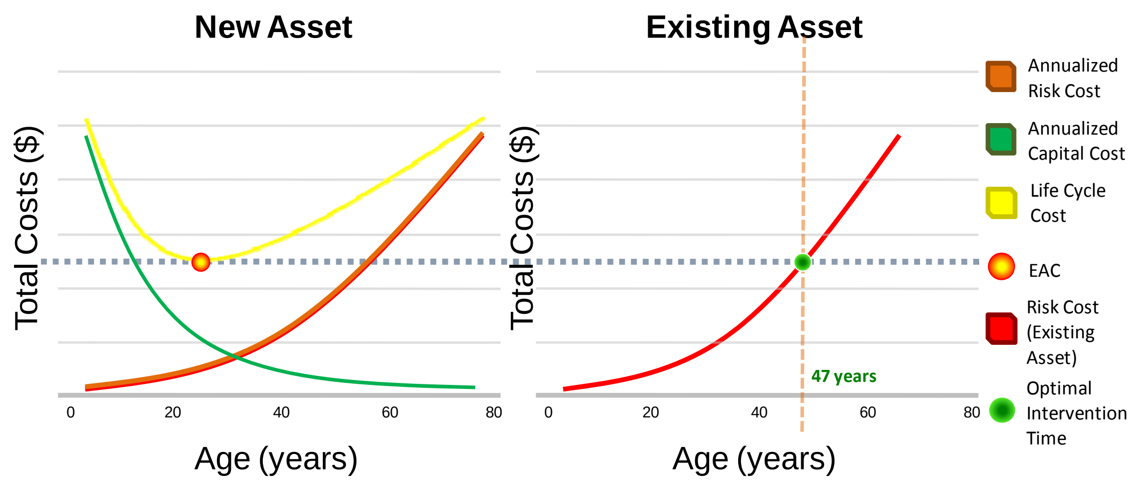



**Figure A2: Typical Example of Optimal Intervention Time (Existing Assets)**

Note that for the example in Figure A2, should the asset be replaced prior to the 47 year optimal intervention time, this would represent a sacrificed life to the asset. Should the asset be replaced after the optimal intervention time, this would represent an excess estimated risk.

Rear lot conversion falls under the "non-in-kind project" category, in which existing rear lot overhead assets are removed from the system (existing state) and new underground front lot assets are installed as part of a completely new design (new state).

Non-in-kind projects are evaluated based on the "cost of ownership" between the existing state and new state. In order to establish the cost of ownership of a single asset, the estimated annualized risk for the existing asset is plotted along with its EAC, as shown in Figure A3. The EAC defines the cost that is incurred every year, for the ownership of the asset, in a specific design for all future years. For the existing asset, only the risk is taken into account since the replacement cost is a sunk cost. As such, the asset follows its risk cost curve until it reaches its optimal replacement timing, at which point it should be replaced and thus, begins to follow the EAC line. The net present value of these costs from the current age onwards, over a 100 year period, represents the asset-related cost of ownership of an asset in a particular design. The cost of ownership is represented by the region shaded blue in Figure A3.

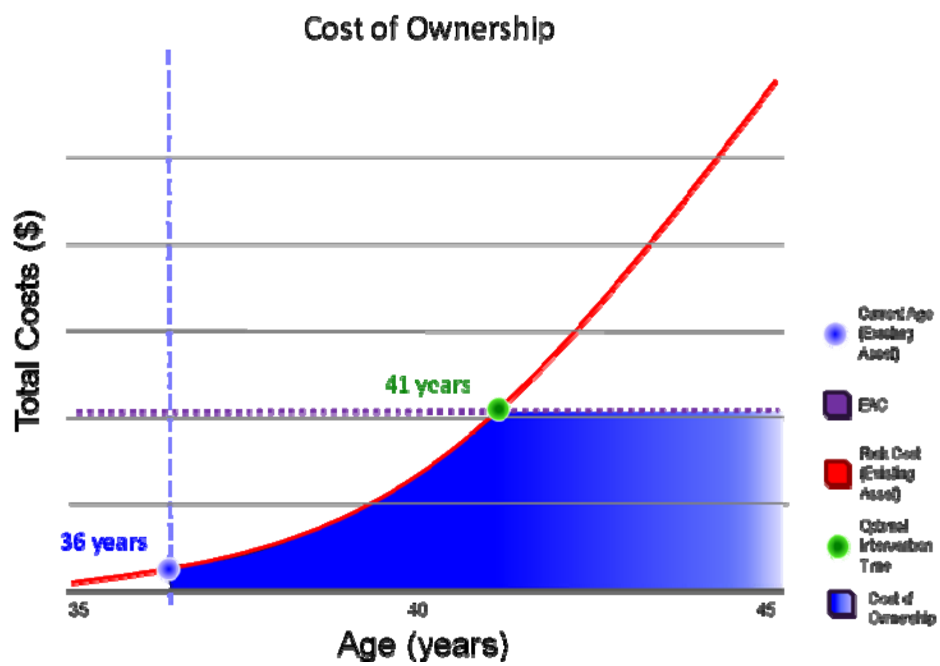



**Figure A3: Typical Example of the Cost of Ownership of the Existing Asset**

## 5.1 Data Collection - Procedure

For the rear lot conversion segment, the cost of ownership must be calculated for both the existing rear lot overhead assets, as well as the new front lot underground assets to be installed. Each existing rear lot asset must be replaced with an underground asset counterpart. For example, each overhead (O/H) transformer is replaced with an equivalent underground (U/G) submersible transformer. Similarly, each O/H Switch is replaced with a U/G SF6-Insulated pad-mounted switch. Finally, poles do not have an equivalent U/G component, but the O/H primary conductor is accounted for and used in determining the quantity and length of required U/G concrete-encased tree-retardant (TR) cross-linked polyethylene (XLPE) cable. Asset-related risks are calculated for both the existing overhead rear-lot infrastructure as well as the new underground front-lot infrastructure as part of the cost of ownership determination.

Each asset is installed within a protected region, which is defined as the fused section of circuit, from the fuse asset right down to the transformers and connected customers. The length of rear lot infrastructure within each protected region was determined based upon the length of rear lot O/H primary conductor installed within this protected region. These same lengths were used to estimate the total U/G concrete-encased TR-XLPE cable to be installed as part of the future state.

The existing assets' age and condition data, along with the installed load within their respective protected regions' were utilized as part of the existing asset risk calculation. These same loading parameters were then applied to the new front lot underground infrastructure as part of the new asset risk calculation.

In addition to those risks related to an asset's age and condition, by knowing the length and loading of each protected region, the non-asset risks (NAR) of the current and future states can also be calculated and utilized as part of the cost of ownership determination.

### 5.2 Non Asset Risk - Procedure

Non-Asset Risks (NAR) are risks incurred due to any factor that may lead to an outage on the system that is not directly tied to the assets' age and condition, including animal contact, lightning, adverse weather, and human elements.

These risks are based upon historical failures that were identified to be caused by factors that are considered to be non-asset related. The information regarding the historical failures is attained from ten years worth of historical outage data.

Information regarding the number of outages, customer interruptions (CI) and customer hours interrupted (CHI) are captured at the feeder level from this historical outage data. This information is then normalized over the total length of the feeder, such that this historical non-asset-related information is calculated on a per meter basis for that given feeder. This normalized value is multiplied by the length of the area of study in order to project this historical non-asset risk information to the area of study.

This information can then be translated into a quantified NAR by accounting for the customer interruption costs, as well as the installed load within the area of study, measured in kVA, which will be impacted should any of these non-asset-related events take place.

These costs are used as part of a net present value calculation to produce the final quantified NAR associated with the area of study. Therefore, it is assumed that these non-asset risks will continue to exist over the entire life cycle of each asset.

The overhead system and the underground system have varying non-asset outage causes associated with them because the non-asset factors that affect an overhead system are different from those that affect the underground system. The NAR sources that impact the overhead distribution system include storms, tree contacts, adverse environments (e.g., salt spray), animal/bird contacts, human elements, extreme temperature, and vehicles. In contrast, the underground distribution system is only affected by dig-ins, and then only for underground direct buried cables, because the underground system is sheltered from the majority of risks that face the overhead system. As a result, underground cables located in concrete-encased conduits do not face non-asset risks because the concrete encasement of the cables protects them from dig-ins.

### 5.3 Project Net Benefit (NPV) Calculation - Procedure

As previously described, the cost of ownership represents the net present value of the various costs associated with the respective existing assets across their life cycles (100-year period). Both asset-related and non-asset-related risk costs are considered as part of this cost of ownership calculation.

Also as previously mentioned, asset-related risks include the direct and indirect costs associated with asset replacement and resulting outage impacts to customers, while non-asset risks include the indirect costs associated with outage impacts due to weather, animal and human-related events.

The cost of ownership was calculated for each “state” of the assets – the existing overhead rear lot assets as well as the new underground front lot assets. The individual cost of ownership values for each asset are summed up to represent these respective states.

In addition, this business case evaluation also considers other alternatives, such as rebuilding the existing rear lot overhead assets to front lot overhead assets, or rebuilding the existing rear lot assets like-for-like as new rear lot assets. Cost of ownership was calculated using the formulas provided below:

- Cost of Ownership for Existing Assets ($COO_E$) = (NPV1 + NAR1)
- Cost of Ownership for New Assets ($COO_N$) = (NPV2 + NAR2)

Where:

- NPV1 represents cost of ownership of the existing overhead rear-lot assets to be replaced, including the assets' probability of failure multiplied with their impacts of failure which include direct and indirect cost attributes associated with in-service asset failures, costs of customer interruptions, emergency repairs and replacement.
- NAR1 represents the NPV calculation of non-asset risks associated with the existing overhead rear-lot plant, including animal-related, weather-related and human-related impacts taking place over the life cycle of this infrastructure. Further explanation of the Non-Asset Risk calculation is provided in Section 5.2.
- NPV2 represents cost of ownership of the new assets to be installed, including the assets' probability of failure multiplied with their impacts of failure which include direct and indirect cost attributes associated with in-service asset failures, costs of customer interruptions, emergency repairs and replacement.
- NAR2 represents the NPV calculation of non-asset risks associated with the new state. For underground front-lot plant, this would be attributed to dig-in impacts taking place over the life cycle of this infrastructure. Further explanation of the Non-Asset Risk calculation is provided in Section 5.2.

The overall project net present value is calculated using the following formula shown below:

- Project NPV = ($COO_E$ – $COO_N$) – Project Cost

Thus, the segment NPV value reflects the difference in the cost of ownership between the existing construction and new construction, after the total cost of the project has been subtracted.

## 5.4 Project Net Benefit (NPV) Calculation – Numerical Calculation

The following options have been considered as part of the business case evaluation:

- Option 1: Status Quo (Do not replace existing rear lot construction, plus remediation on an as-needed basis)
- Option 2: Like-for-Like Replacement of Existing O/H Rear Lot with New O/H Rear Lot
- Option 3: Replacement of Existing O/H Rear Lot with New O/H Front Lot
- Option 4: Replacement of Existing O/H Rear Lot with New U/G Front Lot

Options 1, 2 and 4 were further analyzed as per the quantitative Project NPV calculation, in order to determine the most optimal option for execution. Option 3 – Replacement of existing rear lot infrastructure with overhead front lot infrastructure – was not considered as part of this analysis, as it was determined not to be a feasible solution. This is due to the historically strong opposition to front lot overhead conversion that has been experienced in the past, including customer opposition as well as difficulties in securing permits from the City of Toronto. A specific example of this instance is the Whitebirch rear lot conversion job, in which the planned approach was to convert the existing rear lot infrastructure to an overhead front lot design. This approach was met with extreme opposition from city councillors, and was ultimately rejected by the councillors and residents. Tables A1 through to A3 highlight the results of the evaluation options.

**Table A1: Status Quo (Remediation on an as-needed basis)**

| Business Case Element | Estimated Cost ($, millions) |
|---|---|
| **OPTION 1 – Status Quo (Remediation on an as-needed basis)** | |
| **Cost of Ownership of Existing Rear Lot Construction ($COO_E$)** | |
| Projected risk cost of existing rear lot (NPV) | $7.96 |
| Projected non-asset risk cost of existing rear lot (NPV) | $84.05 |
| Maintenance cost of existing rear lot | $0.67 |
| **TOTAL ($COO_E$)** | **$92.68** |

**Table A2: Like-for-Like Replacement of Existing O/H Rear Lot with New O/H Rear Lot**

| Business Case Element | Estimated Cost ($, millions) |
|---|---|
| **OPTION 2 – Like-for-Like Replacement of Existing O/H Rear Lot with New O/H Rear Lot** | |
| **Cost of Ownership of New Standardized Rear Lot Construction ($COO_N$)** | |
| Projected risk cost of new overhead rear lot (NPV) | $2.37 |
| Projected non-asset risk cost of new overhead rear lot (NPV) | $84.05 |
| Maintenance cost of new overhead rear lot | $0.67 |
| **TOTAL ($COO_N$)** | **$87.09** |
| **Option 2 Project Net Benefit** | |
| **TOTAL ($COO_E$)** | **$92.68** |
| **TOTAL ($COO_N$)** | **$87.09** |
| **PROJECT COST** | **$7.36** |
| **PROJECT NPV: (($COO_E$ – $COO_N$) – PROJECT COST)** | **-$1.77** |

**Table A3: Replacement of Existing O/H Rear Lot with New U/G Front Lot**

| Business Case Element | Estimated Cost ($, millions) |
|---|---|
| **OPTION 4 – Replacement of Existing O/H Rear Lot with New U/G Front Lot** | |
| **Cost of Ownership of New Standardized Underground Front Lot Construction ($COO_N$)** | |
| Projected risk cost of underground front lot (NPV) | $11.55 |
| Projected non-asset risk cost of underground front lot (NPV) | $0 |
| Maintenance cost of underground front lot | $0.42 |
| **TOTAL ($COO_N$)** | **$11.97** |
| **Option 4 Project Net Benefit** | |
| **TOTAL ($COO_E$)** | **$92.68** |
| **TOTAL ($COO_N$)** | **$11.97** |
| **PROJECT COST** | **$66.14** |
| **PROJECT NPV: (($COO_E$ – $COO_N$) – PROJECT COST)** | **$14.57** |

To further illustrate the relationship between Non-Asset Risk and Asset Risk, a comparison was made against historically tracked CHI over the last ten-year period due to asset and non-asset causes for the rear lot feeders.

**Table A4: NPV and CHI ratios of Non-Asset to Asset Risk for Existing Rear Lot**

| | NPV ($ in Millions) | CHI (hrs) |
|---|---|---|
| **Asset Risk** | 7.96 | 784.45 |
| **Non-Asset Risk (NAR)** | 84.05 | 6193.21 |
| **Ratio (NAR/Asset Risk)** | 10.56 | 7.90 |

The difference between the two ratios is attributed to the increasing trend of non-asset related outages. The graph includes outages from tree contacts, animal contacts, lightning, and adverse weather. Over the last five years, there has been an increasing trend in the amount of non-asset related failures. This is further illustrated in Figure A4. The 10.56 ratio represents a value that will be held constant over the next three years, even though the expected number of non-asset outage duration is forecasted to rise. It also reflects a run-to-fail approach of the assets, while the historical CHI data represents assets that have had planned work performed on them.

