ICM Project – Network Infrastructure and Equipment

Network Vaults and Roofs Segment

Toronto Hydro-Electric System Limited (THESL)

I EXECUTIVE SUMMARY

1. Project Description

The network vaults associated with the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown core. Today, there are many critical structural issues inherent with the condition of these assets which must be addressed immediately in order to mitigate reliability and safety risks to the public and THESL workers (See Section III, 2). Figure A shows a photograph of a vault that is losing its structural integrity.

Figure A: Photo of a large portion of concrete detached from vault wall King/Yonge Street

Currently, THESL has 1,064 network vaults in the downtown core supplying the network system. Figure 1 below shows the age distribution of all network vaults and comparison to the useful life of both the overall vault and the roof. While a vast majority of vaults have reached or are quickly approaching their expected end-of-life (60% will have reached end-of-life within the next ten years or less), a majority (81%) of network vault roofs are already well past the vault roof expected life of 25 years.

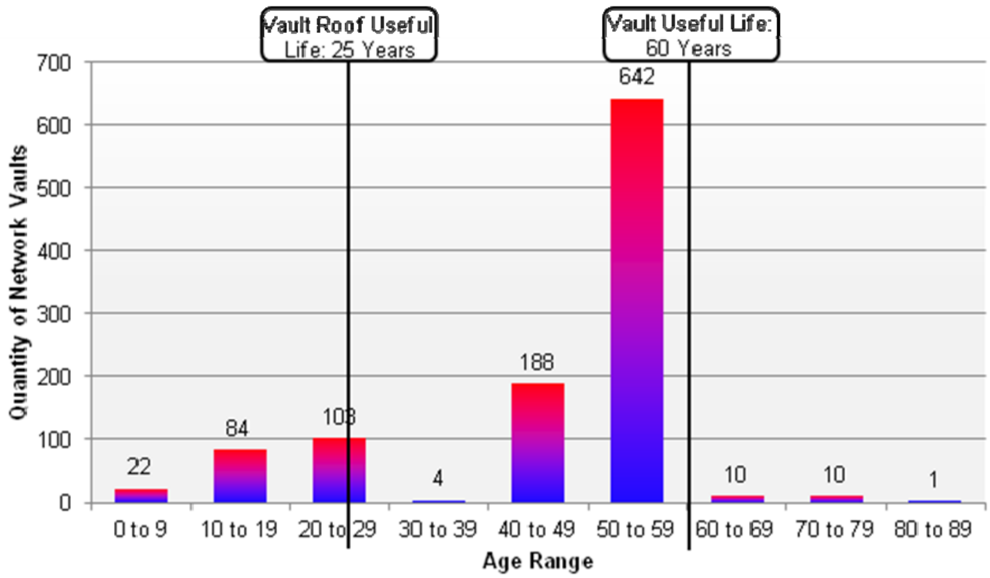

Figure 1: Distribution of Network Vaults

Under the Network Vaults and Roofs segment, THESL proposes to eliminate immediate structural vault deficiencies of 50 high risk vaults (which represent 4.7% of all vaults in THESL's system): eight through decommissioning at an estimated cost of $0.33 M, 15 through roof rebuilding at an estimated cost of $4.49 M, and 27 through complete vault rebuilds at an estimated cost of $36.63 M. The total estimated cost of the segment over the 2012 through 2014 period is $41.45M (See Section II, 1).

2. Why the Project Needed Now

The immediate need to rebuild the vaults has been highlighted by THESL's Asset Condition Assessment (ACA), developed by Kinectrics Inc., which has identified vaults classified as either "very poor" or "poor" and which require major civil rebuilds (See Section III, 1). These vaults pose an immediate safety concern to THESL workers, the public, and the reliability of the network system. The ACA uses inspection data to determine the condition of an asset, and drives replacement of that asset at the optimal time. The "very poor" status indicates that the assets need to be replaced within one year, while the "poor" assets need to be replaced within three years. In 2009, the ACA was revised to recognize that failing structural elements (roof, floor, and walls) dominate overall asset health. This revision caused a 9% increase in the network vaults classified by the ACA as 'poor' and 'very-poor.' Generally, the replacement of a network vault may take up to 24 months to complete because of the complexity of rebuilding civil and electrical work in the downtown core. This long timeframe further supports the need for a repair program to commence now.

The degradation of network vaults contributes to safety risks for both THESL crew workers and the public. THESL crews routinely enter vaults for routine maintenance on equipment, and are at risk of falling concrete and debris. Similarly, the public is subject to tripping hazards and other personal injuries, as most network vaults are located in heavy pedestrian areas (below sidewalks) in Toronto's downtown core (See Section III, 3). Figure B shows a vault where a portion of the roof has collapsed.

Figure B: Structural failure of vault located near Lawrence/Yonge Street front of a bus shelter, with plywood temporarily covering the hole in sidewalk.

In addition, a failure of a vault, through leaks and falling debris, can contribute or directly result in damage to the equipment contained within (valued at upwards of $0.24M for two network units), resulting in further reliability risks to THESL's system. The poor condition of vaults can also be a contributing factor of catastrophic failures such as vault fires. Also, from a design perspective, there are a large number of network assets within THESL's vaults (such as Fibertop Network Units, for example) which require immediate replacement. THESL submits that it is not prudent to replace failing assets without properly securing the vault in which these new assets will be housed.

3. Why the Proposed Project is the Preferred Alternative

Four options were evaluated to mitigate the risks associated with the existing network vaults:

(a) Decommission Vault
(b) Rebuild Vault Roof
(c) Rebuild Entire Vault
(d) Eliminate the vault and install a new supply

THESL submits that options (a), (b) and (c) can each be appropriate depending on the specific circumstances existing in any particular vault (See Section IV, 5). Option (a), to decommission the vault, is only considered effective when load was displaced in a specific location and the vault is no longer needed as part of the secondary grid (See Section IV, 1).

The relative benefits of Options (b) and (c) are determined by analyzing the specific vault conditions (See Sections IV, 2 and 3). The vault roof has a life cycle of only 25 years since it is exposed to harsh environmental conditions at ground level. As a result, over the 60-year expected life of an entire vault the roof should to be rebuilt several times. However, most vaults have never had their roofs rebuilt. As a result, there are situations where only a vault roof rebuild is required, and other situations in which the entire vault must be rebuilt.

Option (d) is not considered feasible due to the high cost for connecting a customer to an alternative supply, along with limited supply options available in the downtown core for alternative supply arrangements (See Section IV, 4).

II DETAILED PROJECT INFORMATION

1. Project Description

The network vaults associated with the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown Toronto core. Today, there are many critical structural issues inherent with the condition of these assets which must be addressed immediately in order to mitigate potential safety risks to the public and to THESL's workers, as well as the potential negative impact on the reliability and prudent operation of THESL's distribution system.

Under the Network Vaults and Roofs segment, THESL proposes to eliminate immediate structural vault deficiencies of 50 high risk vaults identified by the ACA as being in "poor" or "very poor" condition. This segment includes decommissioning eight vaults at an estimated cost of $0.33M, rebuilding 15 vault roofs at an estimated cost of $4.49M and completely rebuilding 27 vault s at an estimated cost of $36.63M. The estimated total three-year cost of the segment is $41.45M.

1.1. Project Segment Category 1: Network Vault Decommissioning

THESL proposes to decommission 8 network vaults where load has been displaced and the vaults are no longer needed. This is expected to eliminate any structural deficiencies associated with these vaults and any corresponding safety issues for both THESL crews and pedestrians.

Decommissioning a network vault involves removing any network transformer and protectors within the vault, along with primary and/or secondary cables. The empty vault is then backfilled with gravel, and the sidewalk overtop is rebuild. Figure 1 below shows the locations where a vault decommissioning is required.

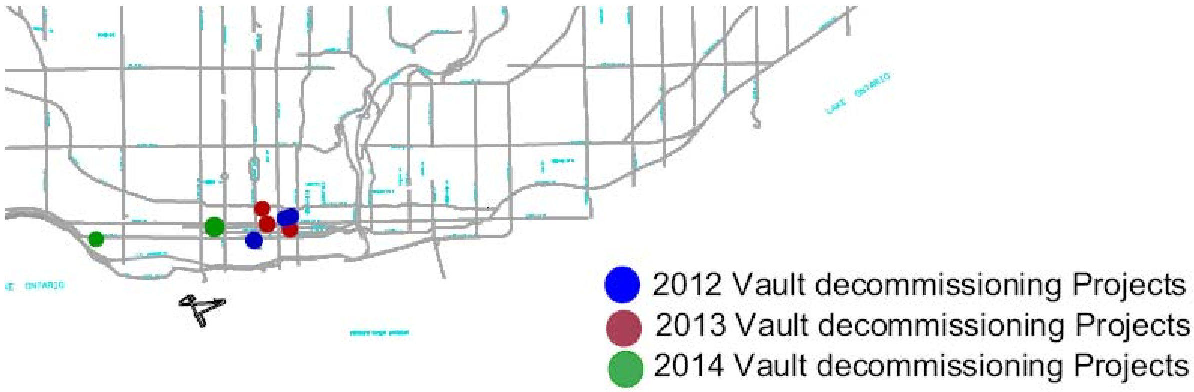

Figure 1: Locations of Network Vault Decommission Projects – 2012-2014

Table 1: Required Capital Costs

Job Number	Job Title	Job Year	Estimated Cost ($M)
X12207	X12207 Loc #4287 60 Simcoe St	2012	$0.01
X12858	X12858 Decommission 2 Network Vaults	2012	$0.08
X12844	X12844 Decommission 3 Network Vaults	2013	$0.12
X14404	X14404 Decommission 2 Network Vaults	2014	$0.12
		Total:	**$0.33**

1.2. Project Segment Category 2: Network Vault Roof Rebuild Program

THESL proposes to rebuild 15 network vault roofs which have been identified by the ACA as "poor" or "very poor" thereby having severe structural deficiencies, but which are located on network vaults that are otherwise structurally sound. A roof replacement involves installing a temporary false roof under the existing roof to protect the vault equipment, cables, and fuse panels, removing any asbestos secondary cable and Paper Insulated Lead primary cables, installing new primary and secondary cables, rebuilding the actual vault roof, and rebuilding the adjoining sidewalk.

Figure 2 below shows the locations of the proposed network vault roof rebuild jobs for 2012, 2013, and 2014.

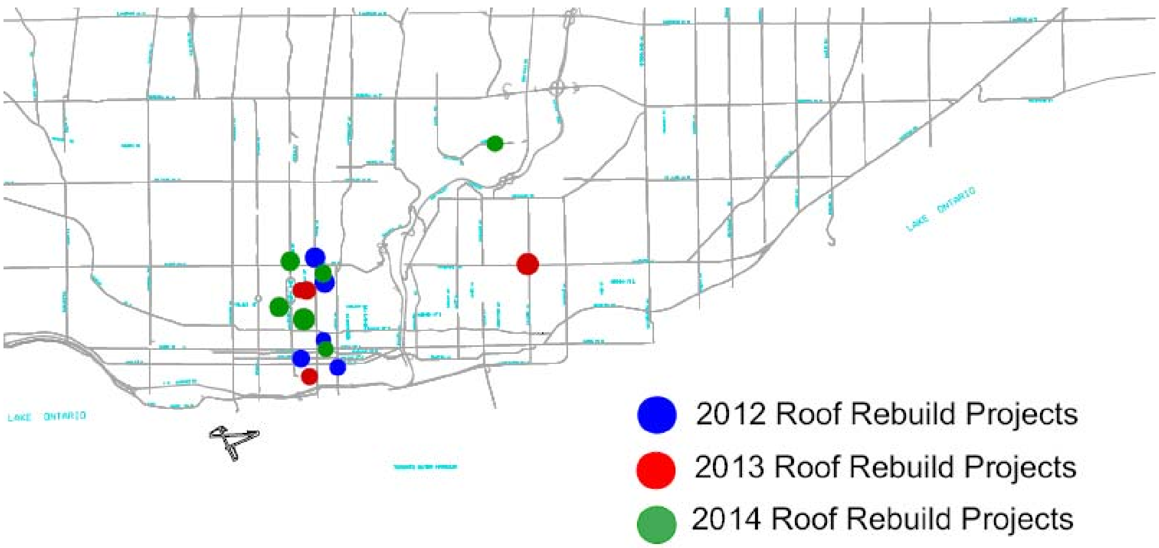

Figure 2: Locations of Network Vault Roof Rebuild Projects – 2012-2014

The Table below shows all capital costs required for the rebuilding of the vault roof, by job. These costs include any associated primary and secondary cable replacement activities. Where possible, the vaults in the worst structural condition have been prioritized to be addressed first.

Table 2: Vault Roof Rebuild Capital Costs by Job

Job Number	Job Title	Job Year	Estimated Cost ($M)
X12350	X12350 Loc#4510, Rebuild Vault Roof, 60 Gloucester St A50CS and A51CS	2012	$ 0.60
X12652	X12652 Loc #4252 and 4308, Victoria and Shuter	2012	$0.35
X12321	X12321 Loc#4931, Rebuild Vault Roof Front St. East and Jarvis St. A40GD	2012	$0.29
X12208	X12208 - Loc#4485, 105 Adelaide St. West – Rebuild Vault Roof	2012	$0.29
X12327	X12327 Loc#4262, Rebuild Vault Yorkville St and Yonge St. High Level Network	2012	$0.29
X11351	X11351 Rebuild Location #4174, Bay St/Front St. West	2013	$0.12
X13428	X13428 3 Vault Roof Rebuild	2013	$0.84
X14386	X14386 6 Vault Roof Rebuild	2014	$1.69
		Total:	**$4.49**

1.3. Project Segment Category 3: Network Vault Rebuild Program

THESL proposes to rebuild 27 network vaults which have been identified as having severe structural deficiencies requiring a complete reconstruction. These vaults cannot be decommissioned, but require more extensive repairs beyond a vault roof replacement.

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A complete network vault rebuild first involves inspections and testing of equipment in adjacent vaults, as these adjacent vaults will operate under contingency and will be required to supply additional loads to the grid while the vault is being rebuilt. In addition, in order to maintain power to customers during a vault rebuild, THESL has to install additional secondary cables from the network grid or add additional temporary transformers in an adjacent vault. In some cases, the vaults will be rebuilt in the original location and existing auxiliary civil infrastructure will be maintained. In other cases, a new vault along with auxiliary civil infrastructure will be constructed in a new location, and the old vault will be decommissioned. In both cases network units (transformer and protectors) are installed, along with new primary and secondary cables, and the sidewalk surface is repaired.

Figure 3 below shows the locations of the network vault rebuild jobs for 2012-2014.

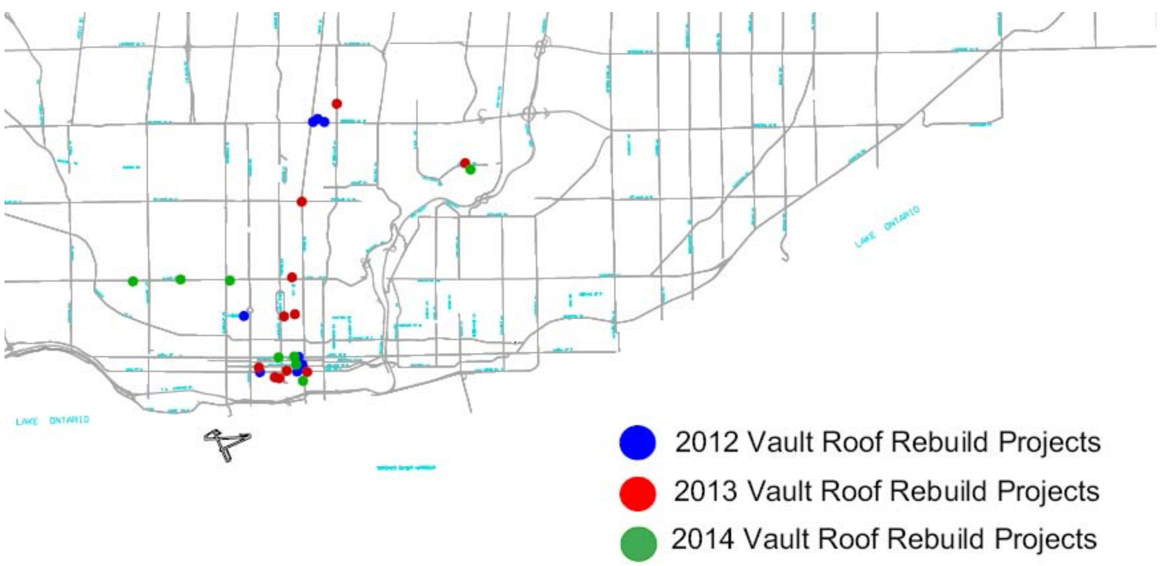

Figure 3: Locations of Network Vault Rebuild Projects – 2012-2014

The Table below shows all capital costs required for the rebuilding of complete vault rebuild jobs. These costs include any associated primary and secondary cable replacement activities. Where possible, the vaults in the worst condition have been prioritized to be addressed first.

1 **Table 3: Complete Vault Rebuild Capital Costs by Job 2012-2014**

Job Number	Job Title	Job Year	Estimated Cost ($M)
X12289	X12289 Vault Loc#4412, Build a new Vault Adelaide St. West/Grand Opera Lane	2012	$1.88
X11533	X11533 Loc#4818, Rebuild Vault at Richmond/Bay	2012	$ 1.58
X11362	X11362 -Loc# 4111 -Augusta and College	2012	$0.70
X12371	X12371 -Loc# 4431 -Blue Jays Way and King St. West	2012	$0.99
X12830	X12830 Loc# 4432 vault rebuild job	2012	$1.87
X11441	X11441 -Loc# 4512 -Eglinton Ave E./Holly St	2012	$1.01
X11487	X11487 Vault Rebuild, Loc#4312, King St. West/Yonge St.	2012	$1.62
X12834	X12834 Vault Rebuild Job	2012	$1.98
X11234	X11234 Location # 4481, Eglinton Avenue East/ Holly St.	2013	$2.06
X12835	X12835 Vault Rebuild Job	2013	$1.72
X11440	X11440 Vault Relocate, Loc#4642 St. Clair Ave. W/Yonge St.	2013	$0.97
X12345	X12345 Loc#4562, Vault Roof Rebuild, King St West/Jordan St. A54WR	2013	$0.72
X11529	X11529-2 Vaults--Loc# 4790 East + West Vault Wellington St. W/ Emily St	2013	$2.78
X12334	X12334 Loc#4299 Rebuild Vault Peter St/Adelaide St West A66WR	2013	$1.58
X13323	X13323 Vault Rebuild - TD-21 York and King	2013	$0.29

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Job Number	Job Title	Job Year	Estimated Cost ($M)
X13347	X13347 - Loc#4795, 77 Grenville St. Vault Rebuild	2013	$0.23
X11504	X11504 -Loc# V4511 -Overlea Blvd/William Morgan Dr. (E. York)	2013	$0.86
X14385	X14385 9 units Vault Rebuild Job	2014	$13.77
		Total:	**$ 36.63**

III. NEED

1. Asset Condition

In addition to tracking the age of its assets, THESL has been analyzing asset life using its Asset Condition Assessment (“ACA”), developed by Kinectrics Inc. The ACA uses inspection data to determine the condition of an asset, and drive replacement of that asset at the optimal time. The ACA for the network vaults indicates vaults are classified as either “very poor” or “poor” and require major civil rebuilds. The “very poor” status indicates that the assets need to be replaced within one year, while the “poor” assets need to be replaced within three years. Generally, the replacement of a network vault may take up to 24 months to complete because of the complexity of rebuilding civil and electrical work in the downtown core. This long timeframe further supports the need for a repair program to commence in the very near term.

Currently, THESL has 1,064 network vaults in the downtown core supplying the network system. Figure 1 below shows the age distribution of all network vaults and comparison to the useful life of both the overall vault and the roof. While a vast majority of vaults have reached or are quickly approaching their expected end-of-life (60% will have reached end-of-life within ten years or less), a majority (81%) of network vault roofs are already well past the vault roof expected life of 25 years, and in need of a rebuild. In addition, the ACA suggests that some vaults have been aging at an accelerated pace and require repairs even though they have yet to reach their expected end-of-life of 60 years. Under this segment, 4.7% of the total vaults will be addressed over three years.

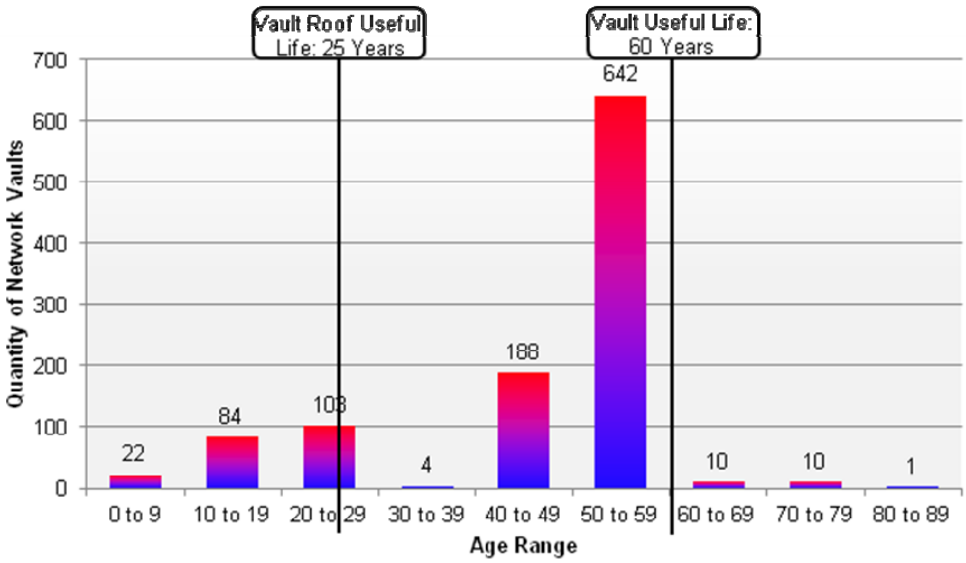


Figure 4: Distribution of Network Vaults

The degradation of network vaults contributes to potential safety risks for both THESL crew workers as well as the public. THESL crews routinely enter vaults for routine maintenance to equipment, and are at risk of falling concrete and debris. Similarly, the public is subject to tripping hazards and other personal injuries, as most network vaults are location in heavy pedestrian areas (below sidewalks) in Toronto's downtown core.

In addition, a failure of a vault, through leaks and falling debris, can contribute or directly result in damages to the equipment contained within, resulting in further reliability risks to THESL's system. The poor condition of vaults can also be a contributing factor to catastrophic failures such as vault fires. In addition, from a design perspective, there are a large number of network assets within THESL's vaults (such as Fibertop Network Units, for example) which require immediate replacement. THESL submits that it would be imprudent to replace failing assets without properly securing the vault in which these new assets will be housed.

2. Structural Issues Affecting Vaults

Structural deficiencies of these vaults are mainly due to old age and the adverse environment as these assets. Many vaults are located in high pedestrian areas under sidewalks in the downtown core which are excessively salted in the winter to melt ice and snow for pedestrians. When melted, this salted water drains into vaults, corroding and damaging the vault. Some commonly found structural deficiencies are identified below.

(a) Exposed Roof Rebar:

An exposed roof rebar weakens the vault's roof structure and can potentially lead to the collapse of the entire network vault roof, which may damage the equipment in the vault and also poses a potential risk to pedestrian safety, as pedestrians could suffer injuries by tripping on the crumbling or depressed vault roof.

Figure 5 illustrates exposed rebar on the inside of a Network Vault roof.

Figure 5: Roof Exposed Rebar

(b) Exposed Wall Rebar:

The walls within a network vault are critical to the load bearing capability of the entire vault. Corrosion of the rebar within these walls significantly weakens the structural integrity of the vault as a whole. Over time, corrosion will result in the collapse of the vault walls and may damage the electrical assets contained within, causing a power outage to customers and requiring costly repairs for power restoration. Figure 6 illustrates an example of a network vault wall with exposed rebar.

Figure 6: Network Vault Wall with Exposed Rebar

(c) Corroded I-Beams:

The I-Beam represents the major support structure for the vault roof. The failure of the I-Beam will result in the complete collapse of the roof. Figure 7 below shows a heavily corroded I-Beam.

Figure 7: Corroded I-Beams

(d) Cracked Roof:

A cracked roof will result in water leaking into the vault. This will accelerate the degradation of rebar and I-beams and may also lead to rusting, contamination, and degradation of the electrical assets inside. Leaking water will also increase the risk of a catastrophic failure of critical electrical assets such as Network Units. In addition, pedestrians may trip and fall due to the uneven surface caused by the cracks. See Figure 8 below.

Figure 8: Cracked Roof

(e) Cracked wall:

When a network vault wall develops cracks it increases the likelihood of water entering the vault, which may ultimately result in vault flooding, thus potentially causing a short circuit and overall outage to the secondary network system. Figure 9 illustrates a typical crack found inside a THESL vault.

Figure 9: Cracked Wall

The consequence and risk of deferring vault and vault roof rebuild activities beyond 2015 will likely increase the risk to the public (tripping and other personal injury hazards) and THESL crew (falling debris). In addition, damaged vaults will likely negatively affect the equipment contained inside through flooding, potentially contributing to a catastrophic failure of the network assets contained within the vaults, leading to power outages in the downtown core. A power outage could impact between 500 customers (5 MVA) for smaller network grids, up to 3,000 customers (50 MVA) for the large network grids in the downtown core, and can last from several hours to up to a few days, depending on the location and which network distribution system is impacted by an outage. The cost of repairing the vaults under such reactive circumstances - typically on weekends and during the night, are much higher than planning and performing the work during regular hours. It is also important to note that damage to equipment as a result of vault failures is often extensive (as in the case of vault fires, for example), and tends to result in incremental costs beyond regular costs related strictly to the restoration of power.

Section 2.2 below further highlights some of the risks associated with recent cases of THESL's network vaults that have structurally failed.

3. Recent Failures

Network vaults that have been classified as ‘very poor’ or ‘poor’ have been shown to result in structural failures which could pose potentially serious safety hazards which call for being remedied by THESL in a timely manner. Because these vaults are beneath sidewalks in the busy downtown core, any failure in the vault structure could cause a person to trip and fall, often onto hazardous areas (such as the adjacent road, rusty exposed rebar, crumbled concrete of the vault roof, etc). In 2009, the ACA was revised to allow failing structural elements (roof, floor, and walls) to dominate or over-ride asset health. This revision caused a 9% increase in the network vaults classified by the ACA as ‘poor’ and ‘very-poor.’

Figures 10 and 11 below illustrate a structural failure of a vault located near Lawrence and Yonge Streets (during March 2010) in front of a bus shelter. The hole in the vault roof is covered temporarily by a piece of plywood, and surrounded by pylons. This failure resulted in disruption to the daily commuter traffic in the vicinity of the station, and had the potential to cause serious personal injury to pedestrian traffic until it was isolated.

Figure 10: Structural failure of vault located near Lawrence/Yonge St front of a bus shelter, with plywood temporarily covering the hole in sidewalk.

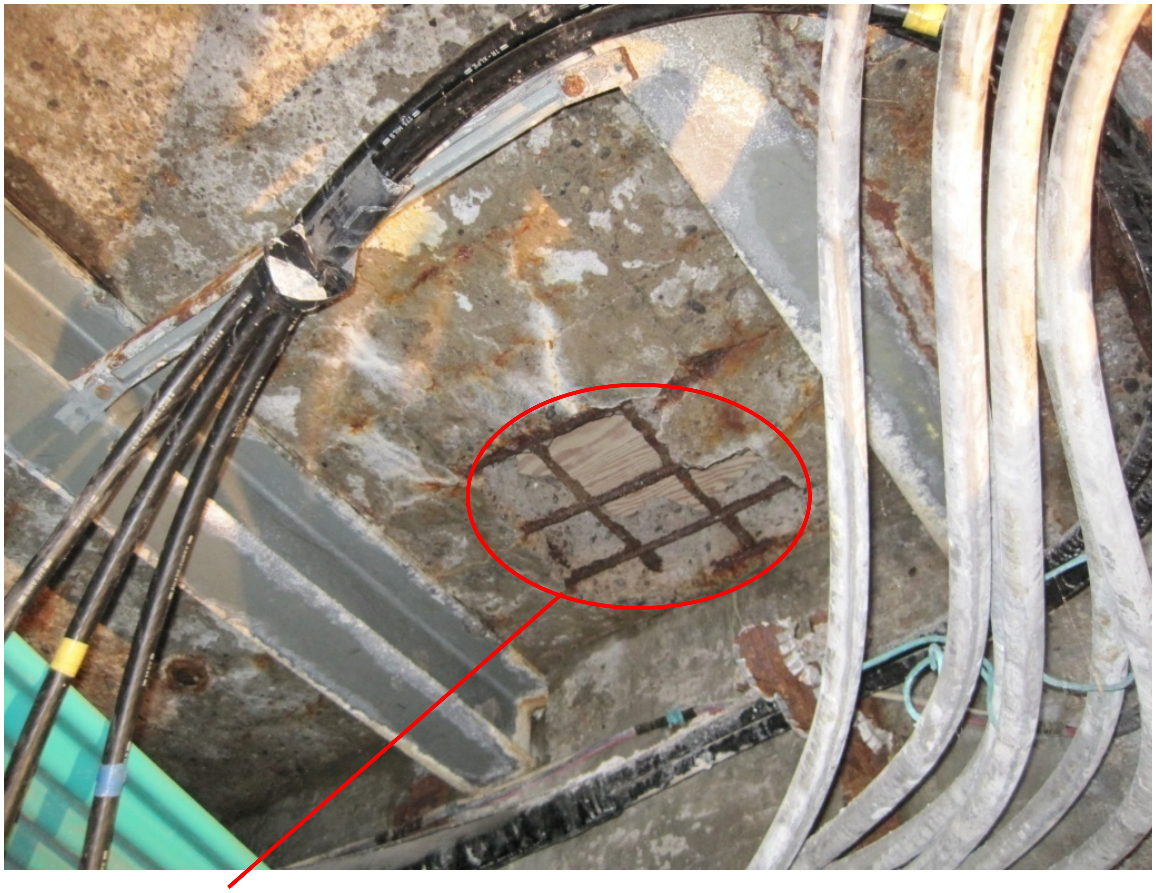


Figure 11: Structural failure of vault located near Lawrence/Yonge Street, as seen from within the vault chamber.

Figure 12 below illustrates a network vault at the intersection of King and Yonge Streets (during April 2010) where a large piece of concrete has fallen off the vault wall. This was caused by a structural deficiency as a result of old age, as well as salt and water entering the vault through cracks in the vault roof and side walls. The falling concrete had the potential to cause injuries to THESL crews if they had been present inside the vault performing switching operations at the time of the failure.

Figure 12: Photo of a large portion of concrete detached from vault wall King/Yonge St

Figure 13 below illustrates the failure of a vault roof located in a busy downtown area. The edges of the concrete roof have cracked and fallen into the vault. As this is a busy area with a large amount of pedestrian traffic, this failure posed a potential safety risk to the public. It was determined that both the beams and roof slabs had deteriorated due to old age and salt usage on the sidewalk during winter.

1 **Figure 13: Photo of a vault roof collapsed due to failed supporting beam**

IV PREFERRED ALTERNATIVE

Generally, there are four options to mitigate risks associated with a structurally failing vault:

(a) Decommission the Vault
(b) Rebuild the Vault Roof
(c) Rebuild the Entire Vault
(d) Eliminate the vault and install a new supply

The above options are considered for the vaults mentioned in this document that are structurally failing, and beyond the point of repair. As vaults are inspected each year, maintenance to the civil structure is typically performed as needed to fix small problems, and further extend the life of a vault. However, once a vault reaches the point where there is major structural failures and repairs can no longer address the problem, the above options are considered.

1. Option (a) – Decommission the Vault

In certain areas of the city, the low voltage, network secondary load is no longer desired when new high rise buildings are constructed and fed from a primary high-voltage arrangement. If the network secondary system no longer requires the capacity from a specific vault, this specific vault can be decommissioned. Decommissioned vaults are backfilled and the sidewalk is rebuilt to eliminate any safety risks. A typical cost to decommission a vault is approximately $50,000 and takes approximately one month to perform. Where possible, this is the most cost effective option to address structural and safety concerns with poor condition vaults.

2. Option (b) – Rebuild Vault Roof

A network vault roof rebuild is not as complex when compared to a total vault rebuild, but replacement or re-arrangement of the secondary and primary cables within the vault is still required. In most cases, this involves the removal of the existing damaged roof and the replacement with a new vault roof.

Rebuilding the network vault roof can take between three and nine months to perform because a temporary roof needs to be constructed, work restrictions prevent work during peak pedestrian times, and extensive precautions are required due to working around live electrical equipment. The typical cost is approximately $250,000 per vault. Due to the fact that a network vault roof possesses a reduced useful life of 25 years when compared to the overall vault useful life of 60 years, the roofs must be rebuilt more frequently. This is the second most cost effective option to address structural concerns with poor condition vaults, but is only a viable option for vaults where only the roof is in bad condition and the walls and floor of the vault are structurally acceptable.

3. Option (c) – Rebuilding Entire Vault

A complete rebuild or relocation of defective network vaults in some cases requires a rebuild of the neighbouring cable chamber, the installation of new ducts and the replacement of both primary cables and secondary grid cables. In addition, in order to maintain power to customers during a vault rebuild, THESL has to install additional secondary cables from the network grid or add additional temporary transformers in an adjacent vault.

In some cases, the vaults will be rebuilt in the original location and existing auxiliary civil infrastructure will be maintained. In other cases, a new vault along with auxiliary civil infrastructure will be constructed in a new location, and the old vault will be decommissioned. In addition, vaults also need to be redesigned according to current design and construction standards. The new rebar and I-Beams for the vault either need to be made of corrosion-resistant steel, or be coated with corrosion-resistant materials. This new material standard for vaults is expected to address the problems with I-beams and rebar corroding rapidly from sidewalk salt exposure. In addition, the ventilation grade of vaults must also be redesigned to meet the latest by-laws.

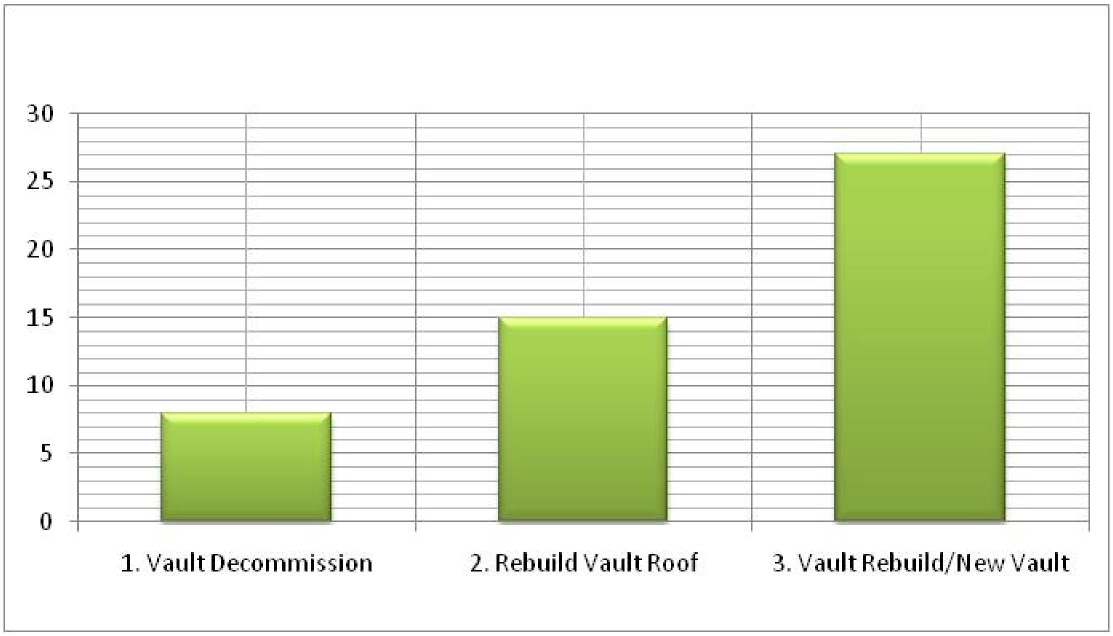
The typical cost for rebuilding a vault, including both civil and electrical work is approximately $1 million, which includes the average costs due to both civil and electrical plant replacement in adjacent network vaults. Depending on the complexity of the job, THESL estimates it will take between 18 and 24 months to complete a vault rebuild job. As a result of the cost and job complexity, only those poor condition vaults which cannot be addressed via decommissioning or through a vault roof rebuild would need to be addressed through this option.

4. Option (d) – Eliminating Vault and Installing New Supply

This option would involve eliminating the network system and supplying existing customers directly from the street via an alternate type of supply. In urban areas and within the downtown core, there are often limited options and physical constraints associated with installing alternative types of supply while also maintaining the same high reliability to the customer. This option could cost upwards of $2M per customer to feed them with a new supply. Therefore, this is not considered a comparatively cost effective alternative to rebuilding the existing network civil infrastructure.

5. The Proposed Approach

THESL submits that given the current circumstances and the options available, the most reasonable and cost effective approach is to undertake the option most suitable to the circumstances and conditions affecting any particular poor condition vault. This would involve decommissioning a vault in circumstances where the capacity is no longer required, rebuilding only the vault roof where the remaining structure is in an acceptable condition, and rebuilding the entire vault only where absolutely necessary. Figure 14 below shows a breakdown of vaults identified by the ACA as being in a condition requiring repair. Based on THESL's analysis, 8 vaults in "poor" or "very poor" condition can be decommissioned, 15 of the vaults will only require a roof rebuild, and 27 will required a complete vault rebuild.



1 **Figure 14: Vault Inspection Results and Civil Work Recommendations**

ICM Project – Network Infrastructure and Equipment

Fibertop Network Units Segment

Toronto Hydro-Electric System Limited (THESL)

ICM Project | Fibertop Network Units Segment

I EXECUTIVE SUMMARY

1. Project Description

The purpose of this segment is to mitigate the risk caused by existing Fibertop Network Units, by replacing these units with Submersible Network Units. The total cost of completing the segment is $26.73 M**,** which would address a total of 187 Fibertop Network Units. The Fibertop Network Units are currently the oldest vintage network protectors used on THESL's system. The assets selected for replacement have been identified as possessing the highest probability of failure, based on inspection of all THESL units (See Section II, 1).

Network Units are comprised of both a network transformer and a network protector. At least two Network Units are connected together to form a grid. For reliability, customers connected to this grid receive supply from multiple sources. One purpose of the protector is to open and isolate the secondary side of the circuit from the supply side when a fault is detected. This action prevents reverse current flowing from the low-voltage secondary network grid, feeding the fault on the supply side of the circuit. When a failure occurs at the top of a protector, it is unable to open the circuit to stop the fault current flow, often resulting in a vault fire.

2. Why the Project is Needed Now

Fibertop Network Units feature a design in which the top of the secondary protector, where interconnections are made to the secondary grid, is extremely susceptible to moisture and contamination (See Section III, 1). The interconnections themselves are also spaced very closely together. This design increases the probability of inter-phase tracking occurring between these connections, potentially igniting a vault fire. Such fires often result in extensive damage and the de-energization of the entire network grid, causing a substantial outage for a large number of customers.

Vault fires caused by Fibertop units can also affect the safety of THESL crews, fire fighters, and the general public due to the fact that the assets are often located in high traffic pedestrian areas. Additional hazards may be introduced because these assets are often connected to the secondary grid using Asbestos-Insulated Lead-Covered (AILC) secondary cables. All Fibertop Network Units are at least 39 years of age and are all well beyond their expected useful life of 20 years as determine by the Asset Condition Assessment (ACA).

3. Why the Proposed Project is the Preferred Alternative

THESL recognizes catastrophic failures associated with Fibertop Network Units as a serious issue and in recent years has increased maintenance, cleaning, and tarping of the Fibertop Network Units to mitigate this risk. While the maintenance has helped in minimizing build up of contaminates on top of the protectors it has not been able to adequately address the deficiencies inherent in the design of the Fibertop Network Units, nor significantly reduce the rate of catastrophic failures. As a result, several options were considered for Fibertop Network Unit replacement, including conversion to a Compact Radial design (CRD), removal of the existing asset and resupplying the customer from the remainder of the secondary network grid, and finally replacement of the assets with standardized Submersible Network Units (See Section IV).

The compact radial design would possess a higher installation cost and higher overall cost of ownership while providing inferior reliability when compared to Submersible Network Units. Removal of an existing Fibertop Network Unit and connecting customers directly to the secondary grid is not a viable option, as the existing secondary grids do not possess the necessary capacity to connect customers in this manner. Ultimately, replacement of these existing assets with new standardized Submersible Network Units is expected to be the most cost effective, reliable, and prudent approach.

THESL has concluded that all Fibertop Network Units in its system require replacement, but workforce and grid operation limitations constrain THESL's ability to do so within a three year timeframe (See Section II, 1). As a result, THESL has identified 187 Fibertop Network Units (that are located underground and more susceptible to failure) and proposes to replace these, prioritized based on risk of failure, with Submersible Network Units over the next three years.

II DETAILED PROJECT INFORMATION

1. Project Description

The purpose of this segment is to mitigate the risk caused by existing Fibertop Network Units in THESL's system, by replacing them with Submersible Network Units. The total cost of completing this segment is $26.73M**,** which would address 187 Fibertop Network Units (of a total of 240 in operation). The assets selected for replacement have been prioritized based on condition data retrieved during inspections. All units that are located below street level will be addressed as these are most susceptible to failure.

Network Units are comprised of both a network transformer and a network protector. At least two Network Units are connected together to form a grid. For reliability, customers connected to this grid receive supply from multiple sources. One purpose of the protector is to open and isolate the secondary side of the circuit from the supply side, should a fault be detected. This action prevents reverse current flowing from the low-voltage secondary network grid, feeding the fault on the supply side of the circuit. When a failure occurs at the top of a protector, it is unable to open the circuit to stop the fault current flow, often resulting in a vault fire.

The Fibertop Network Units are currently the oldest vintage network protectors used in THESL's network system. Because of their age and design, there is a much higher probability of a catastrophic failure than more modern designs used by THESL. In the past, these types of protectors have been directly linked to the cause of most network vault fires.

The work associated with Network Unit replacements is constrained by operational concerns. When performing Network Unit replacements, the supplying primary feeders must be taken offline and grounded and all connected loads are transferred to adjacent feeders and backup supplies. During this time the distribution grid is highly susceptible to any further outages that may cascade into a larger outage with a larger impact to customers. As a result, any work that requires feeders to be de-energized cannot be performed during the summer season, when loading is at its highest levels. Given these constraints, THESL is required to schedule Fibertop

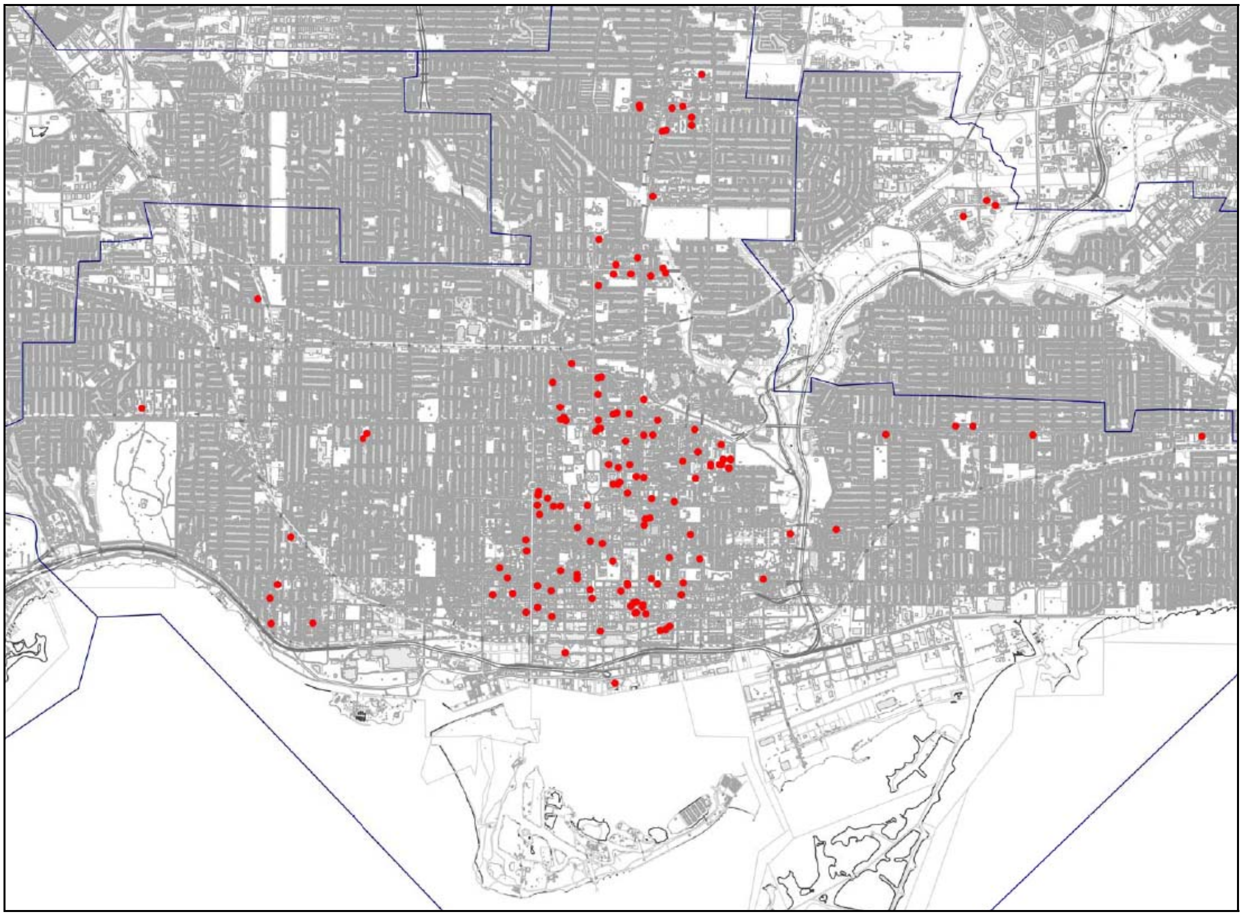
Network Units replacement over the course of the next three years. The segment cost schedule is shown below in Table-1. Complete job listings are shown in Appendix A.

Table-1: Project Budget Details

Project Title	Project Year	Estimated Cost ($M)
Fibertop Changeouts	2012	$8.59
Fibertop Changeouts	2013	$8.78
Fibertop Changeouts	2014	$9.36
	Total	**$26.73**

Figure 1 below shows the locations of the Fibertop Network Units that are scheduled to be replaced. Most are located in downtown Toronto and parts of East York, particularly along the Yonge Street corridor where dense commercial load requires reliable distribution equipment.

In the recent past THESL has replaced 40 to 60 Network units annually due to corrosion. Leaking transformers and fibertops have made up a significant portion of these replacements (40% in 2009 and 60% in 2010). The proposed segment would be an increase to the existing replacement strategy as more units would be replaced annually.



1 **Figure 1: Map of Immediate Fibertop Network Unit Replacements**

III. NEED

1. Sources and Consequences of Fibertop Failure

As a result of their design, Fibertop Network Units have been identified as having a much higher probability of catastrophic failure than any other Network Units currently within THESL's distribution grid. A catastrophic failure is defined as an outage that requires the grid to be de-energized in order to restore power to the vault. The duration of this outage can vary but is typically about four hours for the grid interruption and between eight to twelve hours interruption at the vault.

On a Fibertop Network protector the secondary bus extensions are spaced very closely together and level with the insulating top surface (see Figure 2 below). This fiber surface is also permeable to moisture and contamination through gaps around the bus bars and voids in the insulating material, which, in combination with the minimal spacing of the secondary connections, makes it prone to inter-phase tracking (short circuit between phases) which can result in catastrophic failure and vault fires. Modern protector designs (see Figure 10) are much more resistant to such inter-phase tracking.

Figure 2: Top of Fibertop Network Unit. Photo Taken September 4, 2009

THESL recognizes catastrophic failures as a serious issue and has already increased maintenance, cleaning, and tarping of the Fibertop Network Units to mitigate the risk. The maintenance has helped in minimizing build up of contaminates on top of the protectors and reducing the failure rate, but it has not been able to address the deficiencies inherent in the design of the Fibertop Network Units, nor significantly reduce the rate of catastrophic failures. Recent Fibertop Network Unit failures (discussed in Section 2) were attributed to contamination issues, and the susceptibility of Fibertop Network Units to moisture. These inherent design deficiencies, which cannot be sufficiently mitigated despite increased maintenance, make replacement of these assets necessary.

Most network vaults that contain the Fibertop Network Units are located underneath heavily trafficked pedestrian sidewalks in the downtown core of the City of Toronto (often in busy corridors such as Yonge Street). This poses a potential safety risk due to the vault fires that often occur during an asset failure, as seen in Figure 3 below. In addition, network vault fires are typically dissipated only when the power system controller de-energizes all primary feeders supplying the grid, which leads to substantial outages of up to nine primary network feeders, affecting approximately 3,000 customers on the secondary grid and about 60MVA of load, usually in the downtown core. Typically high impact customers such as hospitals, public transit, and financial institutions are affected.

Figure 3 - Vault fire on Yonge Street, March 24, 2007 (photo from citynews.ca)

In addition to the concern of vault fires and system reliability, the Fibertop Network Units were often installed with Asbestos-Insulated Lead-Covered (AILC) secondary cables. These cables remain a potential health and safety hazard, which can be further exacerbated during a vault fire. After the fire department extinguishes a fire, a dedicated asbestos removal team is often required to remove the secondary cables, which extends the duration of the outages and safety impact to the public.

THESL's records indicate that at least one catastrophic failure event has occurred annually. Should no action be taken to replace these assets, it is anticipated that these catastrophic failures will increase to three events annually, greatly increasing the potential risk to public safety, property damage, and customer outages. The increase in catastrophic failures is based on the cumulative probability of failure of all the Fibertop Network Units in service. These incidents typically occur in the winter months where a build-up of salt contamination at the top of the protector surface results in inter-phase tracking between the secondary connections. These failures have also occurred in the spring due to high levels of water which can pool on the top of the equipment during periods of heavy rain. The average interruptions caused by these failures are detailed in Table 2 below:

Table 2: Customer Interruptions and Customer Minutes Out from a Vault Fire

	CI (in MVA)	CMO (Hrs)	
Initial Fire	0	0	Network Grid is de-energized to isolate vault
Grid De-Energized	20-60	4 Hours	Crews isolate vault from network grid (60MVA accounts for about 3000 customers)
Vault Isolated	0.5-1	8-12 Hours	Vault Repair and equipment replacement
Restoration	-	-	Customers brought back online

2. Recent Failures Related to Fibertops

According to THESL records, there have been 18 vault fires in the past ten years, many of which were directly traced back to Fibertop Network Units as the root cause. Typically, these network vault fires have significant reliability impacts on the distribution system because in most cases all the feeders supplying the entire network grid need to be de-energized in order to safely put out the fire. Several of these failures are detailed below.

2.1. Incident #1: July 22, 2001 Vault Fire Investigation

On Friday June 22, 2001 at about 1:40 AM, a fire occurred in vault 4644; a network vault in the Parkdale neighbourhood. This was a network protector fire, which damaged both primary feeders supplying this vault and network as well as several other spot network vaults, customer vaults, and substations. Only two feeders; A23T and A26T were supplying these vaults. Power could not be restored until both feeders were replaced and repairs were made to vault 4644. This situation caused a prolonged outage in the neighbourhood lasting several hours.

THESL's investigation concluded that recent heavy rain had caused a significant amount of water to leak through the vault roof caulking and dripped on top of the Fibertop Network Units, causing conduction between the phases of the terminals passing through the fibre top. While some water is typically expected in network vaults, the design deficiencies of the Fibertop

Network protector allow the water to soak into debris that collects on top of the protector, and in heavy rain situations such as this one the likelihood of tracking is higher than with other protector styles. The conduction initiated arcing, which started a fire on the protector top. As the Fibertop Network Unit burned, the heavy bus bars lost their support and collapsed under their own weight and the weight of the AILC cables. This collapse caused the bus bars of different phases to short against each other, causing the bulk of the fire damage.

	Duration	Impact
A26T and A23T	14.8 Hours	~ 16 MVA

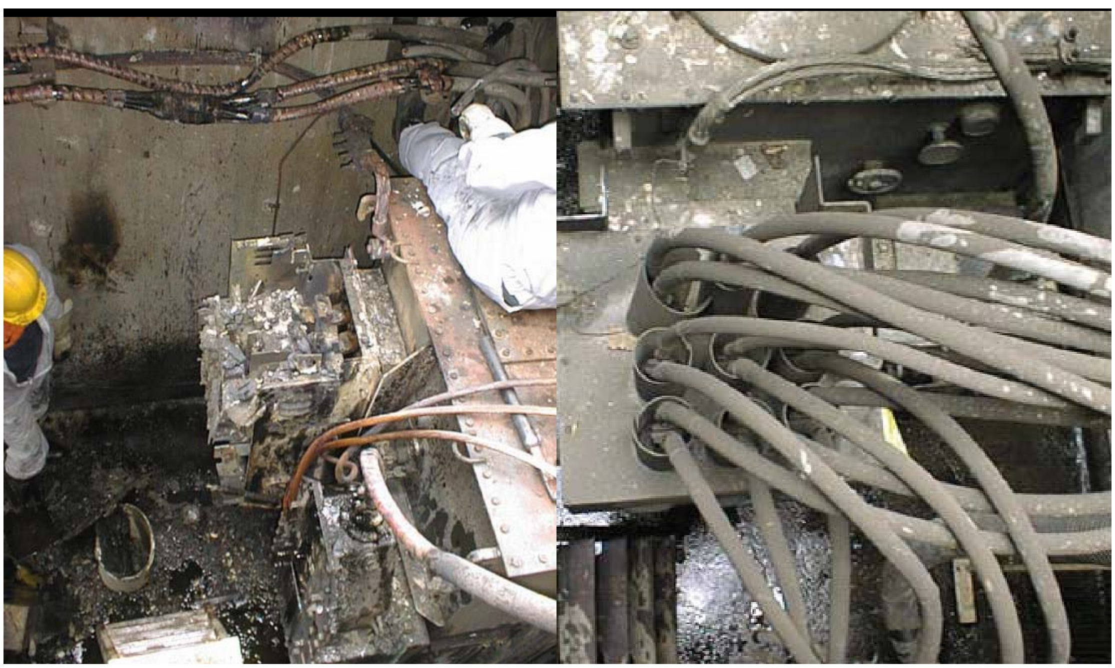


Figure 4 - LEFT: A23T Protector and Transformer. Damaged primary cables on the wall near the network protector. RIGHT: A26T Protector and Transformer – Undamaged. This unit also has a fibre top network protector. (June 22, 2001)

2.2. Incident #2: March 24, 2007 Vault Fire Investigation

At Vault 4323 (Richmond and Bay), following rain showers, a fire began on top of a 50 year old Fibertop Network protector, damaging the transformer attached to it. As with previous Network Protector fires, THESL suspects that this fire was caused by rain water on the Fibertop Network protector. As a result of the fire, oil began leaking from the secondary bushings of the damaged transformer, which continued to further fuel the fire and caused flames and sooty smoke to be emitted from the vault. The Terauley East Network was de-energized to allow the fire to be extinguished and to isolate damaged equipment.

This is the second time a vault fire occurred at this location. There was a vault fire in August of 2005 that began at the network protector on the transformer beside this unit. In that incident there was damage to the network protector, the transformer and the secondary cables, which also contained asbestos.

	Duration	Impact
A64A	9.75 hours	~ 8 MVA
Terauley East Network	7.95 hours	~70 MVA

Figure 5 - LEFT: Fire fighters working to extinguish the fire. RIGHT: Asbestos Clean-up. Photos taken March 24, 2007

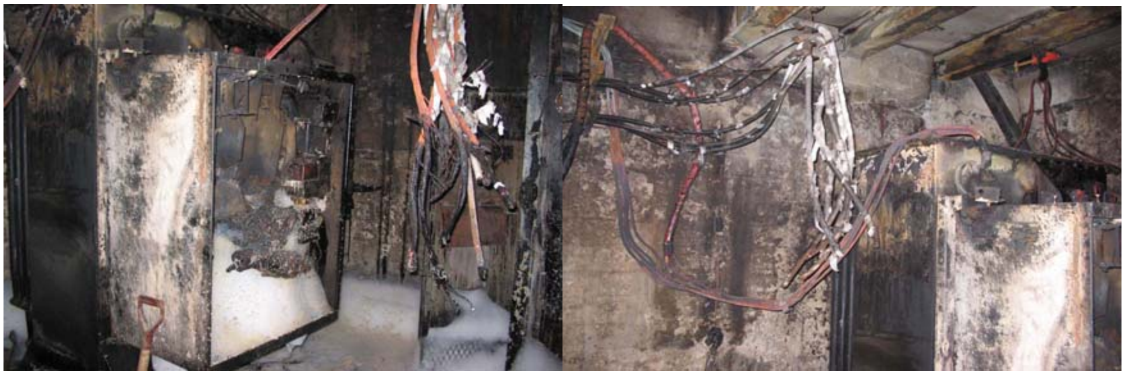


Figure 6 - LEFT: Failed Protector. RIGHT: Burnt AILC cables. (March 24, 2007)

2.3. Incident #3: June 1, 2010 Vault Fire Investigation

On June 1, 2010, a vault fire caused by a Fibertop Network protector occurred on Erskine Ave west of Mount Pleasant. It was noted that there were garbage bins placed on the roof of the network vault and garbage had fallen on top of the network unit, likely contributing to the cause of the fire. The feeder supplying the network unit was damaged by the fire and the grid was dropped during the isolation of the feeder. The fire department was called in to put out the fire. Power was restored seven hours after the initial incident.

	Duration	Impact
Glengrove South Network	4.6 Hours	~ 32 MVA
Vault 4557	7 Hours	~1000 kVA

Figure 7 - LEFT: Vault 4557 with roof slabs off, signs of heavy smoke apparent in vault. RIGHT: damaged Fibertop Network Unit. (June 1, 2010)

Figure 8 - Vault fire on Erskine Ave, near Yonge and Eglinton. Photo from ctv.ca, taken June 1, 2010.

2.4. Incident #4: December 31, 2011 Vault Fire Investigation

On December 31, 2011 another incident occurred at 165 Erskine Avenue with many of the same factors that caused the first vault fire.

A grid response crew was dispatched to the site at 9:05AM. Operations crew isolated the vault by opening both network feeders A7GL and A8GL. After the fire was put out by fire crews, the

THESL crew found that the Fibertop Network Unit inside the vault was severely damaged. A reactive crew was called in to repair the transformer. Full power was only restored to customers at 12:40PM on January 1, 2012, after repairs could be completed.

	Duration	Impact
Glengrove South Network	6.7 hours	~ 32 MVA
Terauley East Network	27.55 hours	~1000 kVA

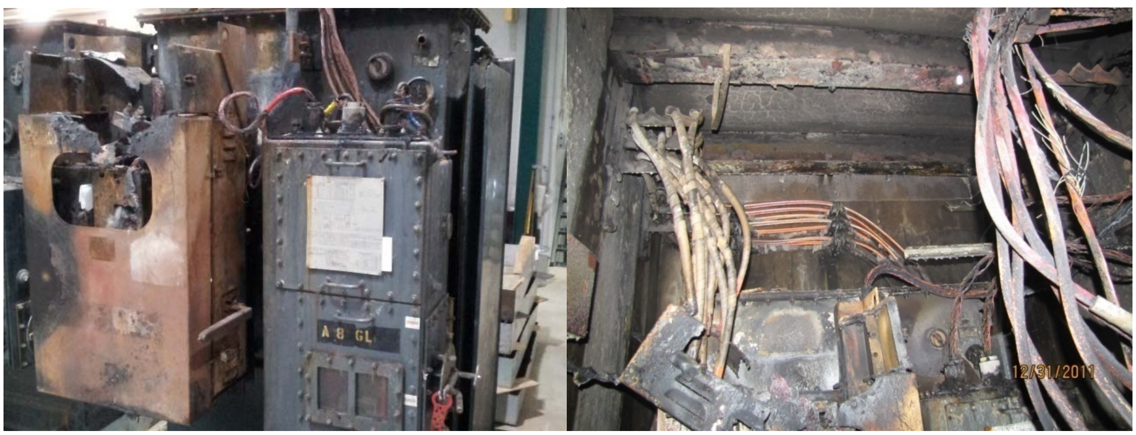


Figure 9 - LEFT: Fire damaged Fibertop Network Unit, Incident #4. RIGHT: Damaged vault from fire, Incident #4. (January 3, 2012)

Based on THESL's recent experiences it is clear that a catastrophic failure of Fibertop Network Units can result in serious reliability concerns and safety risks to THESL crews, fire fighters, and the public as a whole. To mitigate these risks, THESL submits that immediate investments are required such that the removal of Fibertop Network Units from the system can be accelerated.

IV PREFERRED ALTERNATIVE

In recent years, THESL has increased maintenance for Fibertop Network Units in an attempt to reduce the number of catastrophic failures. While the maintenance has helped in minimizing build up of contaminates on top of the protectors and reducing the failure rate, it has not been able to adequately address the deficiencies inherent in the design of the Fibertop Network Units, nor significantly reduce the number of associated catastrophic failures. As a result, in order to effectively mitigate the risks associated with Fibertop Network Units, THESL has considered the following options:

(a) Replacement of the Fibertop Network Unit with a standardized Submersible Network Unit -- $145,000 ($115,000 Material Cost and $30,000 Labour Cost)

(b) Replacement of the Fibertop Network Unit with a Compact Radial Design Unit -- $170,000 ($140,000 Material Cost and $30,000 Labour Cost)

(c) Remove and eliminate the Fibertop Network Unit, connect the load/customers to the existing network grid -- Variable Costs

Option (a) to replace the Fibertop Network Unit with a standardized Submersible Network Unit remains the least expensive solution, as the network vault location is already configured to support a Network Unit asset. The design of the Submersible Network Unit, introduced as a THESL standard in 2003, allows the unit to operate even if completely submerged in water, and is a proven, robust product used by utilities for decades. As illustrated in Figure 8. This new design effectively reduces the probability of inter-phase tracking due to the separation distance of the low voltage connections and the elevation of the buses. In addition, the bushings themselves are water proof and are impervious to moisture penetration and contamination.

Figure 8 - Submersible Network Unit. Secondary Bus raised above top of Protector. (September 4, 2009)

Option (b) is to replace the Fibertop Network Units with Compact Radial (CR) equipment and retain one existing distribution transformer, as seen in Figure 11 below. This design replaces the secondary bus with primary switching equipment, and as such is applicable at 120/208V and 240/416V. However, customers experience inferior reliability with this option, as restoration of service is delayed following unplanned feeder interruptions because crews must be sent to manually operate the CR switches. In addition, the particular style of SF_6 switches contained within this configuration (as shown in Figure 5 below) requires frequent maintenance, which contributes to higher ongoing maintenance costs. As a result of the higher cost of implementation and maintenance, and lower reliability to the customer, this solution is not preferred.

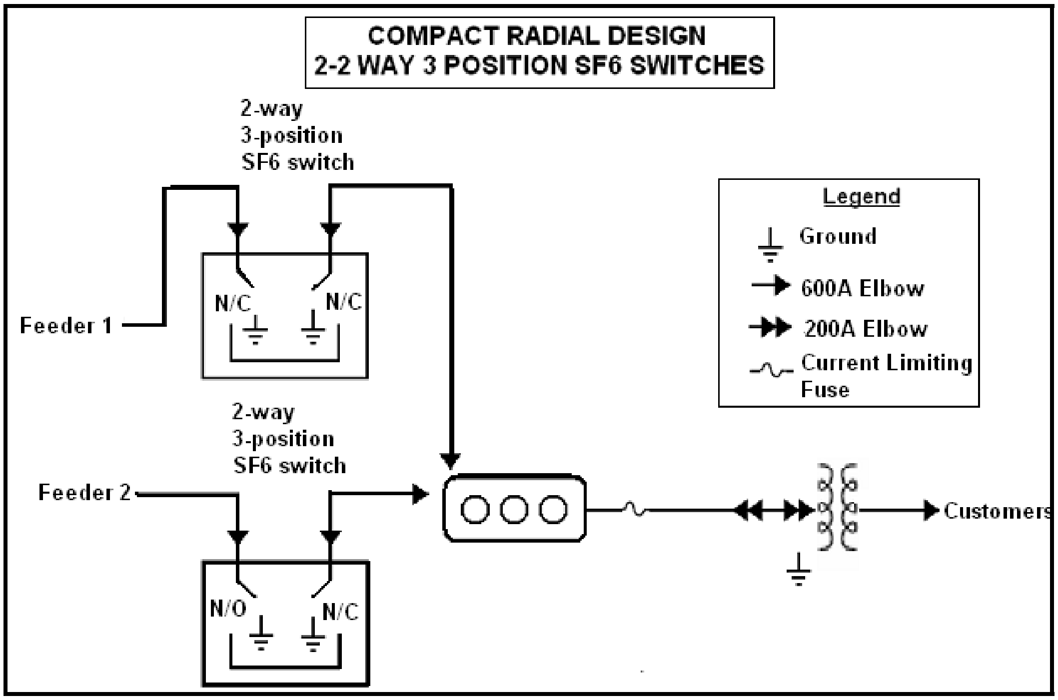


Figure 9 - Compact radial (submersible equipment)

Option (c) is to eliminate the Fibertop Network Unit vault from the network entirely and allow the customer to be fed from the rest of the secondary network grid. This option is generally only practical in areas with networks with a lot of available growth capacity, where removal of the capacity associated with the Fibertop Network Unit can be supported by the rest of the connected network. However, THESL has determined that most of its networks do not have the available capacity to remove the Fibertop Network Units. As a result, this option is not technically feasible in most situations, and in the few locations where it may be possible, extensive engineering design effort is generally required along with civil construction work that is disruptive to the neighbourhood. The cost of implementation is also extremely variable, ranging from a low of $50k in some rare instances, to as much as $1M per location.

Based upon the above findings, THESL has concluded that replacement of the Fibertop Network Units with standardized Submersible Network Unit is the best option, both from a cost and a reliability perspective. However, there are limitations to the number of Fibertop Network Units that THESL can efficiently remove from service at any one time. While replacing all units would be the ideal option, it is infeasible due to the potential contingency issues that would arise from executing all of this work at once.

In order to replace a Fibertop Network Unit, the primary feeder needs to be taken out of service and therefore the entire load fed by that feeder has to be shifted onto back-up supplies. The system would be under first contingency (a situation in which one feeder may be de-energized and customers would remain energized) and would be vulnerable to any system outage that may occur. It is THESL policy not to operate under first contingency during high load times such as the summer period, and usually not to operate under first contingency for any extended period of time. Given these limitations, a complete replacement program for the entire population of Fibertop Network Units over 2012-14 would not be possible.

Furthermore, highly skilled workers that are qualified to work on THESL plant are required to replace Fibertop Network Units; these worker's responsibilities encompass maintenance as well as most underground capital work. There are approximately 854 available crew days that must be divided amongst the entire underground capital program. Even if these resources were entirely dedicated to replace Fibertop Network Units, only approximately 131 units could be addressed annually.

Given these constraints, THESL proposes to replace only units that are deemed high risk of immediate failure and have a direct impact on the safety of the general public. These 187 Fibertop Network Units are all located below ground and subject to detrimental environmental conditions. THESL proposes to replace them over the next three years at a total estimated cost of $26.73M.

Units not selected for immediate replacement are those located above ground in building electrical rooms (as seen in Figure 12 below) where they are less susceptible to catastrophic failure. These remaining units will be addressed over the next ten-year period such that all Fibertop Network Units are eventually removed from the system. THESL's ongoing inspection and maintenance program will ensure that Fibertop Network Units are prioritized to mitigate the risk associated with these units.

Figure 10 – Walk-in Building Network Vault. (November 2011)

Economic Benefits of Preferred Solution

THESL has calculated the economic benefits of undertaking the Fibertop Network Unit replacement segment, by determining how much cost is avoided by executing this work immediately, as opposed to executing it in 2015 (for comparison purposes). The avoided costs used in this model include quantified risks, taking into account the assets' probability of failure, and multiplying this with various direct and indirect cost attributes associated with in-service asset failures, including the costs of customer interruptions, emergency repairs, and replacement.

Based on THESL's calculations, carrying out immediate work on this asset class will result in an avoided estimated risk cost of $31.3 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 Appendix B.

1 **APPENDIX A**

2 **Detailed List of Projects**

Estimate Number	Project Title	Year	Cost Estimate ($M)
24911	4768SV_A11DX	2012	$0.13
24053	4540_A66DX	2012	$0.11
24053	4540_A61DX	2012	$0.11
24096	4491_A62DX	2012	$0.13
24086	4286_A53WR	2012	$0.12
24092	N1034_A65H	2012	$0.12
21583	4561_A55H	2012	$0.12
24912	4768SV_A13DX	2012	$0.12
22690	N1125_A67WR	2012	$0.13
24913	N1125_A64WR	2012	$0.13
23958	N1044_A65WR	2012	$0.13
23960	4517_A91A	2012	$0.16
23961	4517_A92A	2012	$0.16
24098	4643_A23T	2012	$0.12
24028	4794_A48CE	2012	$0.12
24090	4499WV_A66H	2012	$0.14
24146	4219EV_A54WR	2012	$0.15
24094	4646_A23T	2012	$0.12
24093	N1107_A53CS	2012	$0.15
24146	4219WV_A51WR	2012	$0.15
24520	4099_A66H	2012	$0.13
24530	4131_A67WR	2012	$0.18
24533	4131_A68WR	2012	$0.18
24521	4160_A69WR	2012	$0.13
24522	4336_A44GD	2012	$0.13

ICM Project | Fibertop Network Units Segment

Estimate Number	Project Title	Year	Cost Estimate ($M)
24523	4336_A48GD	2012	$0.13
24518	4523_A20T	2012	$0.14
24525	4553_A56H	2012	$0.13
24526	4625_A50DX	2012	$0.13
24534	4651_A53H	2012	$0.18
24535	4651_A54H	2012	$0.18
24519	4745_A55H	2012	$0.14
24536	4897NV_A43CE	2012	$0.18
24527	N1010_A41CE	2012	$0.13
24528	N1102_A71CE	2012	$0.13
24529	N1102_A72CE	2012	$0.13
25078	4768NV_A12DX	2012	$0.14
25078	N1029_A43GD	2012	$0.14
25078	4378_A43CE	2012	$0.14
25078	V4511_A16L	2012	$0.14
25078	4186_A69WR	2012	$0.14
25078	V4511_A17L	2012	$0.14
25078	4529WV_A49GD	2012	$0.14
25078	N1087_A67WR	2012	$0.14
25078	V4733_A16L	2012	$0.14
25078	4050_A83WR	2012	$0.14
25078	4172_A67H	2012	$0.14
25078	4205_A41GD	2012	$0.14
25078	4710NV_A62CS	2012	$0.14
25078	4340_A49GD	2012	$0.14
25078	4653SV_A65CS	2012	$0.14
25078	4521_A54WR	2012	$0.14
25078	4478_A66WR	2012	$0.14
25078	4776SV_A44CE	2012	$0.14

ICM Project | Fibertop Network Units Segment

Estimate Number	Project Title	Year	Cost Estimate ($M)
25078	N1090_A37X	2012	$0.14
25078	4376_A63H	2012	$0.14
25078	N1011_A63WR	2012	$0.14
25078	N1011_A66WR	2012	$0.14
25078	4709_A39DN	2012	$0.14
25078	4057_A73CS	2012	$0.14
25078	N1045_A77CS	2012	$0.14
24714	N1051_A15K	2013	$0.14
24714	4619_A94B	2013	$0.14
24714	4254WV_A75CS	2013	$0.14
24714	N1051_A13K	2013	$0.14
24714	4555_A70CE	2013	$0.14
24714	4210_A34A	2013	$0.14
24714	4210_A36A	2013	$0.14
24714	4752_A75CS	2013	$0.14
24714	4726_A23T	2013	$0.14
24714	4760_A10MN	2013	$0.14
24714	4883_A78CS	2013	$0.14
24714	4176_A5K	2013	$0.14
24714	N1071_A78E	2013	$0.14
24714	4667_A30DN	2013	$0.14
24714	4243_A12K	2013	$0.14
24714	4614_A42CE	2013	$0.14
24714	4274_A25W	2013	$0.14
24714	4274_A38W	2013	$0.14
24714	4630_A31DN	2013	$0.14
24714	4412EV_A40GD	2013	$0.14
24714	4518_A72A	2013	$0.14
24714	4518_A71A	2013	$0.14

ICM Project | Fibertop Network Units Segment

Estimate Number	Project Title	Year	Cost Estimate ($M)
24714	4068SV_A62H	2013	$0.14
24714	V4476_A16L	2013	$0.14
24714	4518_A70A	2013	$0.14
24714	4769_A92B	2013	$0.14
24714	4777_A44CE	2013	$0.14
24714	4509_A62A	2013	$0.14
24714	N1033_A62H	2013	$0.14
24714	4940_A41GD	2013	$0.14
24714	N1083_A43GD	2013	$0.14
24714	N1083_A49GD	2013	$0.14
24714	4753_A49H	2013	$0.14
24714	4753_A48H	2013	$0.14
24714	4317_A91A	2013	$0.14
24714	4177_A65WR	2013	$0.14
24714	4657_A43GD	2013	$0.14
24714	4198_A64H	2013	$0.14
24714	N1072_A92A	2013	$0.14
24714	4164_A84A	2013	$0.14
24714	4851_A5GL	2013	$0.14
24714	4438_A65WR	2013	$0.14
24714	4543EV_A7GL	2013	$0.14
24714	4325_A50CE	2013	$0.14
24714	N1115_A94CS	2013	$0.14
24714	4710SV_A60CS	2013	$0.14
24714	N1053_A71CS	2013	$0.14
24714	4426_A72CE	2013	$0.14
24714	4394_A52CS	2013	$0.14
24714	4394_A53CS	2013	$0.14
24714	4789_A91B	2013	$0.14

ICM Project | Fibertop Network Units Segment

Estimate Number	Project Title	Year	Cost Estimate ($M)
24714	4736_A64H	2013	$0.14
24714	4106_A91A	2013	$0.14
24714	4562_A54WR	2013	$0.14
24714	4499EV_A65H	2013	$0.14
24714	N1005_A77CS	2013	$0.14
24714	4123_A70H	2013	$0.14
24714	4003_A68H	2013	$0.14
24714	4627_A61CS	2013	$0.14
24714	4627_A60CS	2013	$0.14
24714	4339WV_A92CS	2013	$0.14
24950	4230WV_A40GD	2014	$0.14
24950	4769_A94B	2014	$0.14
24950	4666EV_A86A	2014	$0.14
24950	4666EV_A81A	2014	$0.14
24950	4666WV_A82A	2014	$0.14
24950	4666WV_A85A	2014	$0.14
24950	4518_A73A	2014	$0.14
24950	4917SV_A69WR	2014	$0.14
24950	4766NV_A62CS	2014	$0.14
24950	4766SV_A64CS	2014	$0.14
24950	4543EV_A8GL	2014	$0.14
24950	4238_A47GD	2014	$0.14
24950	4238_A40GD	2014	$0.14
24950	4340_A46GD	2014	$0.14
24950	4637_A57H	2014	$0.14
24950	4637_A55H	2014	$0.14
24950	4885_A11E	2014	$0.14
24950	4885_A12E	2014	$0.14
24950	4407_A47H	2014	$0.14

ICM Project | Fibertop Network Units Segment

Estimate Number	Project Title	Year	Cost Estimate ($M)
24950	4770_A56H	2014	$0.14
24950	4653NV_A63CS	2014	$0.14
24950	4026_A82CS	2014	$0.14
24950	4654EV_A63CS	2014	$0.14
24950	N1109_A65CS	2014	$0.14
24950	N1115_A91CS	2014	$0.14
24950	4723_A71CE	2014	$0.14
24950	4658_A61CS	2014	$0.14
24950	4658_A60CS	2014	$0.14
24950	4387_A55WR	2014	$0.14
24950	4509_A67A	2014	$0.14
24950	4564_A18T	2014	$0.14
24950	4654WV_A65CS	2014	$0.14
24950	4696NV_A62CS	2014	$0.14
24950	4696SV_A63CS	2014	$0.14
24950	4774_A63H	2014	$0.14
24950	4187_A11E	2014	$0.14
24950	4187_A12E	2014	$0.14
24950	V4476_A6L	2014	$0.14
24950	V4476_A17L	2014	$0.14
24950	N1114_A65WR	2014	$0.14
24950	N1114_A69WR	2014	$0.14
24950	4542_A4K	2014	$0.14
24950	4022EV_A57WR	2014	$0.14
24950	4244_A6K	2014	$0.14
24950	4031_A64WR	2014	$0.14
24950	N1128_A67WR	2014	$0.14
24950	4562_A58WR	2014	$0.14
24950	_A67WR	2014	$0.14

ICM Project | Fibertop Network Units Segment

Estimate Number	Project Title	Year	Cost Estimate ($M)
24950	4826_A3K	2014	$0.14
24950	4465_A90B	2014	$0.14
24950	4733_A16L	2014	$0.14
24950	4214_A54DX	2014	$0.14
24950	N1048_A73CS	2014	$0.14
24950	N1048_A77CS	2014	$0.14
24950	N1196_A36MN	2014	$0.14
24950	N1196_A38MN	2014	$0.14
24950	4768-NV_A12DX	2014	$0.14
24950	4648_A90B	2014	$0.14
24950	4648_A91B	2014	$0.14
24950	4481WV_A51DX	2014	$0.14
24950	4154_A66DX	2014	$0.14
24950	N5003_A67H	2014	$0.14
24950	N5003_A65H	2014	$0.14
24950	4539_A55CS	2014	$0.14
24950	4100_A46CE	2014	$0.14

APPENDIX B

Network Unit 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 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 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.

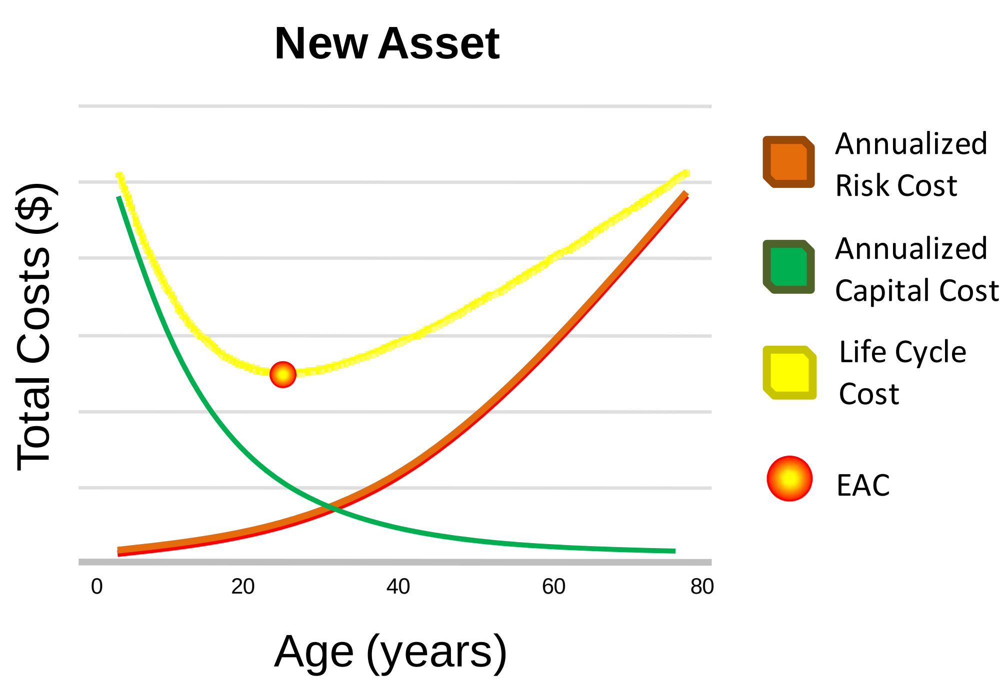


Figure 1: Typical Example of Optimal Intervention Time (New Assets)

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.