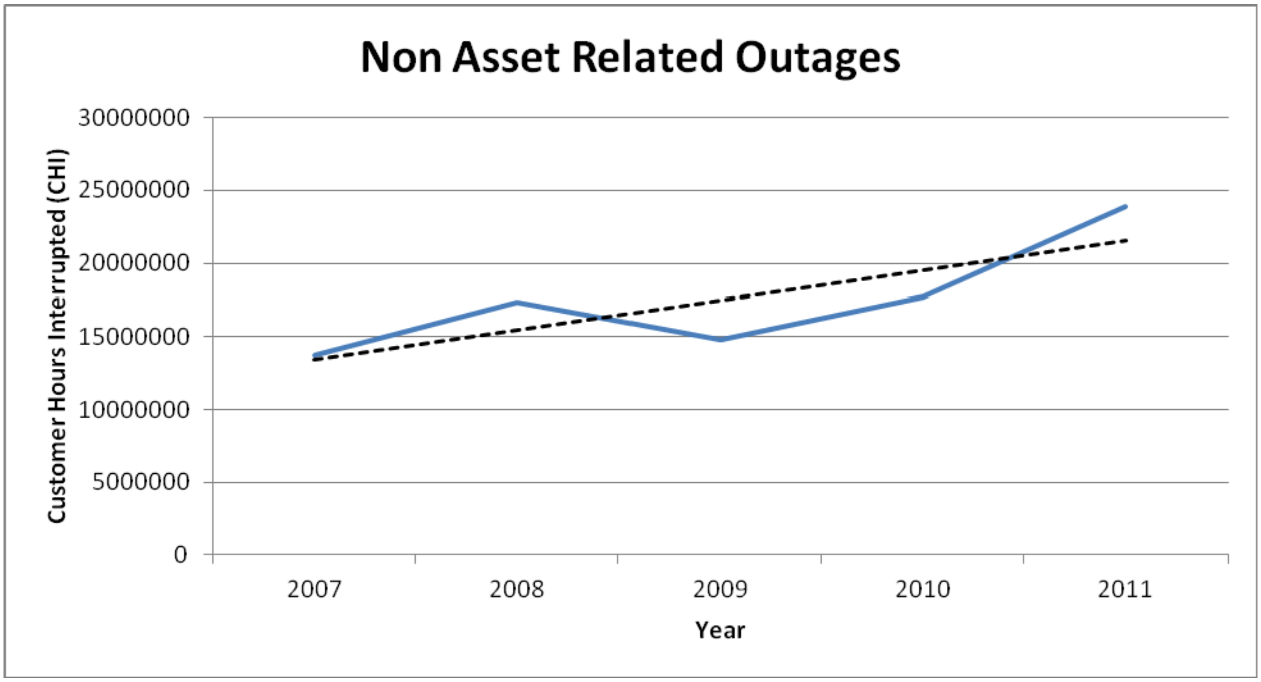



**Figure A4: Growth of CHI due to increasing non-asset outages system-wide**

# ICM Project – Overhead Infrastructure and Equipment

## Polymer SMD-20 Switches Segment

**Toronto Hydro-Electric System Limited**

# ICM Project | Polymer SMD-20 Switches Segment

## I EXECUTIVE SUMMARY

### 1. Project Description

Polymer SMD-20 ("SMD-20") switches are used to mount SMU fuse units on distribution poles. SMU fuse units are designed to protect upstream circuits and assets from faults encountered on downstream conductors and equipment in outdoor distribution systems. These switches must be physically operated by THESL crews using an 8' LoadBuster tool with a significant amount of force. Opening and closing of these switches must be swift and purposeful. If the switches are opened slowly, there is the potential for drawing a large arc and possibly a flash over.

There have been two incidents reported since November 2011 where SMD-20 switches broke apart in the field during operation (See Appendix 1). These occurrences caused THESL to undertake a failure analysis study where THESL selected 14 new SMD-20 switches from its warehouse for testing. The results of this study showed that 13 of the 14 switches tested broke within ten operations with four of the switches failing during their first operation (See Section III, 1). Moreover, the manufacturer conducted similar testing procedures and derived to similar conclusions as shown in Appendix 5. Based on these results, and information from other industry sources, as discussed below, THESL determined that the SMD-20 switches installed during the period of 2006 and 2011 are defective.

There are 5,226 defective SMD-20 switches installed on 2,553 locations (many locations are on three phase systems and incorporate three defective SMD-20 switch installations) identified to require replacement on the THESL system and this segment targets replacing all of them over the next three years with "new design" SMD-20 switches (See Section II, 1).

THESL has confirmed through testing that the manufacturer has remedied the defect in the new design. Priority for replacement will be given to locations that have experienced the highest number of outages due to faults of the type that would activate the fuses on the SMD-20 switches and lead to their operation.

The cost of the segment is presented in Table 1. These costs are all incremental because the defect was not found until late 2011 and until it was found, THESL had no plans and received no funding to replace these switches because they were assumed to have a useful life of 45 years. THESL is in discussion with the manufacturer to determine the level of compensation that can be recovered. THESL will return any compensation received for defective SMD-20 switches as revenue offset at rebasing.

**Table 1: Number and Cost of SMD-20 Switches to be replaced**

| Job Estimate Number | Job Title | Project Year | Number of Switches | Cost Estimate ($M) |
|---|---|---|---|---|
| 24773 | SMD-20 Replacement | 2012 | 1,787 | $3.06 |
| 24942 | SMD-20 Replacement | 2013 | 1,723 | $2.95 |
| 24943 | SMD-20 Replacement | 2014 | 1,716 | $2.94 |
| Total | | | 5,226 | $8.95 |

## 2. Why the Project Is Needed Now

SMD-20 switches have failed in the field. Failure analysis by THESL and others in the industry as discussed below showed a switch manufacturing material defect. Although there have been no injuries or property damage reported to date, the mode of failure for these switches may impact public safety due to the potential for falling debris when the switch fails. SMD-20 failures can also cause physical injuries to field crews by exposing them to electrical flash-over during live operation. In addition, this issue can increase outage restoration times if the switch fails and must be replaced during an emergency response situation.

**3. Why the Proposed Project is the Preferred Alternative**

Given that the currently installed switches are defective and must eventually be replaced, only two options were evaluated: proactive and reactive replacement (See Section IV). Based on this evaluation, the proactive approach was selected. Under this approach THESL will begin replacing all SMD-20 switches immediately with the intent of completing replacement within three years.

The reactive approach would replace defective polymer SMD-20 switches as they failed or once they exceeded their useful lives. Since the defective SMD-20 switches were recently manufactured, this would take decades. This replacement rate is unacceptable because defective SMD-20 switches would continue to pose risks for THESL crews and the public over this extended period.

## II PROJECT DESCRIPTION

### 1. SMD-20 Switches

SMU fuse units are designed to protect upstream circuits and assets from faults encountered on downstream conductors and equipment in outdoor distribution systems. They incorporate precision-engineered, non-damageable silver or nickel-chrome fusible elements with time-current characteristics that are precise and permanently accurate. These characteristics allow SMU fuse units to provide continued reliability of system coordination plans and reduced reaction to energy dissipation during activation. SMU fuse units are mounted on THESL distribution poles using SMD-20 switches as shown in Figure 1.


**Figure 1: SMD-20 Switch**

On September 14, 2011, THESL received the first incident report regarding an SMD-20 switch physically breaking during field operation at the mid-point just above the mounting bracket as shown in Figure 2. Another incident was reported on October 31, 2011. THESL tested a sample of the switches, as discussed below. Based on the results of THESL's tests, and testing undertaken by the manufacturer as shown in the Appendix, meetings were held with manufacturer, supplier and various utilities to discuss the potential production failure. Following these meetings, all parties agreed that the switches manufactured during the period 2006 to 2011 are defective and require replacement.

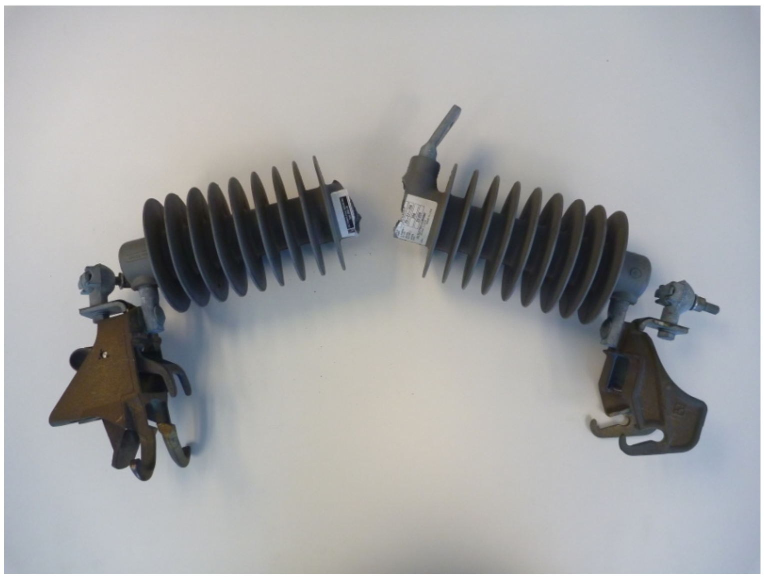


**Figure 2: Failed SMD-20 Switch**

Although there have been no injuries or property damage reported to date, the mode of failure for these switches may impact public safety due to the potential for falling debris when the switch fails. SMD-20 switches also have the potential to cause physical injuries to field crews when an electrical flash occurs during live operation and there are currently no alternative load breaking tools available in the market that can mitigate the known safety risks. In addition, switch failure can increase outage restoration times by approximately two hours if it occurs during an emergency response situation due to the need for replacing the defective switch instead of replacing the fuse only.

## III NEED

### 1. Identification of the Problem with SMD-20 Switches

After two instances where SMD-20 switches broke during operation, a failure analysis was initiated to investigate the unexpected premature failure of these switches. The failure analysis determined that the root cause was a small internal crack in the polymer core material which introduced a weak point in the insulator core. The crack could have resulted from improper mould temperature, mould fill speed or improper core handling prior to silicon over-moulding during the manufacturing process.

Unfortunately, the crack in the polymer core is covered by the outer silicone housing and is not detectable in the field as shown in Figure 3. Moreover, the crack may not manifest itself as a complete fracture of the insulator until or unless a significant load is applied to the device, such as might occur during fault interruption at high currents or during opening with a LoadBreak Tool.

The method of opening or closing the SMD-20 switches must be swift and purposeful. If the switches are opened slowly, there is a possibility of drawing a large arc and a flash over. Therefore, a fair amount of force must be applied when operating the switch.

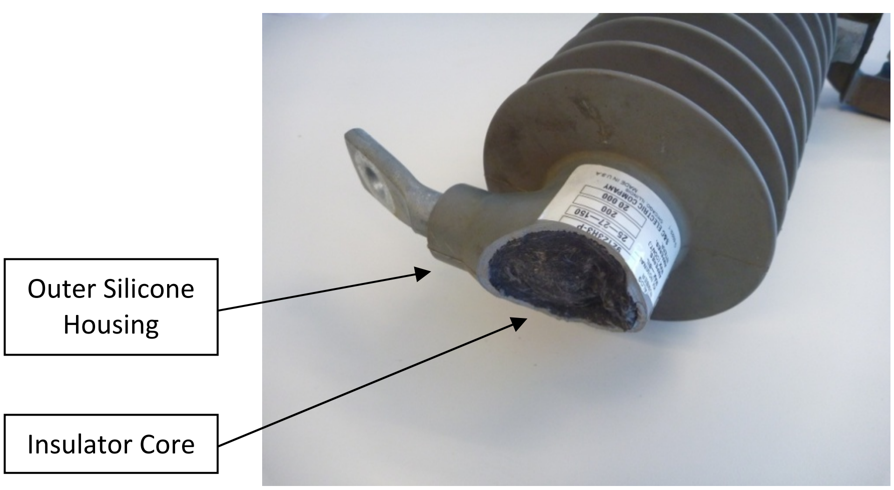



**Figure 3: Failed SMD-20 Switch**

As part of THESL's in-house investigation, 14 new SMD-20 switches were randomly selected from the THESL warehouse to determine the extent of the product failure. The samples were tested at THESL and the results are shown in Table 2.

**Table 2: Field Test Results**

| SMD-20 SWITCH THESL FIELD TEST RESULTS | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sample | Voltage Class | Manufactured Date | Operation Number | | | | | | | | | |
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1 | 25kV | Jul-11 | | | | | | | | | | |
| 2 | | Jan-11 | | | | | | | | | | |
| 3 | | Sep-11 | | | | | | | | | | |
| 4 | | Jul-11 | | | | | | | | | | |
| 5 | | Jan-11 | | | | | | | | | | |
| 6 | | Jul-11 | | | | | | | | | | |
| 7 | | Jul-11 | | | | | | | | | | |
| 8 | | Jan-11 | | | | | | | | | | |
| 9 | | Jan-11 | | | | | | | | | | |
| 10 | 15kV | Jan-11 | | | | | | | | | | |
| 11 | | Oct-10 | | | | | | | | | | |
| 12 | | Jan-11 | | | | | | | | | | |
| 13 | | Sep-09 | | | | | | | | | | |
| 14 | | Sep-09 | | | | | | | | | | |

**(Green is for successful operation and Red is for failed operation)**

Table 2 shows the number of operations that took place before the switch broke in half using the force typically required for its operation under real field conditions. The green colour illustrates a successful operation and the red colour illustrates a failed operation. Out of the 14 samples, 13 failed in less than ten operations. Among the samples where failure occurred, the mean number of operations to failure was approximately 3.5 and the median was 3. Figure 4 shows the switch before and after the second test operation of sample "6".

## ICM Project | Polymer SMD-20 Switches Segment


**Figure 4: Before and After Switch Operation**

Since the first incident in September 2011, awareness has grown among utilities across the province and bulletins from the distributor (November 28, 2011), THESL (November 9, 2011), ESA (December 9, 2011) and the manufacturer (November 30, 2011) have been issued to demonstrate and communicate the seriousness of the matter. These bulletins are attached as Appendices 1 to 4.

The potential hazard of a switch breaking may cause an electrical flash over. Although field crews would be wearing all protective equipment and using an 8’ LoadBuster Tool while operating the switch, hazards such as heat, flying debris, extremely loud noise and visual impairment can occur. Moreover, the failure will lead to longer outage restoration time as well as the potential for impacts on pedestrians and vehicles. To address these issues, the manufacturer developed and released new design switches to be used as replacements.

## 2. Impacts of the Defective SMD-20 Switches

The potential risk posed by the 5,226 defective SMD-20 switches is widespread. THESL records show that these switches are located throughout its service area. A map of these locations is presented in Figure 5.

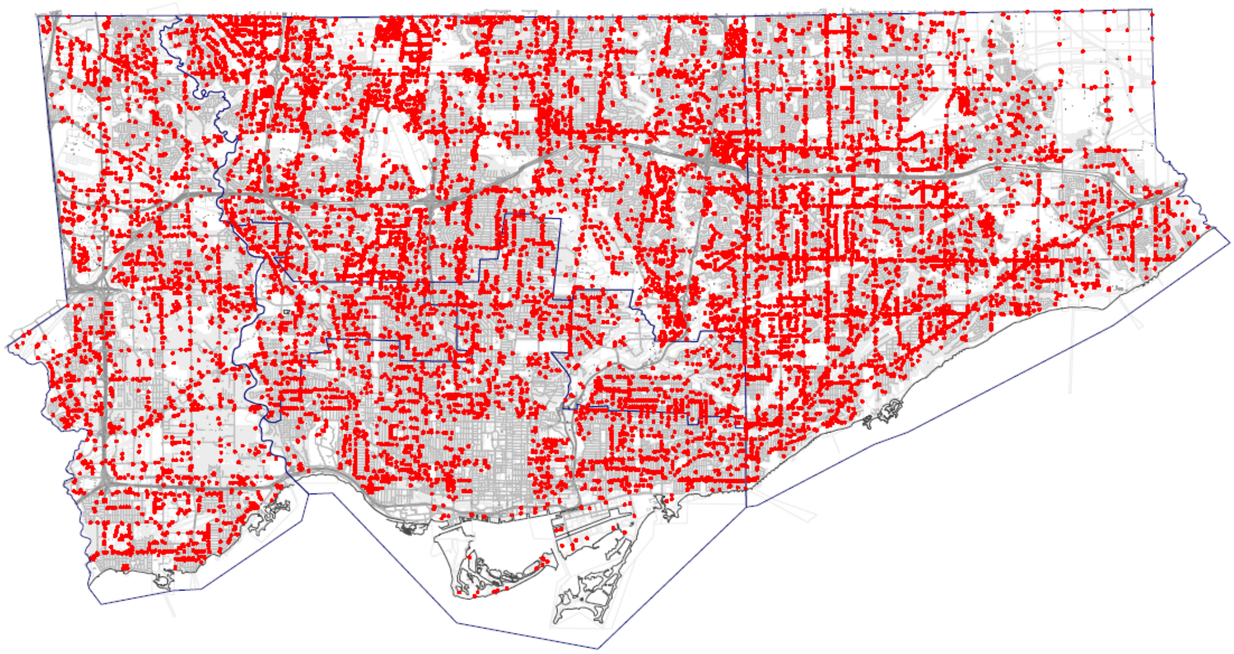


**Figure 5: Location of SMD-20 switches in the system**

A switch rupture, which can occur either during switching to address a fault or when the switch is manually operated, can lead to pieces of the switch falling to the ground. This creates the potential for safety risks and property damage. Failure during live operation may cause an electrical flash that creates the potential for physical injuries to field crews and there are currently no alternative load breaking tools available in the market that can mitigate the known safety risks.

In 2010, the Electrical Safety Authority ("ESA") issued a study, *Asset Management from a Public Safety Perspective*. This study is part of an ESA effort to explore the safety risks associated with aging and deteriorating electrical distribution infrastructure. The study shows that "falling parts" is one of the five major factors impacting public safety. Figure 6 shows the breakdown of these factors.