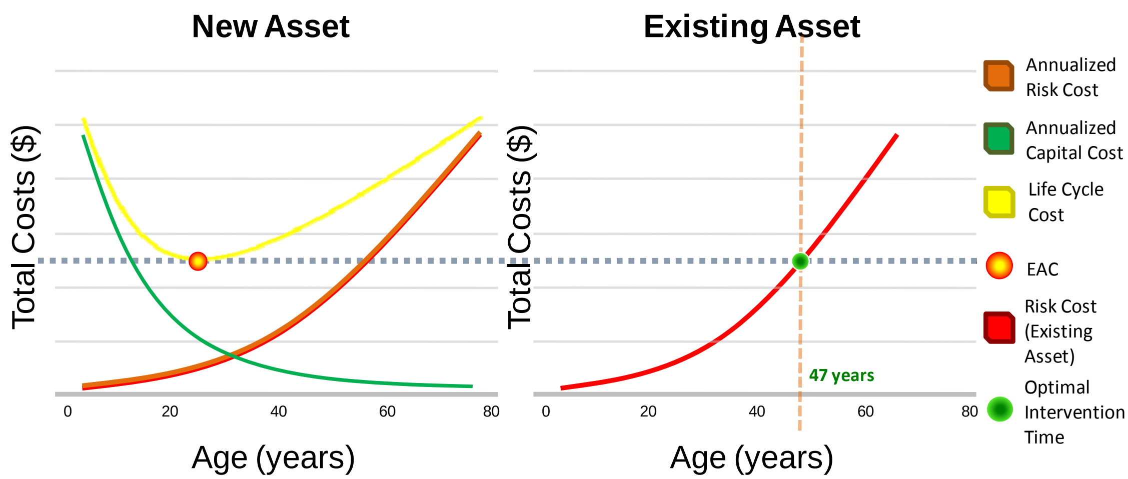


Figure 2: Typical Example of Optimal Intervention Time (Existing Assets)

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.

1.2 Project Evaluation Results

The Fibertop Network Unit Replacement segment represents an “in-kind” replacement project in which the existing Fibertop Network Units are being replaced with new standardized Submersible Network Units; 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 this would represent the next available year when THESL may 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 weighted against the total costs in order to produce an overall project net cost calculation. However, in this instance, the Fibertop Network Units Replacement 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 and the total costs as the ordinate. As such, the minimum point of this curve provides the highest Net Project Benefit and defines the optimal year to execute the specific project.

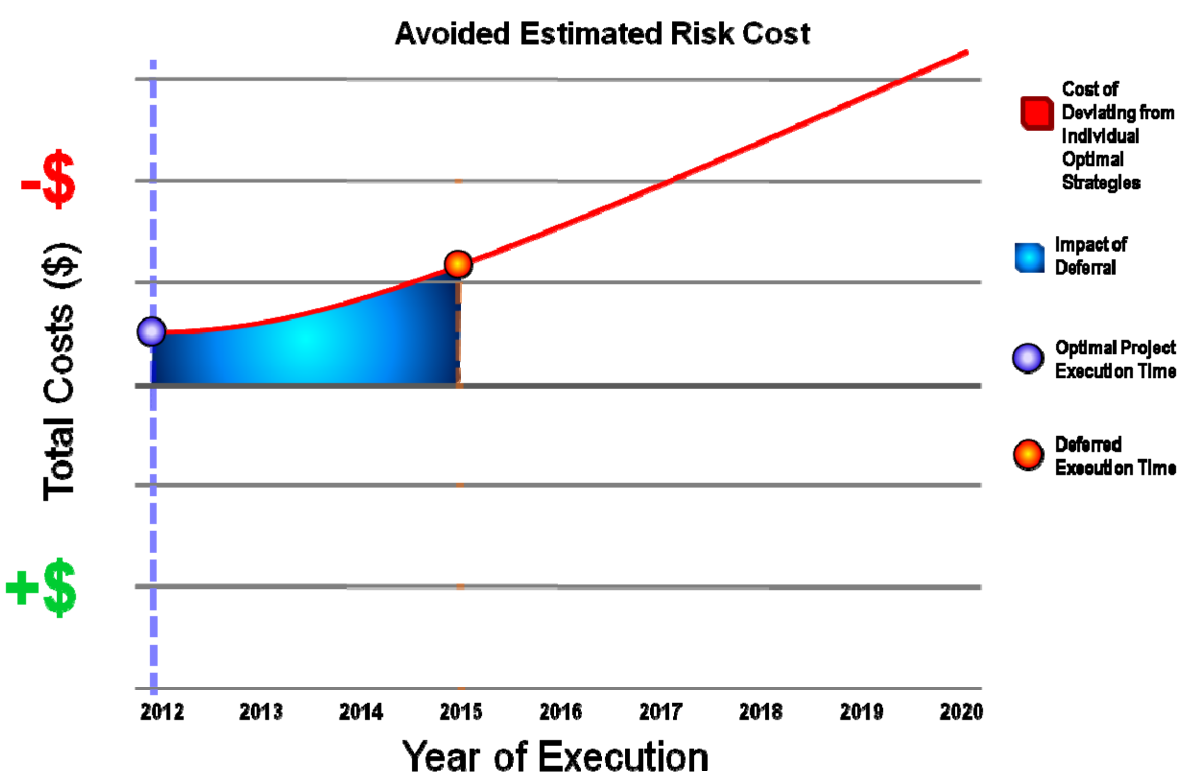


Figure 3: Typical Example of Project Net Benefit Analysis

The effectiveness of the project 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, these estimated risks can be eliminated. Therefore, these avoided costs represent the benefits of the in-kind project execution.

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 Fibertop Network Unit Replacement segment, individual optimal intervention timing results were calculated for each of the 187 Fibertop Network Units, 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 Fibertop Network Units within this project 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.

1 **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))	$31.6
Project Net Cost in 2012 (PROJECT$_{NET_COST}$(2012))	$0.3
Avoided Estimated Risk Cost	**$31.3**

2

3 When this avoided cost is calculated as a positive value, it means that estimated risk costs for
4 the job assets in 2015 will exceed the estimated risks that exist today. By performing the work
5 immediately as opposed to waiting until 2015, we can eliminate these estimated risks.
6 Therefore, these avoided costs represent the benefits of job execution.

ICM Project – Network Infrastructure and Equipment

Automatic Transfer Switches (ATS) and Reverse Power Breakers (RPB) Segment

Toronto Hydro-Electric System Limited (THESL)

I EXECUTIVE SUMMARY

1. Project Description

Automatic Transfer Switches (ATS) automatically switch a customer to a designated standby feeder in the event the normal primary feeder fails. Reverse Power Breakers (RPB) automatically open primary feeder supplies to customers in the event of feeder outages to prevent dangerous backfeed conditions. ATS and RPB assets are generally used to supply medium size customers that require a reliable supply, such as schools, supermarkets, seniors' homes, and other mid- sized buildings (See Section II, 1).

Both ATS and RPB assets have degraded rapidly in 2010 and 2011. THESL's Asset Condition Assessment (ACA) results indicate that approximately 30 ATS assets will need to be replaced over the next three years (See Section III, 1 and Appendix 1). In addition, based on physical inspection data, a further six RPB assets have been identified as requiring immediate replacement. The proposed ATS and RPB Segment will replace these assets with Stand Alone Network Protectors or Standard Network Equipment at a total cost of $9.8 M.

Table 1: ATS and RPB Segment Capital Cost

Description	**Year**	**Design Estimate ($M)**	**Estimated Total Cost ($M)**
Replace 10 ATS Locations	2012	$2.57	$7.68
Replace 10 ATS Locations	2013	$2.59	
Replace 10 ATS Locations	2014	$2.52	
Replace 2 RPB Locations	2012	$0.71	$2.12
Replace 2 RPB Locations	2013	$0.71	
Replace 2 RPB Locations	2014	$0.71	
	Total:	**$9.80**	**$9.80**

2. Why the Project is Non-Discretionary

The impact that failing ATS and RPB assets have on the reliability of the system and the general public can be extensive (See Section III, 2). For example, an ATS vault fire incident at 33 Princess Street (January 16, 2012) affected a daycare centre, a seniors' home, and the St. James Campus of George Brown College. Similarly, an RPB failure at 50 Marlborough (January 10, 2010) resulted in an explosion and damage to equipment in other locations, and an extended interruption to the entire neighbouring grid network. Replacing ATS and RPB units is needed for the following reasons:

- Unrepairable – ATS and RPB assets were purchased from many different manufacturers and over many different vintages, which makes each unit unique. Manufacturer support and spare parts are unavailable for these assets, so continuing ongoing maintenance is not a viable option. Upon failure, they need to be replaced with new equipment.
- Asset Condition – There are many ATS assets which have degraded to poor and very poor condition (based on the ACA categorization). In addition to the ACA, recent field inspections have also identified additional RPB assets in deteriorating condition requiring immediate replacement. Failing to make immediate replacements will likely result in accelerated reliability issues. Based on recent ACA data, 10% of ATS assets can be expected to fail within the next year, and a comparable percentage of RPB assets would also be expected to fail. The customers supplied by these assets would experience loss of supply incidents following unplanned feeder outages.

  Public Safety Risks – ATS and RPB assets can ignite a vault fire when they fail. As these assets are located in densely populated downtown areas, there is a potential risk to public safety.

The table below provides details on the expected failure rates of the ATS and RPB assets and the likely impact of failure on THESL's reliability in the affected areas.

Table 2: ATS and RPB Failure Impacts

Asset	Number of Assets to be Replaced	Expected Failure Rate in 2013	Average consequences of failure (CI and CHI)
ATS	30	10%	1 and 4.5
RPB	6	10%	1 and 4.5

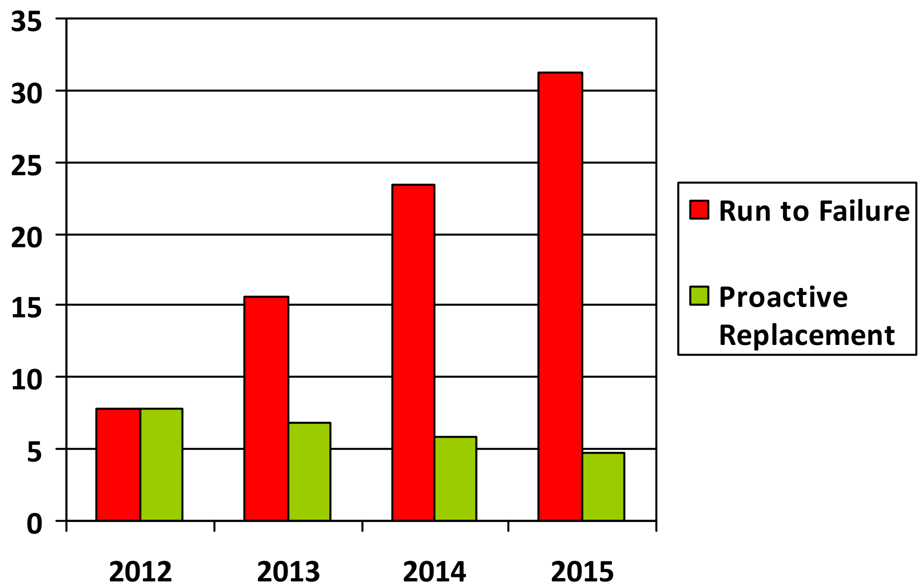


Figure 1: Predicted ATS Failures

3. Why the Proposed Project is the Preferred Alternative

Many options were evaluated to address the failing ATS and RPB units, as follows:

a) Like-for-Like Replacement with new ATS and/or RPB
b) Decommission the Vault
c) Modular Switchgear
d) Compact Radial Switchgear
e) Modified TTC Design Switchgear
f) Stand-Alone Network Protectors
g) Standard Network Equipment

Option (a) was not considered viable, due to the fact that the ATS and RPB assets both are obsolete. They are no longer being manufactured or supported by the original suppliers, and spare stock is not available. Option (b) would involve connecting the customers to an existing secondary network grid, but this option is typically more costly than other alternatives because of the conversion costs to connect to the network and is not feasible in many areas. Options (c), (d) and (e) would result in the installation of new switchgear to connect to the pre-existing distribution transformer assets. Each of these three options, however, would produce an inferior supply of electricity to the customer in terms of reliability, when compared to the existing ATS and/or RPB installation, as manual switching is required to transfer to the standby supply. The ATS and RPB units typically supply medium-sized customers that require high reliability, such as schools and senior housing.

As a result of the limitations of the above options, THESL has concluded that in cases where existing transformers and adequate space exists can be reused it is preferable to install new Stand-Alone Network Protectors (SANP) as per Option (f). Alternatively, if there isn't enough room to accommodate SANPs, or the transformer units also need to be replaced, it is preferable for the ATS and RPB assets to be replaced by Standard Network Equipment as per Option (g). These two solutions are the preferred alternatives with the one chosen depending on the specific circumstances as outlined above. They both re-use the existing civil infrastructure, maintain high levels of reliability, and represent cost-effective approaches.

Should this segment be deferred, THESL would only replace equipment that fails catastrophically. Where equipment is not destroyed by the failure, THESL would attempt to repair it, and if not successful, would manually transfer the customers' supply cables as necessary following feeder outages.

II DETAILED PROJECT INFORMATION

1. Project Details

Automatic Transfer Switches (ATS) are designed to automatically switch from the normal supply to the Standby supply in the case of an interruption on the normal supply feed. Reverse Power Breaker (RPB) assets normally supply customers from two primary supplies, and automatically open one of these supplies in the event of feeder outages in order to prevent dangerous backfeed conditions. ATS and RPB assets are generally used to supply medium size customers that require a reliable supply, such as schools, supermarkets, seniors' homes, and other mid-sized buildings.

The purpose of this segment is to replace end-of-life, very poor condition ATSs and RPBs. In total there are 30 ATS locations and six RPB locations that have been identified as requiring immediate equipment replacement. THESL's proposed ATS and RPB Segment will replace these assets with either new Stand-Alone Network Protectors or Standard Network Equipment at a total cost of $9.8M, as summarized in Table 2 and Table 3 below.

Each asset location will be assessed on a case by case basis to determine the best replacement solution. In cases where the transformer is salvageable it is reused and a Stand Alone Network Protector (SANP) is installed to replace the obsolete and failing equipment at an approximate average cost of $145,000. If the transformer also requires replacement then the equipment will be replaced with standard network equipment, at an approximate average cost of $325,000.

Given workforce constraints, THESL proposes to replace the equipment at a rate of ten ATS locations and two RPB locations a year in each of 2012, 2013 and 2014. Jobs have been prioritized based on addressing the very poor condition units first, followed by units that are currently in poor condition, but expected to degrade to very poor condition at the time of replacement.

1 **Table 2: ATS Replacement Jobs**

Job Estimate Number	Job Title	Job Year	Cost Estimate ($M)
19381	D9012 - Near 654 Castlefield, Toronto	2012	$0.32
23252	D3031 - 2108 Queen St East, Toronto	2012	$0.21
24544	4862 - 77 Ryerson Ave, Toronto	2012	$0.14
24546	4023 - Near 142 Pears Ave, Toronto	2012	$0.37
24548	D9010 - 205 Richmond St W, Toronto	2012	$0.14
24549	D3022 – 75 Dowling Ave, Toronto	2012	$0.14
24550	4064 – 295 College St, Toronto	2012	$0.37
24634	D3002 – 70 Elmsthorpe, Toronto	2012	$0.14
24634	D9013 - 2727 Dundas W, Toronto	2012	$0.36
24634	4063 - 645 Adelaide St W, Toronto	2012	$0.36
24952	4086 – 499 St Clair Ave W, Toronto	2013	$0.32
24952	4081 – 700 St Clair Ave W, Toronto	2013	$0.32
24952	4321 – 245 Eglinton Ave W, Toronto	2013	$0.32
24952	4027 - 14 Spadina Road	2013	$0.32
24952	D3012 – 439 Sherbourne Ave, Toronto	2013	$0.13
24952	4046 - Near 130 EGLINTON, Toronto	2013	$0.32
24952	N1164 – 35 Jackes Ave, Toronto	2013	$0.13
24952	4129 - Heath Street East	2013	$0.32
24952	D9008 – 40 Scollard Rd, Toronto	2013	$0.13
24952	4158 - Duncan Ave	2013	$0.32
24953	4817 - ADJ. to 330 GERRARD	2014	$0.36
24953	D9007 – 658 to 668 Danforth Ave, Toronto	2014	$0.14
24953	D3014 – 2001 Bloor St W, Toronto	2014	$0.14
24953	4157 – 175 Elm, Toronto	2014	$0.36
24953	D3041 – 1141 Bloor St W, Toronto	2014	$0.14
24953	D3003 – 75 Eglinton Ave W, Toronto	2014	$0.14
24953	4118 – 197 Wellesley St E, Toronto	2014	$0.36

Job Estimate Number	Job Title	Job Year	Cost Estimate ($M)
24953	4763 – 700 Ontario St, Toronto	2014	$0.14
24953	4121 – 36 Earl, Toronto	2014	$0.36
24953	4861 – 165 Grange Ave, Toronto	2014	$0.36

Table 3: RPB Replacement Jobs

Job Estimate Number	Job Title	Job Year	Cost Estimate ($M)
24905	4515 - 25 Lascelles Blvd, Toronto	2012	$0.35
24905	D3039 – 186 Cowan, Toronto	2012	$0.35
24954	4662 – 245 Dunn Ave, Toronto	2013	$0.35
24954	4476 – Bloor opposite Mossom, Toronto	2013	$0.35
24955	4175 – 160 John St, Toronto	2014	$0.35
24955	4669 – 200 Balliol, Toronto	2014	$0.35

Figure 1 below shows the job locations of all proposed ATS and RPB identified as needing replacement. The ATS and RPB units were installed at medium sized customer locations within network areas which were not sufficiently close to be tied into the local network grid. These are generally located in the former Toronto area.

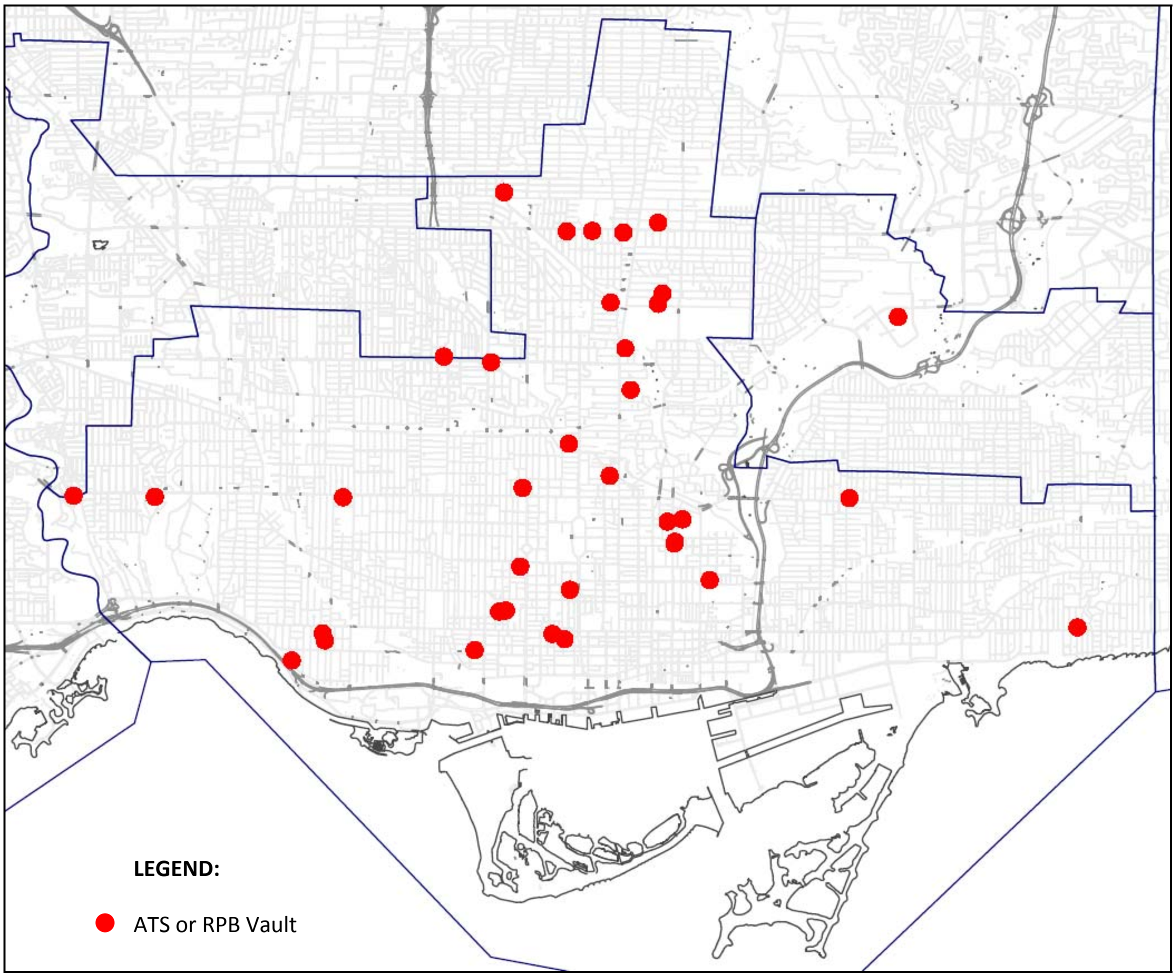


Figure 1: ATS and RPB Replacement Job Locations

III NEED

1. Asset Condition

THESL's 2011 Asset Condition Assessment (ACA) shows that for ATS assets there has been a 22.28% increase in the poor asset category and a 10.17% increase in the very poor asset category between 2010 and 2011. This trend shows that an increasingly large percentage of ATSs are near imminent failure. RPB assets were not assessed in the 2010 and 2011 ACA program. However, RPBs are of similar vintage to ATSs and placed in similar operating environments, and their equally poor condition has also been confirmed by physical inspections by THESL crew.

In general, there were 30 identified ATS assets that degraded from a condition of fair to poor or very poor status between 2010 and 2011, which represents 32.45% of the total asset population (see Appendix 1 for further details). The very poor status indicates that the units need to be replaced immediately within one year; the poor assets need to be replaced within three years. Figure 1 below illustrates that the ATS assets have moved dramatically from each condition category to worse categories in the past year. These statistics suggest that the assets, which are past their end of life, and have been fully utilized and depreciated, are deteriorating rapidly. The ACA identifies the useful life of ATSs as 25 to 30 years. The ATSs proposed for replacement are as old as 49 years of age and generally well past typical useful life. Only three units have deteriorated to poor condition before having reached their expected useful life.

Figure 2: Asset Condition for ATS units

Table 4: Asset Condition Assessment for ATS units

		Very Poor		Poor		Fair		Good		Very Good	
	Year	% Sample	% Change	% Sample	% Change	% Sample	% Change	% Sample	% Change	% Sample	% Change
ATS	2010	0.00%	10.17%	4.84%	22.28%	37.10%	-26.93%	16.13%	14.38%	41.94%	-19.91%
	2011	10.17%		27.12%		10.17%		30.51%		22.03%	

The dramatic increase of “poor” and “very poor” ATSs in the past year is characteristic of assets well past normal useful life. Although 14 units were replaced in the last year, new failures are occurring at an increasing rate.

Due to manufacturing design changes applied over the years to ATSs and RPBs, and the different manufacturers of these assets, many require unique and specialized spare parts. In the majority of cases these replacement parts are no longer available and these units must be replaced with an entirely new set of assets as part of a new configuration.

Without proactive investment into replacing these units and approval for this segment, failures will continue and escalate in frequency, each time impacting THESL customers.

If this segment is deferred, THESL would place the failing units into its Defective Equipment Tracking System (DETS), which is used to track equipment that has failed when found during operational procedures or scheduled maintained tasks were being performed. These units would be replaced only when new units become available. The impact of this inaction is a one- to 4.5 hour interruption to all customers supplied by the ATS and RPB units following each unplanned feeder outage. In some cases, a catastrophic failure may occur which could result in property damage and serious risks to public safety.

2. Current Status and Recent Failures

There are approximately 90 ATS units and 130 RPB units operational in THESL's distribution system, which includes four ATSs already on the DETS List.

Two examples of recent ATS and RPB failure incidents are discussed below.

2.1. 33 Princess Street

On January 16, 2012 at approximately 13:25 a vault fire began at 33 Princess Street (near Front and Sherbourne), tripping two back to back feeders (A15GD and A14GD). This fire was contained to the defective ATS that switches between feeders A14GD and A15GD. However, the fire damaged the primary cables on both feeders as well as the two distribution transformers supplying 33 Princess Street. The back to back feeders were sectionalised at the station and power was promptly restored to most customers. However, two locations (Esplanade Development Corp, 109 Front Street East and King James Place, 151 King Street East) which were supplied only from feeders A14GD and A15GD experienced extended outages. Some customers were without power until approximately 14:00 the following day.

This fire affected about 40 properties, including a nearby daycare and community center, a number of condominiums and business towers, as well as the George Brown College St. James campus. In total about 460 students and 50 seniors in a nearby seniors' home were affected, and 50 children from the daycare were evacuated.

Although no injuries resulted from this incident, the risk of injury and extensive property damage was notable.

Figure 3: LEFT: Photo of a typical ATS unit. RIGHT: The fire department putting out the fire at 33 Princess Street. PHOTO TAKEN January 16, 2012

Figure 4: The figures above show the damaged equipment from the failure at 33 Princess Street. The fire destroyed the ATS unit (right). PHOTO TAKEN January 17, 2012

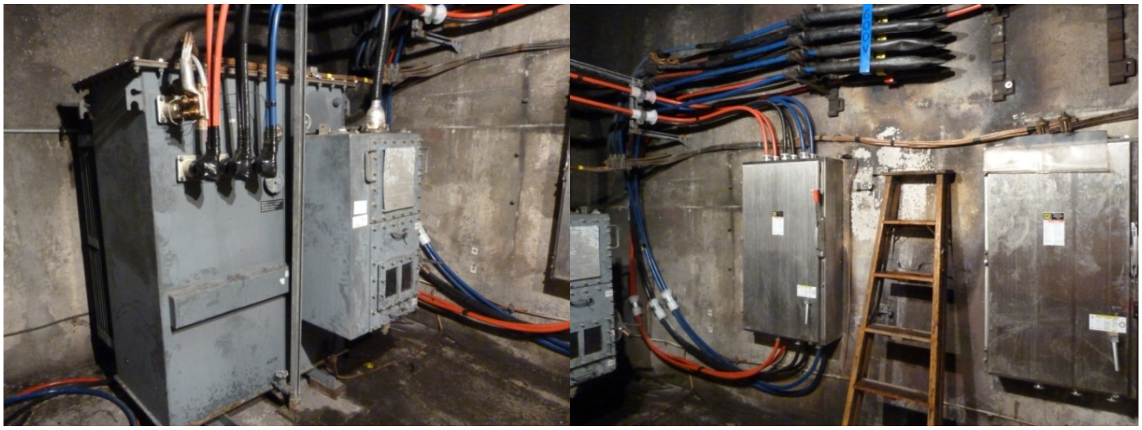


Figure 5: The transformers and ATS unit were replaced after the fire. PHOTO TAKEN January 23, 2012

2.2. 50 Marlborough Avenue

On January 10, 2010 a defective RPB at 50 Marlborough Avenue (near Yonge and Davenport) failed to open. This allowed a backfeed into a primary fault, resulting in an explosion and damage to equipment in other nearby vaults, as well as damage to the two transformers within this RPB vault. Figure 7 below shows the damaged transformers with overheated neutrals and burned oil discharge from the pressure relief valves. This incident resulted in almost ten hours of interruption to the associated network grid and over 26 hours of interruption to 50 Marlborough Avenue.

In addition, two THESL crew workers were affected by the explosion that took place; one crew worker suffered injuries, while the other case was identified as a near miss.

Figure 6: RPB units following failure at 50 Marlborough. PHOTOS from January 10, 2010

Figure 7: Damaged transformers at 50 Marlborough. PHOTOS from January 10, 2010

RPBs are particularly prone to such extensive external damage upon failure. Replacing the RPBs is expected to result in improved safety and reliability, and reduced risks to both the directly supplied customers, as well as all customers on the associated network grid.

IV PREFERRED ALTERNATIVE

1. Available Alternatives

ATS and RPB assets were purchased from many different manufacturers and over many different vintages, which make each unit unique. Manufacturer support and spare parts are unavailable for these assets, so continuing ongoing maintenance is not a viable option. As inaction under a work-to-failure approach will result in unmitigated risk to customers supplied by the ATS and RFB assets, many options were evaluated as a solution to remedy these failing units:

(a) Like-for-Like Replacement with new ATS and/or RPB
(b) Eliminate the Vault
(c) Modular Switchgear
(d) Compact Radial Switchgear
(e) Modified TTC Design Switchgear
(f) Stand Alone Network Protectors
(g) Standard Network Equipment

Option (a), to replace on a like for like basis is not feasible. In order to replace ATS and RPB units with like for like equipment, custom made units are required. Custom manufacturing this equipment is a very expensive option and would provide less continuity of service to customers than other alternatives considered. In addition, when custom equipment is purchased, availability of spare parts and support is limited. Figure 8 below shows an existing ATS unit and schematic. Figure 9 below shows an existing RPB unit and schematic.

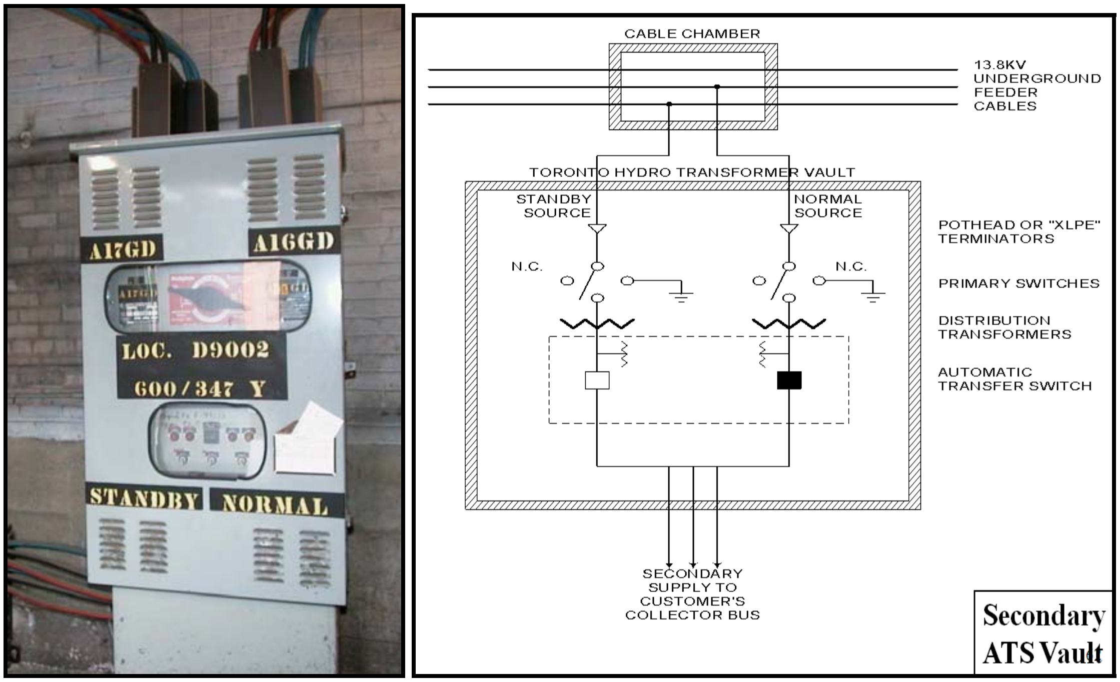


Figure 8: ATS vault (existing non-submersible equipment)

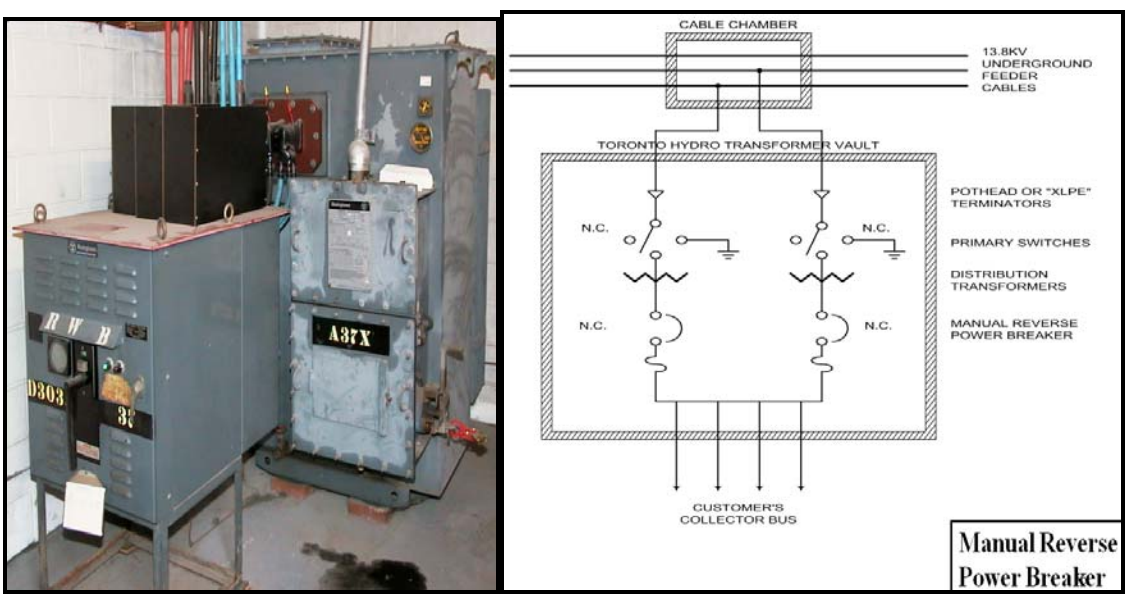


Figure 9: RPB vault (existing non-submersible equipment)

Option (b) is to eliminate the ATS or RPB vault and feed the customer directly from the street (as shown in Figure 10 below). This option is generally only practical in areas that already possess nearby network grid facilities with available growth capacity to pick up the decommissioned ATS or RPB vault load. As such, this option is only applicable to 120/208V ATS and RPB customers which match the 120/208V network distribution voltage. Those customers that can convert to a secondary network grid supply option could be expected to experience improved operating characteristics, as no momentary interruptions result from unplanned feeder outages. RPB customers would experience unchanged reliability. The cost of this option is extremely variable and depends on available infrastructure to support it. In many cases customers were supplied with ATS or RPB units because they were isolated from the grid, and therefore this option would not be feasible. In addition, the cost of this option is extremely variable, ranging from $50k in some rare circumstances, to as much as $1M per location. This solution is typically not cost effective compared with other options.

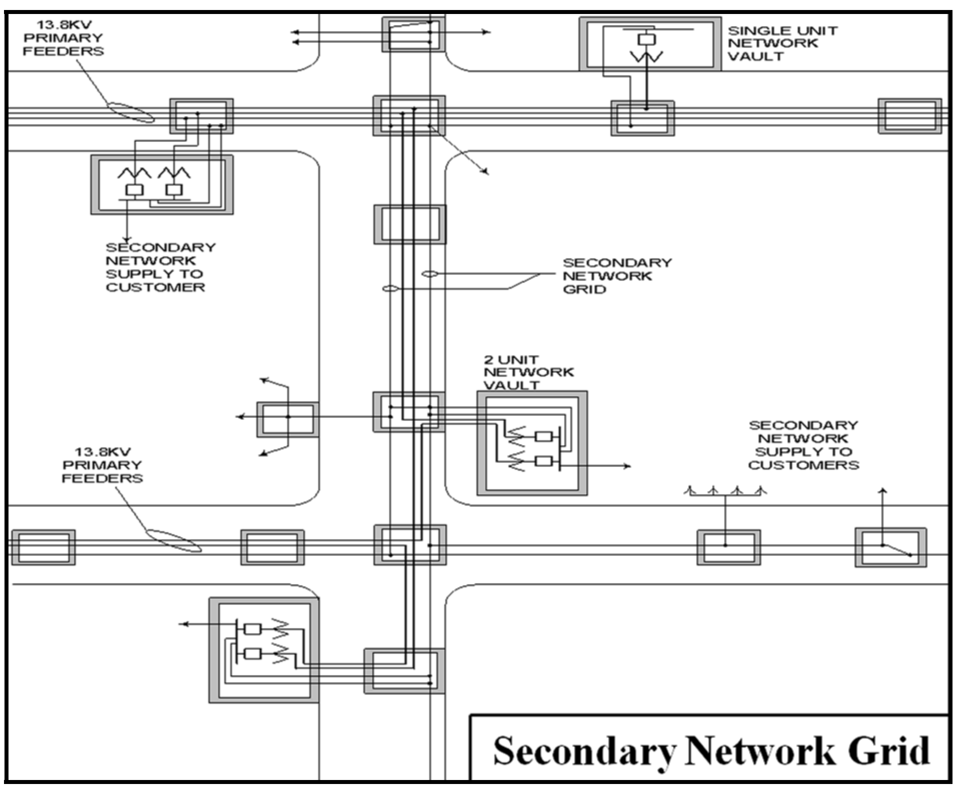


Figure 10: Network grid supply from street

Option (c) is to replace the ATS with modular switchgear equipment and retain one existing distribution transformer (as shown in Figure 11 below). This design replaces the secondary ATS with primary switching equipment, and as such is applicable at 120/208V, 240/416V and 347/600V (i.e., all three ATS voltages). Customers could be expected to experience inferior operating characteristics with this option, as restoration of service is delayed following unplanned feeder interruptions, due to the requirement to send crews to manually operate the switches. The time required to perform switching would typically take between one to 4.5 hours. Modular switching equipment also requires unusually large vaults, and would therefore only be applicable to a small percentage of ATS locations. It is not applicable to RPB locations.

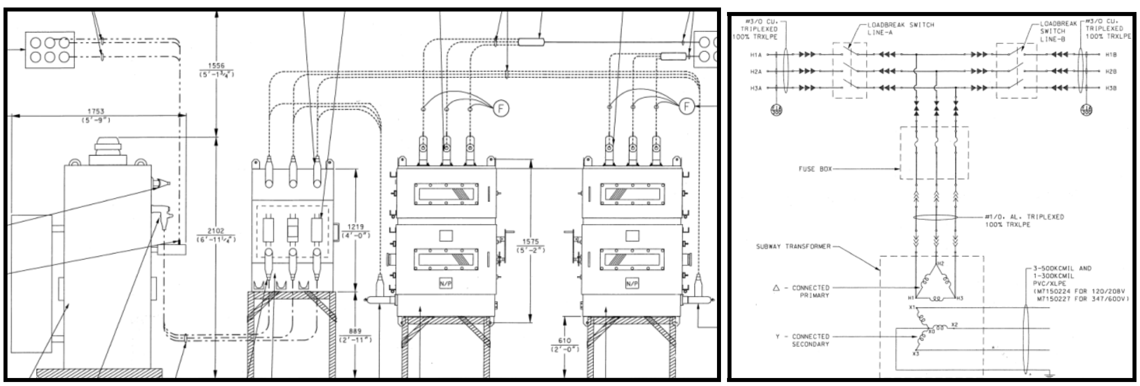


Figure 11: Modular switchgear (submersible equipment)

Option (d) is to replace the ATS or RPBs with compact radial (CR) equipment and retain one existing distribution transformer (as shown in Figure 12 below). This design replaces the secondary ATS or RPBs with primary switching equipment, and as such is applicable at 120/208V, 240/416V and 347/600V (i.e., all three ATS voltages). Customers could be expected to experience inferior operating characteristics with this option, as restoration of service is delayed following unplanned feeder interruptions, due to the requirement to send crews to manually operate the CR switches. This switching would typically take between one to 4.5 hours. CR switches have also proven to be operationally problematic and require higher maintenance than other options.

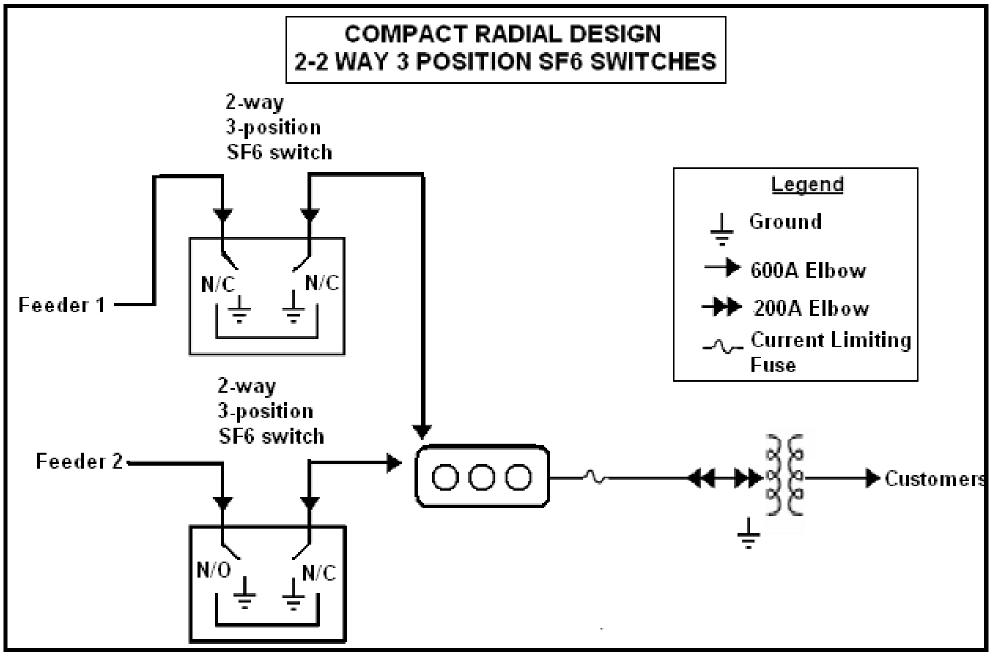


Figure 12: Compact radial (submersible equipment)

Option (e) is to replace the ATS or RPBs with modified TTC vault switchgear and retain the two existing distribution transformers (as shown in Figure 13 below). This option is applicable 120/208V, 240/416V and 347/600V (i.e., all three ATS voltages). Customers could experience inferior operating characteristics with this option, as restoration of service is delayed following unplanned feeder interruptions, due to the requirement to send crews to manually operate the switches. This switching typically takes between one to 4.5 hours. The switching equipment is very compact and can fit into virtually all existing customer vaults, but is limited to smaller customers with no more than a 600A service size.

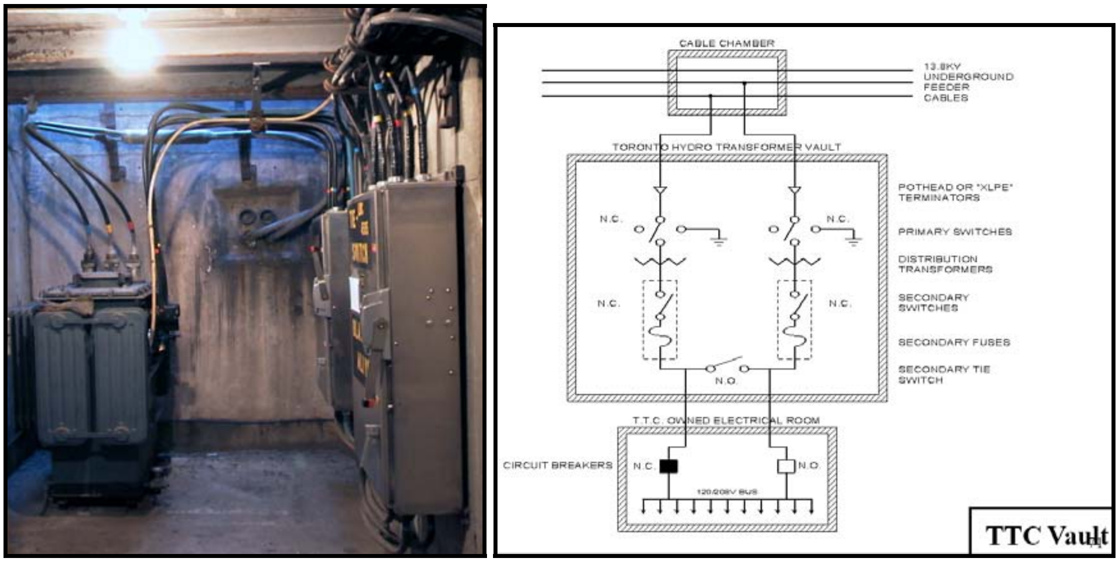


Figure 13: Modified TTC vault (non-submersible equipment)

Option (f) is to replace the ATS or RPBs with two Stand Alone Network Protectors (SANPs) (as shown in Figure 14 below) and retain the two existing distribution transformers. This option is applicable to 120/208V and 240/416V ATS vaults (i.e., two of the three ATS voltages). ATS customers experience improved service characteristics, as no momentary interruptions result from unplanned feeder outages and RPB customers experience unchanged reliability. Although SANPs have a slightly larger footprint than ATSs, they can generally fit into most existing customer vaults. Installing two SANPs and removing the ATS or RPBs while reusing the existing transformers would typically cost approximately $145,000 per location. In situations in which full replacement of aged vault equipment is required but other alternatives do not offer the required capacity, the cost to install both an SANP and the vault equipment is typically $0.33M per location. In applicable situations, THESL submits that the installation of SANPs is the preferred approach due to the combination of reliability and cost, but is conditional on the availability of suitable existing civil infrastructure and in most situations, transformers that are in good working condition.

Figure 14: Stand alone network protector (submersible equipment)

Option (g) is to replace the ATS or RPBs and two distribution transformers with two standard network units (as shown in Figure 15 below). This option is only applicable at 120/208V, and for customers with loads of approximately 500kVA or greater. ATS customers experience improved service characteristics, as no momentary interruptions result from unplanned feeder outages. RPB customers experience unchanged reliability. The average cost of this option is $0.15M per location. The reliability of this option is expected to be the same as Option (f). Network equipment can fit into almost all existing customer vaults.

Option (f) and option (g) are both viable options and each ATS and RPB to be replaced will be evaluated on a case by case basis. If there is available space and a reusable transformer Option (f) will most likely be employed. However, if the transformer also needs to be replaced or there isn't enough room for a SANP, then Option (g), a standard network transformer and protector, will be used.

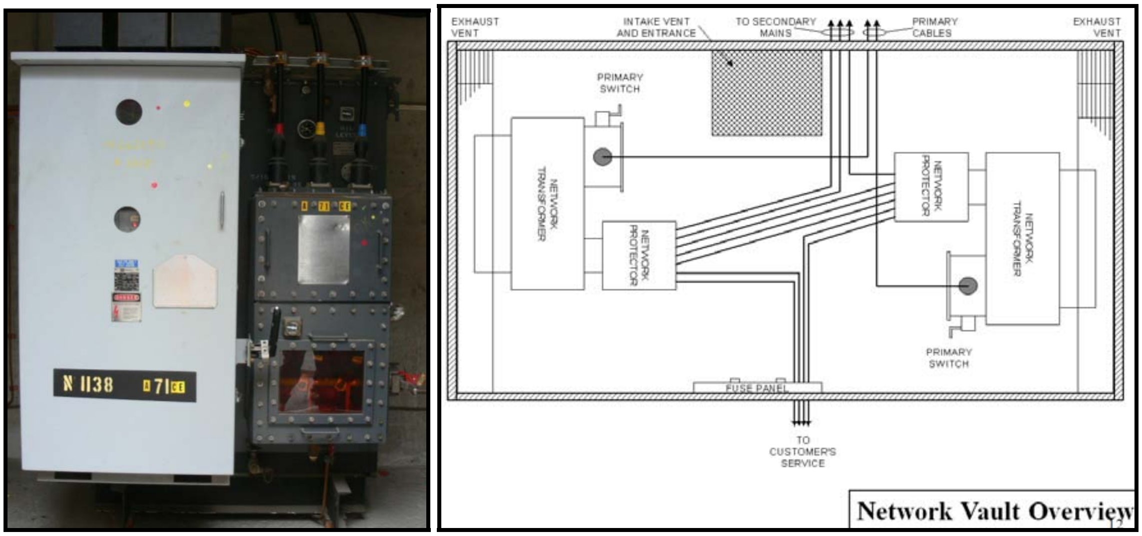


Figure 15: Network vault (submersible or non-submersible equipment)

Both options (f) and (g) are expected to provide superior reliability due to the interconnection of multiple transformers and supply feeders. The main advantage of installing either SANPs or network equipment is the ability to utilize available civil infrastructure to supply THESL's customers with a highly reliable system that normally would be cost prohibitive due the need to construct additional civil infrastructure. Replacing the obsolete ATS and RPB equipment is expected to lead to higher reliability for customers and a safer environment for THESL employees and the general public. Installing Option (f), and Option (g) where required, is the preferred alternative because this approach provides the best combination of reliability, safety and cost.

2. Economic Benefits of the Preferred Alternative

THESL has calculated the economic benefits of undertaking this segment, by taking into account outage costs and the costs of emergency repairs and replacement. If no proactive replacements were to occur and equipment was run to failure, then the resulting NPV of this strategy would be \$12.67M. This accounts for the replacement cost and an average outage cost for each outage of \$0.06M per failure (with outage cost based on \$30 per customer per interruption and

$15 per kWh interrupted). The alternative proposed replacement strategy would yield an NPV of $10.41M, resulting in a savings of $2.26M.

The applied outage costs represent indirect cost attributes associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement. The calculations for this analysis can be found below:

ATS & RPB Program Analysis			
A) Base Case	Year 1	Year 2	Year 3
ATS Replacement	$3,250,000		$6,500,000
RPB Replacement	$650,000		$1,300,000
Outage	$756,000		$1,512,000
Total	$4,656,000		$9,312,000
STRATEGY NPV	**$12,668,241**		
B) Proactive Replace	Year 1	Year 2	Year 3
ATS Replacement	$3,250,000	$3,250,000	$3,250,000
RPB Replacement	$650,000	$650,000	$650,000
Total	$3,900,000	$3,900,000	$3,900,000
STRATEGY NPV	**$10,413,185**		

A) Scenario A: Under this scenario the assets are run to failure with no proactive intervention.

In Year 1, THESL assumes the ten units identified in THESL's ACA to be in very poor condition will fail. Each of these failures is accompanied by a four-hour outage that impacts on average 700kVA of load. This outage includes time for switching as well as isolation to remove the failed piece of equipment. In many instances emergency work occurs at a higher labour cost due to overtime but the overtime cost has been omitted to employ a conservative analysis. The interruption cost to THESL is $63,000 per incident. In addition, after these loads are brought back online the equipment needs to be replaced at a cost of $325,000 per unit. The total cost in Year 1 is **$4,656,000** which takes into account 10 ATS replacements and 2 RPB replacements following 12 outages.

By Year 3, the ACA suggests that 24 more ATS & RPB failures should be expected. The resulting total cost in Year 3 is $9,312,000. Taking the present value for all costs in Scenario A, the total cost would be **$12,668,241**.

B) Scenario B: Under this scenario proactive investment is employed.

In this case replacements are made in each year as proposed under this segment, to mitigate potential failures and the outages that would occur by letting assets run to fail. Replacement of assets is performed proactively and it is assumed that no outages will occur under this scenario. Taking the net present value of this strategy, the total cost is $10,413,185.

Evaluating both scenarios leads to the conclusion that proactive replacement of ATS & RPB assets is the more cost-effective approach.

APPENDIX 1

HEALTH INDEX METHODOLOGY

Health indexing quantifies equipment condition based on numerous condition criteria that are related to the long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

The Health Index formulation developed for Station Transformers is provided as an example of the method.

The condition criteria shown in Table 1 are weighted based on their importance in determining the transformer's end-of-life. For example, those that relate to primary functions of the asset receive higher weights than those that relate to more ancillary features and functions.

For purposes of formulating the Health Index, a particular piece of equipment is assessed and assigned a numeric vale for each of the condition criteria. This value was based on reviews of inspection records and diagnostic test reports extracted from THESL's databases. In assessing the information available against end-of-life criteria, condition values of 0 to 4 were assigned with the following general meanings:

- "4" means the component is in "as new" condition;
- "3" means the component has some minor problems or evidence of aging;
- "2" means the component has many minor problems or a major problem that requires attention;
- "1" means the component has many problems and the potential for major failure; and
- "0" means the component has completely failed or is damaged/degraded beyond repair.

These condition rating numbers (i.e., 4, 3, etc.) are multiplied by the assigned weights to compute weighted scores for each condition criteria. The weighted scores are totalled for each transformer. Because of the importance of the DGA tests, if any of the tests scored a "0", then the Health Index was divided by 2.

Totalled scores are used in calculating final Health Indices for each transformer. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This step normalizes scores by producing a number from 0-100 for each transformer. For example, a transformer in perfect condition would have a Health Index of 100 while a completely degraded transformer would have a Health Index of 0.

Table 1 shows the condition criteria, weightings, condition ratings, plus the total possible maximum score for each member of this asset class.

Table 1: Transformer Health Index Formulation

#	Transformer Condition Criteria	Weight	Factors	Maximum Score
1	Bushing Condition	1	4,3,2,1,0	4
2	Oil Leaks	1	4,3,2,1,0	4
3	Main Tank/Cabinets and Controls	1	4,3,2,1,0	4
5	Radiators/Cooling System	1	4,3,2,1,0	4
6	Foundation/Support Steel/Ground	1	4,3,2,1,0	4
7	Overall Power Transformer	2	4,3,2,1,0	8
8	DGA Oil Analysis*	4	4,3,2,1,0	16
11	Oil Quality Test	3	4,3,2,1,0	12
12	Thermograph (IR)	2	4,3,2,1,0	8

Max Score= 64, HI = 100*Score/Max.

*In the case of a score of "0", overall Health Index is divided by 2

After performing the steps described above, the Health Index scale shown below was used to determine the overall condition of the transformer asset class.

Table 2: Health Index Scale for Transformers

Health Index	Condition	Description	Requirements
85 - 100	Very Good	Some ageing or minor deterioration of a limited number of components	Normal maintenance
70 – 85	Good	Significant deterioration of some components	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At end-of-life, immediately assess risk; replace or rebuild based on assessment

ICM Project – Station Infrastructure and Equipment

Stations Power Transformers Segment

Toronto Hydro-Electric System Limited (THESL)

I EXECUTIVE SUMMARY

1. Project Description

This segment consists of replacing 12 power transformers at ten Municipal Stations (MS) over the period 2012 through 2014. The transformers to be replaced and their cost of replacement are shown in Table 1. Total cost for this segment is approximately $4.73 M. These transformers range in size from 3 MVA to 15 MVA and are used to step down voltage from primary voltages of 27.6 kV or 13.8 kV to secondary voltages of 13.8 kV or 4.16 kV.

Table 1: Job Cost Estimates

Estimate Number	Job Title	Project Year	Cost Estimate ($M)
18419	S12062 Ellesmere White abbey MS Replace Station Transformer TR1	2012	$0.36
20647	S12376 Thistletown MS Replace Station Transformer TR1	2012	$0.29
20675	S12389 Scarborough Golf Club Rd MS: Replace Station Transformer TR1.	2012	$0.35
20685	S12391 Thistletown MS replace Station Transformer TR2 - 3/4 MVA.	2012	$0.29
21573	S13127 Kingston Morningside MS: Replace Station Transformer TR1	2013	$0.33
21651	S13144 Edenbridge MS Replace Station Transformer TR1	2013	$0.37
21722	S13154 High Level MS Replace Station Transformer TR1	2013	$0.46
21723	S13155 High Level MS Replace Station Transformer TR2	2013	$0.54
21802	S13168 Blaketon MS Replace Station Transformer TR1	2013	$0.47

ICM Project | Station Power Transformers Segment

Estimate Number	Job Title	Project Year	Cost Estimate ($M)
21852	S13170 Albion MS Replace Station Transformer TR2	2013	$0.39
22876	S14091 Norseman MS Replace Station Transformer TR1	2014	$0.45
22877	S14092 Underwriter Crouse MS Station Replace Transformer TR1	2014	$0.43
		Total:	**$4.73**

2. Why the Project is Needed Now

In terms of both financial and operational risks, power transformers are the most important assets employed in municipal stations. All customers supplied through municipal stations will have their power pass through a station power transformer. Each municipal station serves somewhere between a few hundred and a few thousand customers.

These jobs selected for this segment were chosen from 276 in-service station transformers based on their age (See Table 2) transformer leakage, or their condition assessment (Refer to Appendix 5). A significant proportion of power transformers on THESL's system were installed in the 1950s, 1960s or early 1970s. Based on the Kinetrics Report, the typical end of useful life for a station power transformer is 43 years. The 12 power transformers to be replaced through this segment are between 36 and 84 years old; only two are less than 43 years old.

Due to its low cost, high dielectric strength, excellent heat-transfer characteristics, and ability to recover after dielectric overstress, mineral oil is the most widely used insulating material in transformers. The presence of increasing levels of dissolved gases in transformer oil is indicative of various faults (See Appendices 1, 2 and 3). For a majority of transformers, end of life is expected to be indicated by the failure of pressboard and paper insulation. While the insulating oil can be treated by oil reclamation or changed when there is presence of water or sludge, it is not practical to change the paper and pressboard insulation. Although failure rates have been modest to date, rapid changes in a transformer's condition can occur when transformer reach advanced age.

The consequences of power transformer failure include long duration customer interruptions. Table 2 shows the number of customers served by each of the transformers selected for replacement. Catastrophic failure of transformers may also result in collateral damage to other transformers, damage to other station equipment, and if staff are present, potential injury to personnel. Furthermore, because transformers are filled with mineral oil, there is environmental risk of oil spills contaminating ground and water systems if the tank fails. Even if transformer failures do not occur, should a unit's health decrease significantly, it would need to be off-loaded to reduce further stress. This in turn increases the stress placed on other units, and decreases capacity to be used to deal with a contingency. This impacts system reliability.

Table 2: Age profile and Customers Affected due to Transformer failure

Station Name – Transformer	Age	Customers affected due to Transformer failure
Ellesmere White Abbey MS – TR1	50	524
Thistletown MS – TR1	56	1,377
Thistletown MS – TR2	59	1,377
Scarborough Golf Club Rd MS – TR1	59	963
Kingston Morningside MS – TR1	55	855
Edenbridge MS – TR1	45	759
High Level MS – TR1	84	11,368
High Level MS – TR2	65	11,368
Blaketon MS – TR1	42	277
Albion MS – TR2	36	2,729
Norseman MS – TR1	61	519
Underwriter Crouse MS – TR1	53	783

3. Why This is the Preferred Alternative

THESL considered three options to mitigate the potential reliability and safety risks associated with the deteriorated state of these 12 station power transformers: maintaining the status quo, eliminating the need for the station transformer via area voltage conversions in these selected stations or replacing the station transformer (See Section IV).

The status quo option presents safety, reliability and performance risks (See Section IV, 1). Catastrophic failure of transformers may result in damage to other transformers and other station equipment, and if staff are present, potential injury to personnel. In addition to the risk of failure, when a station transformer's health decreases significantly, THESL transfers load to other transformers. This in turn increases their loading and decreases the capacity available to be used to deal with system contingencies, which impacts reliability. Performance risk also increases over time due to the deterioration of both the insulating oil and the paper insulation as moisture levels increase (See Section IV).

Voltage conversion is not typically undertaken based on the condition of station equipment alone. The cost of the distribution system served by the station usually exceeds the cost of the station. Thus it is not economic to advance the replacement of distribution systems due to station asset issues.

Carrying out immediate work on this asset class will result in the avoided estimated risk cost of approximately $66.6 million (Refer to Appendix 4), as opposed to executing this work in 2015. Therefore, there are distinct economic benefits to executing this work immediately.

The most cost-effective option is replacement of obsolete equipment before failure. Options have been examined to replace the units and the benefits of doing so in terms of reliability have been calculated. The result shows that the most cost-effective option is to replace the station power transformers, compared to the option of eliminating the need of station power transformers by conversion of the area to higher voltage.

II DETAILED INFORMATION

1. Objectives

The objective of the station transformer replacement program is to replace those Power Transformers that are beyond their end of useful life, or have environmental leakage, and where the risk of transformer failure is high due to deteriorating insulating conditions represented by the Health Index shown in Appendix 5. In addition to aging, transformers with DGA oil tests indicating poor insulation condition will be prioritized for replacement (See Appendices 1, 2 and 3). The objectives for each job are described in Table 3.

Table 3: Objectives for each Transformer Replacement Job

Job	Objectives	Planned Year
Ellesmere White abbey MS	Replace the existing 5/6.7 MVA, 27.6/4.16kV station transformer, TR1, with a new 27.6kV/4.16kV, 5/6.7MVA station transformer at Ellesmere White Abbey MS station.	2012
Thistletown MS	Replace the existing 3/4MVA, 27.6/4.16kV station transformer, TR1, with a new 3/4 MVA, 27.6/4.16kV station transformer at Thistletown MS station.	2012
Thistletown MS	Replace the existing 3/4MVA, 27.6/4.16kV station transformer, TR2, with a new 3/4 MVA, 27.6/4.16kV station transformer at Thistletown MS station.	2012
Scarborough Golf Club Rd MS	Replace the existing station transformer, TR1, with a new 5MVA, 27.6/4.16kV station transformer at Scarborough Gold Club Rd MS station.	2012

ICM Project | Station Power Transformers Segment

Job	Objectives	Planned Year
Kingston Morningside MS	Replace the existing 5/6.7 MVA, 27.6/4.16kV station transformer, TR1, with a new 27.6kV/4.16kV, 5/6.7MVA station transformer at Kingston Morningside MS station.	2013
Edenbridge MS	Replace the existing 5/6.7 MVA, 27.6/4.16kV station transformer, TR1, with a new 27.6kV/4.16kV, 5/6.7MVA station transformer at Edenbridge MS station.	2013
High Level MS	Replace the existing 9/12 MVA, 13.8/4.16kV station transformer, TR1, with a new 9/12 MVA, 13.8/4.16kV station transformer at High Level MS station.	2013
High Level MS	Replace the existing 12/15 MVA, 13.8/4.16kV station transformer, TR2, with a new 12/15 MVA, 13.8/4.16kV station transformer at High Level MS station.	2013
Blaketon MS	Replace the existing 7.5/10 MVA, 27.6/13.8kV station transformer, TR1, with a new 7.5/10 MVA, 27.6/13.8kV station transformer at Blaketon MS station.	2013
Albion MS	Replace the existing 5/6.7 MVA, 27.6/4.16kV station transformer, TR2, with a new 5/6.7MVA, 27.6kV/4.16kV station transformer at Albion MS station.	2013
Norseman MS	Replace the existing 5/6.7 MVA, 27.6/4.16kV station transformer, TR1, with a new 5/6.7MVA, 27.6kV/4.16kV station transformer at Norseman MS station.	2014

Job	Objectives	Planned Year
Underwriter Crouse MS	Replace the existing 5 MVA, 27.6/4.16kV station transformer, TR1, with a new 5/6.7MVA, 27.6kV/4.16kV, station transformer at Underwriter Crouse MS station.	2014

2. Scope of Work

The scope of work for all of the transformer replacement jobs listed above consists of the following tasks:

(a) Procure and purchase a new station transformer appropriately sized
(b) Removal of the old TR1/TR2 transformer
(c) Deliver and install the new station transformer to replace the existing TR1/TR2 transformer
(d) Perform testing, commissioning and energization of the new transformer

3. Map and Locations

The stations are located across Toronto as shown in Figure 3 below.

ICM Project | **Station Power Transformers Segment**

1 **Figure 3: Map showing all locations**

1 **Table 4: Station name with their respective address**

Reference Number	Station Name - Transformer	Address
1	Ellesmere White Abbey MS – TR1	159 Ellesmere Rd, Toronto
2	Thistletown MS – TR1 and TR2	55 Thistle Down Blvd, Toronto
3	Scarborough Gold Club Rd MS – TR1	1000 Scarborough Golf Club Rd, Toronto
4	Kingston Morningside MS – TR1	4446 Kingston Rd, Toronto
5	Edenbridge MS – TR1	294 Scarlett Rd, Toronto
6	High Level MS – TR1 and TR2	292-296 MacPherson Ave, Toronto
7	Blaketon MS – TR1	395 The East Mall, Toronto
8	Albion MS – TR2	2 Rampart Rd, Toronto
9	Norseman MS – TR1	1066 Islington Ave, Toronto
10	Underwriter Crouse MS – TR1	20 Underwriters Rd, Toronto

III NEED

Each of the 12 station power transformers to be replaced is operating at or beyond its useful life, exhibits transformer leakage, exhibits deteriorated trending of insulation conditions, or exhibits combinations of these factors. The following sections provide the DGA results for the 12 stations.

1. Ellesmere White Abbey MS

Transformer: TR1

Age: 50

Transformer Leakage: Yes

DGA Results: Condition 1 (Refer to Appendix 2)

Justification:

(a) The transformer was manufactured in 1962 and has reached the end of its operating life.

(b) Risk of transformer oil leakage poses a potential environmental risk and high consequence costs.

Figure 1: Station Transformer, TR1, leakage at Ellesmere White Abbey MS (November 16, 2011)

2. Thistletown MS

Transformer: TR1

Age: 56

Transformer Leakage: No

DGA Results: Condition 1 (Refer to Appendix 2)

Table 5: DGA result for TR1 transformer at Thistletown MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	30/05/2009	15/05/1996	
Oil Temperature (°C)	32	10	1. Carbon dioxide: Exceeds condition limit (2500ppm) 2. Dielectric breakdown exceeds limit for in-service oil (26kV) 3. Overall equipment condition code: 1
Hydrogen (H2) (PPM)	23	24	
Methane (CH4) (PPM)	9	10	
Ethane (C2H6) (PPM)	8	7	
Ethylene (C2H4) (PPM)	11	7	
Acetylene (C2H2) (PPM)	0	2	
Carbon Monoxide (CO) (PPM)	242	429	
Carbon Dioxide (CO2) (PPM)	**2915**	2218	
Nitrogen (N2) (PPM)	74998	66813	
Oxygen (O2) (PPM)	32623	19701	
Total Dissolved Gas (PPM)	110829	89211	
Total Dissolved Combustible Gas (PPM)	293	479	
Moisture in Oil (PPM)	20	--	
Acid Number (mg KOH/g)	0.052	0.020	
Dielectric Breakdown (kV)	**20**	46	
Power Factor at 25°C (%)	0.032	--	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR1) at Thistletown MS (Refer to Appendix 1A). The condition of the transformer has been shifting from a mixture of electrical and thermal faults region (DT region) to thermal faults at temperature greater than 700 C region (T3 region).

Justification:

(a) The transformer was manufactured in 1956 and has reached the end of its operating life.

(b) The Dissolved Gas report indicates a trend of continuous degradation of insulation paper above normal acceptable level. The high CO_2 value shows that the paper insulation is becoming brittle and less resistant to electrical stress, which could lead to a transformer failure.

(c) The Dissolved Gas report shows high moisture content has degraded the dielectric strength of the insulating oil to an operating level outside of limits and if left in service, this unit is at risk of failure.

(d) DGA results indicate degradation of insulation paper and dielectric strength, indicating an increased risk of failure with its associated impacts.

3. Thistletown MS

Transformer: TR2

Age: 59

Transformer Leakage: No

DGA Results: Condition 1 (Refer to Appendix 2)

Table 6: DGA result for TR2 transformer at Thistletown MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	30/05/2009	15/05/1996	
Oil Temperature (°C)	32	10	1. Acid number is within the sludge forming range 2. Overall equipment condition code: 1
Hydrogen (H2) (PPM)	3	10	
Methane (CH4) (PPM)	2	5	
Ethane (C2H6) (PPM)	0	2	
Ethylene (C2H4) (PPM)	12	10	
Acetylene (C2H2) (PPM)	0	2	
Carbon Monoxide (CO) (PPM)	120	258	
Carbon Dioxide (CO2) (PPM)	1733	1959	
Nitrogen (N2) (PPM)	74128	67332	
Oxygen (O2) (PPM)	37115	24245	
Total Dissolved Gas (PPM)	113113	93823	
Total Dissolved Combustible Gas (PPM)	137	287	
Moisture in Oil (PPM)	26	--	
Acid Number (mg KOH/g)	**0.167**	0.14	
Dielectric Breakdown (kV)	33	37	
Power Factor at 25°C (%)	0.037	--	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR2) at Thistletown MS (Refer to Appendix 1B). The condition of the transformer has been declining in the T3 region which exhibits thermal faults at temperature greater than 700 C.

Justification:

(a) The transformer was manufactured in 1953 and has reached the end of its operating life.

(b) High acid content of 0.167 mg KOH/g which is 67% higher than the limit of 0.1mg KOH/g. Higher acidity has a damaging effect on the paper insulation.

(c) Interfacial Tension of 21.6 in 1996 to 21.7 in 2009 which is 11% lower than the limit of >24. Decreasing "Interfacial Tension" from normal acceptable level indicates an increase in contaminants and/or oxidation products within the oil resulting to the formation of sludge that affects the oil circulation inside the transformer.

(d) DGA results indicate degradation of insulation paper and dielectric strength, indicating an increased risk of failure with its associated impacts.

4. Scarborough Golf Club MS

Transformer: TR1

Age: 59

Transformer Leakage: Yes

DGA Results: Condition 1 (Refer to Appendix 2)

Figure 2: Station Transformer, TR1, leakage at Scarborough Golf Club MS (November 16, 2011)

Justification:

(a) The transformer was manufactured in 1953 and reached the end of its operating life.

(b) Transformer oil leakage pose environmental potential risk and increases maintenance cost since the cost of cleaning oil spillage is high.

5. Kingston Morningside MS

Transformer: TR1

Age: 55

Transformer Leakage: No

DGA Results: Condition 3 (Refer to Appendix 2)

Table 7: DGA result for TR1 transformer at Kingston Morningside MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	07/07/2010	03/07/2008	
Oil Temperature (°C)	58	20	1. Acetylene: Condition 3 indications of significant arching activity (5ppm) 2. Moisture in oil exceeds limit for in-service oil (35ppm) 3. Overall equipment condition code: 3
Hydrogen (H2) (PPM)	5	13	
Methane (CH4) (PPM)	3	2	
Ethane (C2H6) (PPM)	1	2	
Ethylene (C2H4) (PPM)	10	7	
Acetylene (C2H2) (PPM)	**6**	2	
Carbon Monoxide (CO) (PPM)	103	68	
Carbon Dioxide (CO2) (PPM)	2566	1157	
Nitrogen (N2) (PPM)	58337	62343	
Oxygen (O2) (PPM)	33170	29047	
Total Dissolved Gas (PPM)	94201	92641	
Total Dissolved Combustible Gas (PPM)	128	94	
Moisture in Oil (PPM)	**50**	9	
Acid Number (mg KOH/g)	0.057	0.072	
Dielectric Breakdown (kV)	27	44	
Power Factor at 25°C (%)	0.044	0.006	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR1) at Kingston Morningside MS (Refer to Appendix 1C). The condition of the transformer has been shifting from a mixture of electrical and thermal faults region (DT region) to electrical discharges of high energy (D2 region) region.

Justification:

(a) The transformer was manufactured in 1957 and has reached the end of its operating life.

(b) DGA results indicate degradation of insulation paper and dielectric strength, indicating an increased risk of failure with its associated impacts.

(c) The Dissolved Gas report indicates a trend of continuous degradation of insulation paper above normal acceptable level. The high CO_2 value shows that the paper insulation is becoming brittle and less resistant to electrical stress, which could lead to a transformer failure.

(d) The Dissolved Gas report shows high moisture content has degraded the dielectric strength of the insulating oil to an unsafe operating level and if left in service, this unit is at risk of failure. The high acetylene gas reading which shows that there is a failure of the dielectric strength of the paper insulation in some parts of the insulating paper of the transformer and as a result arcing is going on inside the transformer. If the arcing continues to exist, transformer failure will be imminent; therefore, it is prudent to replace the transformer at this stage.

6. Edenbridge MS

Transformer: TR1

Age: 45

Transformer Leakage: No

DGA Results: Condition 4 (Refer to Appendix 2)

Table 8: DGA result for TR1 transformer at Edenbridge MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	07/07/2010	03/07/2008	
Oil Temperature (°C)	11		1. Ethylene: Condition 4 indications of severely overheated oil (200ppm) 2. Overall equipment condition code: 4
Hydrogen (H2) (PPM)	64	59	
Methane (CH4) (PPM)	152	357	
Ethane (C2H6) (PPM)	153	283	
Ethylene (C2H4) (PPM)	**810**	1654	
Acetylene (C2H2) (PPM)	0	4	
Carbon Monoxide (CO) (PPM)	248	170	
Carbon Dioxide (CO2) (PPM)	1997	1971	
Nitrogen (N2) (PPM)	69525	66796	
Oxygen (O2) (PPM)	29998	30776	
Total Dissolved Gas (PPM)	102947	102070	
Total Dissolved Combustible Gas (PPM)	**1427**	2527	
Moisture in Oil (PPM)	12	26	
Acid Number (mg KOH/g)	0.045	0.046	
Dielectric Breakdown (kV)	55	32	
Power Factor at 25°C (%)	0.041	0.237	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR1) at Edenbridge MS (Refer to Appendix 1D). The condition of the transformer has been declining in the T3 region which exhibits thermal faults at temperature greater than 700C.

Justification:

(a) The transformer was manufactured in 1967 and has reached the end of its operating life.

(b) DGA results show that the fault condition is deteriorating with elevated gas levels, indicating an increased risk of failure with its associated impacts.

(c) The Dissolved Gas report indicates that the dissolved gas levels are elevated with Ethane at 153 PPM, Ethylene at 810 PPM and Methane at 152 PPM. The elevated gas levels indicate overheating of the oil, likely the result of an overheating conductor, which could lead to a transformer failure.

7. High Level MS

Transformer: TR1

Age: 84

Transformer Leakage: No

DGA Results: Condition 2 (Refer to Appendix 2)

Table 9: DGA result for TR1 transformer at High Level MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	04/06/2010	05/09/2002	
Oil Temperature (°C)	50	20	1. Carbon monoxide: Condition 2 indications of overheated cellulose insulation (350ppm) 2. DGA Cellulose (Paper) insulation: CO2/CO < 7 is an indication of thermal decomposition of cellulose 3. Power factor at 25°C exceeds limit for in-service oil (0.5%) 4. Overall equipment condition code: 2
Hydrogen (H2) (PPM)	21	13	
Methane (CH4) (PPM)	127	87	
Ethane (C2H6) (PPM)	210	39	
Ethylene (C2H4) (PPM)	19	21	
Acetylene (C2H2) (PPM)	0	0	
Carbon Monoxide (CO) (PPM)	**523**	547	
Carbon Dioxide (CO2) (PPM)	2893	2260	
Nitrogen (N2) (PPM)	74719	96515	
Oxygen (O2) (PPM)	5542	11910	
Total Dissolved Gas (PPM)	84054	111392	
Total Dissolved Combustible Gas (PPM)	**900**	707	
Moisture in Oil (PPM)	10	12	
Acid Number (mg KOH/g)	0.039	0.031	
Dielectric Breakdown (kV)	52	31	
Power Factor at 25°C (%)	**1.10**	0.357	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR1) at High Level MS (Refer to Appendix 1E). The condition of the transformer has been declining in the T1 region which exhibits thermal faults at temperature less than 300C.

Justification:

(a) The transformer was made in 1928 and has reached the end of its operating life.

(b) DGA results indicate degradation of insulation paper and dielectric strength, indicating an increased risk of failure with its associated impacts.

(c) The Dissolved Gas report indicates a trend of continuous degradation of insulation paper above normal acceptable level. The high CO2 and CO value indicates internal arching and shows that the paper insulation is becoming brittle and less resistant to electrical stress, which could lead to a transformer failure.

(d) The Dissolved Gas report indicates that the dissolved gas levels are elevated with Ethane at 210 PPM and Methane at 127 PPM. The elevated gas levels indicate overheating of the oil, likely the result of an overheating conductor, which could lead to a transformer failure.

(e) The Dissolved Gas report shows Power Factor greater than 1% at 25 °C indicating dielectric loss of the insulating oil to an operating level outside of limits and if left in service, the oil may cause failure of the transformer; replacement or reclaiming of the oil is required immediately.

8. High Level MS

Transformer: TR2

Age: 65

Transformer Leakage: No

DGA Results: Condition 2 (Refer to Appendix 2)

Table 10: DGA result for TR2 transformer at High Level MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	04/06/2010	01/06/2005	
Oil Temperature (°C)	50	50	1. Carbon monoxide: Condition 2 indications of overheated cellulose insulation (350ppm) 2. DGA Cellulose (Paper) insulation: CO2/CO < 7 is an indication of thermal decomposition of cellulose 3. Power factor at 25°C exceeds limit for in-service oil (0.5%) 4. Overall equipment condition code: 2
Hydrogen (H2) (PPM)	10	10	
Methane (CH4) (PPM)	141	84	
Ethane (C2H6) (PPM)	252	154	
Ethylene (C2H4) (PPM)	22	28	
Acetylene (C2H2) (PPM)	0	2	
Carbon Monoxide (CO) (PPM)	**549**	411	
Carbon Dioxide (CO2) (PPM)	3434	2939	
Nitrogen (N2) (PPM)	73361	100740	
Oxygen (O2) (PPM)	4704	24481	
Total Dissolved Gas (PPM)	82473	128849	
Total Dissolved Combustible Gas (PPM)	974	689	
Moisture in Oil (PPM)	22	15	
Acid Number (mg KOH/g)	0.047	0.042	
Dielectric Breakdown (kV)	45	42	
Power Factor at 25°C (%)	**0.650**	0.202	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR2) at High Level MS (Refer to Appendix 1F). The condition of the transformer has been shifting from thermal faults between the temperatures of 300C to 700C region (T2 region) to thermal faults at temperature less than 300C region (T1 region).

Justification:

(a) The transformer was manufactured in 1947 and has reached the end of its operating life.

(b) DGA results indicate degradation of insulation paper and dielectric strength, indicating an increased risk of failure with its associated impacts.

(c) The Dissolved Gas report indicates a trend of continuous degradation of insulation paper above normal acceptable level. The high CO_2 and CO value indicates internal arching and shows that the paper insulation is becoming brittle and less resistant to electrical stress, which could lead to a transformer failure.

(d) The Dissolved Gas report indicates that the dissolved gas levels are elevated with Ethane at 252 PPM and Methane at 141 PPM. The elevated gas levels indicate overheating of the oil, likely the result of an overheating conductor, which could lead to a transformer failure.

9. Blaketon MS

Transformer: TR1

Age: 42

Transformer Leakage: No

DGA Results: Condition 3 (Refer to Appendix 2)

Table 11: DGA result for TR1 transformer at Blaketon MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	11/04/2010	05/23/2008	
Oil Temperature (°C)	34		1. Carbon monoxide: Condition 3 indications of significantly overheated cellulose insulation (570ppm) 2. Overall equipment condition code: 3
Hydrogen (H2) (PPM)	41	62	
Methane (CH4) (PPM)	96	100	
Ethane (C2H6) (PPM)	45	34	
Ethylene (C2H4) (PPM)	39	29	
Acetylene (C2H2) (PPM)	0	0	
Carbon Monoxide (CO) (PPM)	**893**	1066	
Carbon Dioxide (CO2) (PPM)	17073	24595	
Nitrogen (N2) (PPM)	78248	84391	
Oxygen (O2) (PPM)	5684	3687	
Total Dissolved Gas (PPM)	102119	113964	
Total Dissolved Combustible Gas (PPM)	**1114**	1291	
Moisture in Oil (PPM)	6	64	
Acid Number (mg KOH/g)	0.005	0.008	
Dielectric Breakdown (kV)	49	31	
Power Factor at 25°C (%)	0.085	0.078	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR1) at Blaketon MS (Refer to Appendix 1G). The condition of the transformer has been declining in the T2 region which thermal faults between the temperatures of 300C to 700C.

Justification:

(a) The transformer was manufactured in 1970 and has reached the end of its operating life.

(b) DGA results indicate degradation of insulation paper and dielectric strength, indicating an increased risk of failure with its associated impacts.

(c) The Dissolved Gas report indicates a trend of continuous degradation of insulation paper above normal acceptable level. The high CO2 and CO value indicates internal arching and shows that the paper insulation is becoming brittle and less resistant to electrical stress, which could lead to a transformer failure.