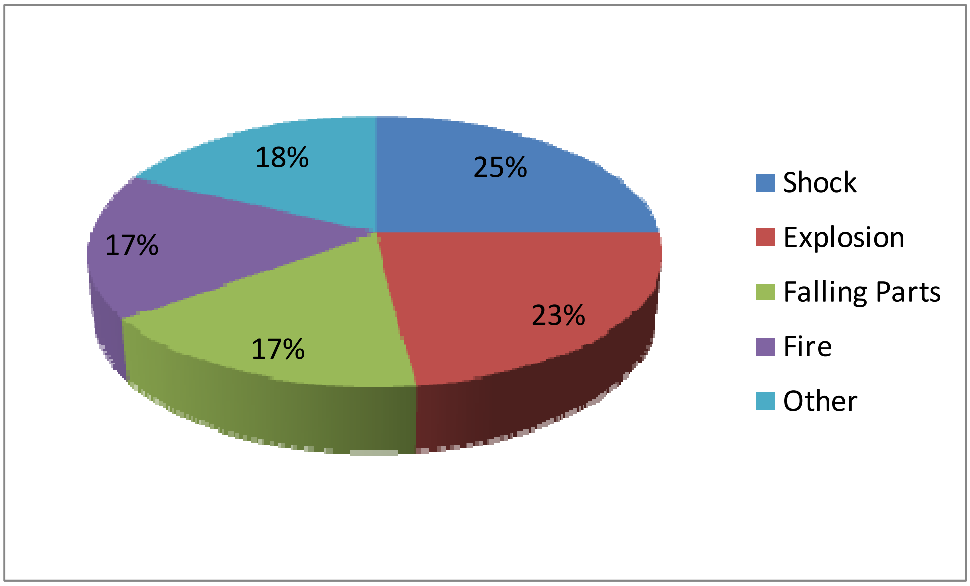



**Figure 6: ESA Serious Incident Reporting Data and Factors Impacting Public Safety**

SMD-20 switches also can impact reliability by extending the time necessary to restore power. During outages due to a blown fuse on an SMD-20 switch, replacement of a defective SMD-20 switch that broke during operation can add an additional two hours to the time required by the emergency response team.

## 3. Available Substitutes for SMD-20 Switches

The polymer SMD-20 switch is a proprietary product and it is currently made by one manufacturer only. There are currently no other available approved solutions for implementation that can meet the same electrical and performance characteristics.

The manufacturer has introduced a new polymer insulator design which incorporates a fibreglass core that provides greater flexibility and strength. Its ultimate bend strength is five times greater than the old design. Moreover, improved design, production testing and quality assurance policies and procedures have been implemented by the manufacturer.

THESL has also implemented additional preventative measures. THESL has started a quality assurance and vendor management program for this product to improve quality by increasing the audit count, introducing vigorous test report reviews and revising construction standards, specifications and quality procedures. These actions will significantly reduce the probability of future defective switches by addressing product quality risks during the manufacturing and installation stages.

The new switches were tested in the field by THESL personnel. One of the testing criteria of IEEE C37.41 (standard for design test on disconnecting cut-out type switches) is to operate the switch 67 times at the manufacturing stage. In order to ensure that the newly designed switches met this test, ten new design SMD-20 switches were randomly selected and each of them was operated 70 times. None of them failed.

## IV PREFERRED ALTERNATIVE

### 1. Description of the Preferred Alternative

The preferred plan is to replace all 5,226 defective SMD-20 switches installed at 2,553 locations (many locations are on three phase systems and incorporate three defective SMD-20 switch installations) on the THESL system with the "new design" SMD-20 switches over the next three years.

If the fuse on a defective SMD-20 switch blows due to a downstream fault, the switch itself will break and introduce a risk of injuries and property damage. Therefore, the replacements will be prioritized based on locations that experience the highest number of outages related to the types of faults that cause the fuses associated with SMD-20 switches to blow.

For each feeder, THESL monitors the number of outages experienced on all of its connected laterals. Table 3 shows the number of switches that are targeted for replacement between 2012 and 2014. Priority is given to the switches connected to the feeders with the highest number of lateral outages.

**Table 3: SMD-20 Switch Replacement Priority List**

| Year | # of Switches | Total # of Outages between 2001 and 2011 |
|---|---|---|
| **2012** | 1787 | More than 45 |
| **2013** | 1723 | Between 17 and 44 |
| **2014** | 1716 | Less than 17 |
| **Total** | 5226 | |

Replacing the units in a proactive fashion will reduce the probability of potential safety hazards to the public and field crews as well as the possibility of the increased outage duration during emergency responses due to the need to replace the defective SMD-20 switch along with the fuse. Therefore, this is the preferred option.

## 2. Project Cost

Table 4 below present the costs of the segment. The labour and material cost for replacing each switch averages about $1,711. THESL is in discussion with the manufacturer to determine the potential for compensation and the amount that may be recovered. THESL will return any compensation received for defective SMD-20 switches as revenue offset at rebasing.

**Table 4: Number and Cost of SMD-20 Switches to be replaced**

| Job Estimate Number | Job Title | Project Year | Number of Switches | Cost Estimate ($M) |
|---|---|---|---|---|
| 24773 | SMD-20 Replacement | 2012 | 1,787 | $3.06 |
| 24942 | SMD-20 Replacement | 2013 | 1,723 | $2.95 |
| 24943 | SMD-20 Replacement | 2014 | 1,716 | $2.94 |
| **Total** | | | **5,226** | **$8.95** |

None of these costs are included in existing rates. THESL did not uncover the manufacturing defect in these switches until late 2011. Once the manufacturing defect was confirmed, THESL began planning to replace all existing SMD-20 switches with “new design” switches. Given that THESL had no plans to replace these switches prior to the discovery of the design defect, it neither sought nor obtained funding for this purpose in previous rate applications.

## 3. Economic Benefit of the Preferred Alternative

The effectiveness of the SMD-20 segment can be further highlighted by determining the difference in cost of ownership between the assets currently installed downstream from these SMD-20 switches, and the cost of ownership of those same downstream assets connected to a newly designed SMD-20 switch. This cost of ownership evaluation can be simplified by examining the incremental estimated quantified risks that are introduced due to the additional two-hour interruption as a result of the time required to replace defective SMD-20 switches when the associated fuse blows.

These estimated quantified risks represent the product of the assets' probability of failure and the various direct and customer costs associated with asset failures. The costs considered include customer interruptions, emergency repairs and replacement. In addition, risks that are unrelated to asset age and condition, such as animal-caused, human-caused and weather-caused events, are also considered.

Carrying out immediate work on this asset class will result in a present value of $8.10 M, which ultimately represents the difference between the current and future costs of ownership values reduced by the total segment cost of $8.95M. Thus, there are distinct economic benefits to executing this work immediately. These results as well as the business case evaluation process are further explained in Appendix 6.

## V APPENDICES

Appendix 1 – Environmental Safety and Health Bulletin, November 2011

Appendix 2 – ESA Safety Bulletin, December 2011

Appendix 3 – Letter from HD Supply – Utilities, November 2011

Appendix 4 – Letter S&C Canada Ltd., November 2011

Appendix 5 –Test Results Document from S&C Canada Ltd., December 2011

Appendix 6 – SMD-20 Switches Business Case Evaluation (BCE) Process

## Appendix 1 – Environmental Safety and Health Bulletin, November 2011

**November 2011 – Issue: S&C Polymer SMD-20 Switch Failures**

# EHS Bulletin

Posting Date: November 9, 2011
Removal Date: December 9, 2011

### S&C Polymer SMD-20 Switch Failures

Two recent failures have occurred in the field on S&C manufactured SMD-20 pole-mounted switches, where the insulator has broken in half during switching operation (one during open, one during close). These switches are the polymer-type insulators and are used for both 15kV (stock code 7050009) and 25kV (stock code 7050006) applications. Figure 1 is of a switch installed in the field, and Figure 2 is a failed switch returned from the field.

Figure 1 – Switch Installed

Failure at the mid-point of the insulator

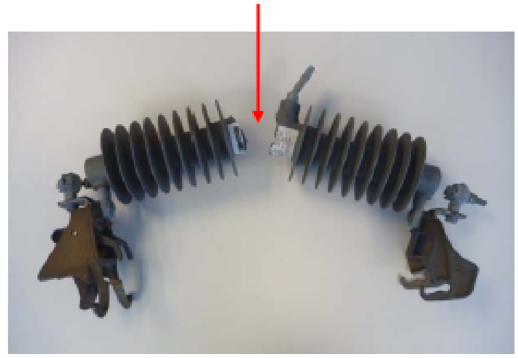


Figure 2 – Failed Switch

S&C has indicated that these failures are a result of a small, internal crack in the polymer core material. These cracks have several possible causes within the manufacturing process, and the cracks are hidden by the outer silicone housing and unable to detect. To date, all failures returned from the field have occurred at the mid-point of the insulator, near the bracket, on 25kV models.

Potential hazards associated with this failure are falling debris and an electrical flash. When operating this switch, always use your required Personal Protective Equipment and obey the safe limits of approach, using approved safe work procedures. Asset Management is working to address this issue, and crews can greatly assist the investigation by reporting any equipment failures through tagging defective equipment and returning it to a warehouse in addition to reporting the concern to your supervisor.

**IRS In Action**: Thanks go to the DPE and DPW crews for bringing this to the Quality group's attention. The failed switches that were tagged and returned back from the field alerted us to this problem and started the investigation.

EHS Bulletin – 2011-23

My Goal is Zero

## Appendix 2 – ESA Safety Bulletin, December 2011

Electrical Safety Authority

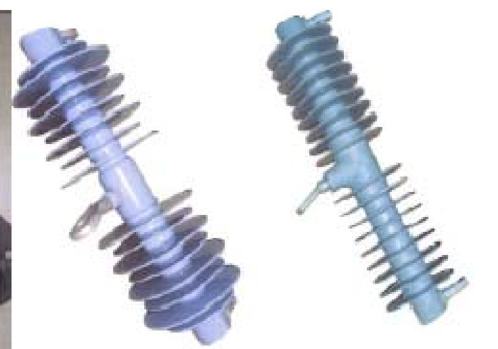
# Distributor Safety Bulletin

HAZARD AWARENESS

Electrical Distribution Safety

## HAZARD DESCRIPTION – S&C ELECTRIC CANADA LTD:

ESA would like to ensure that the attached S&C Electric Canada Ltd notification, identifying product failures for certain polymer insulators, with the subject heading "Overhead – Pole-Top Style SMD-20 Power Fuses Furnished with Polymer Insulator" is available to all bulletin subscribers.



New Design Old Design

## ATTACHED INFORMATION:

The notification released by S&C has been appended to this bulletin.

## ADDITIONAL INFORMATION:

Information requests and follow-up may be directed to ESA at Utility.Regulations@ElectricalSafety.on.ca.
For questions on this bulletin please be prepared to quote Bulletin "DSB-08/11."



Provincial Office 155A Matheson Blvd. West, Suite 200, Mississauga, Ontario L5R 3L5
Fax 905-507-4572
Website: www.esaeds.info E-Mail: Utility.Regulations@ElectricalSafety.on.ca

## Appendix 3 – Letter from HD Supply – Utilities, November 2011

## Appendix 4 – Letter S&C Canada Ltd., November 2011

**S&C ELECTRIC CANADA LTD.**
Excellence Through Innovation

90 BELFIELD ROAD
TORONTO, ONTARIO M9W 1G4
CANADA
PHONE: (416) 249-9171
FAX: (416) 249-6051

November 30, 2011

10-AG11-022

Electrical Safety Authority
155A Matheson Blvd. West
Suite 202
Mississauga, ON L5R 3L5

Attention: David Collie, President & CEO

Subject: Overhead—Pole-Top Style SMD-20 Power Fuses Furnished with Polymer Insulator

Dear David:

It has come to our attention that the polymer insulator furnished on certain S&C Overhead—Pole-Top Style SMD-20 Fuse Mountings may fracture when the fuse is opened with an S&C Loadbuster® Load-break Tool. Should this occur, the unsupported upper portion of the insulator could, depending on the utility's construction practices, make contact with an energized conductor, resulting in electrical arcing.

Only single-insulator mountings furnished with a polymer (not a porcelain) insulator are potentially subject to this issue. They include the following catalogue numbers:

- 92123R3-PD
- 92123R3-PD-T201
- 92123R3-PM
- 92142R3-PM

From field reports and sample testing which S&C has conducted, it appears that all mountings manufactured in 2011 are potentially susceptible to this issue. S&C is continuing to investigate the matter to determine if a larger manufacturing date range is affected.

As a point of information, S&C has now incorporated a polymer insulator design which, among other advantages, incorporates a fiberglass core that provides greater flexibility and strength. Its ultimate bend strength is five times greater than the old design. Operating personnel can readily distinguish between the two designs as the redesigned insulator utilizes alternating-diameter sheds, as shown below. The alternating-diameter sheds help prevent "bridging" in wet or polluted environments.

New Design

Old Design

Once a date range has been identified a second letter will be issued to you with our findings.

In the meantime please advise your members and notify them of the potential issues.

We are very sorry for the inconvenience this matter causes you. Should you require any further information, please contact David Moore, Manager-Customer Service at 416-249-9171 Ext. 3314 or david.moore@sandc.com.

Yours truly,

Angelo Gravina, P.Eng.
Vice President - Sales

## Appendix 5 –Test Results Document from S&C Canada Ltd., December 2011

S&C ELECTRIC CANADA LTD.
Excellence Through Innovation

90 Belfield Road
Toronto, ON M9W 1G4
Canada
Phone 416-249-9171
Fax 416-249-6051
www.sandc.com

Reference Number: TEST-T098-B
Original Issue Date: December 15, 2011
Test date: December 14, 2011

### TEST DOCUMENT

**TYPE OF TEST**: Mechanical endurance test for the SMD-20 Power Fuse Mounting, outdoor distribution, over-head pole-top style with polymer insulator, catalogue number 92123R3-P.
The purpose of the test was to mechanically verify the endurance of various SMU-20 Mountings with polymer insulator, KA-70265, when operated with an S&C Loadbuster ® Tool. This polymer insulator is now obsolete and replaced by TR-10982. The date stamps of the tested insulators were: Sept/06, Aug/07, May/08, July/08 and Dec/08.

The test was witnessed by Jeremy Dutka of Toronto Hydro, Jamie Campbell of HD Supply, and Chris Lettow of S&C Chicago,

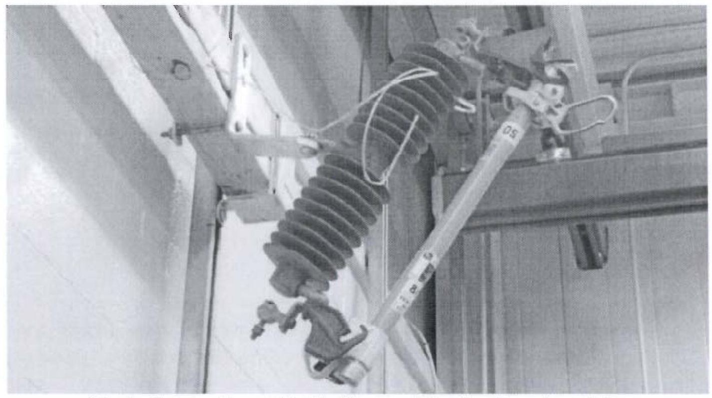
**TYPE OF EQUIPMENT:**

- Twelve (qty. 12) S&C SMD-20 Power Fuse Mountings, outdoor distribution, over-head pole-top style with polymer insulator, catalogue number 92123R3-P;
- One (qty. 1) S&C SMU-20 Fuse Unit with its respective end fittings;
- One (qty. 1) S&C Loadbuster ® Tool, 25/34.5 kV, catalogue number 5400R3;
- One (qty. 1) S&C Fiberglass Pole Unit.

**TEST FEATURES**: The tested fuse mountings were provided by Toronto Hydro. Previous to the test all units had been installed in the field. The units were marked using the following code: year of manufacture – unit number. Three of the units had lightening arrester brackets provided and installed by the customer to the Fuse Latch Assembly.

**TEST PROCEDURE**: One fuse mounting was tested at a time. For safety reasons, the top portion of each insulator was secured as shown in the photograph on page 2. The opening operations were performed using the S&C Loadbuster ® Tool. The closing operations were performed with the fiberglass Pole Unit. Both left and right hooks on the Fuse Latch Assembly were selected for hooking the Loadbuster Tool anchor in the sequence specified for each test.

Reference Number: TEST-T098-B
Original Issue Date: December 15, 2011



*Typical mounting with the fuse unit in the closed position*

**TEST RESULTS:**

***Test # 1: Unit marked 08-1, Insulator date stamp: May/08***
Right hook – 5 operations
Left hook – 5 operations
Alternating - 10 operations
Left hook - 5 operations
Right hook - 5 operations
The unit separated during the 31st opening operation. The separation occurred above the centre insert.