10. Albion MS

Transformer: TR2

Age: 36

Transformer Leakage: No

DGA Results: Condition 3 (Refer to Appendix 2)

Table 12: DGA result for TR2 transformer at Albion MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	11/05/2010	23/07/2006	
Oil Temperature (°C)	27	50	1. Ethylene: Condition 3 indications of significantly overheated oil (100ppm) 2. Carbon monoxide: Condition 2 indications of overheated cellulose insulation (350ppm) 3. Overall equipment condition code: 3
Hydrogen (H2) (PPM)	56	99	
Methane (CH4) (PPM)	61	43	
Ethane (C2H6) (PPM)	25	16	
Ethylene (C2H4) (PPM)	**144**	128	
Acetylene (C2H2) (PPM)	0	0	
Carbon Monoxide (CO) (PPM)	**390**	265	
Carbon Dioxide (CO2) (PPM)	2552	1527	
Nitrogen (N2) (PPM)	69952	71346	
Oxygen (O2) (PPM)	23783	22700	
Total Dissolved Gas (PPM)	96963	96124	
Total Dissolved Combustible Gas (PPM)	676	551	
Moisture in Oil (PPM)	8	18	
Acid Number (mg KOH/g)	0.019	0.032	
Dielectric Breakdown (kV)	56	38	
Power Factor at 25°C (%)	0.054	0.070	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR2) at Albion MS (Refer to Appendix 1H). The condition of the transformer has been declining in the T3 region which exhibits thermal faults at temperature greater than 700C.

Justification:

(a) The transformer was manufactured in 1976 and has reached the end of its operating life.

(b) DGA results indicate degradation of insulation paper and dielectric strength, indicating an increased risk of failure with its associated impacts.

(c) The Dissolved Gas report indicates a trend of continuous degradation of insulation paper above normal acceptable level. The high CO2 and CO value indicates internal arching and shows that the paper insulation is becoming brittle and less resistant to electrical stress, which could lead to a transformer failure.

(d) The Dissolved Gas report indicates that the dissolved gas levels are elevated with Ethylene at 144 PPM. The elevated gas levels indicate overheating of the oil, likely the result of an overheating conductor, which could lead to a transformer failure.

11. Norseman MS

Transformer: TR1

Age: 61

Transformer Leakage: No

DGA Results: Condition 1 (Refer to Appendix 2)

Table 13: DGA result for TR1 transformer at Norseman MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	02/06/2011	15/05/2009	
Oil Temperature (°C)	35	--	1. Acid number is well within the sludge forming range 2. Overall equipment condition code: 1
Hydrogen (H2) (PPM)	5	8	
Methane (CH4) (PPM)	2	2	
Ethane (C2H6) (PPM)	--	1	
Ethylene (C2H4) (PPM)	11	12	
Acetylene (C2H2) (PPM)	0	0	
Carbon Monoxide (CO) (PPM)	158	181	
Carbon Dioxide (CO2) (PPM)	1072	1535	
Nitrogen (N2) (PPM)	55939	75246	
Oxygen (O2) (PPM)	25451	35635	
Total Dissolved Gas (PPM)	82638	112620	
Total Dissolved Combustible Gas (PPM)	176	204	
Moisture in Oil (PPM)	18	16	
Acid Number (mg KOH/g)	**0.101**	0.073	
Dielectric Breakdown (kV)	28	45	
Power Factor at 25°C (%)	0.048	0.102	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR1) at Norseman MS (Refer to Appendix 1I). The condition of the transformer has been declining in the T3 region which exhibits thermal faults at temperature greater than 700C.

Justification:

(a) The transformer was made in 1951 and has reached the end of its operating life.

(b) DGA results indicate degradation of insulation paper, indicating an increased risk of failure with its associated impacts.

(c) High acid content of 0.101 mg KOH/g which is 1% higher than the limit of 0.1mg KOH/g. Elevated acid number indicates oil oxidation is advanced, enough so to have produced some sludge deposits within the transformer. Higher acidity has a damaging effect on the paper insulation.

12. Underwriter Crouse MS

Transformer: TR1

Age: 53

Transformer Leakage: No

DGA Results: Condition 1 (Refer to Appendix 2)

Table 14: DGA result for TR1 transformer at Underwriter Crouse MS

Dissolved Gas Analysis			
Test Type	**Test Results**		**Result Analysis**
	07/12/2010	12/04/2008	
Oil Temperature (°C)	47	20	1. Dielectric breakdown exceeds limit for in-service oil (26kV) 2. Overall equipment condition code: 1
Hydrogen (H_2) (PPM)	14	11	
Methane (CH_4) (PPM)	2	2	
Ethane (C_2H_6) (PPM)	0	1	
Ethylene (C_2H_4) (PPM)	5	4	
Acetylene (C_2H_2) (PPM)	0	0	
Carbon Monoxide (CO) (PPM)	111	156	
Carbon Dioxide (CO_2) (PPM)	2278	1261	
Nitrogen (N_2) (PPM)	59201	72163	
Oxygen (O_2) (PPM)	33837	36218	
Total Dissolved Gas (PPM)	95448	109816	
Total Dissolved Combustible Gas (PPM)	132	174	
Moisture in Oil (PPM)	34	11	
Acid Number (mg KOH/g)	0.020	0.027	
Dielectric Breakdown (kV)	**23**	46	
Power Factor at 25°C (%)	0.108	0.077	

Duval Triangle Analysis:

Based on the DGA tests recorded in our Ellipse system, analysis using the Duval Triangle method (Refer to Appendix 3) shows a declining condition trend for the transformer (TR1) at Underwriter Course MS (Refer to Appendix 1J). The condition of the transformer has been declining in the T3 region which exhibits thermal faults at temperature greater than 700C.

Justification:

(a) The transformer was made in 1959 and has reached the end of its operating life.

(b) DGA results indicate degradation of dielectric strength, indicating an increased risk of failure with its associated impacts.

(c) The Dissolved Gas report shows high moisture content has degraded the dielectric strength of the insulating oil to an operating level outside of limits and if left in service, this unit is at risk of failure.

IV PREFERRED ALTERNATIVE

1. Problem Mitigation Options

THESL considered three options to mitigate the potential reliability and safety risks associated with the deteriorated state of these 12 station power transformers: maintaining the status quo, eliminating the need for the station transformer via area voltage conversions in these selected stations or replacing the station transformer.

2. Status Quo

Maintaining the status quo and not replacing the station transformers has the following implications:

- Safety: Catastrophic failure of transformers may result in collateral damage to other transformers, damage to other station equipment, and if staff are present, potential injury to personnel. Given that many municipal stations are located in residential neighbourhoods, there would be significant impact to homes and the public.
- Loading/Capacity impacts: Should a unit's health decrease significantly, it would need to be off-loaded to reduce further stress, in turn increasing the stress placed on other units and decreasing capacity to be used to deal with a system contingency. This impacts reliability.
- Decreased performance: Presence of moisture in transformer oil is inevitable during the normal service life of a transformer. Moisture constitutes a hazard not only to the insulating qualities of the oil but also to the insulations that are immersed in the oil. With age, the moisture content in oil increases, which will accelerate the deterioration of both the insulating oil and the paper insulation (loss of mechanical strength).

3. Voltage Conversion to Eliminate the Need for Transformers

Eliminating the need for the station power transformer requires that the service area being supplied by the transformer be converted to higher voltage levels. In the conversion process, the station and its components must be in service until the last customer is converted. As the cost of the distribution system served usually exceeds the cost of the station, it is not economic to advance the replacement of distribution systems due to station asset issues.

4. Replacement

Replacement of the station power transformer is feasible and much more economical. Also, it reduces the risk to other stations whose customers are served by these transformers under contingency. Table 15 shows the benefit cost evaluation of this option.

5. Avoided Risk Cost of the Selected Option

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

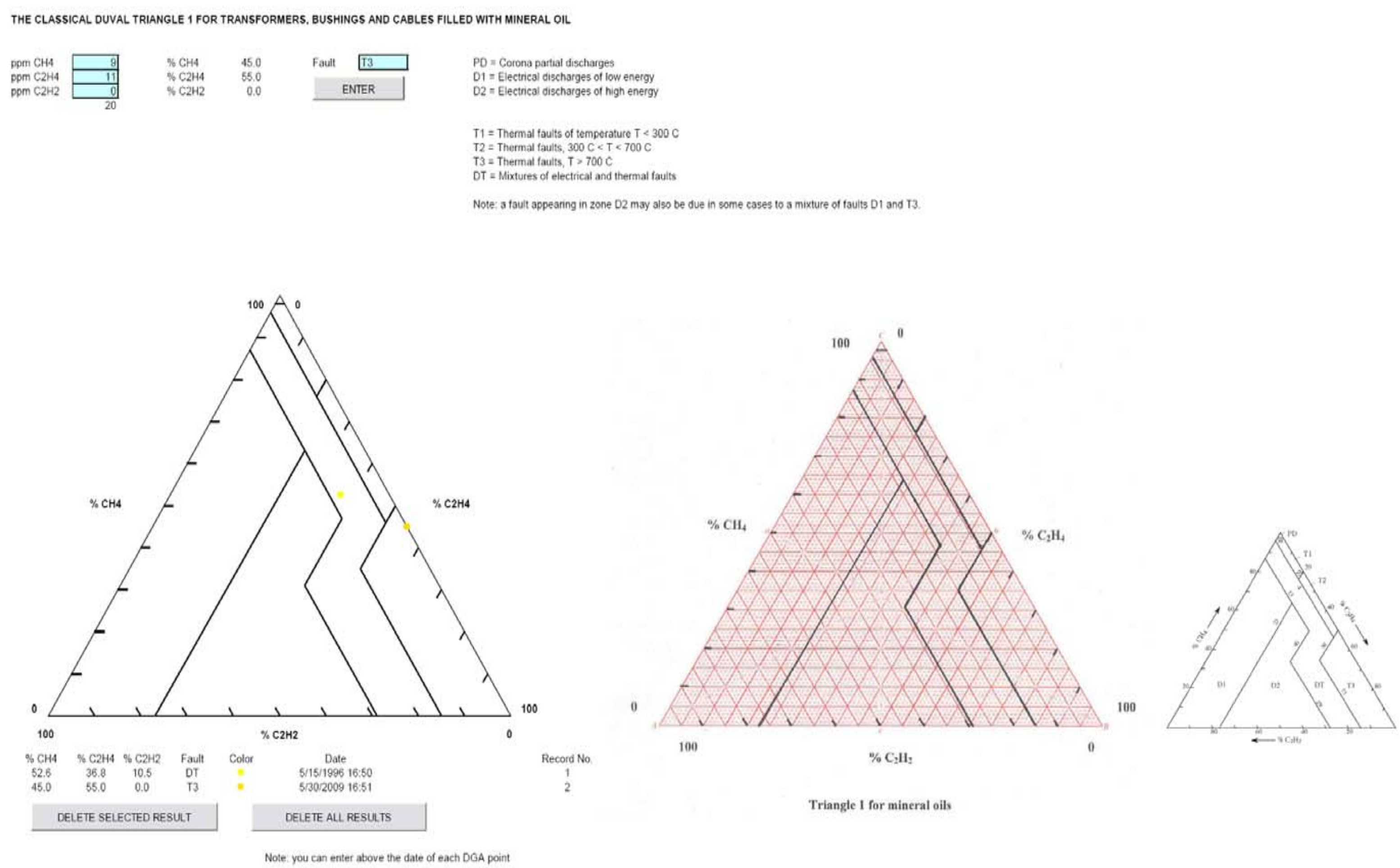
Carrying out immediate work on this asset class will result in the avoided estimated risk cost of approximately $66.6 million (Refer to Appendix 4), as opposed to executing this work in 2015. Therefore, there are distinct economic benefits to executing this work immediately. Further details with regards to the methodologies applied within business case are provided within Appendix 4.

6. Preferred Alternative

Based on comparison of the alternatives, replacement of the existing station power transformer is prudent since it is the most cost-effective option and provided a benefit/cost ratio greater than unity.

IV APPENDICES

1 **Appendix 1A**



1 ## Appendix 1B

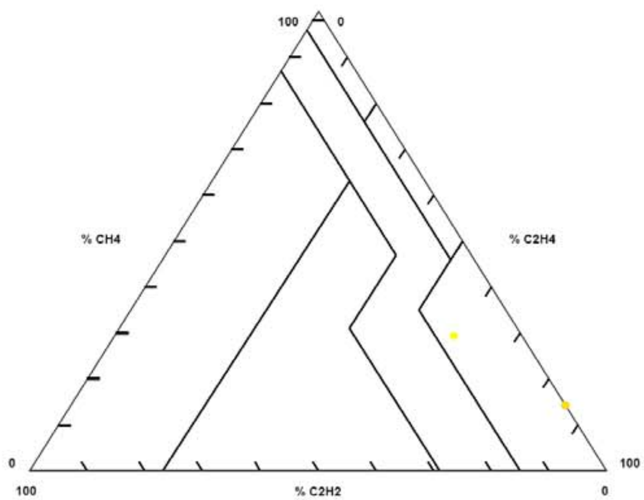
THE CLASSICAL DUVAL TRIANGLE 1 FOR TRANSFORMERS, BUSHINGS AND CABLES FILLED WITH MINERAL OIL

ppm CH4	2	% CH4	14.3	Fault	T3
ppm C2H4	12	% C2H4	85.7		ENTER
ppm C2H2	0	% C2H2	0.0		
	14				

PD = Corona partial discharges
D1 = Electrical discharges of low energy
D2 = Electrical discharges of high energy

T1 = Thermal faults of temperature T < 300 C
T2 = Thermal faults, 300 C < T < 700 C
T3 = Thermal faults, T > 700 C
DT = Mixtures of electrical and thermal faults

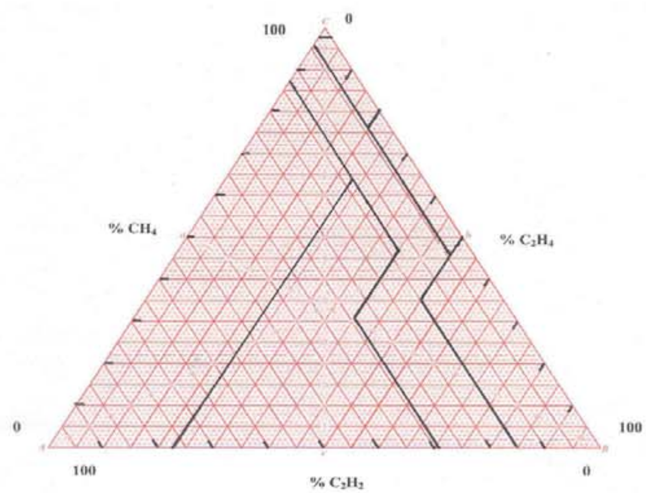
Note: a fault appearing in zone D2 may also be due in some cases to a mixture of faults D1 and T3.



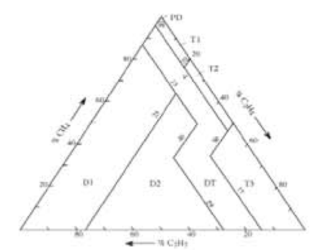
% CH4	% C2H4	% C2H2	Fault	Color	Date	Record No.
29.4	58.8	11.8	T3	●	5/15/1996 16:52	1
14.3	85.7	0.0	T3	●	5/30/2009 16:53	2

DELETE SELECTED RESULT | DELETE ALL RESULTS

Note: you can enter above the date of each DGA point



Triangle 1 for mineral oils



1 ## Appendix 1C

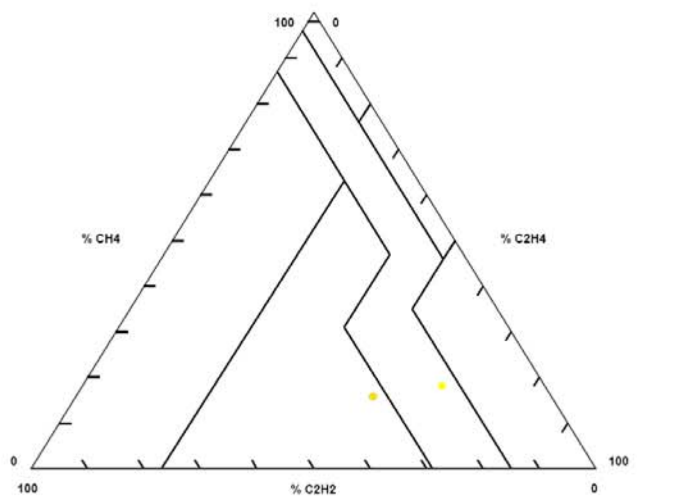
THE CLASSICAL DUVAL TRIANGLE 1 FOR TRANSFORMERS, BUSHINGS AND CABLES FILLED WITH MINERAL OIL

ppm CH4	3	% CH4	15.8	Fault	D2
ppm C2H4	10	% C2H4	52.6	ENTER	
ppm C2H2	6	% C2H2	31.6		
	19				

PD = Corona partial discharges
D1 = Electrical discharges of low energy
D2 = Electrical discharges of high energy

T1 = Thermal faults of temperature T < 300 C
T2 = Thermal faults, 300 C < T < 700 C
T3 = Thermal faults, T > 700 C
DT = Mixtures of electrical and thermal faults

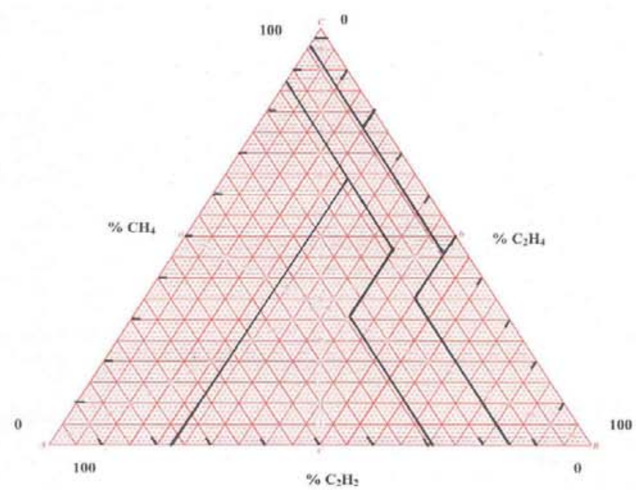
Note: a fault appearing in zone D2 may also be due in some cases to a mixture of faults D1 and T3.



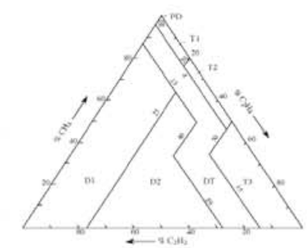
% CH4	% C2H4	% C2H2	Fault	Color	Date	Record No.
18.2	63.6	18.2	DT	●	3/7/2008 16:54	1
15.8	52.6	31.6	D2	●	7/7/2010 16:55	2

DELETE SELECTED RESULT | DELETE ALL RESULTS

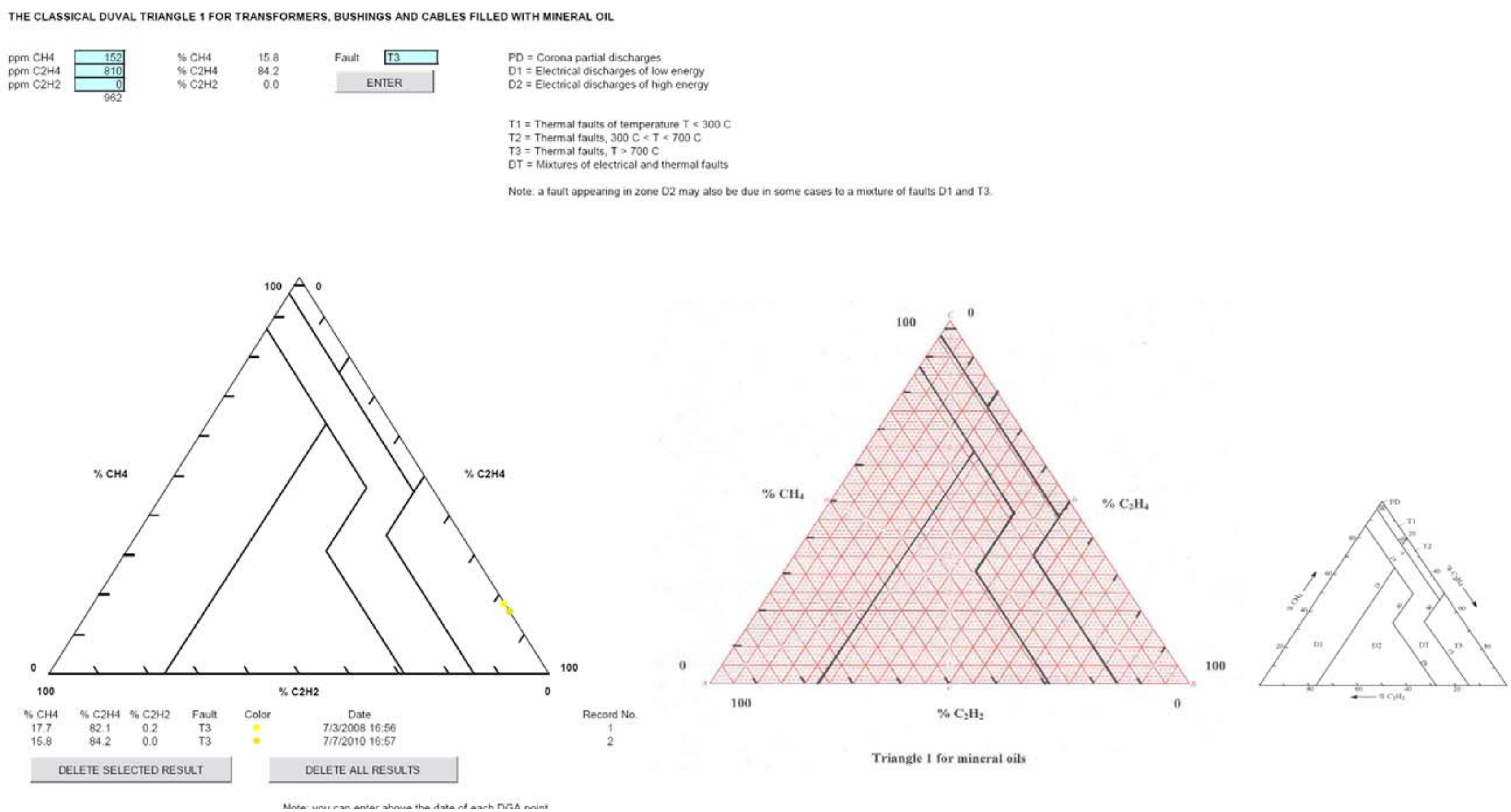
Note: you can enter above the date of each DGA point



Triangle 1 for mineral oils



1 ## Appendix 1D



1 ## Appendix 1E

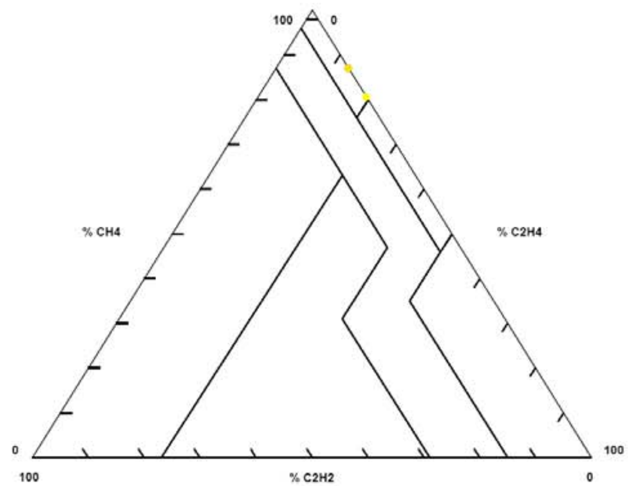
THE CLASSICAL DUVAL TRIANGLE 1 FOR TRANSFORMERS, BUSHINGS AND CABLES FILLED WITH MINERAL OIL

ppm CH4	127	% CH4	87.0	Fault	T1
ppm C2H4	19	% C2H4	13.0		ENTER
ppm C2H2	0	% C2H2	0.0		
	146				

PD = Corona partial discharges
D1 = Electrical discharges of low energy
D2 = Electrical discharges of high energy

T1 = Thermal faults of temperature T < 300 C
T2 = Thermal faults, 300 C < T < 700 C
T3 = Thermal faults, T > 700 C
DT = Mixtures of electrical and thermal faults

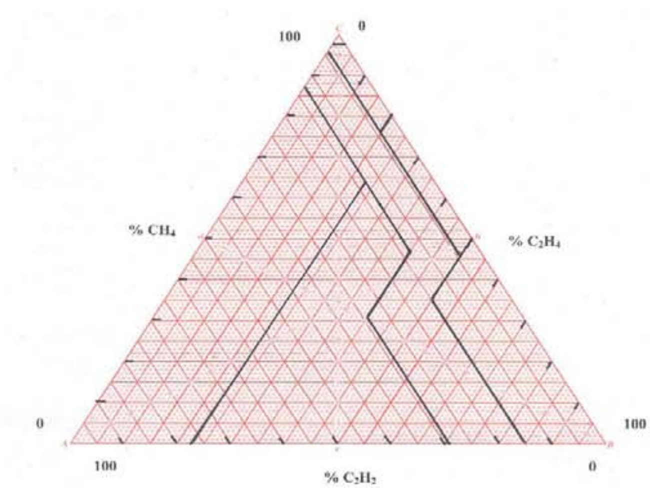
Note: a fault appearing in zone D2 may also be due in some cases to a mixture of faults D1 and T3.



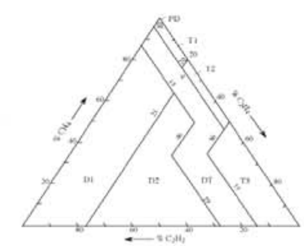
% CH4	% C2H4	% C2H2	Fault	Color	Date	Record No.
80.6	19.4	0.0	T1	•	9/5/2002 16:58	1
87.0	13.0	0.0	T1	•	6/4/2010 16:59	2

DELETE SELECTED RESULT   DELETE ALL RESULTS

Note: you can enter above the date of each DGA point



Triangle 1 for mineral oils



1 ## Appendix 1F

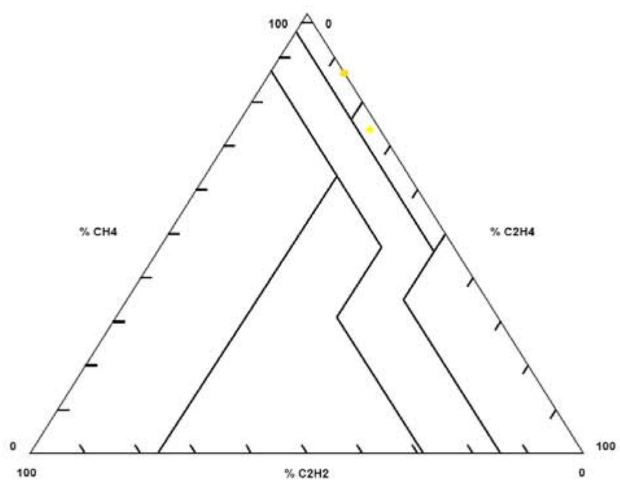
THE CLASSICAL DUVAL TRIANGLE 1 FOR TRANSFORMERS, BUSHINGS AND CABLES FILLED WITH MINERAL OIL

ppm CH4	141	% CH4	86.5	Fault	T1
ppm C2H4	22	% C2H4	13.5	ENTER	
ppm C2H2	0	% C2H2	0.0		
	163				

PD = Corona partial discharges
D1 = Electrical discharges of low energy
D2 = Electrical discharges of high energy

T1 = Thermal faults of temperature T < 300 C
T2 = Thermal faults, 300 C < T < 700 C
T3 = Thermal faults, T > 700 C
DT = Mixtures of electrical and thermal faults

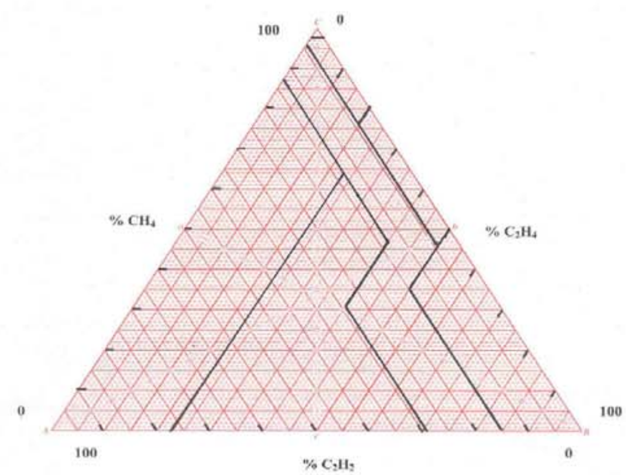
Note: a fault appearing in zone D2 may also be due in some cases to a mixture of faults D1 and T3.



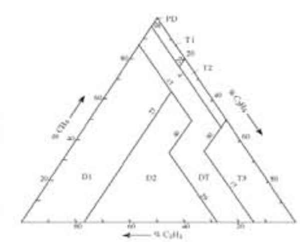
% CH4	% C2H4	% C2H2	Fault	Color	Date	Record No.
73.7	24.6	1.8	T2	●	6/1/2005 16:59	1
86.5	13.5	0.0	T1	●	6/4/2010 17:00	2

DELETE SELECTED RESULT   DELETE ALL RESULTS

Note: you can enter above the date of each DGA point



Triangle 1 for mineral oils



1 ## Appendix 1G

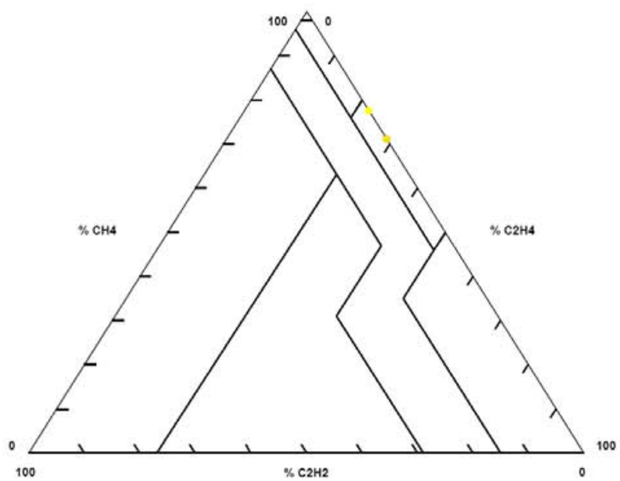
THE CLASSICAL DUVAL TRIANGLE 1 FOR TRANSFORMERS, BUSHINGS AND CABLES FILLED WITH MINERAL OIL

ppm CH4	96	% CH4	71.1	Fault	T2
ppm C2H4	39	% C2H4	28.9	ENTER	
ppm C2H2	0	% C2H2	0.0		
	135				

PD = Corona partial discharges
D1 = Electrical discharges of low energy
D2 = Electrical discharges of high energy

T1 = Thermal faults of temperature T < 300 C
T2 = Thermal faults, 300 C < T < 700 C
T3 = Thermal faults, T > 700 C
DT = Mixtures of electrical and thermal faults

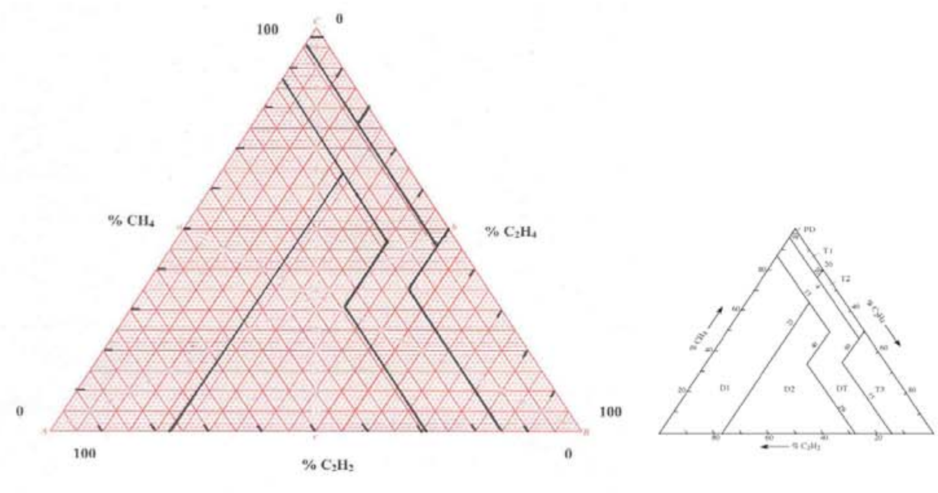
Note: a fault appearing in zone D2 may also be due in some cases to a mixture of faults D1 and T3.



% CH4	% C2H4	% C2H2	Fault	Color	Date	Record No.
77.5	22.5	0.0	T2	●	23/5/2008 5:00:53 PM	1
71.1	28.9	0.0	T2	●	4/11/2010 17:01	2

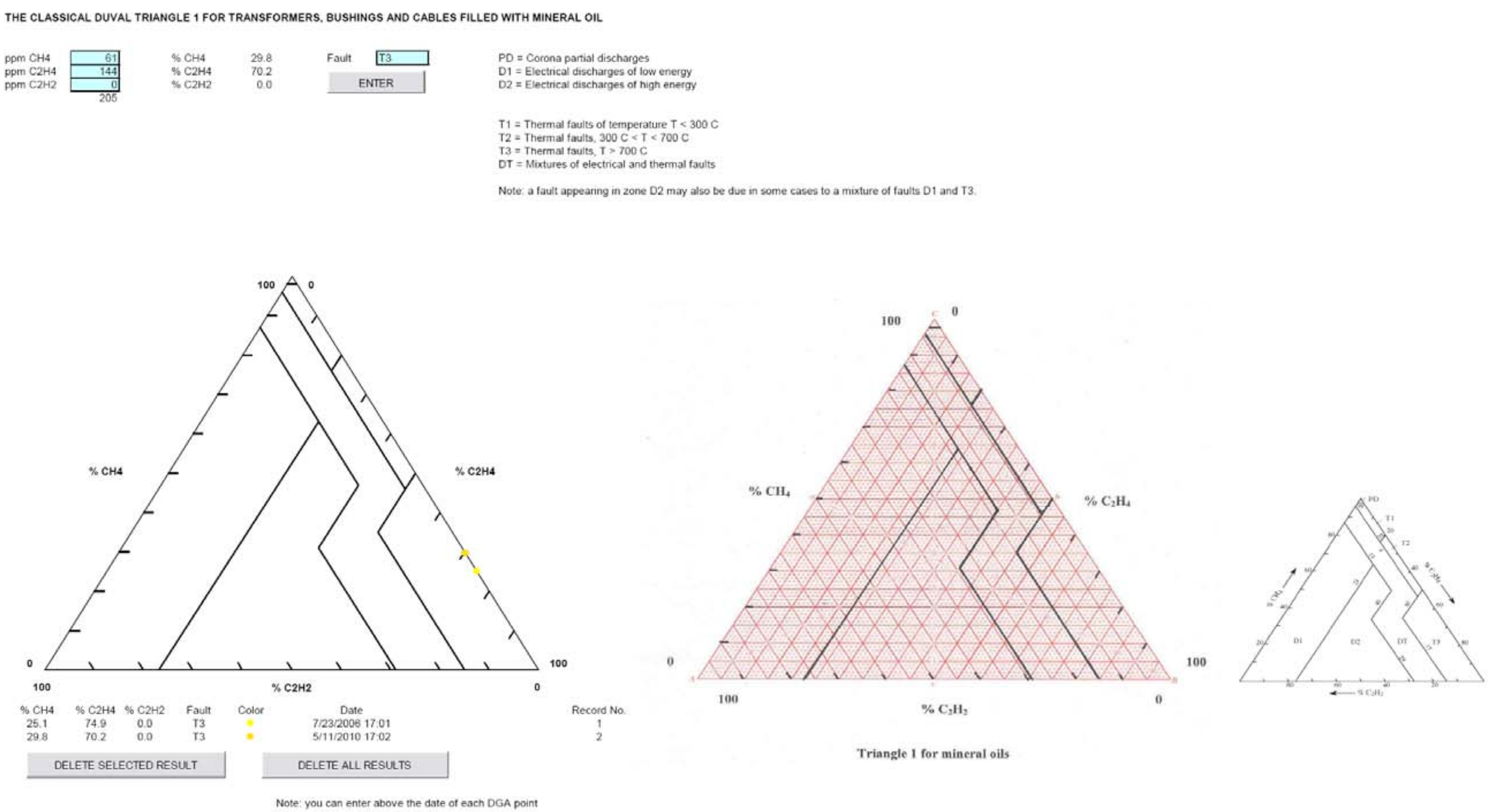
DELETE SELECTED RESULT | DELETE ALL RESULTS

Note: you can enter above the date of each DGA point



Triangle 1 for mineral oils

1 ## Appendix 1H



1 ## Appendix 1I

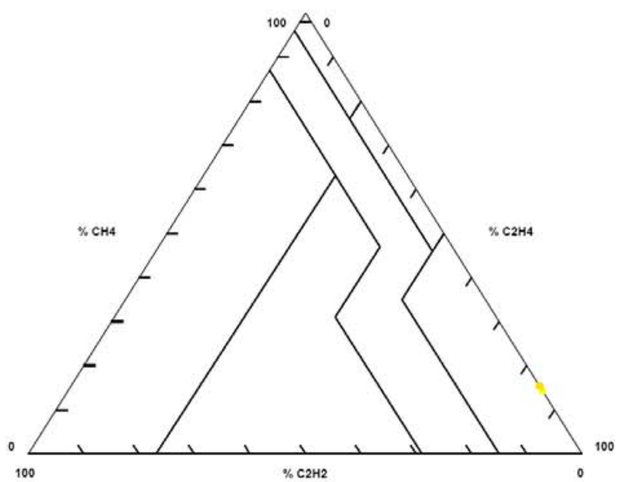
THE CLASSICAL DUVAL TRIANGLE 1 FOR TRANSFORMERS, BUSHINGS AND CABLES FILLED WITH MINERAL OIL

ppm CH4	2	% CH4	15.4	Fault	T3
ppm C2H4	11	% C2H4	84.6	ENTER	
ppm C2H2	0	% C2H2	0.0		
	13				

PD = Corona partial discharges
D1 = Electrical discharges of low energy
D2 = Electrical discharges of high energy

T1 = Thermal faults of temperature T < 300 C
T2 = Thermal faults, 300 C < T < 700 C
T3 = Thermal faults, T > 700 C
DT = Mixtures of electrical and thermal faults

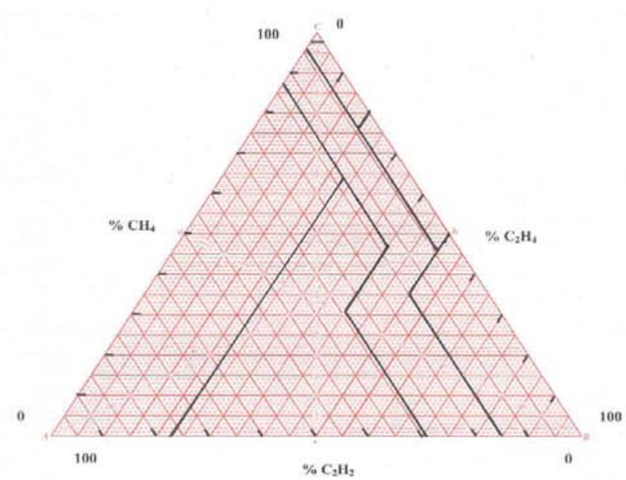
Note: a fault appearing in zone D2 may also be due in some cases to a mixture of faults D1 and T3.