***Test # 2: Unit marked 08-2, Insulator date stamp: May/08***
Left hook – 5 operations
Alternating - 10 operations
Left hook - 5 operations
The unit separated during the 21st opening operation. The separation occurred above the centre insert.

***Test # 3: Unit marked 06-1, Insulator date stamp: Sept/06***
The unit separated during the first opening operation. The separation occurred between the second and the third skirts above the centre insert.

***Test # 4: Unit marked 06-2, Insulator date stamp: Sept/06***
Left hook – 5 operations
The unit separated during the 6th opening operation. The separation occurred between the first and the second skirts above the centre insert.

***Test # 5: Unit marked 08-3, Insulator date stamp: July/08***
Left hook – 5 operations
Right hook – 2 operations
The unit separated during the 8th opening operation. The separation occurred above the centre insert.

Reference Number: TEST-T098-B
Original Issue Date: December 15, 2011

***Test # 6: Unit marked 08-4, Insulator date stamp: July/08***
Alternating - 20 operations
Left hook – 3 operations
The unit separated during the 24th opening operation. The separation occurred between the second and the third skirts above the centre insert.

***Test # 7: Unit marked 07-1, Insulator date stamp: Aug/07***
Left hook - 5 operations
Right hook - 5 operations
Alternating - 2 operations
The unit separated during the 13th opening operation. The separation occurred between the second and the third skirts above the centre insert.

***Test # 8: Unit marked 06-3, Insulator date stamp: Sept/06***
Right hook – 5 operations
Left hook – 1 operation
The unit separated during the 7th opening operation. The separation occurred above the centre insert.

***Test # 9: Unit marked 08-5 with lightening arrester bracket, Insulator date stamp: July/08***
Right hook – 5 operations
Left hook – 5 operations
Right hook – 5 operations
Left hook – 10 operations
Right hook - 5 operations
Left hook - 5 operations
Right hook - 2 operations
The unit separated during the 38th opening operation. The separation occurred above the centre insert.

***Test # 10: Unit marked 08-8, Insulator date stamp: Dec/08***
The unit separated during the first opening operation. The separation occurred above the centre insert.

***Test # 11: Unit marked 08-7 with lightening arrester bracket, Insulator date stamp: July/08***
Right hook – 5 operations
Left hook – 5 operations
Right hook – 5 operations
Left hook – 10 operations
Right hook - 8 operations
The unit separated during the 34th opening operation. The separation occurred above the centre insert.

***Test # 12: Unit marked 08-6 with lightening arrester bracket, Insulator date stamp: July/08***
Right hook – 5 operations
Left hook – 3 operations
The unit separated during the 9th opening operation. The separation occurred above the centre insert.

**CONCLUSION:**
All insulators separated. No correlation was found between the vintage of the insulator and the number of operations performed before separation.

Reference Number: TEST-T098-B
Original Issue Date: December 15, 2011

*Typical mounting with separated insulator*

Prepared by: ______________________
Elena Popa, P. Eng.
Product Engineer

Witnessed by: ______________________
Frank Bucci, P.Eng.
Director – Product Engineering and QA

Witnessed by: ______________________
Angelo Gravina, P. Eng.
Vice-President - Sales

**Appendix 6 – SMD-20 Switches Business Case Evaluation (BCE) Process**

The business case evaluation (BCE) process involves the calculation of the net benefit of a capital project and incorporates quantified risk, which is calculated based upon the assets' probability and impact of failure. The probability of asset failure is determined based upon the asset's age and condition.

Calculation of the probability of failure relies on the assets' Hazard Distribution Function ("HDF"), which represents a conditional probability of an asset failing from the remaining population that has survived up till that time. These functions are validated either directly by THESL or through the assistance of asset life studies from third-party consultants. The impacts of failure are then quantified by accounting for the direct costs associated with the materials and labour required to replace an asset upon failure, as well as the indirect costs. These indirect costs would include the costs of customer interruptions, emergency repairs and asset replacements. The final estimated risk cost represents the product of a hazard rate function for the given asset and its corresponding impact costs. Finally, as shown in Figure 1, the lifecycle cost is produced, representing the total operating costs for a new asset, taking into account the annualized risk and capital over its entire lifecycle. The optimal intervention time would then be the red marker at which the Equivalent Annualized Cost ("EAC") is at its lowest.

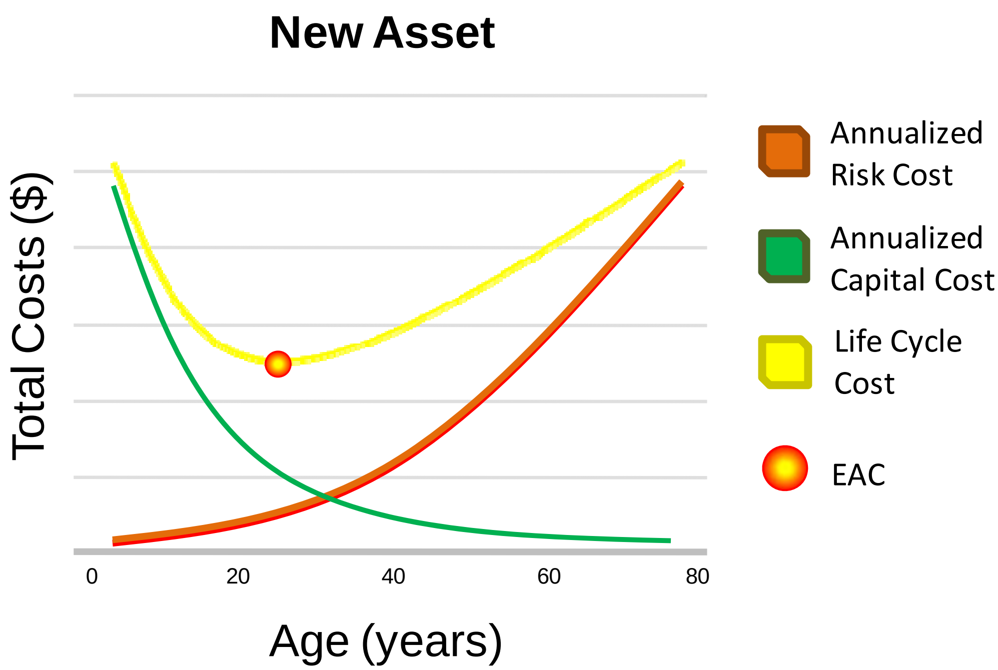



**Figure 1: Typical Example of Optimal Intervention Time (New Assets)**

This EAC value from the lifecycle cost curve would then need to be cross-referenced against the total costs of the existing asset to determine optimal replacement timing, as shown by the green marker in Figure 2. This specific point in time would indicate that the existing asset has reached its economic end-of-life at 47 years of age and requires intervention. Note that for the existing asset, there is no capital cost component, as this is a sunk cost. Therefore, the existing asset costs are comprised exclusively of the estimated risks that are remaining.

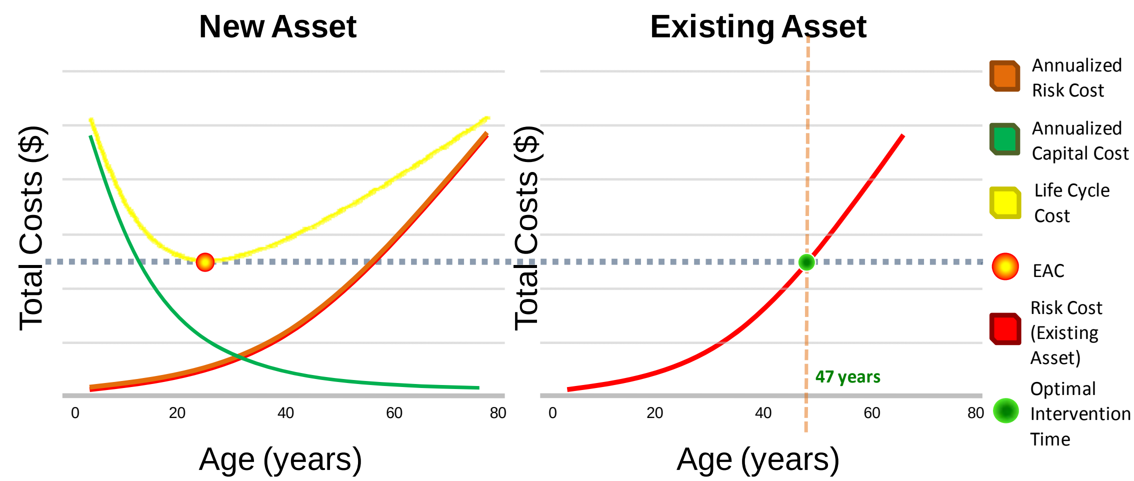



**Figure 2: Typical Example of Optimal Intervention Time (Existing Assets)**

Note that for the example in Figure 2, should the asset be replaced prior to the 47 year optimal intervention time, this would represent a sacrificed life to the asset. Should the asset be replaced after the optimal intervention time, this would represent an excess estimated risk.

The SMD-20 switch replacement segment falls under the “non-in-kind project” category, in which the replacement of the defective SMD-20 switches provides a benefit to existing assets that are installed downstream. In this instance, the benefit is the elimination of the additional two hours required during outages to replace the defective SMD-20 switch.

Non-in-kind projects are evaluated based on the ‘cost of ownership’ between the existing state (the defective SMD-20 switches installed) and new state (new standardized SMD-20 switches). In order to establish the ‘cost of ownership’ of a single asset, the estimated annualized risk for the existing asset is plotted along with its ‘Equivalent Annual Cost’ (EAC), as shown in Figure 3. The EAC defines the cost that is incurred every year for asset ownership for all future years. For the existing asset, only the risk cost is taken into account since the replacement cost is a sunk cost. As such, the asset follows its risk cost curve until it reaches its optimal replacement timing, at which point it should be replaced and thus, begins to follow the EAC line. The present value of these costs from the current age onwards, over a 100-year period, represents the asset-related 'Cost of Ownership' of an asset in a particular design. The cost of ownership is represented by the region shaded blue in Figure 3.

**Figure 3: Typical Example of the Cost of Ownership of the Existing Asset**

In the case of the SMD-20 switch replacement segment, this cost of ownership comparison between the existing state and the new state can be largely simplified by calculating just the incremental risks introduced by the defective SMD-20 switches and the additional two-hour outage duration time that these switches introduce when an outage event takes place.

Individual estimated risks of assets can be calculated for every asset. Estimated Probability of Failure for each individual asset can be calculated based upon their age and condition data. However, since SMD-20 switches fail almost every time they are operated, a 100% Estimated Probability of Failure is assumed for these assets. The Estimated Impact of Failure for each individual asset can be calculated based upon their installed configuration and connected load. Asset risk can then be calculated as the product of Estimated Probability of Failure and Estimated Impact of Failure.

Operation of SMD-20 switches produces an increased outage time of approximately 2 hours. This additional time is required for the replacement of the SMD-20 switch after it is operated and breaks. As a result, when any failure occurs downstream of an SMD-20 switch, requiring operation of this switch, the resulting outage is extended by two hours. As such, the inherent quantified risk of an installed SMD-20 switch, as opposed to current redesigned SMD-20 switch, is associated solely with the additional outage duration cost that these switches cause. The presence of an SMD-20 switch has no impact on the probability of outages for downstream assets, as these outages will occur regardless of what this type of switch is installed upstream of them.

## 5.1 General Procedure and Data Collection

In calculating the overall risk associated with SMD-20 switches, the asset risk contributions for every asset within a SMD-20 switch's protected region are analyzed. A protected region is defined as the fused section of a circuit, from the fuse asset right down to the transformers and connected customers. Risk contributions of only underground submersible transformers, underground single phase pad-mounted transformers, underground switches and overhead switches are considered because these asset classes have been identified to trip the fuse associated with an SMD-20 switch when they experience a failure. For these asset classes, the additional risks that are associated with porcelain accessories are taken into account due to the fact that porcelain accessories are deemed non-standard and can lead to short circuit or arcing scenarios, which will require the operation of the SMD-20 switch, and thus the additional two-hour outage duration.

In addition, the risks that are posed by non-asset incidents are also considered, since these will trip or require the operation of the SMD-20 switch. However, the asset risk contributions of overhead transformers within a protected region are excluded because they contain a local fuse and thus, they do not trip or require the operation of the fuse associated with an SMD-20 switch. Similarly, the asset risk contributions of poles is excluded due to the fact that the majority of pole replacements are identified during asset inspection as part of line patrols, which proactively identify poles requiring replacement in the near-term. These poles are generally replaced during a planned outage and thus do not pose any additional risk.

In order to perform the analysis, the connected load (kVA) of each protected region was collected. In addition, the length of underground cables and overhead conductors that are in each protected region were also obtained. This information was then used to determine the risk associated with the increased outage duration due to the SMD20 switches.

In addition to asset risk, the non-asset risk (NAR) contributions were also considered.

## 5.2 Non Asset Risk - Procedure

Non-Asset Risks are risks incurred due to any factor that may lead to an outage on the system that is not directly tied to the assets' age and condition, including animal contact, lightning, adverse weather, and human elements.

These risks are based upon historical failures that were identified as caused by factors that are considered to be non-asset related. The information regarding the historical failures is obtained from ten years worth of historical outage data.

Information regarding the number of outages, customer interruptions (CI) and customer hours interrupted (CHI) are captured at the feeder level from this historical outage data. This information is then normalized over the total length of the feeder, such that this historical non-asset-related information is calculated on a per meter basis for that given feeder. This normalized value is the multiplied by the length of the area of study in order to project this historical non-asset risk information to the area of study.

This information can then be translated into a quantified Non-Asset Risk (NAR) by accounting for the customer interruption costs as well as the installed load within the area of study, measured in kVA, which will be impacted should any of these non-asset-related events take place. As previously noted, the risks associated with the defective SMD-20 switches are predominantly driven by the two-hour incremental outage. Therefore, only the duration cost component associated with the quantified non-asset risks will be incorporated into the overall quantified risk calculation.

The Overhead System and the Underground System have varying causes associated with each of them since the non-asset factors that affect an overhead system are different from those that affect an underground system. The NAR sources that impact the overhead distribution system are adverse weather, tree contacts, adverse environments, animal/bird contacts, human elements, extreme temperature, and vehicles. However, the underground distribution system is only affected by dig-ins if the design is an underground direct buried cable system, since the underground system is sheltered from the majority of risks that the overhead system experiences. In addition, if the underground cables are constructed with concrete-encased conduits, then it is assumed that there will be no associated non-asset risks, since the concrete encasement of the cables should protect these assets from a potential dig-in.

### 5.3 Project Benefit

As previously described, the cost of ownership represents the present value of the various costs associated with the respective existing assets across their life cycles (100 year period). Both asset-related and non-asset-related risk costs are considered as part of this cost of ownership calculation.

As previously mentioned, asset-related risks include the direct and indirect costs associated with asset replacement and resulting outage impacts to customers, while non-asset risks include the indirect costs associated with outage impacts due to weather, animal and human-related causes.

When comparing the cost of ownership between the existing state with the defective SMD-20 switches installed in place, and the new state with the defective assets replaced with new design SMD-20 switches that work as intended, the overall project present value calculation can be simplified by comparing the incremental risk cost associated with the defective SMD-20 switch assets against the project execution cost.

In order to determine the increased risk cost that is avoided by replacing the existing SMD-20 defective assets, the increased duration cost associated with these existing assets is determined. The Estimated probability of failure associated with the relevant asset classes downstream of an SMD-20 switch, which are the assets within that specific protected region, is calculated. The impact cost is then taken to be simply the outage duration cost due a two-hour outage, which is caused by a SMD-20 switch. The multiplication of these two values provides an estimated risk cost value, which ultimately represents the cost of ownership between the existing state and the new state. This calculation is represented as per the formula below:

$\mathbf{PV_{N\text{-}E}} = \left((FP_{ASSETS})(E\_DURATION)(SAIFI_{EFFECT})(LOAD)\right)$

Where:

- $PV_{N\text{-}E}$: Represents the difference in cost of ownership between the existing state with defective SMD-20 switches installed, and the new state with these defective switches replaced with working versions of these assets. This calculation has been simplified to just account for the incremental asset risk costs that are introduced by the additional two-hour outage duration to replace these defective assets.
- $FP_{ASSETS}$: Represents the total failure probability of assets downstream of the SMD-20 switch.
- E_DURATION: Represents the extended two-hour duration attributed to a SMD-20 switch.
- $SAIFI_{EFFECT}$ ($15): Represents the cost associated with the duration, or second stage of the outage, in which there is on-going disruption to production, sales, office work and entertainment. Note that the customer interruption cost is proportional to the duration of power failure.
- LOAD: Represents the connected load in kVA that is lost for the duration of the outage.

The non-asset risks of the protected regions that are impacted by the fuses associated with SMD-20 switches ($NAR_{N-E}$) were also determined using the methodology explained in Section 5.2, again only accounting for the increased 2 hour duration. These can be incorporated into the overall cost of ownership equation as shown below:

**COO$_{N-E}$** $= PV_{N-E} + NAR_{N-E}$

- Where:
- $NAR_{N-E}$: Represents the incremental non-asset risks introduced by the defective SMD-20 switches in the existing state, as per the additional two-hour outage duration.

The overall project present value is then determined as shown below:

- Project PV = $COO_{N-E}$ – Project Cost

Thus, the Project PV value reflects the difference, or the incremental risks that are introduced as a result of the defective SMD-20 switches, after the total cost of the project has been subtracted.

## 5.4 Project Net Benefit (PV) Calculation – Numerical Calculation

The final calculations associated with the SMD-20 switch replacement project are provided in Table 1.

1 **Table 1: Business Case Evaluation Results**

| **Business Case Element** | **Cost ($, millions)** |
|---|---|
| **BCE Results – Replacement of Defective SMD-20 switches** | |
| **Cost of Ownership between Existing State & New State, or Incremental Risks Introduced by Defective SMD-20 Switches ($COO_{N-E}$)** | |
| Asset-related differences in cost of ownership, derived by examining incremental asset-related risks due to defective SMD-20 switches ($PV_{N-E}$) | $ 13.95 |
| Non-Asset-related differences in cost of ownership, derived by examining incremental non-asset-related risks due to defective SMD-20 switches ($NAR_{N-E}$) | $ 3.10 |
| **TOTAL ($COO_{N-E}$)** | **$ 17.05** |
| **PROJECT PV: (($COO_{N-E}$) – PROJECT COST)** | **$ 8.10** |

# ICM Project – Overhead Infrastructure and Equipment

## SCADA-Mate R1 Switches Segment

**Toronto Hydro-Electric System Limited (THESL)**

# ICM Project | SCADA-Mate R1 Switches Segment

## I EXECUTIVE SUMMARY

### 1. Project Description

Remotely-controlled gang-operated SCADA-Mate load interrupter switches, known as SCADA-Mate R1 switches, are used on THESL's overhead distribution system. These switches are used to rapidly disconnect faulted plant and immediately restore power to as many customers as possible. They offer sensing, control, and communication functions that provide vital advantages to THESL's distribution system such as remote fault isolation and more rapid service restoration.

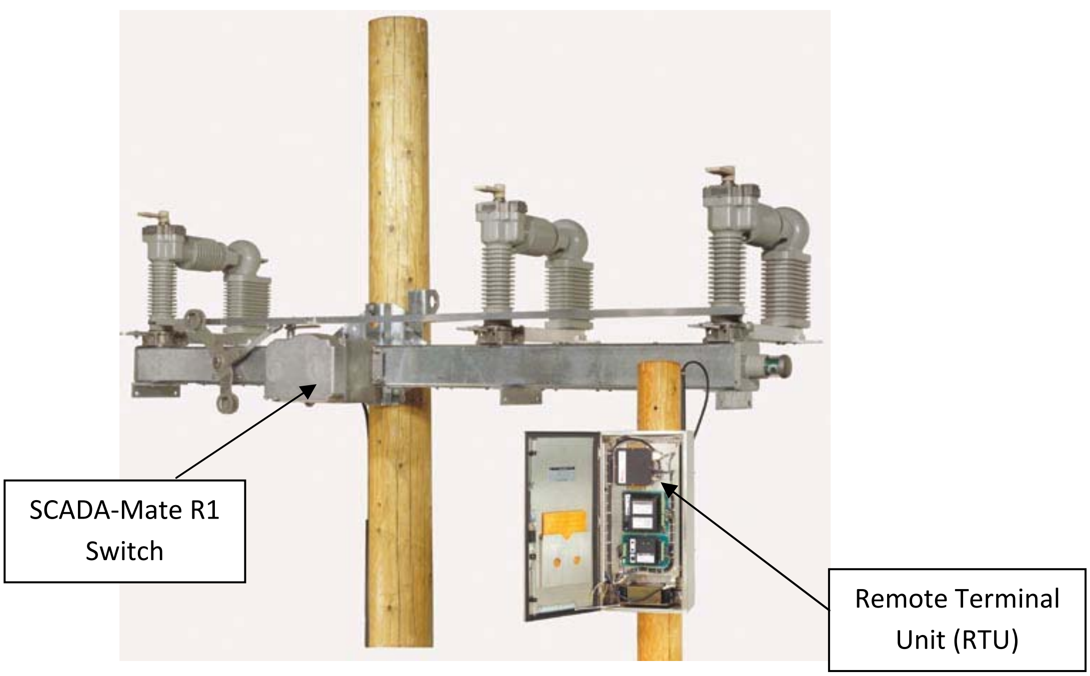



**Figure 1: SCADA-Mate R1 Switch**

SCADA-Mate R1 switches have been identified as a safety risk to THESL crews due to two recorded incidents in June 2008 and three in April 2011, where these switches unexpectedly operated (switch closed) during routine maintenance activities in the field. Following these events, the local mechanical switch indicators (as shown in Figure 3a below) showed conflicting readings with SCADA indicators in the control room (See Section II, 1). The failure of the switches was caused by moisture buildup inside the motor operator compartment, which corroded internal components critical to the switch's operating mechanism.

The defect that causes the SCADA-Mate R1 switches to fail is not externally visible or testable. Thus, THESL crews must treat all of these switches as defective whenever they are encountered (See Section II, 2). To remedy this situation, THESL proposes spending $8.35 million over 2012-2014 to replace the 48% of existing SCADA-Mate R1 switches that are located in heavily contaminated areas such as highways and arterial roads due to the increased failure probability of these switches (See Section IV, 1). Under this approach, 152 switches will have been replaced by the end of the three-year period. Operational constraints discussed below make this the practical upper limit on the number of switches that can be replaced over this period.

THESL proposes spending of $8.35 million over the period 2012-2014 to replace 152 SCADA-Mate R1 switches. The work to replace these SCADA-Mate R1 switches is in addition to existing work planned for the next three years. THESL has confirmed that these switches are subject to a defect that creates potential safety issues, which require their immediate replacement. Prior to confirming that the switches were defective, THESL had no plans to replace them.

## 2. Why the Project Is Needed Now

This safety risk is a result of the SCADA-Mate R1 design, which allows moisture to seep into the motor operator compartment of the switch, eventually leading to corrosion of the internal components. Failure of the motor operator prevents the switch from functioning as intended. An arc may develop as a result of the switch opening slowly under load, resulting in potential safety hazards to THESL crews. Arc flashes have the potential of producing a pressure wave that can disorient and injure a worker nearby (See Section II, 2).

THESL has determined that crews should not operate SCADA-Mate R1 switches or work in proximity to them due to the potential arc flash hazard (See Section III). Consequently, for planned maintenance activities and during outages, construction crews are required to travel further to locate the next available operational switch to avoid the safety hazards associated with these R1 switches. This requirement extends the time to complete repairs and restore service. Identification of this safety risk also led to the suspension of all maintenance activities on these switches due to the unpredictability of their operation with workers nearby. In turn, this has accelerated the deterioration of these switches likely resulting in decreased reliability and safety.

Due to the inherent design flaws and potential safety risks found in SCADA-Mate R1 switches, they must be replaced across the distribution system as soon as possible. A revised R2 design is available, which incorporates a new venting mechanism to mitigate the corrosion issues and a new operating mechanism that eliminates the safety risks found in the current R1 design (See Section II, 3).

### 3. Why the Proposed Project is the Preferred Alternative

As documented in the material below, SCADA-Mate R1 switches impose potential safety risks for THESL crews and negatively impact reliability (See Section II, 2). The safety risks associated with these switches are related to the design of the asset, which allows the ingress of moisture and other contaminants. These risks may occur at anytime, and are not linked to the age of the asset, but rather its operating environment and design. Therefore, all SCADA-Mate R1 switches should be proactively replaced across the board, regardless of age or remaining useful life.

Replacing these switches is the only way to address this situation because there is no practical way of repairing them (See Section II, 2). The root cause of the problem is an inherent design flaw in the R1 switch. This flaw has been remedied with a new design (R2) that is being used as the replacement switch.[1] Thus the only available options are to begin replacement immediately or wait to 2015.

[1] The mechanism in the R2 design prevents the air gap disconnect switch from opening if the interrupters are closed, which addresses the root cause for any potential arc flashes. Even if parts do get corroded, the new interlock system does not allow one function to commence before the other (See Section II, 3).

Beginning replacement immediately is the superior option. It has the lowest risk adjusted cost in terms of maintenance and reliability and will allow crews to safely operate these switches. In contrast, deferring replacement of these switches to 2015 would prolong the operational inefficiencies and safety risks to THESL crews. The following material describes the benefits associated with beginning replacement immediately as opposed to deferring the replacement effort (See Section IV, 2).

## II PROJECT DESCRIPTION

### 1. Background – SCADA-Mate Switches

SCADA-Mate switches are gang-operated load interrupter switches currently used on THESL's overhead distribution system. They offer sensing, control, and communication functions that provide vital advantages to THESL's distribution system such as, remote fault isolation and service restoration, both of which help minimize the scope and length of outages. They also optimize the distribution system and defer capital expenses through remote monitoring of feeder loading and automatic reconfiguration. A typical SCADA-Mate switch is shown in Figure 1.

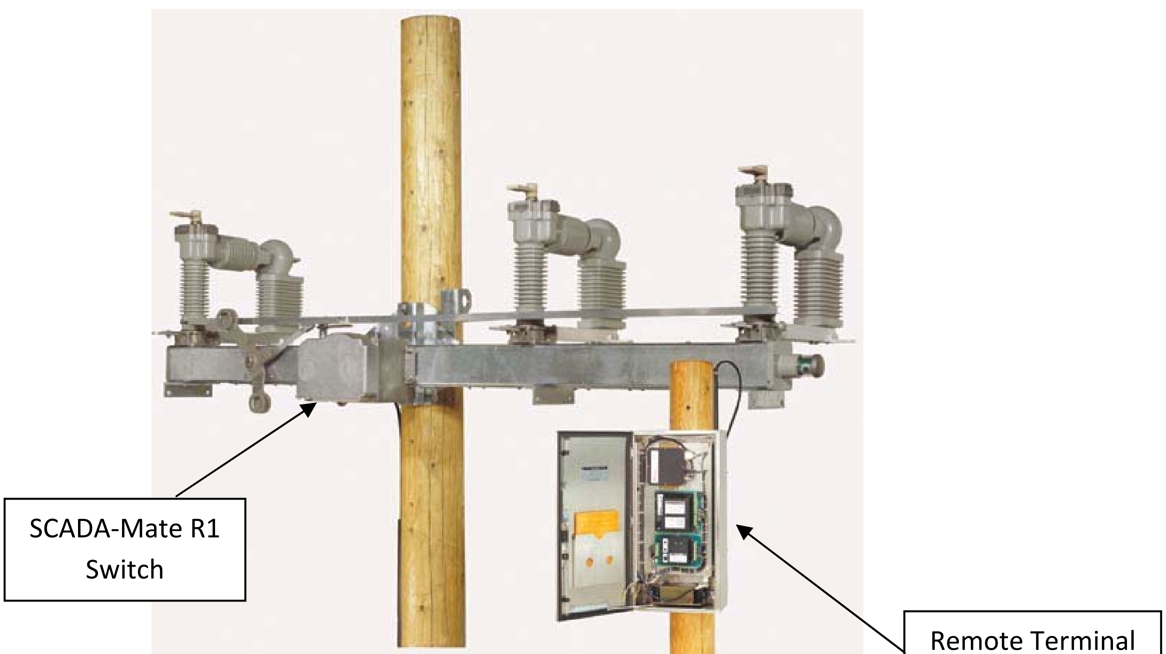



**Figure 1: SCADA-Mate R1 Switch**

There are currently 318 SCADA-Mate R1 switches distributed across all of THESL's overhead distribution system. The SCADA-Mate R1 switches were installed between 1993 and 2000 and a map of all their locations can be seen in Figure 2.

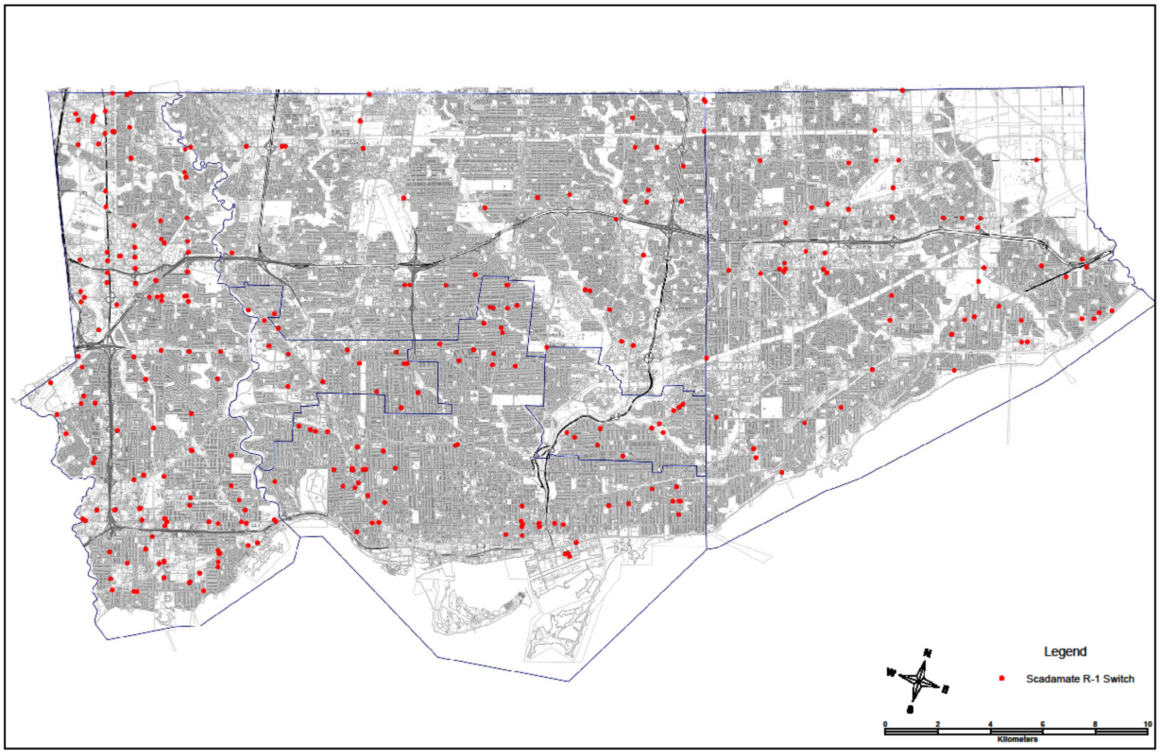
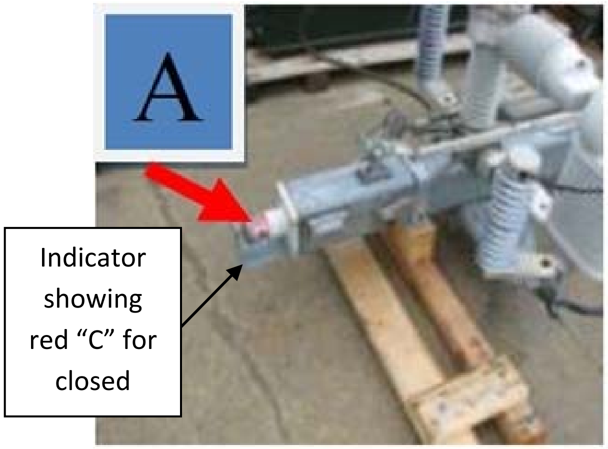



**Figure 2: Location of all SCADA-Mate R1 Switches in the System**

## 2. The Defect in SCADA-Mate R1 Switches

In June 2008 and April 2011, THESL field crews reported incidents in which SCADA-Mate R1 switches unexpectedly operated (switch closed) during routine maintenance activities in the field. Following these events, the local mechanical switch indicators (as shown in Figure 3a) showed conflicting readings with SCADA indicators in the control room.