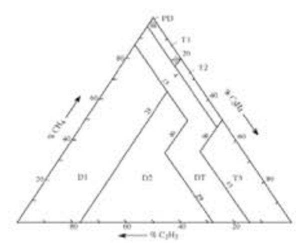
% CH4	% C2H4	% C2H2	Fault	Color	Date	Record No.
14.3	85.7	0.0	T3		5/15/2009 17:03	1
15.4	84.6	0.0	T3		6/2/2011 17:03	2

DELETE SELECTED RESULT | DELETE ALL RESULTS

Note: you can enter above the date of each DGA point



Triangle 1 for mineral oils



1 ## Appendix 1J

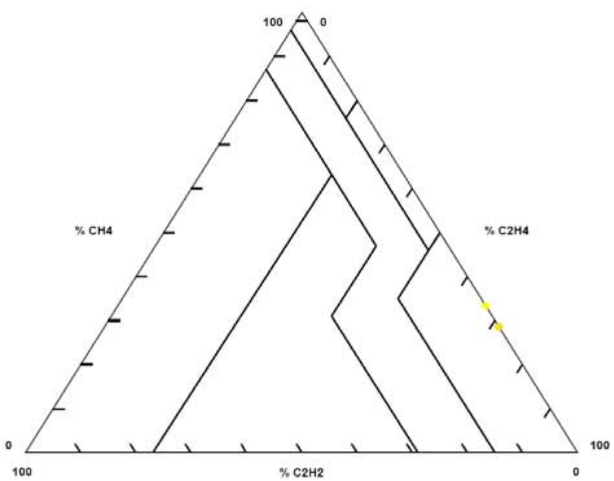
THE CLASSICAL DUVAL TRIANGLE 1 FOR TRANSFORMERS, BUSHINGS AND CABLES FILLED WITH MINERAL OIL

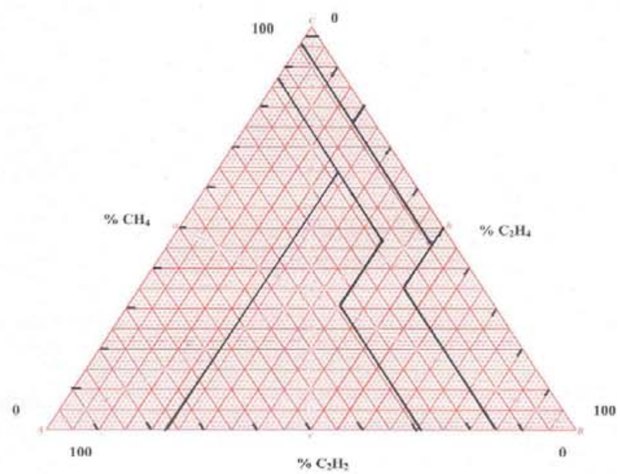
ppm CH4	2	% CH4	28.6	Fault	T3
ppm C2H4	5	% C2H4	71.4	ENTER	
ppm C2H2	0	% C2H2	0.0		
	7				

PD = Corona partial discharges
D1 = Electrical discharges of low energy
D2 = Electrical discharges of high energy

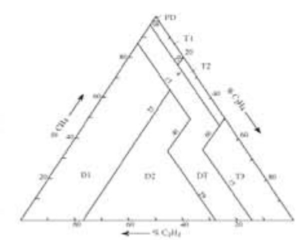
T1 = Thermal faults of temperature T < 300 C
T2 = Thermal faults, 300 C < T < 700 C
T3 = Thermal faults, T > 700 C
DT = Mixtures of electrical and thermal faults

Note: a fault appearing in zone D2 may also be due in some cases to a mixture of faults D1 and T3.





Triangle 1 for mineral oils



% CH4	% C2H4	% C2H2	Fault	Color	Date	Record No.
33.3	66.7	0.0	T3	●	4/12/2008 17:04	1
28.6	71.4	0.0	T3	●	12/7/2010 17:04	2

DELETE SELECTED RESULT | DELETE ALL RESULTS

Note: you can enter above the date of each DGA point

Appendix 2

Condition 1: Total dissolved combustible gas (TDCG) below this level indicates the transformer is operating satisfactorily. Any individual combustible gas exceeding specified levels in table 16 should have additional investigation.

Condition 2: Total dissolved combustible gas within this range indicates greater than normal combustible gas level. Any individual combustible gas exceeding specified levels in table 16 should have additional investigation. A fault may be present.

Condition 3: Total dissolved combustible gas within this range indicates a high level of decomposition of cellulose insulation and/or oil. Any individual combustible gas exceeding specified levels in Table 15 should have additional investigation. A fault or faults are probably present.

Condition 4: Total dissolved combustible gas within this range indicates excessive decomposition of cellulose insulation and/or oil. Continued operation could result in failure of the transformer.

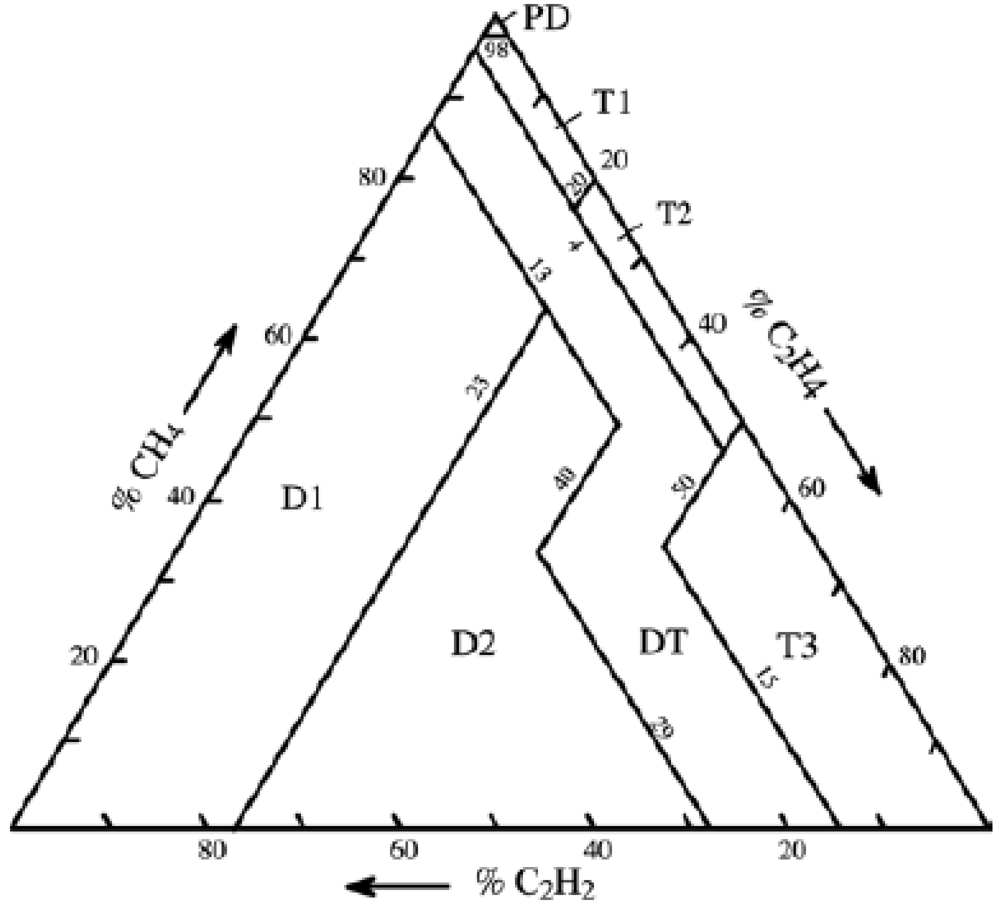
Table 15: Dissolved Key Gas Concentration Limits in Parts Per Million (ppm)

Status	H2	CH4	C2 H2	C2H4	C2H6	CO	CO2 1	TDCG
Condition 1	100	120	35	50	65	350	2,500	720
Condition 2	101-700	121-400	36-50	51-100	66-100	351-570	2,500-4,000	721-1,920
Condition 3	701-1,800	401-1,000	51-80	101-200	101-150	571-1,400	4,001-10,000	1,921-4,630
Condition 4	>1,800	>1,000	>80	>200	>150	>1,400	>10,000	>4,630

Appendix 3

Table 16: Examples of Partial Discharge/ Faults Detectable by DGA using Duval Diagnostic Method

Symbol	Partial Discharge/Fault	Examples
PD	Partial discharges	Discharges of the cold plasma (corona) type in gas bubbles or voids, with the possible formation of X-wax in paper.
D1	Discharges of low energy	Partial discharges of the sparking type, inducing pinholes, carbonized punctures in paper. Low energy arcing inducing carbonized perforation or surface tracking of paper, or the formation of carbon particles in oil.
D2	Discharges of high energy	Discharges in paper or oil, with power follow-through, resulting in extensive damage to paper or large formation of carbon particles in oil, metal fusion, tripping of the equipment and gas alarms.
T1	Thermal fault, T <300 °C	Evidenced by paper turning brownish (> 200 °C) or carbonized (> 300 °C).
T2	Thermal fault, 300 <T<700 °C	Carbonization of paper, formation of carbon particles in oil.
T3	Thermal fault, T >700 °C	Extensive formation of carbon particles in oil, metal coloration (800 °C) or metal fusion (> 1000 °C).
DT	Mixtures of electrical and thermal faults in the transformer	



1 **Figure 4: Duval Triangle Method**

Appendix 4

Power Transformers 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.

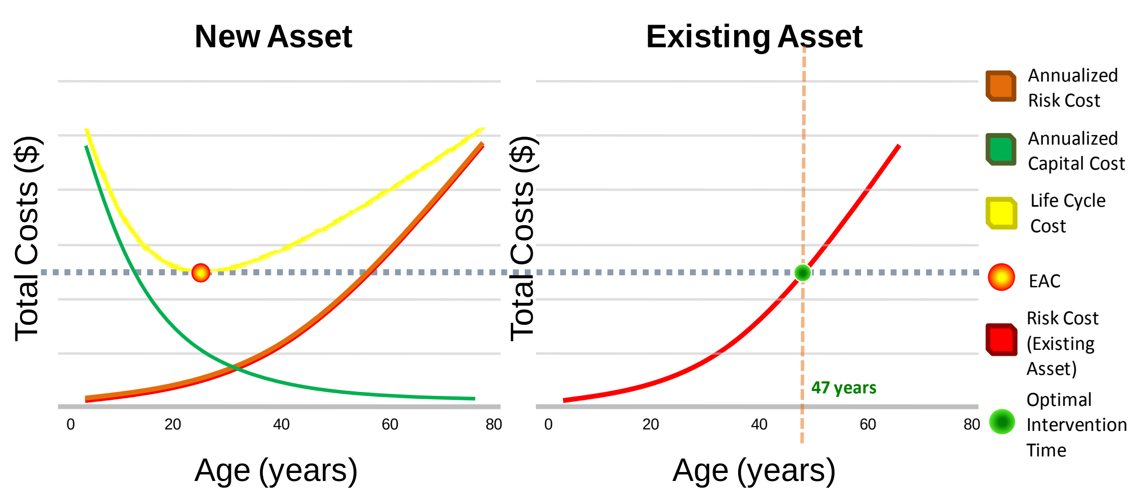
1.1 Life Cycle Cost and Optimal Intervention Timing Results

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 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 that 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.

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

2

3 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.



9 **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.

1.2 Project Evaluation Results

The Stations Power Transformers segment represents an "in-kind" replacement project in which the existing Power Transformer 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 this would represent the next available year when THESL may 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 Stations Power Transformers 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 and the total costs as the ordinate. As such, the minimum point of this curve provides the highest Net Project Benefit and defines the optimal year to execute the specific project.

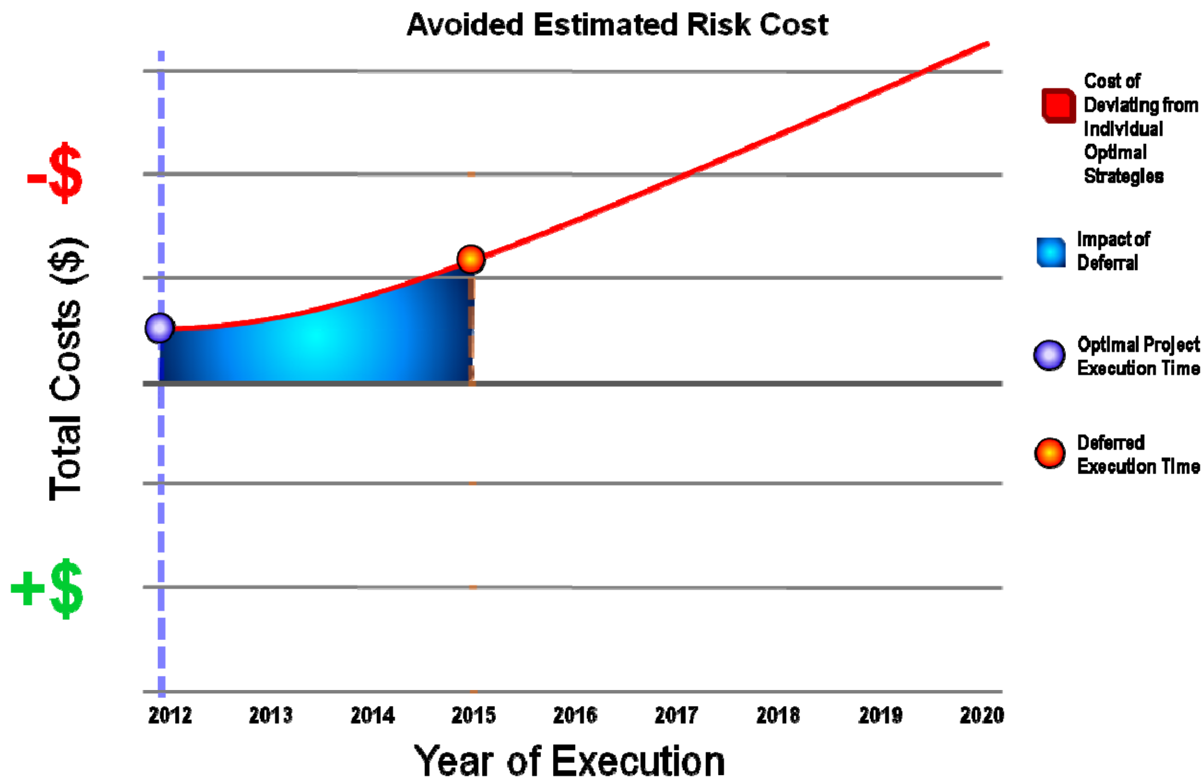


Figure 3: Typical Example of Project Net Benefit Analysis

The effectiveness of the Stations Power Transformers 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, we 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:

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 Power Transformers segment, individual optimal intervention timing results were calculated for each of the 12 power transformer assets, 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 Power Transformer assets within this project 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 ($PV(PROJECT_{NET\_COST}(2015))$)	$ 66.635
Project Net Cost in 2012 ($PROJECT_{NET\_COST}(2012)$)	$ 0.0658
Avoided Estimated Risk Cost = **($PV(PROJECT_{NET\_COST}(2015)) - PROJECT_{NET\_COST}(2012)$)**	**$66.570**

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.

Appendix 5

Table 17: Health Index (HI) of the selected Station Power Transformers

HI Range	Description
Greater 85	Very Good
between 71 and 85	Good
between 51 and 70	Fair
between 31 and 50	Poor
less than 30	Very Poor

Station Name – Transformer	Health Index (HI)
Ellesmere White Abbey MS – TR1	63
Thistletown MS – TR1	63
Thistletown MS – TR2	58
Scarborough Golf Club Rd MS – TR1	75
Kingston Morningside MS – TR1	38
Edenbridge MS – TR1	58
High Level MS – TR1	50
High Level MS – TR2	44
Blaketon MS – TR1	67
Albion MS – TR2	73
Norseman MS – TR1	59
Underwriter Crouse MS – TR1	58

ICM Project – Station Infrastructure and Equipment

Municipal Substation Switchgear Replacement Segment

Toronto Hydro-Electric System Limited (THESL)

ICM Project | Municipal Substation Switchgear Replacement Segment

I EXECUTIVE SUMMARY

1. Project Description

Many Municipal Substations (MS) located outside of downtown Toronto employ switchgear that are past the end of their useful lives and rely on obsolete technology such as non arc-resistant designs with oil circuit breakers and mechanical relays. This type of aged equipment can be kept in service for a time by increased maintenance and harvesting parts from spares. However, as the asset condition continues to deteriorate and the risk of failure increases, maintaining this switchgear in service is unsustainable. In addition, the circuit breakers in some of these substations have auto re-closure problems (i.e., when a circuit breaker is taken out of service for maintenance and put back, it auto re-closes instead of locking, even though the circuit breaker is on open position and the auto re-closure is blocked by control authority), which create potential safety risks (See Section II).

The MS Switchgear to be replaced under this segment in 2012, 2013, and 2014 include Leslie MS, Lawrence Golf MS, Brian Elinor MS, York MS, Brimley Bernadine MS, Porterfield MS, Greencedar Lawrence MS, Neilson Drive MS, Midland Lawrence MS, Pharmacy CPR MS, Islington MS and Thornton MS. The switchgear in all but one of these stations are more than 50 years old. The total cost of this segment is approximately $16.88 million as shown in Table 1.

The switchgear selected for replacement in this segment were chosen from 199 switchgear across 170 Municipal Substations based upon advanced equipment age, equipment obsolescence employing obsolete oil circuit breakers, lack of arc-resistant design and safety related equipment issues. Based on available resources, jobs are scheduled over three years to allow engineering, procurement, construction and commissioning and are closely coordinated with feeder transfers to minimize customer outages and limit single supply contingency.

ICM Project | Municipal Substation Switchgear Replacement Segment

1 **Table 1: Job Cost Estimate**

Job Estimate Number	Job Title	Year Installed	Job Year	Cost Estimate ($M)
20427	S12320 Leslie MS Switchgear Replacement	1978	2012	4.08
20427	S12320 Leslie MS Switchgear Replacement (Continuation)	1978	2013	1.04
20560	S11032 Lawrence Golf Switchgear Replacement	1957	2012	0.82
20561	S11031 Brian Elinor MS Replace switchgear	1954	2012	0.83
22620	S11642 York MS Replace Switchgear	1954	2012	1.39
20544	S11040 Brimley Bernadine MS Replace Switchgear	1959	2012	1.09
20750	S12416 Porterfield MS Replace Switchgear	1956	2012	1.23
21338	S13090 Greencedar Lawrence MS Replace Switchgear	1960	2013	0.83
21581	S13126 Neilson Dr MS Replace Switchgear	1954	2013	1.29
21339	S14044 Midland Lawrence MS Replace switchgear	1960	2013	0.24
21339	S14044 Midland Lawrence MS Replace switchgear (Continuation)	1960	2014	0.62
20779	S14048 Pharmacy CPR MS Replace switchgear	1961	2014	0.94
22804	S14068 Islington MS Replace Switchgear	1955	2014	1.51

Job Estimate Number	Job Title	Year Installed	Job Year	Cost Estimate ($M)
22805	S14070 Thornton MS Replace Switchgear	1955	2012	0.11
22805	S14070 Thornton MS Replace Switchgear (Continuation)	1955	2014	0.86
			Total	**16.88**

2. Why the Project is Needed Now

All the Municipal Substation switchgear proposed to be replaced are over 50 years (with the exception of Leslie MS) and have reached the end of their useful life. The switchgear employ obsolete technology, such as non arc-resistance design, oil circuit breakers and mechanical relays. Non arc-resistant switchgear does not have the ability to channel the energy released during an internal arc fault in ways that minimize the potential injury to personnel and damage to equipment in the surrounding area, including damaging the entire substation.

THESL experienced two substation fires in recent years due to faults in substation equipment that were at their end of service life; one was in 2007 at Lesmil MS in North York area and the second one was in 2009 at station J, in East York area. Both substations were over 50 years old and the fire was attributed to faults in the substation switchgears. Switchgear which is over its useful design life (50 years) can fail catastrophically at any time. Lesmil MS was severely damaged as a result of the fire created due to the fault and Station J was burned down as a result of the fire created by the arc fault in the switchgear and there was no substation equipment left to repair.

The load of both of the above substations was temporarily transferred to their respective adjacent substations. Lesmil MS was ultimately converted to 27.6kV because the station was lightly loaded and replacing or repairing the aging switchgear was not cost effective. Station J MS was also lightly loaded as a result of previous load conversion so converting substation was more cost effective than replacing and/or repairing the aging switchgear. Load conversion also offered the advantage of addressing aging equipment on the distribution system outside the substation.

In addition to the consequences of in-service failures, the existing circuit breakers in all of the switchgear are oil circuit breakers and are obsolete. The maintenance for this type of circuit breaker takes twice as long as the modern vacuum circuit breakers and replacement parts for this type of circuit breaker are no longer manufactured. If they can be obtained at all, they must be harvested from other switchgear or custom manufactured.

The switchgear at Thornton MS, Islington MS, Porterfield MS and Neilson MS have additional operational constraints that pose safety risks to operating personnel. The circuit breakers in these substations have auto re-closure problems, i.e., when a circuit breaker is taken out of service for maintenance and is put back after it is maintained, it auto re-closes instead of locking even though the circuit breaker is in the open position and the auto re-closure is blocked by the control authority. The auto re-closuring poses safety risk to the operating personnel To correct the auto re-closure problem, rewiring of the circuit breakers is required, however, rewiring circuit breakers that are at the end of their life is not cost effective. Therefore, it is prudent to replace the entire switchgear. To mitigate the safety risk temporarily, the circuit breakers are tagged with warning labels.

3. Why the Project is the Preferred Alternative

THESL considered the following options, which are fully discussed in Section IV:

1) Continue to maintain and operate the existing equipment.
2) Transfer load to adjacent sub-stations.
3) Convert the existing 4.16kV load to 27.6kV and decommission Switchgear
4) Replace switchgear with air insulated arc resistant Type C switchgear

Option 1 option has the potential to defer capital investment, but would require increasing time and expense to repair switchgear as it continues to deteriorate (See Section IV, 1). Given the age and condition of this switchgear and the difficulty in obtaining spare parts, this option is not preferred. Option 2 is not feasible because it would create a significant capacity short fall on the system and limit the capability to restore during contingencies in the affected area (See Section IV, 2). Option 3 is not technically feasible because the MS to be addressed by this segment are not close to the 27.6kV distribution system and bringing 27.6kV service into these areas would not be cost effective (See Section IV, 3).

Option 4, which would install air insulated arc resistant Type C switchgear and associated SCADA/RTU equipment, is the preferred alternative because it offers the following benefits:

- Increased system reliability due to the arc-resistant design of the switchgear and the use of remotely operated SCADA/RTU to control and monitor it, which will reduce outage time.
- Reduced maintenance and operating cost since the new switchgear will eliminate the need to maintain existing obsolete oil circuit breakers and also will be remotely operated.
- Increase operational efficiency and flexibility due to the installation of SCADA/RTU controlling and monitoring system. The equipment will be operated remotely and this will help operating personnel manage planned and unplanned outages efficiently.

Based on the advantages and disadvantaged of each option, Option 4, which includes the installation of SCADA/RTU controlling and monitoring systems, is the preferred option (See Section IV, 4.3).

The cost effectiveness of undertaking the proposed segment can be further evaluated by determining how much cost is avoided by executing this work immediately as opposed to executing it in 2015. The results of this exercise are shown in the Business Case Evaluation (BCE) found in Appendix 1. The BCE finds that conducting the proposed segment in 2012 will result in the avoided estimated risk cost of approximately $200,000 as opposed to executing this work in 2015. Therefore, there are distinct economic benefits to executing this work immediately.

II WORK DESCRIPTION

There are 12 switchgears to be replaced in this segment of work in 2012, 2013, and 2014. They are located in the east and west ends of Toronto as illustrated in Figure 1 below.

Map Reference Number	Station Name	Address
1	Leslie MS	5733 Leslie St, Toronto ON
2	Lawrence Scar Golf Club Rd MS	3782 Lawrence Ave E , Toronto ON
3	Brian Elinor MS	54 Brian Ave. , Toronto ON
4	York MS	714 Royal York Rd. , Toronto ON
5	Brimley Bernadine MS	1221 Brimley Rd. , Toronto ON
6	Porterfield MS	2 Guiness Ave. , Toronto ON
7	Greencedar Lawrence MS	29 Greencedar Circuit, Toronto ON
8	Neilson Dr MS	4237 Bloor St. W. , Toronto ON
9	Midland Lawrence MS	1365 Midland Ave. , Toronto ON
10	Pharmacy CPR MS	7 Trestleside Grove, Toronto ON
11	Islington MS	Cordova Ave. , Toronto ON
12	Thornton MS	59 Glen Agar Dr. , Toronto ON

Figure 1: Job Locations

The switchgear selected for replacement in this segment were chosen from 199 switchgear across 170 Municipal Substations based upon advanced equipment age, equipment obsolescence employing obsolete oil circuit breakers, lack of arc-resistant design and safety related equipment issues. Based on available resources, jobs are scheduled over three years to allow engineering, procurement, construction and commissioning and are closely coordinated with feeder transfers to minimize customer outages and limit single supply contingency.

1. Leslie MS Switchgear Replacement

1.1. Job Description

The objective of this job is to construct a new electrical house (E-house) to replace the existing substation facility that is in poor condition, and replace the existing non-arc resistant switchgear with new arc-resistant switchgear in 2012.

1.2. Scope of Work

- Preparing design drawings and necessary documentations
- Purchasing new 13.8kV arc resistant switchgear
- Purchasing a new e-house appropriate to the size of the proposed switchgear
- Building a concrete foundation where the e-house is to be placed, and a
- cable chamber and associated concrete encased ducts as necessary
- Installing and commission the new switchgear
- Installing SCADA/RTU equipment
- Purchasing and installing a new battery and charger set
- Installing a heating and ventilation system
- Installing a fire protection system
- Transferring load over to the new switchgear
- Decommissioning the existing substation

The switchgear at Leslie MS was installed in 1978 and has reached the end of its useful life. Some of the existing circuit breakers have been out of service due to aging and have re-closure issues. Getting replacement parts for the switchgear is becoming very difficult due to the obsolescence of the equipment. If they can be obtained at all, they must be custom manufactured.

The Leslie MS building has deteriorated and is in poor condition. The switchgear housed in this building is obsolete with non-arc resistant design which represents potential safety risks to THESL personnel. Non arc-resistant switchgear does not have the ability to channel the energy released during an internal arc fault in ways that minimize the potential injury to personnel and damaging the equipment in the surrounding area, including damaging the whole substation. In 1977, this substation was burned down as a result of an internal arc fault and failure. All the customers connected to it were out of power for several days.

Leslie MS is an isolated 13.8kV distribution system surrounded by 27.6kV distribution systems and the significant area load makes it difficult to deal with during contingencies. In the event of a major failure at this substation, over 6,000 customers could experience a lengthy outage since there is no other 13.8kV municipal substation that can back up the load in the area.

2. Switchgear Replacement for Remaining MS

2.1. Job Description

The remaining 11 switchgear replacements at Lawrence Golf MS, Brian Elinor MS, York MS, Brimley Bernadine MS, Porterfield MS, Greencedar Lawrence MS, Neilson Drive MS, Midland Lawrence MS, Pharmacy CPR MS, Islington MS and Thornton MS are all driven by the same needs and have the same scope of work as described below in this section. York MS, Porterfield MS, Neilson MS, and Thornton MS also have an additional safety concern, and which is explained in the next section. The objective of each of these jobs is to replace the existing switchgear with modern arc -resistant switchgear and to install a SCADA/RTU monitoring and controlling system

2.2. Scope of Work

Scope of work includes:

- Design and preparation of necessary drawings and documents to purchase switchgear
- Transferring existing load to neighbouring substations and removing existing switchgear
- Installation and commissioning of new switchgear
- Installation and commissioning of SCADA/RTU monitoring and controlling system
- Energizing new switchgear and transferring load to the new switchgear

The existing switchgear at these stations was installed more than 50 years ago and has reached the end of its useful life. The switchgear is obsolete and spare parts required to repair the switchgear are no longer manufactured. Replacement parts, if they can be obtained at all, must be custom made at significant cost.

The switchgear is non-arc resistant design and represents potential safety risk to THESL personnel. Non arc-resistant switchgear does not have the ability to channel the energy released during an internal arc fault in ways that minimize the potential injury to personnel and damaging the equipment in the surrounding area, including damaging the whole substation. Therefore, as the non-arc resistant switchgear continues to age, the safety risk to the operating personnel of THESL also increases and the system reliability decreases.

The oil circuit breakers that are used in the switchgear have a potential of failing catastrophically and due to their oil content and location within the substations, can cause substation fires that could result in the loss of the entire substation.

The switchgear at these substations is required to support the neighbouring substations during contingency or during switchgear or transformer maintenance. If this switchgear fails, there will be a cascading effect on the neighbouring substations that back up its load by limiting their capability to handle load under second contingency. If the switchgear at one MS fails and the switchgear at the back up MS also fails, a significant outage could occur since the load of two switchgears can not be backed up without experiencing capacity shortage and/or voltage drop problems.

3. Additional Safety Concern at York MS, Porterfield MS, Neilson MS, and Thornton MS

When a circuit breaker is put back into position after maintenance is completed at these sub-stations, the breaker recloses from the open position even though the auto re-closure is blocked by the Control Authority. These particular breakers are defective and require immediate attention.

III NEED

All the Municipal Substation switchgears proposed to be replaced have reached the end of their useful life. The switchgear employs obsolete technology, such as non arc-resistance design, oil circuit breakers and mechanical relays. Non arc-resistant switchgear does not have the ability to channel the energy released during an internal arc fault in ways that minimize the potential injury to personnel and damage to equipment in the surrounding area, including damaging the entire substation.

THESL experienced two substation fires in recent years due to faults in substation equipment that were at their end of service life. One was in 2007 at Lesmil MS in North York area and the second one was in 2009 at Station J, in East York area. Both substations were over 50 years old and the fire was attributed to the faults in the substation switchgear.

Lesmil MS was severely damaged as a result of the fire created due to the fault. While Lesmil MS switchgear was out of service due to this fault, another switchgear in the vicinity failed and approximately 700 customers lost power for about 11 hours since the other supporting substations could not back up the load of two failed switchgears.

Station J was burned down as a result of the fire created by the arc fault in the switchgear. The fire completely destroyed the substation equipment. It could not be repaired.

The load of both of the above mentioned substations was temporarily transferred to their respective adjacent substations and Lesmil MS was ultimately converted to 27.6kV because the station was lightly loaded and replacing or repairing the aged switchgear was not cost effective. Station J MS was also lightly loaded as a result of previous load conversion to 27.6kV so converting the load of both the substations was more cost effective than replacing and/or repairing the aged switchgears since load conversion also addressed the aging part of their distribution system outside the substation.

In addition to the consequences of in-service failures, the existing circuit breakers in all of the switchgear are oil circuit breakers and are obsolete. The maintenance for this type of circuit breaker takes twice as long as for modern vacuum circuit breakers and replacement parts are no longer manufactured. If they can be obtained at all, they must be custom manufactured and cost twice as much as spare parts supported by manufacturers. Custom parts also take longer time to obtain lengthening the time to repair equipment and put it back into service.

The switchgear at Thornton MS, Islington MS, Porterfield MS and Neilson MS have additional operational constraints that pose potential safety risks to operating personnel. The circuit breakers in these substations have auto re-closure problems, i.e., when a circuit breaker is taken out of service for maintenance and is put back after it is maintained, it auto re-closes instead of locking even though the circuit breaker is in the open position and the auto re-closure is blocked by the control authority. The auto re-closuring poses safety risk to the operating personnel. To correct the auto re-closure problem, re-engineering and rewiring of the circuit breakers is required. However, rewiring or re-engineering circuit breakers that are at the end of their life is not cost effective; therefore, it is prudent to replace the whole switchgear since the switchgear is at the end of its service life. To mitigate the safety risk temporarily, the circuit breakers are tagged with warning labels for safety reasons

Neighbouring substations are often used to back up failed substations under single contingency event but are unable to handle load under second contingency that could also happen. THESL experienced this very problem in 2007 when Lesmil MS switchgear in North York failed catastrophically and while the Lesmil MS switchgear was out of service, a second substation, (Don Mills MS) in the area failed, resulting in outage to approximately 700 customers for about 11 hours because the neighbouring substations could not handle load under second contingency. Therefore, it is prudent to replace switchgear that is at the end of life proactively to limit the potential negative reliability impacts of “run to failure”.

IV PREFERRED ALTERNATIVE

THESL considered the following alternatives:

- Continue to maintain and operate the existing equipment.
- Transfer load to adjacent sub-stations.
- Convert the existing 4.16kV load to 27.6kV and decommission Switchgear
- Replace existing switchgear with air insulated arc-resistant type C switchgear

1. Option 1: Continue to Maintain and Operate the Existing Equipment

All the switchgear proposed for replacement, except Leslie MS, are over 50 years old and well past their useful lives. It has been possible to continue operating them because THESL has paid particular attention to their maintenance.

To continue to maintain the obsolete equipment, THESL has struggled to obtain spare parts that are no longer manufactured. On occasion THESL has been able to have certain parts custom made; in other instances it has harvested parts from other equipment for repairs. If THESL has to continue maintaining the equipment in this fashion, the cost of maintaining the obsolete equipment through custom fabricated parts will be twice that of parts supported by manufacturers.

This option will defer capital investment but will require continuous repair of the switchgear as they will continue to deteriorate and the repair cost will continue to rise as a result.

This option will result in:

- Increasing potential safety risks to THESL personnel due to the non arc-resistant design of the switchgear, and the potential for oil circuit breaker failure
- Increasing maintenance and operating costs due to aging and obsolescence of the equipment and due to the labour intensive maintenance cost of the oil circuit breakers
- Increasing system reliability risks due to equipment deterioration and lack of spare parts
- Increased costs for emergency replacement (at least 1.2 times greater than planned

replacement)

- Increased risk of collateral damage hence increased cost of repair

2. Option 2: Transfer Load to Adjacent Substations and decommission switchgear

The load transfer option will not be feasible for Leslie MS since there is no other 13.8kV station in the vicinity that can support the load of Leslie MS during contingency. Leslie MS is an isolated 13.8kV distribution system surrounded by 27.6kV distribution system.

Transferring the load of the rest of the 4kV switchgear proposed for replacement, to their respective adjacent substations will eliminate a total capacity of 86MVA out of the total 401MVA available capacity in the area. Therefore, this will reduce the available capacity in the area by 21% which will reduce the capability to handle the load of the area under contingency.

This option will also limit the flexibility required by the system operators to minimize outage duration during contingencies and during maintenance work. Under the current situation, if any switchgear fails, load can be transferred to the adjacent substations within 2 to 3 hours. If any switchgear is eliminated, the existing flexibility to restore power will be affected and restoring power will at least take one and half times more than currently due the switching time required at more tie points that will be added as a result of switchgear elimination.

Voltage drop could also be a problem if load is transferred to a substation located far from the existing load center. Equipment in the adjacent stations is also of similar vintage and has similar equipment in need of replacement. Therefore, this option is not feasible.

3. Option 3: Convert load to 27.6kV and decommission switchgears

This will require capital investment and could improve the reliability of the distribution system and improve line loss as a result of the higher voltage. This option is only possible if the substation is located on the boundary of the 27.6kV distribution system. All of the switchgear that are planned to be replaced in this segment are not close to the 27.6kV distribution system. As a result, this option is not feasible.

4. Option 4: Replace switchgear with air insulated arc-resistant type C switchgear

In this is option, three arc-resistant types of switchgear were considered to replace the existing switchgear.

4.1. Replace existing switchgear with Type A switchgear

This type of switchgear has arc-resistant construction at the front side only. This type of switchgear prevents explosive forces from escaping toward the front of the switchgear, preventing worker injury, but this type of switchgear will not contain the fault within the cell to prevent damage to adjacent cells.

4.2. Replace existing switchgear with Type B switchgear

This type of switchgear has arc-resistant construction at the front, back and both sides of the enclosure. This type of switchgear prevents explosive forces from escaping toward the front, back, and both sides of the switchgear, preventing worker injury and flying objects from damaging other equipment in the vicinity. However this type of switchgear will not contain the fault within the cell to prevent damages to adjacent cells.

4.3. Replace existing switchgear with Type C switchgear

This type of switchgear has arc resistant construction at the front, back, both sides and in the walls separating the cells in an assembly (except for main bus bar barriers) or between compartments of a cell. This type of switchgear prevents explosive forces from escaping towards all sides, preventing worker injury and damaging other equipment in the vicinity as a result of flying parts of the switchgear. This type of switchgear also contains arc fault within the cell and prevents damage to adjacent cells.

Based on advantages and disadvantages of each option, Option “4.3” along with the installation of SCADA/RTU is recommended.

This type of switchgear is expected to:

- Increase system reliability due to the arc-resistant design of the switchgear.

- Minimize the maintenance and operating cost since the new switchgear will eliminate the existing obsolete oil circuit breakers whose maintenance is increasing due to the customer spare part requirements. The need to inspect the oil circuit breakers after every tripping condition will also be eliminated. The new switchgear will be remotely operated thus minimizing operating cost.
- Increase reliability to THESL customers. The very fact that the switchgear is arc-resistant means it will be more reliable. Furthermore the SCADA/RTU controlling and monitoring system will help minimize outage time.
- Increase operational efficiency and flexibility due to the installation of SCADA/RTU controlling and monitoring system. The equipment will be operated remotely and this will help operating personnel manage planned and unplanned outages efficiently.

5. Avoided Risk Cost

The effectiveness of the Stations Switchgear MS replacement project can be further highlighted by determining how much cost is avoided by executing this work immediately as opposed to executing in 2015. These avoided costs include quantified risks, taking into account the assets' probability of failure, and multiplying this with various direct and indirect cost attributes 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 the avoided estimated risk cost of approximately $200,000, as opposed to executing this work in 2015. Therefore, THESL submits that there are economic benefits to ratepayers for executing this work now.

As a practical matter given available resources, jobs are scheduled over three years to allow engineering, procurement, construction and commissioning and are closely coordinated with feeder transfers to minimize customer outages and limit single supply contingency. The methodologies applied within this business case are further described in the Appendix 1.

APPENDIX 1

Stations Switchgear MS 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 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 that 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.

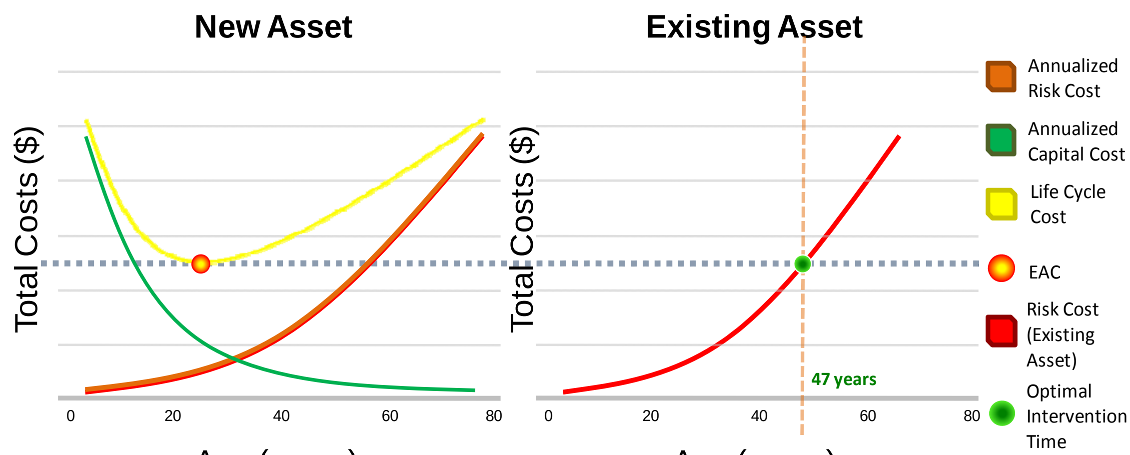


Figure 2: Typical Example of Optimal Intervention Time (Existing Assets)

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.

1.2 Project Evaluation Results

The Stations MS Switchgear segment represents an "in-kind" replacement project in which the existing Switchgear 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 this would represent the next available year when THESL may 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 Stations MS Switchgear 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 and the total costs as the ordinate. As such, the minimum point of this curve provides the highest Net Project Benefit and defines the optimal year to execute the specific project.