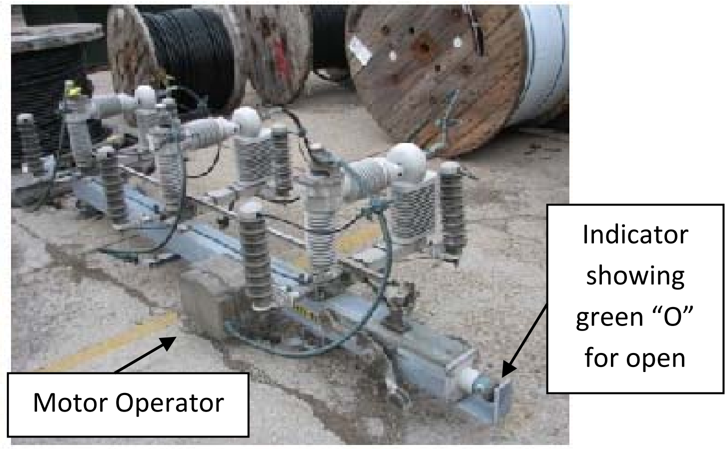




**Figure 3a: Local Mechanical Switch Operation** **Figure 3b: Switch Operation and Indicator**

The switch was physically open when it showed closed indication in the control room. This misrepresentation was due to equipment failure in the field. The failure occurred within the mechanical connector contacts inside the motor drive and motor control unit and resulted from corrosion and contamination inside the operating mechanism.

Normal switch operation is provided through a motor which winds the quick-make quick-break spring mechanism. The SCADA-Mate R1 switch shown in Figure 4 uses a stored energy mechanism for switch operation. A critical drawback in the design is that it allows the visible air-gap disconnects to open, even if the interrupters are not open, prior to attempting to create a visible open point using the visible air-gap disconnect.

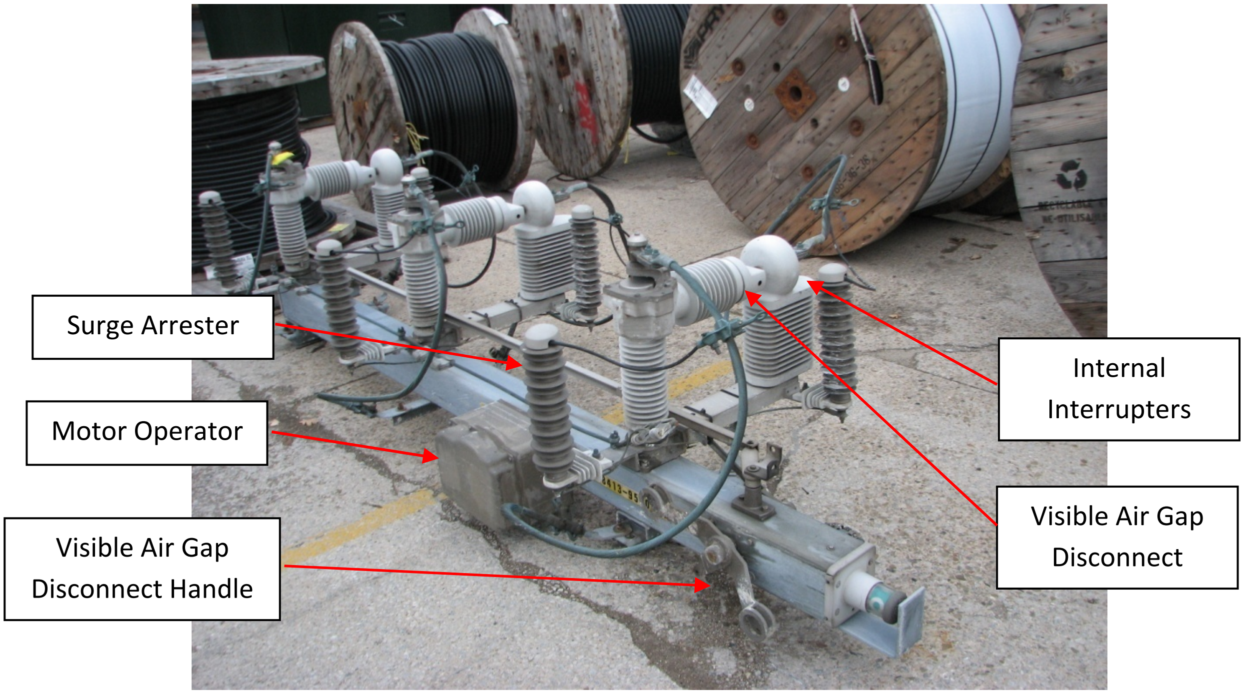



**Figure 4: SCADA-Mate R1 Switch**

In 2008, THESL encountered two isolated incidents pertaining to R1 units that were targeted for maintenance and/or repair. Operations staff had found and confirmed that the switch was initially remotely opened. The crew then proceeded to physically de-clutch and open the switch to view the visual open point. However, during the de-clutching of the switch, the interrupter contacts inadvertently closed. Unaware that the switch had closed electrically, the crew worker continued to physically open the visible air-gap disconnect. This caused a physical open point between the interrupter contacts, drawing an arc and causing both breakers to open and lock out (See Appendix 1).

After three incidents were reported in 2011 (See Appendix 2), work activities around R1 switches were suspended and THESL and the manufacturer cooperatively examined the failed switches to determine the root cause of the failures and ensure that they align with those reported for the incidents in 2008 (See Appendix 3).

The initial removal of the motor operator from the frame exposed some of the internal linkages and showed very little corrosion as shown in Figure 5.

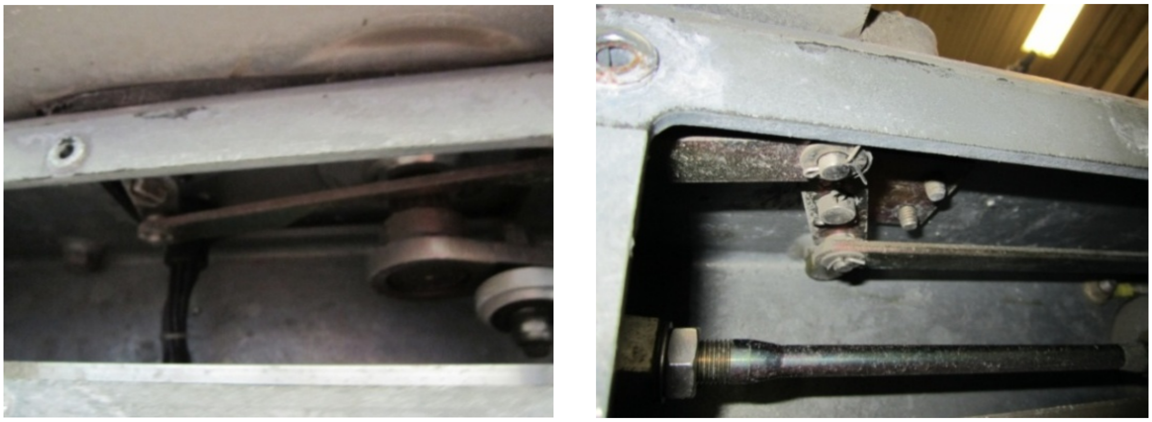


**Figure 5: First Layer of disassembly of the failed SCADA-Mate R1 Switch**

Once the cover of the motor operator was removed, corrosion was found on the fasteners and the solenoid as shown in Figure 6.

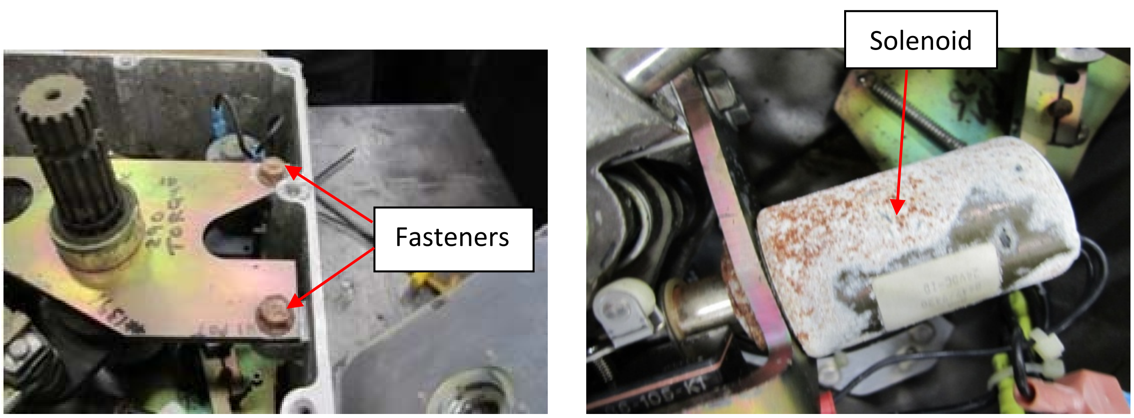



**Figure 6: Inside the Motor Operator of Failed SCADA-Mate R1 Switch**

After further investigation, the cam follower, which operates the interrupter contacts and provides their status, was found to be dislocated due to corrosion resistance of the shaft as shown in Figure 7.

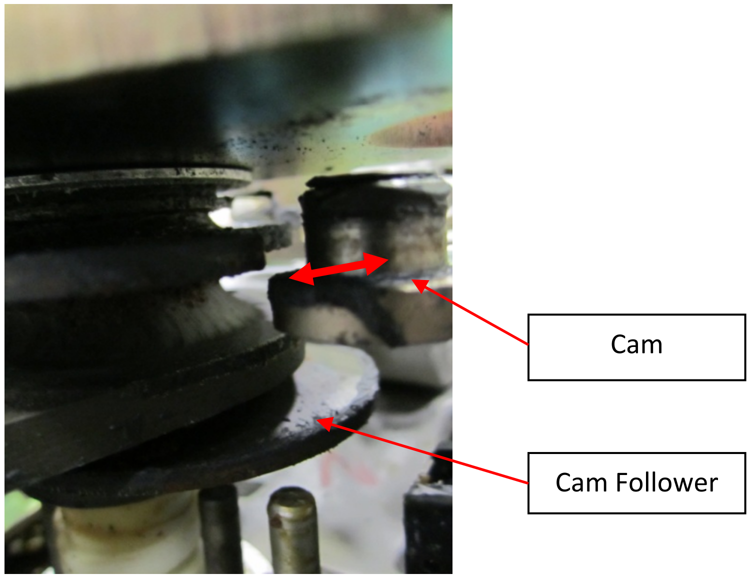



**Figure 7: Inside the Motor Operator of Failed SCADA-Mate R1 Switch**

If the shaft of the solenoid was not disengaged from the cam follower arm, then the solenoid would have allowed the interrupter contacts to toggle position. Therefore, if the interrupter contacts are closed and an attempt is made to open the visible air-gap disconnects, the interrupter contacts would open and prevent an arc from being initiated.

The proper operation of the switch is to ensure that the interrupter contacts are open prior to the opening of the visible air-gap disconnect, which is all coordinated by the cam follower and solenoid. However, due to the corroded coordination components, if the interrupter contacts were already opened and an attempt to open the visible air-gap disconnect occurs, the interrupter contacts will automatically toggle to closed when the visible air-gap disconnect is opened, which causes an arc.

The corrosion observed is caused by years of exposure to moisture. The source of the moisture was found at the rear of the motor operator where the breather is located as shown in Figure 8. The breather was designed to provide surfaces for moisture to condense on and water to collect.

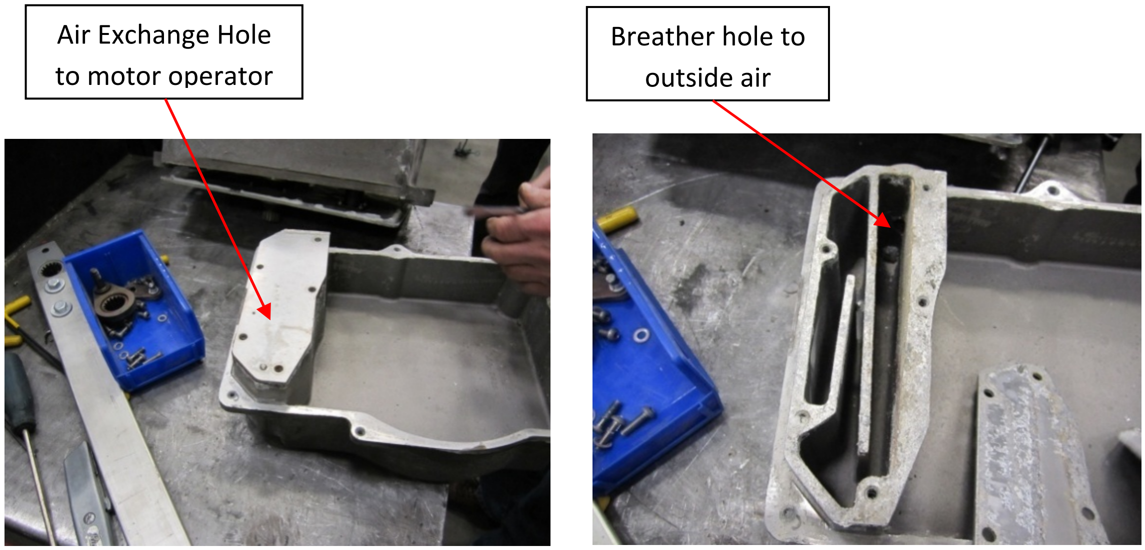



**Figure 8: Breather inside the motor operator of failed SCADA-Mate R1 Switch**

The build up of corrosion in the motor operator will eventually cause the switch to fail. The failure prevents the switch from functioning as intended. An arc will develop as a result of the switch opening slowly under load, resulting in potential safety hazards to THESL crews. Arc flashes have the potential of producing a pressure wave that can potentially disorient and injure a worker nearby.

As demonstrated above, the corrosion is visible only when the switch is completely disassembled. This means that it is impossible to identify the defective SCADA-Mate R1 switches visually, since external observations do not provide any indication that the switch is internally corroded and will not operate correctly. Also, even if a switch is currently operating properly, there is no way to determine when the level of corrosion will begin to impact the operation of the switch.

As a consequence, the only corrective action is to treat all SCADA-Mate R1 switches as defective, ensure that they are not operated if crews are in close proximity and replace them. This corrective action also prevents routine maintenance of R1 switches, which will reduce their operational lives.

THESL's operating approach is to assume that all SCADA-Mate R1 switches eventually will fail due to corrosion build up. When these failures occur, the implications for outage restoration will be significant because of the number of customers likely to be involved and the time required for when replacement. Even in non-failure situations, outage restoration can be delayed due to the extra time required to locate the next available operational switch for isolation.

### 3. The Replacement - SCADA-Mate R2 Switches

In 2000, the manufacturer introduced a new model of SCADA-Mate switches known as R2 (as shown in Figure 9). This model is THESL's current standard and it has been used on the overhead distribution system since September 2000. It is equipped with a simple, robust interlock that blocks the operation of the visible air-gap disconnect until the interrupters are opened, thus eliminating the arc-flash hazard seen in the R1 model. The upgraded operating mechanism in the R2 uses a unique ratchet arrangement that allows the motor to partially wind the spring just short of its release point and hold it there reliably. When a SCADA command is issued or the user pushes the local *push* button, the motor winds the spring past its release point and the switch changes state.

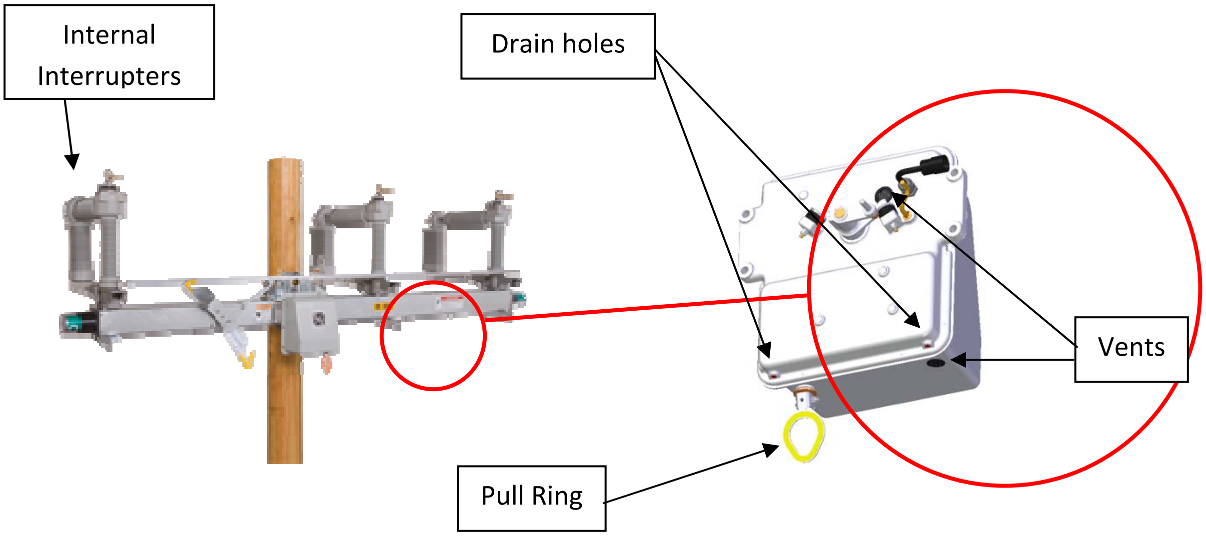



**Figure 9: SCADA-Mate R2 Switch**

The SCADA-Mate R2 model also incorporates a new ventilation mechanism with extra drain holes and vents that allows any water build-up due to condensation to dissipate before causing any corrosion to the internal components inside the motor operator. Also, the R2 switch is able to open and close the interrupters using the pull ring even in the absence of a 120V source, whereas the stored energy in the R1 switch is only sufficient to operate the interrupters one time. After that, the operation depends on the restoration of a 120V source. The ability of the R2 design to operate without a 120V source improves reliability.