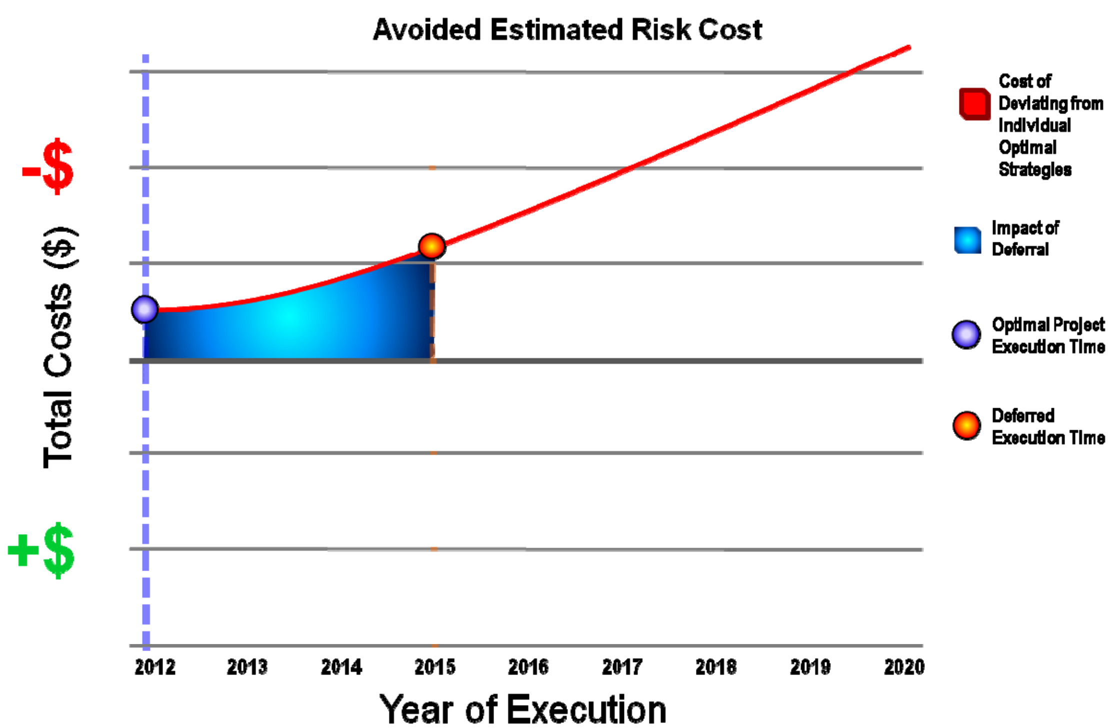


Figure 3: Typical Example of Project Net Benefit Analysis

The effectiveness of the Stations Switchgear MS 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, we 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:

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 Switchgear MS segment, individual optimal intervention timing results were calculated for each of the 12 switchgear assets, 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 switchgear assets within this project 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	Estimated Cost (in Millions)
Present Value of Project Net Cost in 2015 ($PV(PROJECT_{NET\_COST}(2015))$)	$2.355
Project Net Cost in 2012 ($PROJECT_{NET\_COST}(2012)$)	$2.155
Avoided Estimated Risk Cost = **($PV(PROJECT_{NET\_COST}(2015)) – PROJECT_{NET\_COST}(2012)$)**	**$ 0.200**

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, THESL can eliminate these estimated risks. Therefore, these avoided estimated risk costs represent the benefits of job execution.

ICM Project – Station Infrastructure and Equipment

Stations Switchgear – Transformer Stations Segment

Toronto Hydro-Electric System Limited (THESL)

ICM Project | Stations Switchgear – Transformer Stations Segment

I EXECUTIVE SUMMARY

1. Project Description

Switchgear operating at 13.8kV in many downtown Transformer Stations (TS) are past the end of their useful lives and rely on obsolete technology such as brick and mortar enclosures, non arc-resistant designs with air blast or air magnetic circuit breakers and mechanical relays and are in poor condition (See Section II, 3). The existing non arc-resistant switchgear does not channel the energy released during an internal arc fault to minimize potential injury to personnel and minimize damage to surrounding equipment. As a result, this switchgear can cause damage that impacts the entire station, interrupting service to thousands of customers. This equipment has been kept in service via increased maintenance, custom fabrication and harvesting parts from spares. The asset condition continues to deteriorate and safety concerns are increasing.

Switchgear requiring replacement in 2012, 2013, and 2014 include the A7-8T switchgear at Strachan TS, A6-7E switchgear at Carlaw TS, A3-4W and A5-6W switchgear at Wiltshire TS, A5-6WR switchgear at Windsor TS and A5-6DX at Duplex TS. All but one of these are more than 55 years old. The total cost of this segment is approximately $41.53 million for the jobs shown in Table 1

Table 1: Job Costs

Estimate Number	Job Title	Year Installed	Customer Load Served (MVA)	Job Year	Cost Estimate ($M)
18591	Strachan TS A7-8 switchgear replacement preparation	1956	34	2012	0.34
25425	Strachan TS A7-8 switchgear replacement	1956	34	2013	8.11

ICM Project | Stations Switchgear – Transformer Stations Segment

Estimate Number	Job Title	Year Installed	Customer Load Served (MVA)	Job Year	Cost Estimate ($M)
24972	S14406 Strachan TS Load Transfer from A7-8T to A11-12T Switchgear	1956	34	2014	0.30
22025	Carlaw TS A6-7E switchgear replacement	1968	26	2012	2.17
20877	Wiltshire TS A3-4W switchgear replacement	1954	20	2012	7.30
22719	Wiltshire TS A5-6W switchgear replacement	1954	22	2014	7.67
21735	Windsor TS A5-6WR switchgear replacement	1956	56	2014	8.41
20492	Duplex TS A5-6DX switchgear replacement	1954	42	2013	7.24
				Total	**41.53**

These switchgear were selected for replacement based on the following considerations:

- Obsolescence (brick structures, non-arc resistant design, obsolete breakers)
- Age
- Condition
- Space available for transition switchgear, and
- Station egress for cabling

All the switchgear listed are to be replaced with 3,000A air-insulated, arc-resistant type C switchgear with double-bus, double-breaker or breaker-and-half configuration except Duplex switchgear which will be replaced with gas-insulated switchgear (GIS) due to space constraints. These switchgear will be fitted with modern vacuum circuit breakers and digital relays.

2. Why the Project is Needed Now

Most of the equipment proposed for replacement is over 50 years old (56 years on average) and well past their design useful life. THESL has been able to continue operating this equipment because it has paid particular attention to equipment maintenance and has had veteran station mechanics over the years that have been able to harvest spare equipment for parts that are no longer manufactured. In some cases, THESL has been forced to custom fabricate certain parts which is expensive, unreliable, and unsustainable. The cost to repair obsolete equipment using custom fabricated parts is more than twice the cost when spare parts are supplied by manufacturers.

THESL has had several incidents of internal arc faults in its non arc-resistant switchgear. For example, an internal arc fault at Terauley TS in 2007 resulted in an explosion in the circuit breaker compartment and caused the front door to fly away from its mounts as shown in Figures 1 and 2, damaging other equipment in the vicinity. Fortunately no THESL personnel were in the vicinity when the explosion occurred.

Figure 1: [2007] Pothead failed inside Terauley TS switchgear

Figure 2: [2007] Impact of internal arc fault in a switchgear

Internal arc faults can be destructive because of the energy levels reached within the confined compartment. The risk of this type of event on non-arc resistant switchgear increases as switchgear ages. This incident resulted in a loss of service to 31,322 customers for 18 hours.

The asset condition assessment for switchgear have confirmed that their condition is categorized as “poor,” based on the 2006 Kinetrics study report. That report recommends that switchgear in the “poor” category be replaced within three years.

In addition to the consequences of in-service failures, the existing circuit breakers in all of the switchgear, except Duplex TS, are air blast circuit breakers which are obsolete. These breakers have much higher maintenance costs. The maintenance of air blast circuit breakers is labour intensive and takes at least twice as long as modern vacuum circuit breaker. Replacement parts for the air blast circuit breakers are no longer manufactured, and they must be custom manufactured when required. In addition, the air supply systems associated with the air blast breakers have also reached end of life. At least one air supply system out of a population of 14 fails per year and the average cost of repair is $5,000 per incident on top of the planned maintenance which costs $4,400 per year per station.

3. Why the Project is the Preferred Alternative

THESL considered the following options, which are fully discussed in Section IV:

1) Continue to maintain and operate the existing equipment
2) Transfer load to adjacent TS
3) Replace Existing Switchgear with an Arc-Resistant Design and Vacuum Breakers

Option 1 is essentially a “run to failure” scenario with replacement of existing switchgear when failure occurs. This option has the potential to defer capital investment, but replacement will eventually be required and will cost approximately 50% more if done on an emergency basis. In the interim, the potential for damage to other equipment and injury will remain (See Section IV, 1). Given the age and condition of this switchgear and the difficulty in obtaining spare parts, this option is not preferred.

Option 2 is not feasible because in order to undertake a transfer, the receiving TS would require spare capacity, sufficient feeder positions, and physical space for additional infrastructure. The location of the receiving station would also need to be sufficiently close to the load centre to avoid a voltage drop. These conditions cannot be met for any of the TS addressed by this segment (See Section IV, 2).

Option 3, which would install new arc-resistant design switchgear and vacuum breakers is the preferred alternative because it offers the following benefits (See Section IV, 3):

- Mitigate the safety risk to the operating personnel and damage to equipment in the TS due to the arc-resistant design of the switchgear.
- Minimize the maintenance and operating cost since the new switchgear will eliminate the air blast circuit breakers along with the air supply system (air compressors) whose maintenance cost is at least twice that of modern vacuum circuit breakers. The configuration of the switchgear will also be double bus double breaker or breaker and half and this type of configuration cuts maintenance and operating time at least by half.
- Increase reliability because arc-resistant switchgear with double bus double breaker or breaker and half configuration is more reliable. In contrast to the existing switchgear, the new switchgear will allow any circuit breaker to be taken out of service without requiring load transfer.

Carrying out immediate work on this asset class is expected to result in the avoided estimated risk cost of approximately $35 million, as opposed to executing this work in 2015 as shown in the Business Case Evaluation in Appendix 1. Therefore, there are economic benefits to ratepayers for executing this work now. As a practical matter given available resources, jobs are scheduled over three years to allow engineering, procurement, construction and commissioning and are closely coordinated with feeder transfers to minimize customer outages and limit single supply contingency.

II DESCRIPTION OF WORK

1. Strachan TS A7-8T Switchgear

1.1. Job Description

The objective of these jobs is to design and install 13.8kV switchgear to replace the existing A7-8T switchgear at Strachan TS with 3000A air insulated arc-resistant type C switchgear with double bus, double breaker or breaker-and-half switchgear in 2012 - 2013.

1.2. Scope of Work- A7-8T

1.2.1. Scope of work in 2012

- Remove the existing decommissioned A3-4T switchgear from Building A
- Prepare the space vacated by the A3-4T switchgear in Strachan TS building A to install new A11-12T that will replace existing A7-8T switchgear

1.2.2. Scope of work in 2013

- Design, procure, and purchase a new 13.8kV, 72MVA, 4-wire air insulated arc resistant type C switchgear and fit into the space vacated by A3-4T switchgear
- Install, commission and energize the new A11-12T switchgear
- Coordinate with Hydro One on purchase, installation and commissioning of incoming feeder cells and configuring the new bus as 4-wire

1.2.3. Scope of work in 2014

- Transfer load from the existing A7-8T switchgear to the new A11-12 T switchgear.
- Decommission the existing A7-8T switchgear

1.3. Job Cost

Table 2: Strachan TS Costs

Job Estimate Number	Job Title	Job Year	Total Estimated Cost ($M)
18591	Strachan TS A7-8T switchgear replacement preparation	2013	0.34
25425	Strachan TS A7-8T switchgear replacement	2013	8.11
24972	S14406 Strachan TS Load Transfer from A7-8T to A11-12T Switchgear	2014	0.30

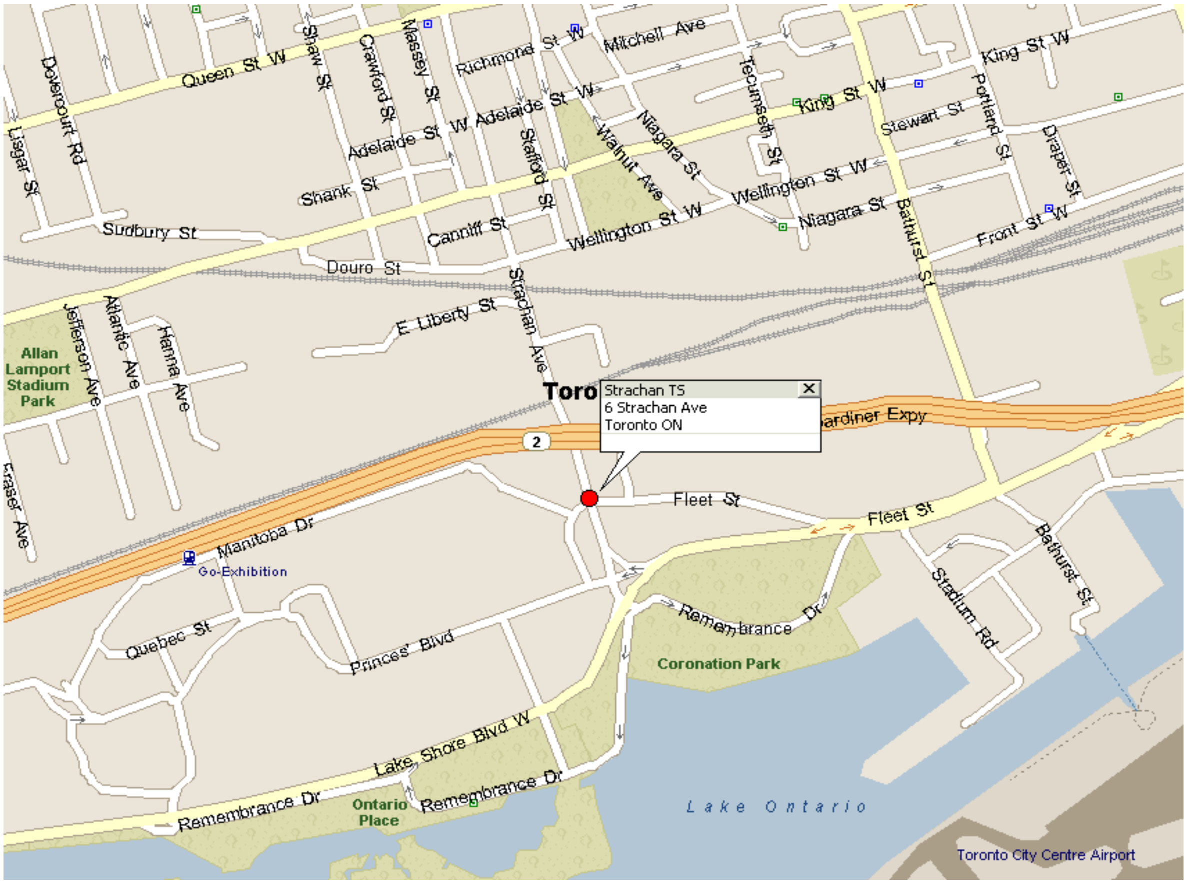


Figure 3: Location of Strachan TS

2. Carlaw TS A6-7E

2.1. Job Description - Carlaw TS A6-7E

The objective of this job is to complete the second part of a two-part replacement job of the Carlaw TS A6-7E switchgear. The first part of this job involved purchasing of the switchgear in 2011. The second part involves commissioning of the new switchgear and the station load transfer from the existing to the new switchgear in 2012.

2.2. Scope of Work-A6-7E

- Prepare drawings to commission the switchgear
- Commission and energize the new switchgear
- Transfer load from the existing A6-7E to new A10-11E switchgear
- Decommission and remove existing A6-7E switchgear

2.3. Job Costs

Table 3: Carlaw TS Costs

Job Estimate Number	Job Title	Job Year	Total Estimated Cost ($M)
22025	Carlaw TS A6-7E switchgear replacement	2012	2.17

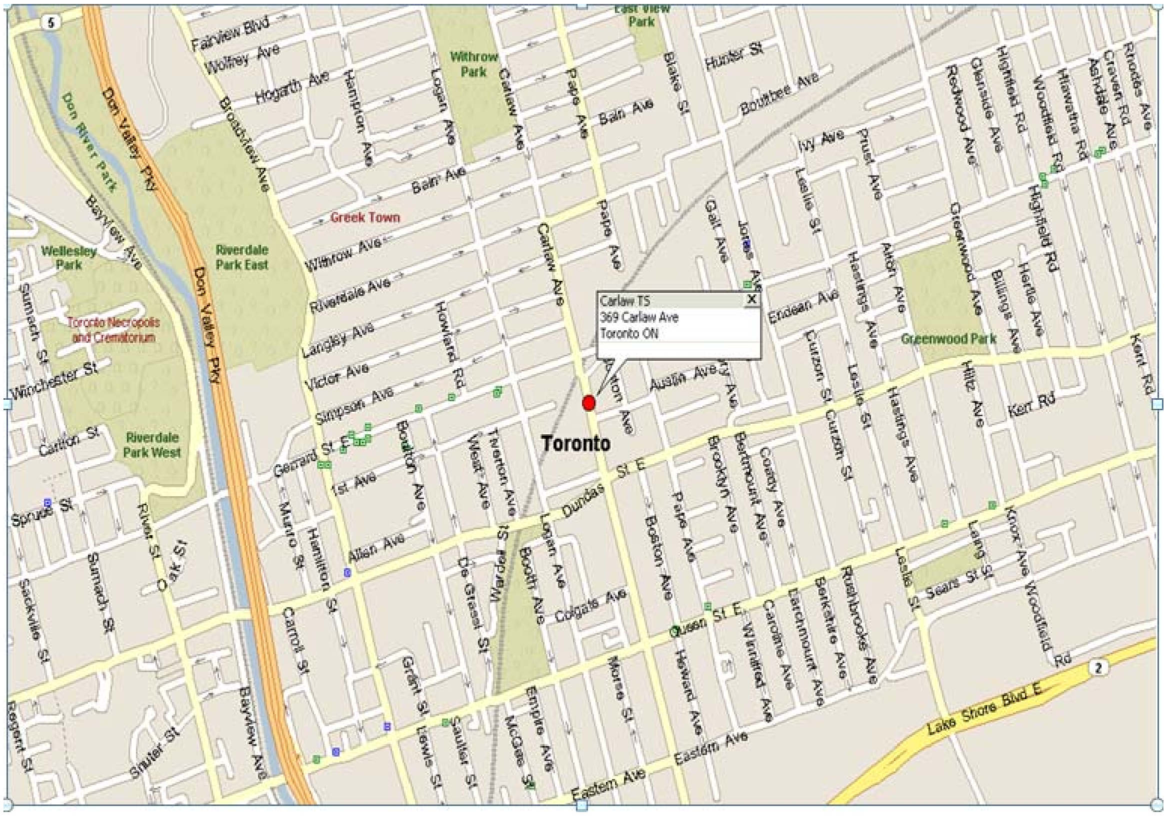


Figure 4: Location of Carlaw TS

3. Wiltshire TS A3-4W and A5-6W Switchgear

3.1. Job Description

The objective of these jobs is to design, purchase and install 13.8kV switchgear to replace the obsolete A3-4W and A5-6W switchgear at Wiltshire TS with 3000A air insulated arc-resistant type C switchgear with a breaker-and-half configuration in 2012, and 2014, respectively. Preparation of floor space in Building A is required to accommodate the new switchgear in place of the decommissioned switchgear.

3.2. Scope of Work – A3-4W

- Design the proposed new A13-14W switchgear to fit into the space that is currently occupied by the obsolete A3-4W switchgear
- Procure and purchase a new 13.8kV, 72MVA, 4-wire, air insulated, arc-resistant type switchgear and replace the aging and obsolete A3-4W (3-wire) switchgear
- Prepare the floor space where the decommissioned A1-2W was located to make space for installation of the proposed A13-14W switchgear
- Modify and/ or construct any necessary civil infrastructures within Wiltshire station property boundary to facilitate the feeder transfer from the existing and obsolete A3-4W switchgear to the proposed new switchgear A13-14W
- Install and commission the new A13-14W switchgear
- Coordinate with Hydro One to provide support for relocation of the HONI incoming LV supply cables from the existing location to the new switchgear location
- Energize and transfer load from the A3-4W to the new A13-14W switchgear
- Decommission and remove the A3-4W switchgear

3.3. Scope of Work – A5-6W

- Design the proposed new A15-16W switchgear to fit into the space that is currently occupied by the obsolete A1-2W switchgear
- Prepare the floor space by removing the decommissioned A1-2W to make space for installation of the proposed A15-16W switchgear
- Procure and purchase a new 13.8kV, 72MVA, 4-wire, air insulated, arc-resistant type switchgear to replace the aging and obsolete A5-6W (3-wire) switchgear
- Install and commission the new A15-16W switchgear
- Transfer load from the existing A5-6W switchgear to the new A15-16W switchgear
- Coordinate with Hydro One to provide support for relocation of the HONI incoming LV supply cables from the existing location to the new switchgear location
- Decommission the A5-6W switchgear and remove the brick structure from Wiltshire TS

3.4. Job Costs

Table 4: Wiltshire TS Costs

Job Estimate Number	Job Title	Job Year	Total Cost ($M)
20877	Wiltshire TS A3-4W switchgear replacement	2012	7.30
22719	WiltshireTS A5-6W switchgear replacement	2014	7.67

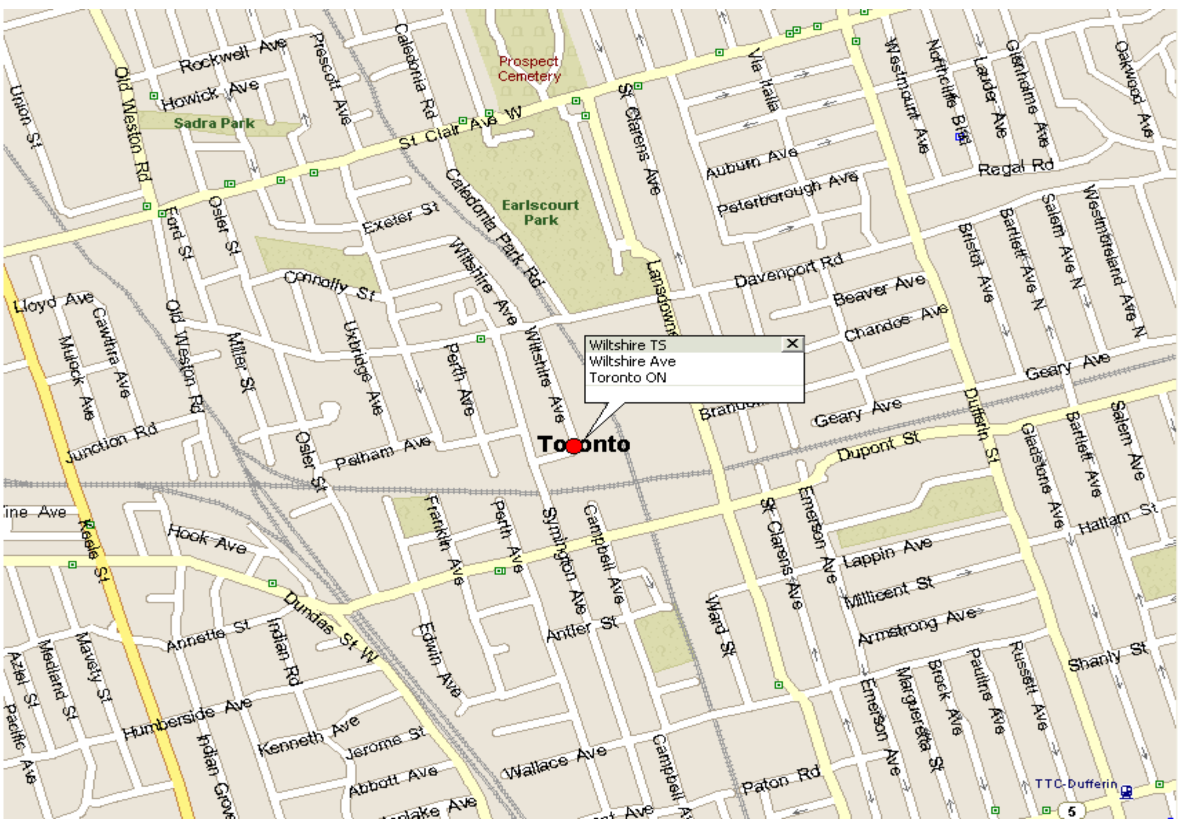


Figure 5: Location of Wiltshire TS

4. Windsor TS A5-6WR Switchgear

4.1. Job Description

The objective of this sjob is to replace the existing A5-6WR switchgear at Windsor TS with 3000A air insulated, arc-resistant type C type switchgear with double bus, double breaker or breaker-and-half switchgear in 2014.

4.2. Scope of Work- A5-6WR

- Design the proposed new A19-20WR switchgear to fit into the space that is currently occupied by the obsolete A5-6-9-10WR
- Decommission and remove the A5-6-9-10WR once load is transferred to Bremner TS
- Procure new 13.8kV, 72MVA, 4-wire, air insulated arc-resistant type switchgear
- Install and commission the new A19-20WR switchgear
- Energize the A19-20WR and transfer load from the A3-4WR switchgear
- Coordinate with Hydro One on purchase, installation and commissioning of incoming feeder cells and configuring the new bus as 4-wire
- Decommission and remove the existing A3-4WR switchgear in Windsor TS building

4.3. Job Costs

Table 5: Windsor TS Costs

Job Estimate Number	Job Title	Job Year	Total Estimated Cost ($M)
21735	Windsor TS A5-6WR switchgear replacement	2014	8.41

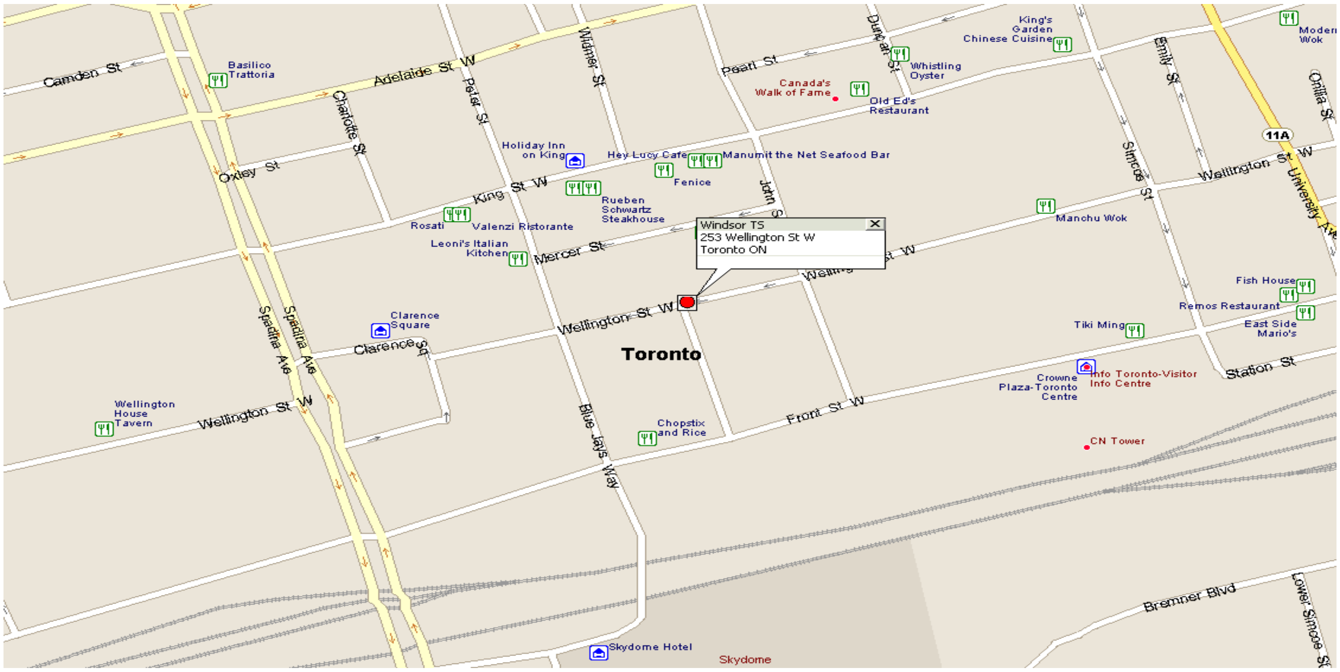


Figure 6: Location of Windsor TS

5. Duplex TS A5-6DX Switchgear

5.1. Job Description

The objective of this job is to design and purchase new 13.8kV 3000A gas-insulated switchgear (GIS) to replace the existing A5-6DX switchgear in 2013.

5.2. Scope of Work- A5-6DX

- Design the proposed A7-8DX switchgear
- Procure and purchase a new 13.8kV, 72MVA, gas-insulated switchgear
- Install and commission the new A7-8DX switchgear
- Transfer load from the existing A5-6DX switchgear to the new A7-8DX switchgear
- Coordinate work with Hydro One to migrate the HONI incoming LV supply cables from the existing switchgear to the new switchgear location.

- Decommission the A5-6DX switchgear and remove it from Duplex TS

5.3. Job Costs

Table 6: Duplex TS Costs

Job Estimate Number	Job Title	Job Year	Total Cost ($M)
20492	Duplex TS A5-6DX switchgear replacement	2013	7.24

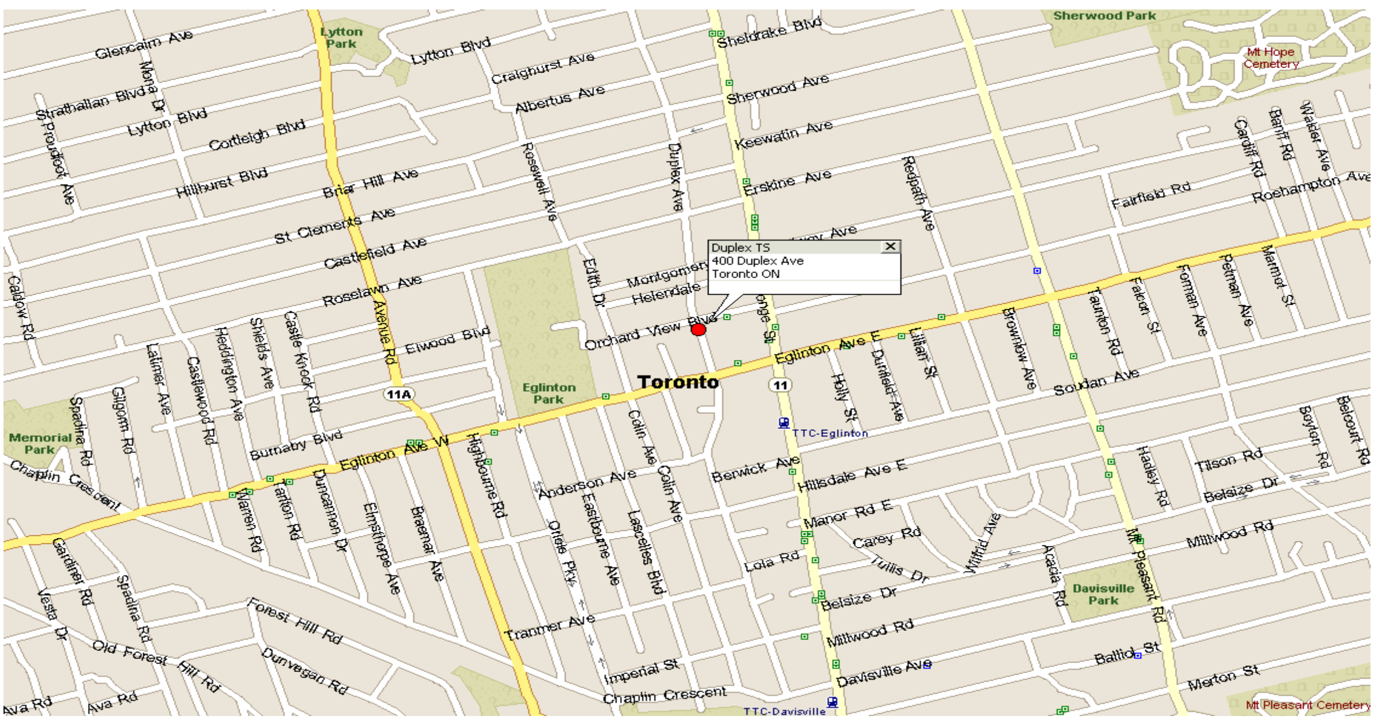


Figure 7: Location of Duplex TS

III Need

1. Overview

All the switchgear in this segment are non-arc resistant designs and past their useful lives. Non-arc resistant designs do not contain the energy released during fault conditions. When an internal arc fault occurs in this type of switchgear, the energy released has the potential to damage adjacent equipment and pose potential safety risks to personnel working in the vicinity. Even though station workers are not present inside stations on a daily basis, they do monthly routine inspections in all THESL stations and do planned maintenance and capital work in stations. If an internal arc fault occurs while station workers are in the vicinity there is a potential that a worker could be injured. A catastrophic failure also increases the severity of collateral damage to adjacent equipment and could potentially cause a complete station outage.

The probability of failure continues to increase with time as the condition of the equipment continues to deteriorate. Table 7 provides the impact resulting from the failure of one switchgear and the impact resulting from a whole station outage from collateral damage. The impact is presented in terms of load at risk and expected duration of outage.

Table 7: Load at Risk and Duration

Substation Name	Failure of One Switchgear		Failure of the Entire Substation	
	Load at Risk (MVA)	Duration(hours)	Load at Risk (MVA)	Duration (hours)
Strachan TS	34	168	138	336
Carlaw TS	26	168	75	336
Wiltshire TS	30	168	70	336
Duplex TS	45	168	113	336
Windsor TS	56	168	311	336

Failure of any switchgear is expected to result in extended outages given that the loading and condition of the other switchgear within the station limits the ability to pick up the load.

Table 8 below includes a list of substations in the area and the spare capacity.

Table 8: Substations with Spare Capacity

Substation Name	95% Rated (MVA) Capacity	Peak Load (MVA)	Available Capacity In Supporting Substation (MVA)	Name of Supporting Station Substation
Strachan TS	182	138	38	Dufferin TS
Carlaw TS	112	75	24	Gerrard TS and Main TS
Wiltshire TS	118	70	38	Dufferin TS
Duplex TS	127	113	65	Glengrove TS and Leaside TS
Windsor TS	340	311	50	Terauley TS

In addition to being non-arc resistant design, the existing circuit breakers that are fitted in these switchgear are of air blast type (with the exception of Duplex), and are obsolete. The maintenance for this type of circuit breaker is labour intensive. Replacement parts for the air blast circuit breakers are no longer manufactured. Any parts required must be custom manufactured and are obtained at high cost. The air blast system has additional $4,400 maintenance cost per year to maintain the air supply system needed for breaker operation.

In addition to the switchgear being non-arc resistant design, past their useful lives, and fitted with obsolete air blast breakers, the replacement of switchgear included in this segment is also driven by the following concerns:

2. Strachan TS

This switchgear was installed in 1956. From the Asset Condition Assessment ("ACA") update report in 2011 and 2012, these switchgear were assigned a Health Index (HI) of 43 (out of 100) which is considered in the Poor category as per the Asset Condition Assessment ("ACA") of

2010. As per Kinetrics's recommendation, switchgear in poor category should be replaced within the next three years.

If the A7-8T switchgear fails 34 MVA of load will be lost

3. Carlaw TS

The A6-7E switchgear was installed in 1968. From the Asset Condition Assessment ("ACA") update report in 2010, the A6-7E switchgear has a 57 (out of 100) which is considered as poor category. As per Kinetrics's recommendation, switchgear in poor category should be replaced within the next three years.

The basic design of the switchgear is an open brick structure. This design poses safety concerns. While controls and PPE are in place to address risk, nonetheless, the nature of the equipment requires that during maintenance personnel are exposed to live high voltage parts of the switchgear. During operation, personnel must stand clear since there is no barrier between them and the high voltage equipment. Unlike other types of switchgear such as metal clad switchgear where the different parts of the switchgear are located inside a metal enclosure and are operated from outside of the enclosure, the switchgear in an open brick structure has to be opened first while it is live and then operated as shown in Figure 8 below.

Figure 8: Carlaw TS 13.8kV live parts of a switchgear in an open brick structure

If the A6-7E switchgear fails 26 MVA of load will be lost.

4. Wiltshire TS

The existing Wiltshire TS A3-4W and A5-6W switchgear were installed in 1954. From the Asset Condition Assessment ("ACA") update report in 2012, these switchgear were assigned a Health Index (HI) of 50 and 47 (out of 100) respectively which is considered in the Poor category, which means they require replacement within three years.

These switchgear are also in an open brick structure with similar limitations to those at Carlaw TS. The Wiltshire TS switchgear supplies a large pumping station, which is a critical customer.

If the A3-4W or A5-6W switchgear fails, 21 MVA and 30 MVA load will be lost, respectively.

5. Duplex TS

In addition to the age of the switchgear, there is additional risk of the basement being flooded with water from the Hydro One deluge system which is located on the main floor above the switchgear. To mitigate this risk, and to address the aging issue of the switchgear, THESL plans to replace in stages all the switchgear at Duplex TS which are located in the basement with water-resistant, gas-insulated switchgear (GIS). The A5-6DX switchgear is the first to be replaced.

If the A5-6DX switchgear fails, 45 MVA of load will be lost.

6. Windsor TS

The A5-6WR switchgear was installed in 1956. From the Asset Condition Assessment (“ACA”) update report in 2012, Windsor TS A5-6WR switchgear was assigned a Health Index (HI) of 50 (out of 100) which is considered in the Poor category, and it needs replacement within three years.

The Windsor TS switchgear supports the financial district, which includes many large customers.

If the A5-6WR switchgear fails, 56 MVA of load will be lost.

IV Preferred Alternative

THESL considered three alternatives:

- Continue to Maintain and Operate the Existing Equipment;
- Transfer load to adjacent stations; and
- Replace the existing switchgear with arc-resistant design.

1. Option 1: Continue to Maintain and Operate the Existing Equipment

This option is essentially a "run to failure" scenario with replacement of existing switchgear when failure occurs. This option will defer capital investment but continuous repair of the switchgear will be required as it will continue to deteriorate. This option is expected to result in:

- Decreased system reliability.
- No mitigation of potential safety risks to THESL personnel
- Increased maintenance and operating costs
- Increased system reliability risk
- Increase risk of damaging equipment in the surrounding area in an eventful failure.

It is estimated that replacement of switchgear under emergency conditions versus planned equipment replacement will increase the costs by at least 50%.

2. Option 2: Transfer Load to Adjacent Stations

Transferring load from the switchgear planned to be replaced to other switchgear in the vicinity and decommission these switchgear was considered. This option would defer most of the capital investment required, if feasible. For this option to be feasible, four conditions need to be met:

(a) The supporting switchgear must have spare capacity to take additional load. This condition cannot be met because there is not enough capacity at the receiving stations to accommodate the required load transfer. The receiving stations would be overloaded when load is transferred or will reach capacity shortly as load grows as shown in Tables 7 and 8 below.

(b) The supporting switchgear must have enough feeder positions to accept the transferred feeders. This condition cannot be met for all of the switchgear proposed to be replaced. As shown in Table 9, Gerrard TS, Main TS, and Terauley TS don't have enough spare feeder positions to transfer load from Carlaw and Windsor TS, respectively. There are enough feeder positions in the receiving stations for the rest of the switchgear proposed to be replaced. However, as discussed in the previous paragraph (a), there is insufficient available capacity in the receiving stations.

(c) Physical space for underground infrastructure must be available if load is to be transferred to another station. THESL shares underground space with other utilities such as Enbridge, Bell, Rogers, and Water and Sewer. Finding space to build underground infrastructure in order to install cables to transfer the load is challenging.

(d) Voltage drop problem does not occur as a result of load transfer to neighboring station. This condition cannot be met as the supplying station will be far from the load center and voltage drop will be a problem.