The manufacturer developed a retrofit kit to upgrade an R1 SCADA-Mate switch into an R2 switch. However, the kit can only be installed by the manufacturer and it cannot be installed while the switch is mounted on the pole. To accomplish the retrofit, THESL must remove the R1 switch, deliver it to the manufacturer and install a replacement R2 switch in the location of the switch undergoing retrofit. When the retrofit is complete and the switch returned by the manufacturer, it would be available to be installed in another location.

The cost difference between a new and a retrofit switch is approximately $3,600. This figure equates to a savings of 6.5% over the $55,000 installed cost of a new R2 switch. Given that the average age of the R1 switches targeted for replacement is 15 years, the retrofit option is not considered cost effective. To achieve a cost saving of only 6.5%, THESL would be introducing 15-year old switches back into the system. Although these switches will have been retrofitted and inspected, inherent risks will remain due to the presence of aged components that are not part replaced as part of the retrofit process. Therefore, in light of the relatively small savings the retrofit option offers, the most economic solution is to install new rather than retrofit R2 switches.

## III NEED

As noted above, THESL has suspended all operation and maintenance on these switches, except for remote operation from the control centre. Given the nature of the defect discussed above and the potential safety risks and reliability problems it produces, this suspension will be permanent. The only reasonable way to remove it and restore full operability to the system is to replace all the SCADA-Mate R1 switches with R2 switches. Maintaining the status quo and deferring replacement would not only extend the time these potentially unsafe switches remain in service, but also prolong the associated operational inefficiencies, increase the potential for unexpected failure and negatively impact system reliability.

Specifically, because THESL crews will not operate them or work in proximity to them, the usefulness of these switches is limited. They can be used only for load transferring and sectionalizing through remote operation. For planned maintenance activities and during outages, construction crews are required to travel further to locate the next available operational switch to avoid the safety hazards associated with the R1 switches.

## IV PREFERRED ALTERNATIVE

### 1. Project Description

The entire population of 318 SCADA-Mate R1 switches requires replacement as soon as possible. However, full replacement will have to be completed in phases for the following reasons:

- Switching required for replacement: SCADA-Mate switches are located on main feeders. If an alternate supply does not exist to serve all customers on that feeder, then complex switching and temporary disconnect switch installations are required to minimize any associated outages.
- Feeder loading restrictions: Load shifting is dependant on the state of the system. In the summer time, feeders tend to be running at capacity and load transfer may increase the risk of outages.
- Limited Control Room resources to accommodate the large number of planned outages required for replacement.
- Limited Protection and Control resources for commissioning and decommissioning of SCADA-Mate switches.

Due to the suspension of routine maintenance, the switches located in highly contaminated areas such as highways and arterial roads are more susceptible to failure. Moreover, there are many R1 switches in the Etobicoke area that are currently using an obsolete Remote Terminal Unit (RTU) complete with an obsolete radio system. The proposed plan is to replace 152 R1 switches, which will result in replacement of all the switches that fall under the first three priorities shown in Table 1 over 2012-2014. Out of the 152 R1 switches, seven are connected to essential customers such as hospitals and pumping stations, and ten are on worst performing feeders with FESI 5 and above ranking.

**Table 1: Priority list for replacing all SCADA-Mate R1 switches**

| Priority | Quantity | Description |
|---|---|---|
| 1 | 52 | Switches in close proximity to highways/arterial roads and using obsolete RTU |
| 2 | 51 | Switches in close proximity (but further than the switches under priority 1) to highways/arterial roads and using obsolete RTU |
| 3 | 49 | Switches in close proximity to highways/arterial roads |
| 4 | 166 | Remaining R1 switches in the THESL overhead distribution system |
| **Total** | **318** | |

This will address approximately 48% of the SCADA-Mate R1 switches in THESL's system. The targeted switches for this segment are shown on the map in Figure 10.

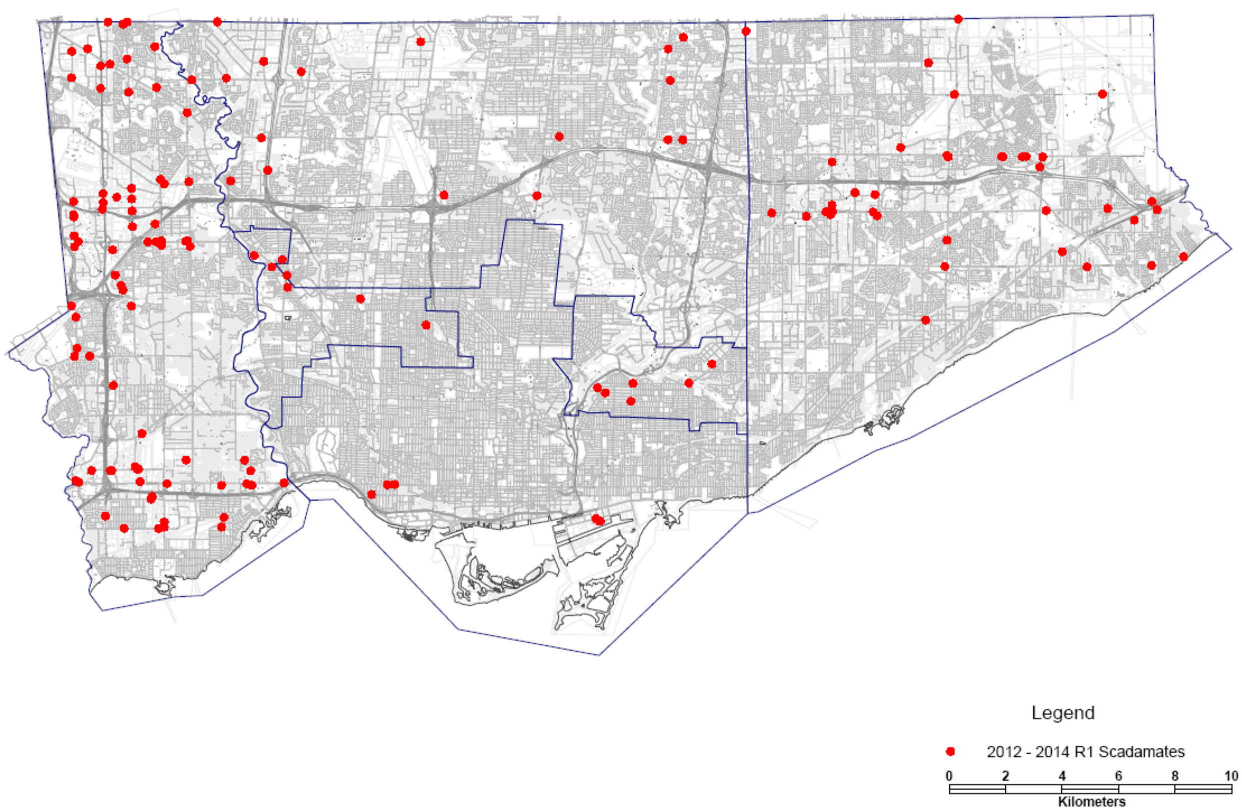



**Figure 10: Map of SCADA-Mate R1 Switches to be replaced**

## 2. Economic Benefit of the Proposed Plan

The effectiveness of the proposed work on the SCADA-Mate R1 segment can be further highlighted by determining how much cost is avoided by executing this work immediately as opposed to executing it in 2015. These avoided costs include quantified risks, taking into account the assets' probability of failure, and multiplying this with various direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement.

Carrying out immediate work on this asset class will result in an avoided estimated risk cost of about $46 million, which represents this avoided cost of executing the planned replacements in 2012 as opposed to deferring them until 2015. This figure shows that there are expected to be substantial economic benefits from executing this work immediately. These results are further explained in Appendix 5, below.
Moreover, should the replacement of these switches be deferred to 2015 it will extend the time these switches are in service and prolong the associated operational inefficiencies posed for THESL's system and the safety risks faced by field crews.

## 3. Project Cost

Table 2 below presents the costs of the segment. The average cost for replacing each unit is about $55,000 and the cost of the segment is based on replacing 152 SCADA-Mate R1 switches over 2012-2014, resulting in full replacement of all the defective switches in the priorities 1-3 above as by the end of the three-year period.

**Table 2: Project Cost**

| **Project Estimate Number** | **Project Title** | **Project Year** | **Cost Estimate $ M** |
|---|---|---|---|
| 22579 | SCADA-Mate R1 Replacement | 2012 | $2.86 |
| 24940 | SCADA-Mate R1 Replacement | 2013 | $2.80 |
| 24941 | SCADA-Mate R1 Replacement | 2014 | $2.69 |
| **Total** | | | **$8.35** |

## V APPENDICES

Appendix 1 – Environmental Safety and Health Bulletin 2008 – Scada-Mate Switches

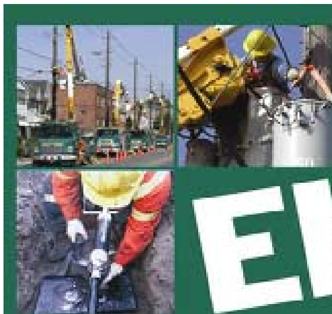
Appendix 2 – Environmental Safety and Health Bulletin 2011 – SCADA-Mate Switches

Appendix 3 – Letter from SandC Electric Canada Ltd.  April 2011 – SCADA-Mate Examination

Appendix 4 – History of SCADA-Mates

Appendix 5 – SCADAMATE R1 Business Case Evaluation (BCE) Process

## Appendix 1 – Environmental Safety and Health Bulletin 2008 – Scada-Mate Switches



Bulletin

EH&S 2008

toronto hydro corporation

**"Environmental, Health and Safety Bulletins"** are intended for immediate notification of potential workplace hazards, accidents, injuries, near misses, environmental issues and important information relative to accident prevention.

The information may not be complete initially but the updates shall be made available as progress is made.

*EH&S ISSUE:* ☑ TOOLS/EQUIPMENT ☐ PROCEDURE ☐ ENVIRONMENTAL ☐ NEAR MISS INCIDENT ☐ ACCIDENT

**Posting Date:** June 9, 2008
**Removal Date:** July 9, 2008

### Scada-mate Switches

We recently experienced two similar incidents involving Scada-mate switches that were targeted for repair/maintenance. In both incidents P&C had been requested to investigate the Scada-mate switches because SCADA and the local mechanical switch indicators showed opposite readings (i.e. SCADA indicated switch was open while the local switch indicator showed the switch as being closed).

First incident: The switch was remotely opened and the local switch indicator showed "O" (open). DGO verified that the parallel was broken and the switch was confirmed electrically open. The crew then proceeded to physically declutch and open switch to show the visual open point. During the declutching of the switch using the disconnection lever the switch inadvertently electrically closed causing an unplanned parallel (switch indicator changed from open to closed as witnessed from the ground). Unaware that the switch had closed electrically, the CPLP continued to physically open the manual disconnect portion of the switch. This caused a physical open point between two electrical contacts thus drawing an arc and resulted in both breakers opening, locking out (hold off was in effect) and extensive damage to the switch.

Second incident: The switch was remotely opened and the local mechanical and electrical (control box) switch indicator showed "O" (open). The crew verified with DGO that the parallel was broken and the switch was confirmed electrically open. The switch was placed in the local remote position and the CCL requested the CPLP to perform a current check (amperage) prior to manually opening of the switch (reading was less than 1 amp). During the physical declutching of the switch using the disconnect operating lever the switch inadvertently electrically closed causing an unplanned parallel. The CPLP was aware of the previous failure and did not continue to physically open of the switch but then checked for current and clipped approx. 40 amps at the switch. A local electrical and remote attempt to open the switch was unsuccessful. The feeder breakers did not lockout. The CCL with directions from DGO performed switching to allow safe electrical isolation of the defective switch. An attempt was made to physically open the electrically de-energized switch but the CPLP could only open the visual disconnect switch approx. 3 inches. The line flexes were removed and the defective switch was replaced.

A detailed Equipment Failure Report will be shared at safety meetings

If Scadamate switches with the above symptoms are encountered in the field, DO NOT OPERATE! Please call your supervisor for further instructions.
Recommended removal procedure: install isolating inline switches on one side of Scadamate prior to removal.

***MY GOAL IS ZERO!***

*Toronto Hydro Environmental, Health and Safety Bulletins are intended for internal use only unless otherwise authorized.*

**EHS Bulletin – 2008 – 009**

## Appendix 2 – Environmental Safety and Health Bulletin 2011 – SCADA-Mate Switches

**April 2011** – Issue: Equipment, SCADA Mate Switches

# EHS Bulletin

**Posting Date: April 11, 2011**
**Removal Date: May 11, 2011**

### SCADA Mate Switch


This bulletin highlights a concern that was previously reported under EHS Bulletin–2008–009 in which a number of SCADA Mate switches unexpectedly operated (switch closed) during routine maintenance activities in the field. Following this event the local mechanical switch indicators in the field (See A) showed conflicting readings with SCADA in the control room.

More recently there has been a series of similar incidents. In one of these incidents, during routine maintenance activities a SCADA Mate switch unexpectedly moved from the open to closed positions as witnessed by Toronto Hydro personnel on site. Following this activity SCADA in the control room showed this switch as open while the indicators in the field show the switch as closed. In keeping with the principles of the IRS the concern was reported to supervision and the control room, who subsequently engaged component reliability to investigate. The switches involved in these recent incidents have been removed and replaced.

The switches exhibiting these concerns are 1st generation SCADA Mate switches (R1) manufactured by S&C in the mid 1990's and appear to be concentrated in Etobicoke and North York. A recent technical investigation of the equipment involved in these incidents has determined that excessive moisture has entered the motor operator compartment of the switch and caused corrosion damage to the components inside. Switches installed post 2004 do not appear to have experienced this problem.

Asset Management is currently developing a long term plan to address the concerns associated with these R1 units in the field. In the meantime a work procedure is being developed to identify measures to further mitigate the risks associated with the conditions covered in this bulletin. Furthermore, work activities on the R1 units will be suspended until the procedure is completed. A list of locations for the R1 units is being verified by Asset Management and will be provided to supervision. If you experience or witness any of the conditions identified in this bulletin do not operate the equipment. Notify your supervisor and the control room immediately and make plans to have the equipment replaced.

**EHS Bulletin – 2011-08**

My Goal is Zero

1 **Appendix 3 – Letter from SandC Electric Canada Ltd. April 2011 – SCADA-Mate Examination**

**S&C ELECTRIC CANADA LTD.**
Excellence Through Innovation

90 BELFIELD ROAD
TORONTO, ONTARIO M9W 1G4
CANADA
PHONE: (416) 249-9171
FAX: (416) 249-6051

April 25, 2011

13-DRM11-049

Toronto Hydro-Electric System Ltd
500 Commissioners Street
Toronto ON M4M 3N7

Attention: Stephen Sheehy

Subject: Scada-Mate Examination - RMA 288481, 289722, 289630

Please find below a summary of the examination of three (3) S&C Scada-Mate switches that were returned from the field as non-operational, and returned to S&C on the RMAs listed above. The purpose of the examination is to determine the root cause of the non-operation and create a plan of action to mitigate the issue for remaining switches in the field.

Do not hesitate to contact the undersigned should you have any further questions on this report.

Yours truly,

David Moore, P.Eng
Manager Customer Support
(416) 249-9171 ext 3314
David.Moore@sandc.com

Cc: Jim Filleter – S&C Electric

**Scope of Examination:**

Toronto Hydro returned to S&C three (3) Scada-Mate Switches that were reported as being non-operational for detailed examination and destructive testing by S&C Electric. These switches were all built in the 1990's and had the R1 high speed switch operator mechanism.

The intended goal was to identify the root cause and lay a ground work to develop a plan of action to mitigate the issue for remaining switches in the field.

On Tuesday February 15, 2011 the following persons gathered at S&C Electric, Toronto facility for the examination. In attendance from Toronto Hydro were Raymond Chokelal, Reliability Engineer, Stephen Sheehy, Inbound Quality Supervisor, and Tarek Turk, Standards and Policy Planning. And from S&C Electric, Chicago, IL, Tom Fanta, Senior Product Engineer for Scada-Mate switches who proceeded over the examination and provided both detailed explanation of how the R1 mechanism functioned and how the switches were rendered non-operational. Also present from S&C Electric Canada Ltd were David Moore, Manager Customer Service, Ron Keddie Senior Inspector and Ben Lin Lead Assembler.

**Conclusions of the Examination:**

The conclusion after the examination of the three switches is that two of the three operator mechanisms had significant corrosion inside the mechanism chamber due moisture ingress into the aerator chamber via the breather assembly. The third operator was found to operate electrically in a normal manner and did not exhibit corrosion of the internal components. It is believed that the field information on this switch was never confirmed and that the real issue may have been with the CCU. The corrosion on the other two operators had caused the various latching and rotational assembles to become stuck in the open/closed or mid motion positions. See photos 1 to 4 on following pages.

There were no signs of water ingress past the sealing between either the front or rear cover plates and the main housing casting. The remainder of the Scada-Mate Switch was in good condition and was fully functional.

The R1 switch operator mechanism uses a restrictive vent design that incorporates an aerator chamber to control the moisture that the housing breathes during temperature and pressure swings. Theoretically the inside of the housing exchanges air with the aerator chamber and not from the outside. If moisture enters either the aerator chamber or housing the relative humidity would raise to 100% for a very long period of time. This would cause an accelerated corrosion of the interior components rendering the switch operator mechanism non-functional.

The source of this moisture was concluded to be pressure washing from the ground that forced water passed the breather assembly and into aerator chamber.

It should be noted that due to the design differences between the current production R2 switch operator mechanism, which is a free vented housing design, and the R1 mechanism this corrosion issue is not a concern for switches originally built or refurbished with the R2 mechanism. For further explanation of the differences between the two mechanisms, see explanation letter 10-WJWF00-011prepared by Jim Filleter, dated April 27, 2000, addressed to Toronto Hydro.

**Appendix 4 – History of SCADA-Mates**

**History of SCADA-Mates:**

1) SCADA-Mate Switches were introduced in 1990.
2) The SCADA-Mate® Switching System provided utilities with an all-in-one automation package to monitor system conditions.
3) The system quickly restores service to all but those on the faulted section and reduces time-consuming travel by line crews.
4) SandC Engineers received 16 patents for various aspects of the switch.
5) Integrated current and voltage sensors
6) RTU functionality with automated control schemes and data logging.
7) Fully sealed SF6 interrupters – Ice is not an issue for switching.

| Scada-Mate Customer List - 2006 through 2011 | | |
|---|---|---|
| Customer / Location | Rating | QTY |
| Utility Customers - Brazil | 15 kV | 75 to 100 |
| Utility Customers - Canada | 15 & 25 kV | Over 750 |
| Utility Customers - Caribbean Islands | 15 & 25 kV | Under 25 |
| Utility Customers - Chile | 15 & 25 kV | Over 200 |
| Utility Customers - China | 15 & 25 kV | 25 to 50 |
| Utility Customers - Philippines | 34.5 kV | Over 150 |
| Utility Customers - USA | 15, 25, & 34.5 kV | Over 4,000 |
| Utility Customers - Venezuela | 34.5 kV | Under 25 |

## Appendix 5 – SCADAMATE R1 Business Case Evaluation (BCE) Process

The business case evaluation (BCE) process involves the calculation of the net benefit of a capital job and incorporates quantified estimated risk, which is calculated based upon the assets' probability and impact of failure. The probability of asset failure is determined based upon the asset's age and condition. The impact of asset failure is derived based upon the various direct and indirect cost attributes associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement. The multiplication of the probability and impact of asset failure respectively provides the quantified estimated risk of asset failure.

### 1.1 Life Cycle Cost and Optimal Intervention Timing Results

Calculation of the probability of failure relies on the assets' Hazard Distribution Function ("HDF"), which represents a conditional probability of an asset failing from the remaining population that has survived until that time. These functions are validated either directly by THESL or through the assistance of asset life studies from third-party consultants. The impacts of failure are then quantified by accounting for the direct costs associated with the materials and labour required to replace an asset upon failure, as well as the indirect costs. These indirect costs would include the costs of customer interruptions, emergency repairs and asset replacements. The final estimated risk cost represents the product of a hazard rate function for the given asset and its corresponding impact costs. Lastly, as shown in Figure 1, the lifecycle cost is produced, representing the total operating costs for a new asset, taking into account the annualized risk and capital over its entire lifecycle. The optimal intervention time would then be the red mark at which the Equivalent Annualized Cost ("EAC") is at its lowest.

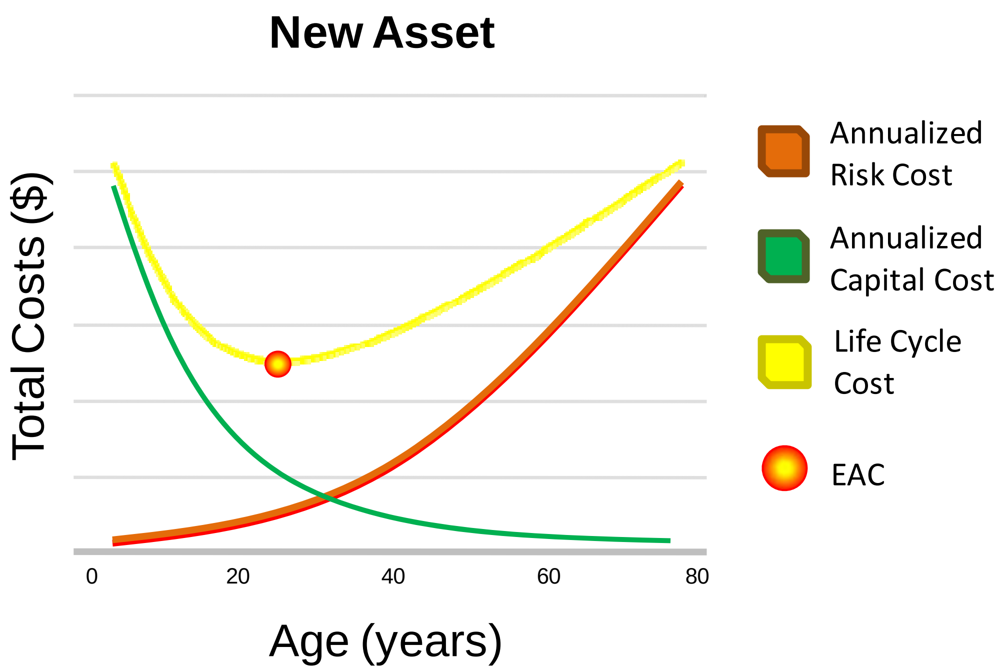



**Figure 1: Typical Example of Optimal Intervention Time (New Assets)**

This EAC value from the lifecycle cost curve would then need to be cross-referenced against the total costs of the existing asset to determine optimal replacement timing, as shown by the green marker in Figure 2. This specific point in time would indicate that the existing asset has reached its economic end-of-life at 47 years of age and requires intervention. Note that for the existing asset, there is no capital cost component, as this is a sunk cost. Therefore, the existing asset costs are comprised exclusively of the estimated risk costs that are remaining.

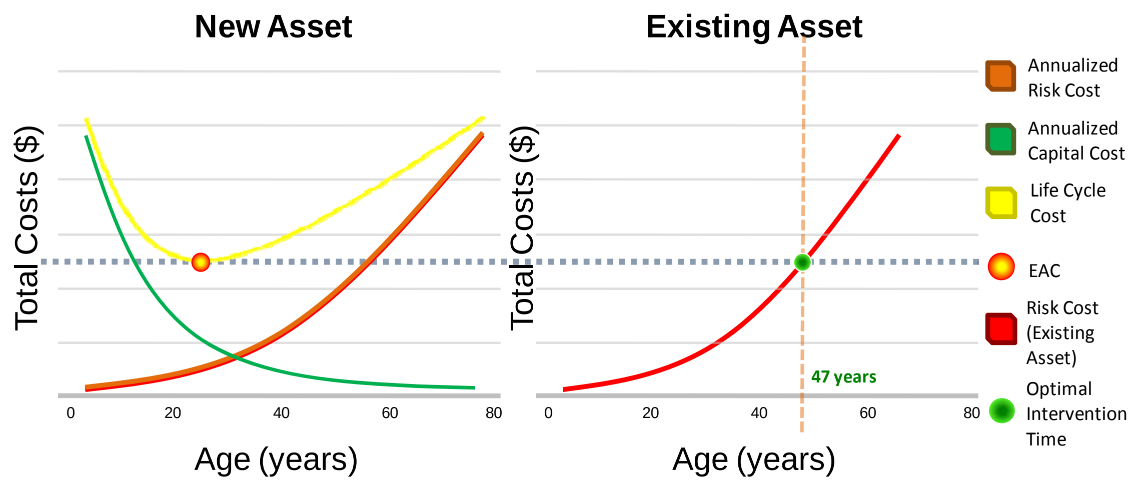



**Figure 2: Typical Example of Optimal Intervention Time (Existing Assets)**

For the example in Figure 2, should the asset be replaced prior to the 47-year optimal intervention time, this would represent a sacrificed life to the asset. Should the asset be replaced after the optimal intervention time, this would represent an excess estimated risk.

### 1.2 Project Evaluation Results

The SCADAMATE R1 segment represents an “in-kind” replacement project in which the existing SCADAMATE R1 switches are being replaced with new standardized SCADAMATE R2 versions of the switches. The overall configuration associated with this infrastructure, however, remains the same.

In-kind projects are evaluated by calculating the ‘avoided estimated risk cost’ of executing the project immediately in 2012 as opposed to delaying it. Within the ICM application, the deferral time has been set to 2015, which represents the next available opportunity for THESL to file a new Cost of Service EDR application. In order to calculate the avoided estimated risk cost of performing a project in 2012 as opposed to 2015, the various costs and benefits associated with executing a project in a particular year is taken into account.

When a project analysis is undertaken, assets within the project may be before, at, or beyond their optimal replacement time. Thus, some assets will have sacrificed economic life and others will have incurred excess risk. The cumulative sacrificed life and excess risk of the assets involved becomes a cost against the project, as shown by the red curve in Figure 3. There may be benefits achieved by performing multiple asset replacements together as part of a linear project, and typically these benefits would be weighed against the total costs in order to produce an overall project net cost calculation. However, in this instance, the SCADAMATE R1 segment consists of targeted asset replacements being performed across the City of Toronto, and therefore these benefits would not be applicable. Therefore, the total Project Net Cost is directly proportional to the total costs including sacrificed life and excess risk.

Note that the Project Net Cost in Figure 3 is plotted with time, in years, as the abscissa ("x" axis) and the total costs as the ordinate ("y" axis). As such, the minimum point of this curve provides the highest Net Project Benefit and defines the optimal year to execute the specific project.

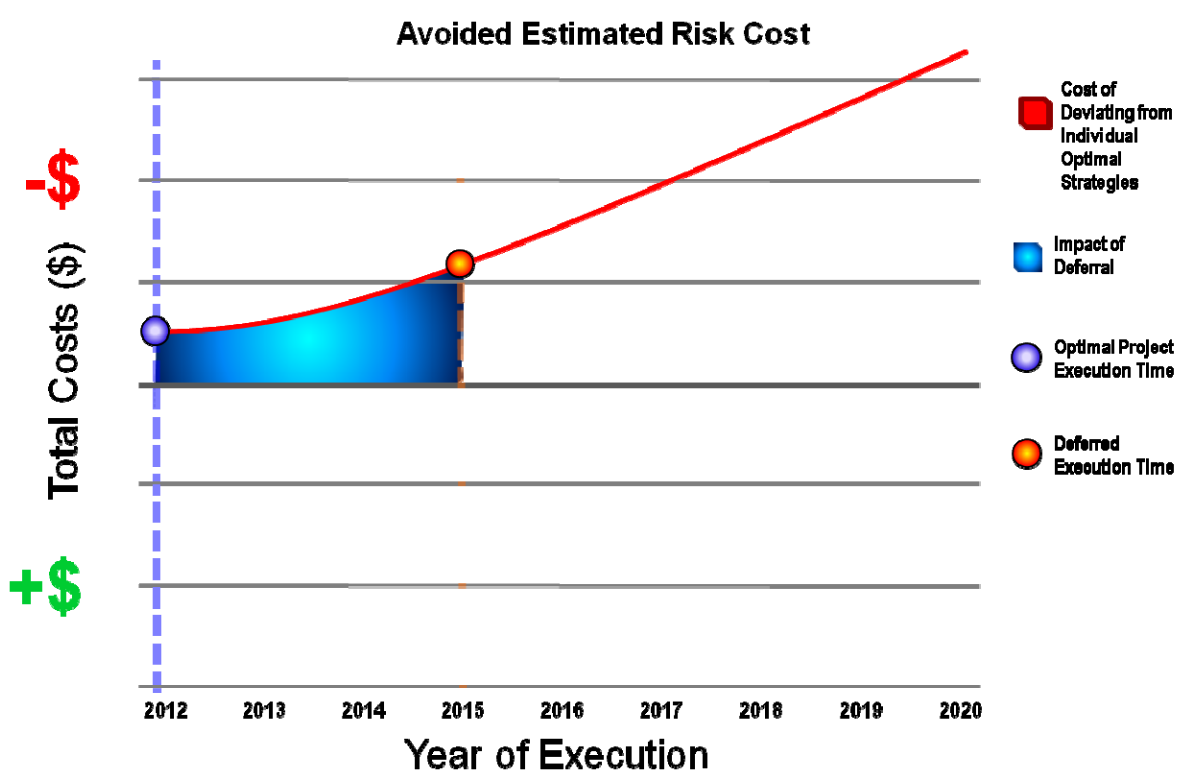



**Figure 3: Typical Example of Project Net Benefit Analysis**

The effectiveness of the SCADAMATE R1 segment can therefore be measured by calculating the total "avoided estimated risk cost" of executing this work immediately in 2012, as opposed to waiting until 2015. In order to calculate the avoided estimated risk cost, the Project Net Cost in 2012 is subtracted from the present value of the Project Net Cost from 2015. An example of this avoided estimated risk cost is shaded in blue in Figure 3.

Since the optimal year is the lowest point on the graph in Figure 3, it means that estimated risk costs for the project assets in 2015 will exceed the estimated risks that exist today. By performing the work immediately as opposed to waiting until 2015, THESL can eliminate these estimated risks. Therefore, these avoided costs represent the benefits of the in-kind project execution.

The formula for this calculation is detailed below:

$$\text{Avoided Estimated Cost} = PV(PROJECT_{NET\_COST}(2015)) - PROJECT_{NET\_COST}(2012)$$

Where:

- $PROJECT_{NET\_COST}(2012)$: Represents the total project net costs in 2012.
- $PV(PROJECT_{NET\_COST}(2015))$: Represents the present value of total project net costs in 2015.

For the SCADAMATE R1 segment, individual optimal intervention timing results were calculated for each of the 152 SCADAMATE R1 switches, based upon the processes identified in Section 1.1. Each of these assets may possess an individual sacrificed life and an excess risk value, which are aggregated to produce the overall Project Net Cost year by year.

As noted in the formula above, this Project Net Cost was then calculated for all individual SCADAMATE R1 switches within this segment at years' 2012 and 2015 respectively. Project Net Costs quantified in 2015 were brought back to a present value and the difference between this value and the Project Net Cost quantified in 2012 was taken as the Avoided Estimated Risk Cost. The final results are provided in Table 1 below.

**Table 1: Summary of values used in the determination of Avoided Estimated Risk Cost**

| Business Case Element | Cost (in millions) |
|---|---|
| Present Value of Project Net Cost in 2015 (PV(PROJECT$_{NET_COST}$(2015)) | \$ 46.14 |
| Project Net Cost in 2012 (PROJECT$_{NET_COST}$(2012)) | \$ 0.28 |
| **Avoided Estimated Risk Cost** | **\$ 45.86** |

When this avoided estimated risk cost is calculated as a positive value, it means that estimated risk costs for the job assets in 2015 will exceed the estimated risks that exist today. By performing the work immediately as opposed to waiting until 2015, we can eliminate these estimated risks. Therefore, these avoided estimated risk costs represent the benefits of job execution.