Table 7: Switchgear Load Transfer to switchgear within station

Switchgear to be Decommissioned	Connected Customers	Load to be transferred(MVA)	% Loading at the Receiving Station(s) After Load transfer
Strachan TS A7-8 switchgear	4,270	37	96
Carlaw TS A6-7E switchgear	9,266	26	102
Wiltshire TS A3-4W switchgear	3,513	21	86
Duplex TS A5-6DX switchgear	4,078	45	141
Wiltshire TS A5-6W switchgear	10,883	30	100
Windsor TS A5-6WR switchgear	14	56	111.1

1 **Table 8: Switchgear Load Transfer to Neighboring Station(s)**

Switchgear To be Decommissioned	Load to be transferred (MVA)	Load to be transferred to	Combined Stations Percentage (%) Loading After Load transferred
Strachan TS A7-8 switchgear	37	Dufferin TS	102
Carlaw TS A6-7E switchgear	26	Gerrard TS, Main TS	107
Wiltshire TS A3-4W switchgear	21	Dufferin TS, Bridgeman TS,	94
Duplex TS A5-6DX switchgear	45	Glengrove TS, Leaside TS,	98
Wiltshire TS A5-6W switchgear	30	Dufferin TS, Bridgeman TS	93
Windsor TS A5-6WR switchgear	56	Terauley TS	107

Table 9: Number of feeder positions required and available

Switchgear Load to be transferred from	Number of feeders to be transferred	Station load to be transferred to	Number of available spare feeder positions
Strachan TS A7-8T switchgear	11	Dufferin TS	30
Carlaw TS A6-7E switchgear	7	Gerrard TS and Main TS	1
Wiltshire TS A3-4W switchgear	10	Dufferin TS and Bridgemen TS	31
Duplex TS A5-6DX switchgear	11	Glengrove TS and Leaside TS	14
Wiltshire TS A5-6W switchgear	8	Dufferin TS and Bridgemen TS	31
Windsor TS A5-6WR switchgear	12	Terauley TS	6

3. Option 3: Replace the Existing Switchgear with Arc-Resistant Design with Vacuum Breakers

Replace existing switchgear with air insulated, arc-resistant switchgear or gas insulated switchgear (GIS) with double bus double breaker or breaker and half configuration is recommended. This option requires capital investment to replace the switchgear and is expected to:

- Mitigate the safety risk to the operating personnel of THESL due to the arc-resistant design of the switchgear. Arc-resistant switchgear contains the pressure due to internal arc fault and channels the energy through the vents located on top of switchgear. This is expected to mitigate the safety risk to personnel and damage to equipment in the vicinity including causing outage to the whole station.
- Minimize the maintenance and operating cost since the new switchgear will eliminate the air blast circuit breakers along with the air supply system (air compressors) whose

maintenance cost is at least twice that of modern vacuum circuit breakers. The configuration of the switchgear will also be double bus double breaker or breaker and half and this type of configuration cuts the maintenance and operating time at least by half. Therefore, the overall maintenance and operating cost will be reduced.

- Increase reliability because switchgear that is arc-resistant with double bus double breaker or breaker and half configuration is more reliable. Unlike in the existing switchgear, any circuit breaker may be taken out of service without requiring load to be transferred.

THESL considered the following five bus configurations for this replacement option:

3.1. Single bus

- Lowest cost
- Failure of bus or any circuit breaker results in shutdown of entire station
- Difficult to do any maintenance without shutting down station

3.2. Double bus, double breaker

- Has flexibility in permitting feeder circuit to be connected to either bus
- Either of the main buses can be taken out of service at any time for maintenance
- All switching is done remotely
- Bus failure does not remove any feeder circuits from service
- High reliability, circuit is supplied from either bus and circuit breaker
- Easier circuit breaker maintenance; any breaker can be taken out of service for maintenance without interrupting the load of a circuit.
- Most expensive, each circuit has two dedicated breakers

3.3. Double bus, single breaker

- Low initial cost
- Switching is somewhat complicated
- Less flexible, failure of either the tie breaker or bus results in the switchgear out of service
- Bus tie breaker failure takes entire station out of service

3.4. Ring bus

- Low initial cost

- Flexible operation during circuit maintenance, any breaker can be taken out of service without interrupting load
- Each circuit requires one circuit breaker
- Automatic reclosing and protective relaying circuitry is rather complex
- Fault in one circuit takes two breakers out of service

3.5. Breaker and a half

- Most flexible
- High reliability operation
- Breaker and half per circuit
- All switching is done remotely using circuit breakers
- Simple operation
- Either main bus can be taken out of service at any time
- Bus failure does not remove any feeder circuits from service
- Breaker failure of bus side removes only one circuit
- Breaker can be taken out of service without disconnecting load

The two types of bus configurations that are preferred are double bus double breaker and breaker and half configurations in order to obtain high reliability and flexibility in the heavily loaded downtown area. Breaker and half configuration is however, preferable if existing circuits can be connected in a back to back setting, but this is not always possible in an existing station with multiple switchgear. The egress of the feeders may make it difficult to reroute feeder cables to connect them back to back so switchgear configuration will be selected depending on the site. As such, the site-specific conditions dictate the bus architecture.

3.6. Avoided Risk Cost

The recent Dufferin transformer station outage in 2009 associated with a failed water deluge system provides insight into potential reliability impacts associated with a complete station outage. Total peak load for Dufferin TS on January 15, 2009 was 118 MW. In that case, 31,322 customers were interrupted (CI) and without service for over 18 hours resulting in 33,827,760 customer minutes of outage (CMO).

The anticipated effectiveness of the Switchgear TS replacement segment can be highlighted by determining how much cost is avoided by executing this work immediately as opposed to executing in 2015 as explained in the Business Case Evaluation found in Appendix 1. These avoided costs include quantified risks, taking into account the assets' probability of failure, and multiplying this with various direct and indirect cost attributes associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement.

Carrying out immediate work on this asset class is expected to result in the avoided estimated risk cost of approximately $35 million, as opposed to executing this work in 2015. Therefore, there are economic benefits to ratepayers for executing this work now. As a practical matter given available resources, jobs are scheduled over three years to allow engineering, procurement, construction and commissioning and are closely coordinated with feeder transfers to minimize customer outages and limit single supply contingency.

4. Preferred Alternative

Based on a comparison of the alternatives, replacement of existing switchgear is the preferred option based on reduced outage risk, technical viability and because it is the most cost-effective option.

Appendix 1

Stations Switchgear TS 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 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 that 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.

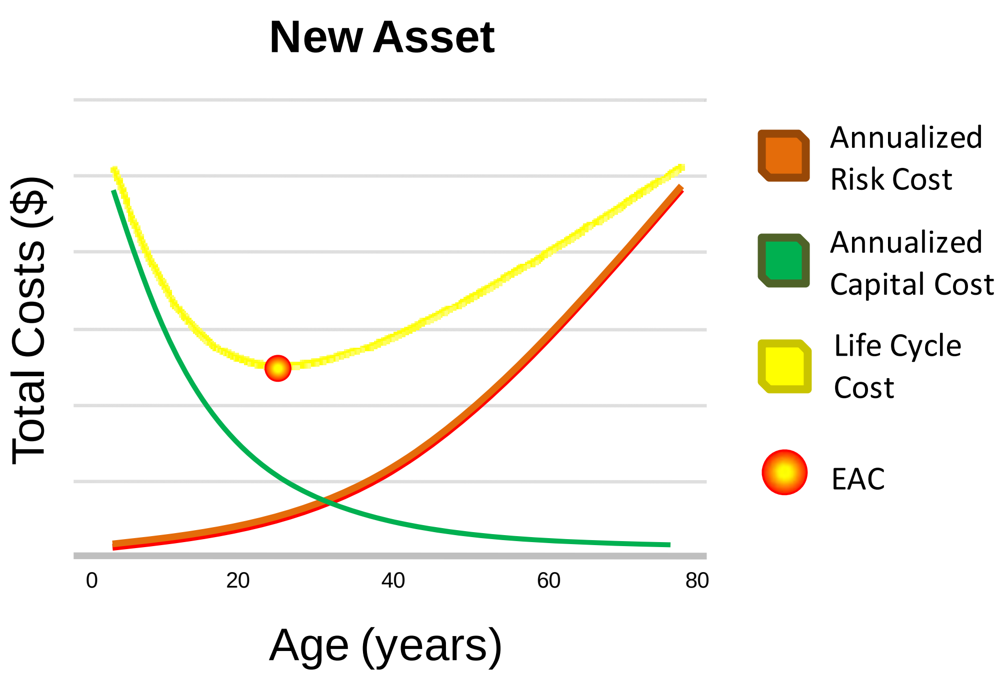


Figure 1: Typical Example of Optimal Intervention Time (New Assets)

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.

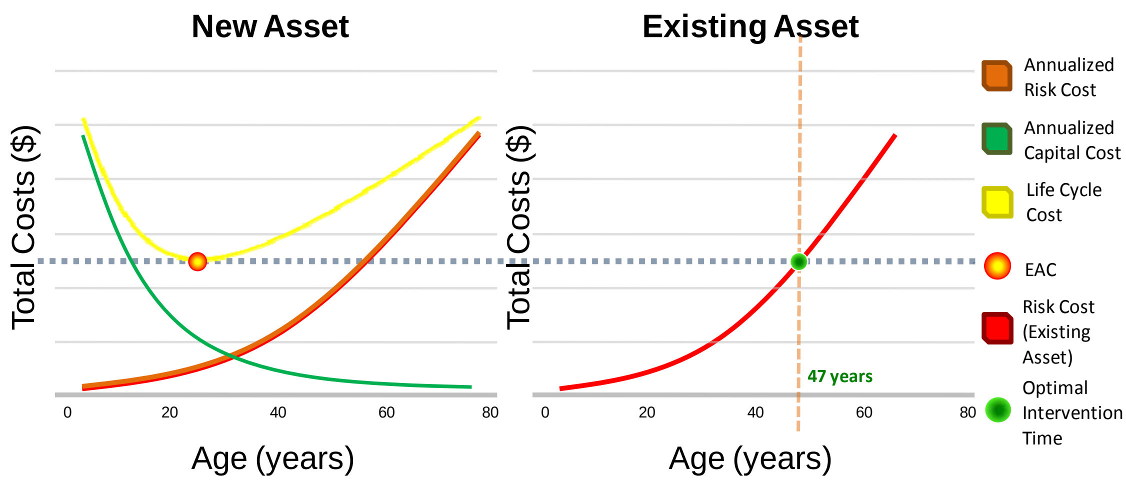


Figure 2: Typical Example of Optimal Intervention Time (Existing Assets)

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.

1.2 Project Evaluation Results

The Stations Switchgear TS segment represents an "in-kind" replacement project in which the existing switchgear 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 this would represent the next available year when THESL may 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 Stations Switchgear TS 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 and the total costs as the ordinate. As such, the minimum point of this curve provides the highest Net Project Benefit and defines the optimal year to execute the specific project.

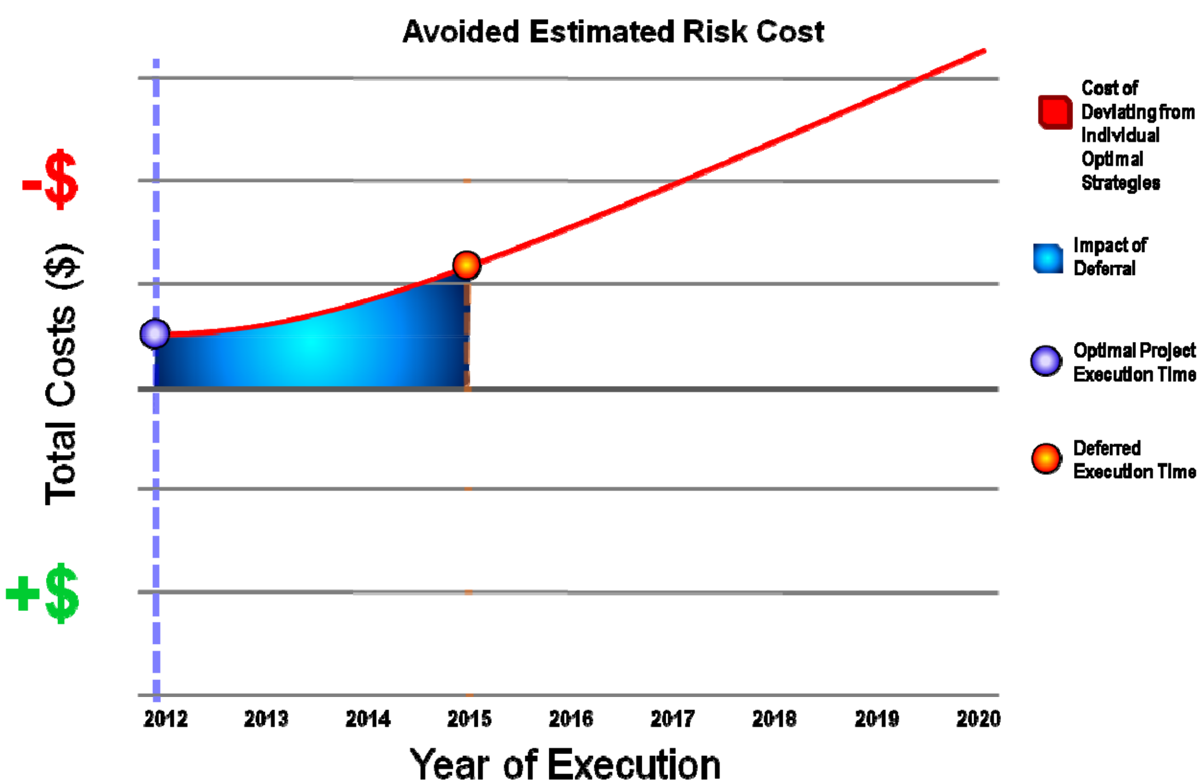


Figure 3: Typical Example of Project Net Benefit Analysis

The effectiveness of the Stations Switchgear TS project 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:

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 TS Switchgear segment, individual optimal intervention timing results were calculated for each of the 6 switchgear TS assets, 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 switchgear assets within this project 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	**Estimated Cost (in Millions)**
Present Value of Project Net Cost in 2015 (PV(PROJECT$_{NET_COST}$(2015))	$ 35.235
Project Net Cost in 2012 (PROJECT$_{NET_COST}$(2012))	$ 0.0298
Avoided Estimated Risk Cost = (PV(PROJECT$_{NET_COST}$(2015)) – PROJECT$_{NET_COST}$(2012))	**$ 35.205**

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.

ICM Project – Station Infrastructure and Equipment

Stations Circuit Breakers Segment

Toronto Hydro-Electric System Limited (THESL)

ICM Project | Stations Circuit Breakers Segment

I EXECUTIVE SUMMARY

1. Description

Station circuit breaker work proposed for 2012, 2013 and 2014 consists of replacing 21 oil circuit breakers (27.6kV) mounted outdoors and associated control boxes with vacuum circuit breakers at five Terminal Stations (TS). The estimated cost for the work is \$3.83 M as shown in Table 1:

Table 1: Job Cost Estimates

Job Estimate Number	Job Title	Job Year	Cost Estimate (\$M)
17662	S11118 Finch TS: Replace KSO CB (55M27)	2012	\$0.07
17669	S11121 Finch TS: Replace KSO CB (55M28)	2012	\$0.07
17654	S11130 Bathurst TS: Replace KSO CB (85M24)	2012	\$0.07
18403	S12001 Leslie TS: Replace KSO OCB (51M4 and 51M6)	2012	\$0.39
18233	S12036 Fairchild TS: Replace KSO CB (80M1)	2012	\$0.19
18237	S12037 Fairchild TS: Replace KSO CB (80M3)	2012	\$0.19
18262	S12043 Fairchild TS: Replace KSO CB (80M5)	2012	\$0.20
18263	S12044 Fairchild TS: Replace KSO CB (80M9)	2012	\$0.20
21657	S13125 Leslie TS: Replace KSO OCB (51M7 and 51M8)	2013	\$0.43
21656	S13146 Bermondsey TS: Replace KSO OCB (53M1, 53M9 and 53M11)	2013	\$0.65
22693	S14052 Finch TS: Replace KSO CB (55M24)	2014	\$0.19
22694	S14054 Finch TS: Replace KSO CB (55M25 and 55M8)	2014	\$0.41
22695	S14055 Bathurst TS : Replace 85M1 KSO CB	2014	\$0.19
22698	S14056 Bathurst TS: Replace 85M4 KSO CB	2014	\$0.20
22699	S14057 Bathurst TS: Replace 85M2 KSO CB	2014	\$0.19

Job Estimate Number	Job Title	Job Year	Cost Estimate ($M)
22700	S14059 Bathurst TS: Replace 85M25 KSO CB	2014	$0.19
		Total:	**$3.83**

2. Why the Project is Needed Now

Circuit breakers are automated switching devices that can carry and interrupt electrical currents under normal and abnormal conditions. Distribution circuit breakers at THESL are commonly used at transmission or distribution stations for switching 27.6, 13.8 or 4.16 kV feeders. Circuit breakers operate infrequently. When an electrical fault occurs however, it is important that breakers operate reliably and with adequate speed to minimize damage. Circuit breaker designs have evolved over the years and many different types are currently in use. Commonly used circuit breaker types include oil circuit breakers (OCB), vacuum breakers, magnetic air circuit breakers and SF_6 circuit breakers. Circuit breakers may be mounted indoors or outdoors.

For OCBs, the interruption of load and fault currents involves the reaction of high pressure with large volumes of hydrogen gas and other arc decomposition products. Thus, both contacts and oil degrade more rapidly in OCBs than they do in either SF_6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, four to eight interruptions with contact erosion and oil carbonization will lead to the need for maintenance, including oil filtration. Oil breakers can also experience re-strike when switching low load or line charging currents with high recovery voltage values. Sometimes this can lead to catastrophic breaker failures. Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor-mounted circuit breakers, the following represent additional degradation factors:

- Corrosion;
- Effects of moisture;
- Bushing/insulator deterioration; and
- Mechanical.

ICM Project | Stations Circuit Breakers Segment

The THESL station circuit breaker segment is focused on outdoor-mounted oil circuit breakers used in 27.6kV stations where the customers will experience average outage duration of two hours in case of a failure. Table 2 shows the number of customers that would be affected in case of a circuit breaker failure.

Consequences of station circuit breaker failure include customer interruptions over significantly long durations. Catastrophic failure of circuit breakers may also result in collateral damage to other transformers, damage to other station equipment, and if staff are present, injury to personnel. Furthermore, considering they are filled with mineral oil, there is a risk of oil spills contaminating ground and water systems if the tank fails.

The failure of an oil circuit breaker at Manby TS station on July 5, 2010 exemplifies the significant impacts that can occur. This event caused a Loss of Supply outage that interrupted a total of 117,042 customers (CI) for over two hours resulting in 14,439,408 customer minutes of outage (CMO).

The oil circuit breakers selected for replacement were chosen from 66 outdoor-mounted oil circuit breakers based on their age and health condition. Based on the Kinetrics Report, the typical end of useful life for an oil circuit breaker is 42 years. As shown in Table 2, all but one of the circuit breakers selected for 2012-2014 replacement are at or beyond this age. The age profile for all oil circuit breakers is shown in Figure 1. From the age profile, approximately 70 percent (46 out of 66) of oil circuit breakers are beyond their useful lives. In addition to aging, the deteriorating condition of the outdoor-mounted oil circuit breakers also was a factor in their being selected for replacement.

1 **Table 2: Age profile and Number of Customers Served for Circuit Breakers to be Replaced**

Station Name – Circuit Breaker ID	Age	Customers	Feeder Load (MVA)
Leslie TS – 51M4	50	781	10.7
Leslie TS - 51M6	50	781	13.0
Leslie TS - 51M7	49	2,350	14.3
Leslie TS - 51M8	49	2,060	18.0
Bermondsey TS – 53M1	51	49	14.0
Bermondsey TS - 53M9	51	9	11.3
Bermondsey TS - 53M11	51	48	3.8
Finch TS – 55M8	52	1,942	15.2
Finch TS - 55M24	52	68	13.6
Finch TS - 55M25	52	2,273	9.9
Finch TS – 55M27	52	2,379	10.8
Finch TS - 55M28	52	4,212	16.6
Fairchild TS – 80M1	42	2,640	9.9
Fairchild TS - 80M3	42	826	18.4
Fairchild TS - 80M5	42	1,134	22.5
Fairchild TS - 80M9	37	800	9.5
Bathurst TS – 85M1	50	2,690	13.9
Bathurst TS - 85M2	50	1,780	13.9
Bathurst TS - 85M4	50	914	13.6
Bathurst TS - 85M24	50	1,191	13.7
Bathurst TS - 85M25	50	2,503	15.0

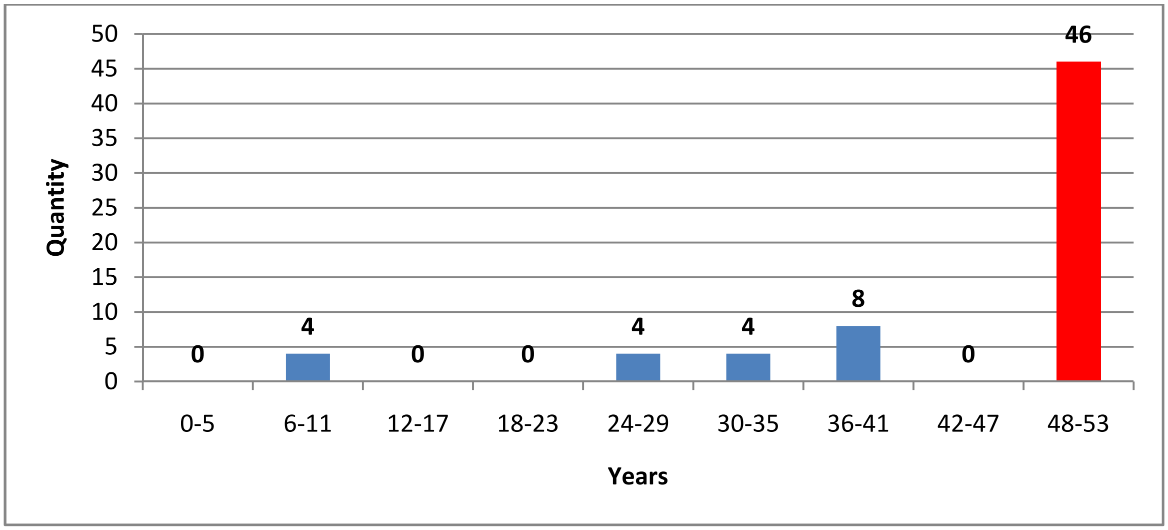


Figure 1: Age profile of outdoor-mounted oil circuit breakers

3. Why the Project is the Preferred Alternative

THESL considered two alternatives to address the issues posed by oil circuit breakers: the status quo option of running them to failure and proactive replacement (See Section IV). Under the proactive replacement alternative, THESL considered two types of replacement circuit breakers.

THESL rejected the status quo approach of allowing these circuit breakers to run to failure because of the significant impacts it would have on reliability and safety (See Section IV, 2). THESL also faces rising maintenance costs and increased difficulty in obtaining parts for oil circuit breakers. The evaluation in Appendix 1, shows that immediate replacement lowers the estimated avoided risk cost associated with these assets by approximately $2.6 million when compared to deferring replacement to 2015. Thus the most cost-effective option is replacement of obsolete equipment before failure.

The two alternative technologies considered for replacing the existing oil circuit breakers are: Vacuum circuit breaker or SF_6 circuit breaker. Both vacuum and SF_6 circuit breakers use technologies that exhibit high degrees of reliability under normal and abnormal conditions. Each has their advantages and disadvantages. One significant advantage of the vacuum circuit breaker is its compact size and ease of maintenance and inspection compared to the SF_6 circuit breaker (See Section III, 1.1 and 1.2). Due to limited space in stations, size of the circuit breaker was an important factor in selecting the preferred alternative. After comparative analysis, vacuum circuit breakers were proposed for the replacement program (See Section III, 1).

II DESCRIPTION OF WORK

1. Overview

KSO[1] circuit breaker replacements are driven by mitigation of collateral damage to adjacent circuit breakers or transformers, which could cause a long outage to the whole bus or even a station and potentially impact thousands of customers. The KSO circuit breaker replacement plan is also driven by the impact on station supply capacity and operational flexibility. The objectives are described in detail below:

Table 3: Objectives for Each Station

Station Name	Objectives	Planned Year
Leslie TS	Replace the 27.6kV KSO circuit breakers (51M4 and 51M6) and control box with a vacuum circuit breaker at Leslie TS	2012
Leslie TS	Replace the 27.6kV KSO circuit breakers (51M7 and 51M8) and control box with a vacuum circuit breaker at Leslie TS	2013
Bermondsey TS	Replace the existing 53M1, 53M9 and 53M11 KSO oil circuit breakers and the associated control boxes with new 38kV vacuum circuit breakers at Bermondsey TS	2013
Finch TS	Replace the 27.6kV KSO circuit breaker (55M28) and control box with a vacuum circuit breaker at Finch TS	2012
Finch TS	Replace the 27.6kV KSO circuit breaker (55M27) and control box with a vacuum circuit breaker at Finch TS	2012

[1] These breakers were made by the same manufacturer and are referred to by their series designation KSO.

ICM Project | **Stations Circuit Breakers Segment**

Station Name	Objectives	Planned Year
Finch TS	Replace the 27.6kV KSO circuit breaker (55M25 and 55M8) and control box with a vacuum circuit breaker at Finch TS	2014
Finch TS	Replace the 27.6kV KSO circuit breaker (55M24) and control box with a vacuum circuit breaker at Finch TS	2014
Fairchild TS	Replace the 27.6kV KSO circuit breaker (80M1) and control box with a vacuum circuit breaker at Fairchild TS	2012
Fairchild TS	Replace the 27.6kV KSO circuit breaker (80M3) and control box with a vacuum circuit breaker at Fairchild TS	2012
Fairchild TS	Replace the 27.6kV KSO circuit breaker (80M5) and control box with a vacuum circuit breaker at Fairchild TS	2012
Fairchild TS	Replace the 27.6kV KSO circuit breaker (80M9) and control box with a vacuum circuit breaker at Fairchild TS	2012
Bathurst TS	Replace the 27.6kV KSO circuit breaker (85M24) and control box with a vacuum circuit breaker at Bathurst TS	2012
Bathurst TS	Replace the 27.6kV KSO circuit breaker (85M1) and control box with a vacuum circuit breaker at Bathurst TS	2014
Bathurst TS	Replace the 27.6kV KSO circuit breaker (85M2) and control box with a vacuum circuit breaker at Bathurst TS	2014

Station Name	Objectives	Planned Year
Bathurst TS	Replace the 27.6kV KSO circuit breaker (85M25) and control box with a vacuum circuit breaker at Bathurst TS	2014
Bathurst TS	Replace the 27.6kV KSO circuit breaker (85M4) and control box with a vacuum circuit breaker at Bathurst TS	2014

1.1. Scope of Work

The KSO circuit breaker replacement work for all the selected jobs consists of the following tasks:

(a) Design necessary drawings for the new vacuum circuit breaker
(b) Co-ordinate with Hydro One on scheduling of Circuit breaker replacement
(c) Transfer the 27.6kV feeder load to adjacent feeders and disconnect the DC supply to the existing KSO circuit breaker
(d) De-energize, isolate and ground the existing KSO circuit breaker
(e) Remove the existing KSO breaker
(f) Install the new vacuum circuit breaker and complete all test requirements in accordance with all THESL required specifications
(g) Reconnect the DC supply to the vacuum breaker and connect and energize the 27.6kV feeder

1.2. Map and Locations

The stations across Toronto are shown in Figure 2 below:

Figure 2: Map showing all proposed CB locations

Table 4: Station Address

Reference Number	Station Name	Address
1	Bathurst TS	165 Goddard St, Toronto
2	Finch TS	1 Signet Dr, Toronto
3	Leslie TS	5733 Leslie St, Toronto
4	Fairchild TS	5750 Yonge St, Toronto
5	Bermondsey TS	178 Bermondsey Road, Toronto

III NEED

All 21 of these circuit breakers selected are outdoor-mounted oil-type and are obsolete.

- Replacement parts are no longer being manufactured.
- Any parts required need to be custom manufactured, making the cost of maintenance high and the repair and return to service time long.
- The KSO oil circuit breakers have additional maintenance cost due to the added expensive of periodic maintenance and replacement of oil, and subsequently makes the overall maintenance cost of the oil circuit breaker high.

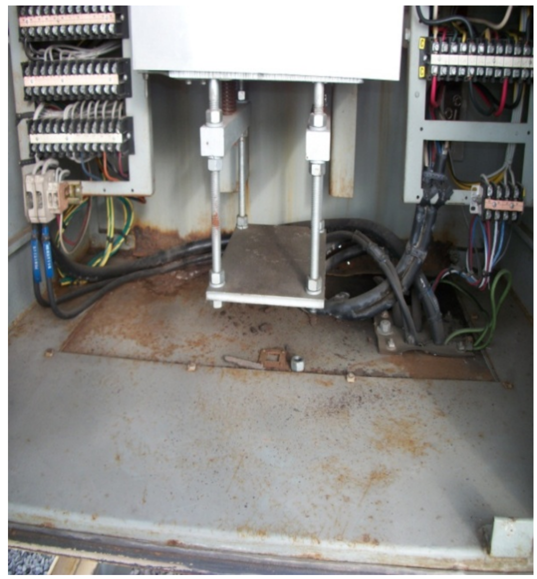
Station Name: Finch TS

Station Circuit Breaker ID: 55M27

Age of the Circuit Breaker: 52

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.



ICM Project | Stations Circuit Breakers Segment

Station Name: Finch TS

Station Circuit Breaker ID: 55M28

Age of the Circuit Breaker: 52

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

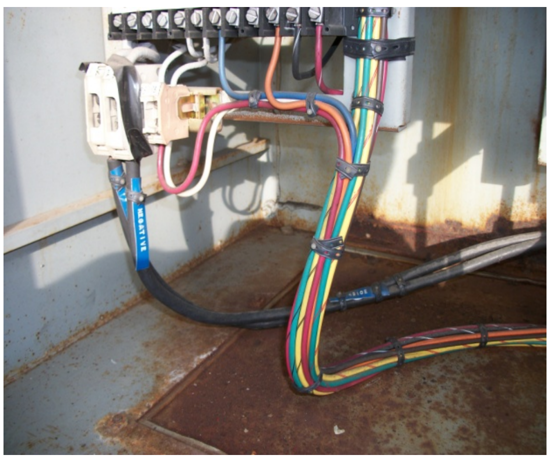


Figure 4: Circuit Breaker at Finch TS 55M28 (September 26, 2011)

Station Name: Bathurst TS

Station Circuit Breaker ID: 85M24

Age of the Circuit Breaker: 50

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 5: Circuit Breaker at Bathurst TS 85M24 (May 20, 2011)

ICM Project | Stations Circuit Breakers Segment

Station Name: Leslie TS

Station Circuit Breaker ID: 51M4

Age of the Circuit Breaker: 50

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 6: Circuit Breaker at Leslie TS 51M4 (February 3, 2012)

ICM Project | Stations Circuit Breakers Segment

Station Name: Leslie TS

Station Circuit Breaker ID: 51M6

Age of the Circuit Breaker: 50

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 7: Circuit Breaker at Leslie TS 51M6 (March 12, 2012)

Station Name: Fairchild TS

Station Circuit Breaker ID: 80M1

Age of the Circuit Breaker: 42

Justification:

This circuit breaker is at end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 8: Circuit Breaker at Fairchild TS 80M1 (March 14, 2012)

Station Name: Fairchild TS

Station Circuit Breaker ID: 80M3

Age of the Circuit Breaker: 42

Justification:

This circuit breaker is at end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 9: Circuit Breaker at Fairchild TS 80M3 (March 14, 2012)

Station Name: Fairchild TS

Station Circuit Breaker ID: 80M5

Age of the Circuit Breaker: 42

Justification:

This circuit breaker is at end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure..

Figure 10: Circuit Breaker at Fairchild TS 80M5 (March 14, 2012)

Station Name: Fairchild TS

Station Circuit Breaker ID: 80M9

Age of the Circuit Breaker: 37

Justification:

Replacement is required due to condition, obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 11: Circuit Breaker at Fairchild TS 80M9 (March 14, 2012)

Station Name: Leslie TS

Station Circuit Breaker ID: 51M7

Age of the Circuit Breaker: 49

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 12: Circuit Breaker at Leslie TS 51M7 (February 3, 2012)

ICM Project | Stations Circuit Breakers Segment

Station Name: Leslie TS

Station Circuit Breaker ID: 51M8

Age of the Circuit Breaker: 49

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

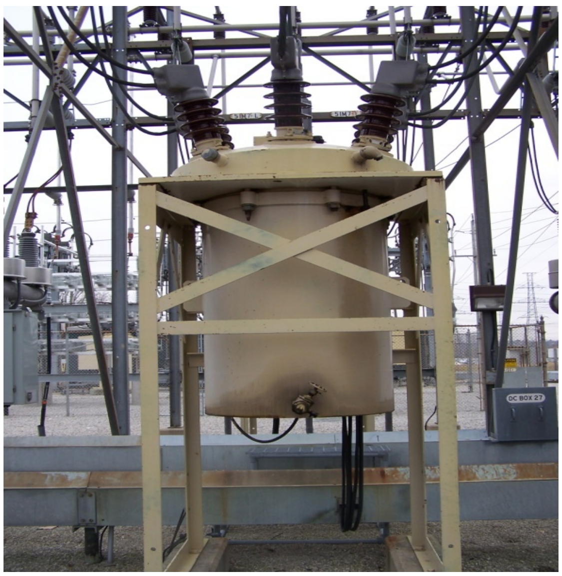


Figure 13: Circuit Breaker at Leslie TS 51M8 (February 3, 2012)

Station Name: Bermondsey TS

Station Circuit Breaker ID: 53M1

Age of the Circuit Breaker: 51

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 14: Circuit Breaker at Bermondsey TS 53M1 (February 3, 2012)

Station Name: Bermondsey TS

Station Circuit Breaker ID: 53M9

Age of the Circuit Breaker: 51

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 15: Circuit Breaker at Bermondsey TS 53M9 (February 3, 2012)

Station Name: Bermondsey TS

Station Circuit Breaker ID: 53M11

Age of the Circuit Breaker: 51

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 16: Circuit Breaker at Bermondsey TS 53M11 (February 3, 2012)

Station Name: Finch TS

Station Circuit Breaker ID: 55M24

Age of the Circuit Breaker: 52

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 17: Circuit Breaker at Finch TS 55M24 (February 2, 2012)

ICM Project | Stations Circuit Breakers Segment

Station Name: Finch TS

Station Circuit Breaker ID: 55M25

Age of the Circuit Breaker: 52

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

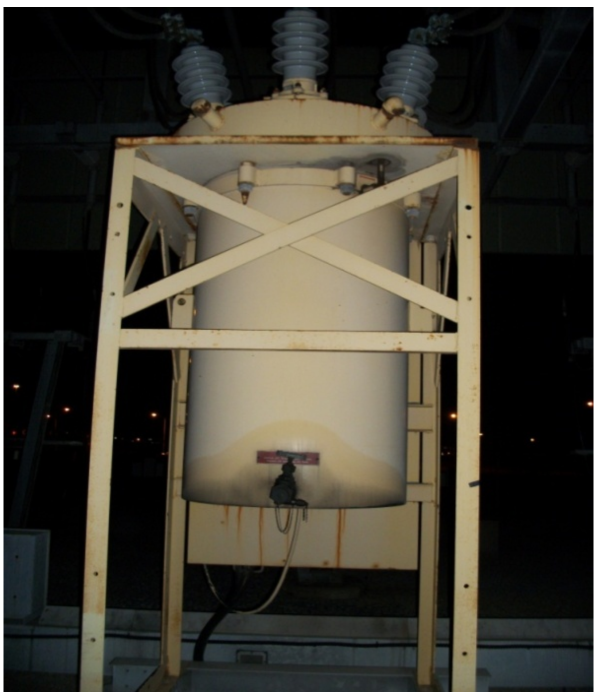


Figure 18: Circuit Breaker at Finch TS 55M25 (February 2, 2012)

ICM Project | Stations Circuit Breakers Segment

Station Name: Finch TS

Station Circuit Breaker ID: 55M8

Age of the Circuit Breaker: 52

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 19: Circuit Breaker at Finch TS 55M8 (March 14, 2012)

Station Name: Bathurst TS

Station Circuit Breaker ID: 85M1

Age of the Circuit Breaker: 50

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 20: Circuit Breaker at Bathurst TS 85M1 (February 2, 2012)

Station Name: Bathurst TS

Station Circuit Breaker ID: 85M4

Age of the Circuit Breaker: 50

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 21: Circuit Breaker at Bathurst TS 85M4 (February 2, 2012)

Station Name: Bathurst TS

Station Circuit Breaker ID: 85M2

Age of the Circuit Breaker: 50

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 22: Circuit Breaker at Bathurst TS 85M2 (February 2, 2012)

Station Name: Bathurst TS

Station Circuit Breaker ID: 85M25

Age of the Circuit Breaker: 50

Justification:

This circuit breaker is past end of life. Replacement is required due to obsolescence, high maintenance requirements and risk of collateral damage in the event of a catastrophic failure.

Figure 23: Circuit Breaker at Bathurst TS 85M25 (February 2, 2012)

III PREFERRED ALTERNATIVE

THESL considered three options to mitigate the reliability and safety risks associated with the deteriorated state of 21 obsolete 27.6kV outdoor-mounted oil circuit breakers in this segment:

- replacement with vacuum circuit breakers
- replacement with SF_6 circuit breakers
- maintain status quo

1. Vacuum Circuit Breakers and SF_6 Breakers

Both SF_6 and vacuum circuit breakers make use of technologies that are considered to be reliable. Each has their own features and capabilities that must be considered when making a choice for particular applications as discussed below.

1.1. Physical Dimension

Both SF_6 and vacuum circuit breakers are significantly smaller in physical size compared to other circuit breakers on the market. However, SF_6 circuit breakers tend to be physically larger in dimensions than vacuum circuit breakers due to the SF_6 open gap being larger than that of a vacuum breaker in order to support the comparable BIL rating. Also, additional space is required by SF_6 circuit breakers to store the puffer cylinder. Physical dimension is an important consideration in the selection of a circuit breaker due to physical space constraint in stations. Therefore, installation of vacuum circuit breaker has an advantage over SF_6 circuit breaker in terms of physical dimensions.

1.2. Maintenance

It is not necessary to monitor the arc-quenching medium during operation of vacuum circuit breakers since the vacuum interrupter seals are manufactured with brazed joints. Also, periodic routine hi-pot checks assure vacuum integrity. On the other hand, SF_6 circuit breakers require continuous monitoring of the arc-quenching medium since seals leak with time. This tends to result in higher maintenance cost on SF_6 circuit breaker compared to vacuum circuit breaker.

1.3. Operating Life

Construction of vacuum circuit breaker is simpler and the number of components inside a vacuum breaker is smaller; approximately 50% less than in a SF_6 circuit breaker. That leads to a longer operation life, with a high number of operating cycles (Refer to Table 5) relative to a SF_6 circuit breaker.

Table 5: Number of various operations for SF_6 and Vacuum circuit breakers

Type of Circuit Breaker	Number of Short-Circuit Operation	Number of full load operation	Number of mechanical operation
SF_6 Circuit Breaker	10-50	5,000-10,000	5,000 – 20,000
Vacuum Circuit Breaker	30-100	10,000 – 20,000	10,000 – 30,000

1.4. Switching of fault currents

Both SF_6 and vacuum circuit breakers are capable of interrupting all fault currents up to their maximum ratings. However, vacuum circuit breakers have a higher rate of dielectric recovery after current interruption. In regards to the recovery voltage that appears after the interruption of a fault current, the vacuum circuit breaker can, in general, handle voltages up to 5 kV whereas SF_6 circuit breaker can handle voltages in the range of 1 kV to 2kV.

Based on the above analysis, replacing the existing oil circuit breaker with vacuum circuit breaker will be more beneficial compared to replacing it with SF_6 circuit breaker.

2. Maintain Status Quo

Should the station breaker replacements not proceed, the following risks will escalate:

- Safety: Catastrophic failure of station breakers, especially outdoor oil breakers, can be explosive throwing flaming oil and debris over a wide area. There is a high risk to personnel, if present, during the failure.
- Unexpected failure/Capacity loss: Catastrophic failure of station breakers, especially outdoor oil breakers, may result in collateral damage to other breakers and station equipment leading to higher restoration costs and more extensive outages.

- The health index of oil circuit breakers has had a 20% increase in the number in fair condition and a corresponding decrease of 16% in good and very good condition from 2010 to 2011.
- Moreover, retaining the existing circuit breakers in service will likely have a negative impact on maintainability:
- Spare parts for the KSO oil circuit breakers are no longer being manufactured; spare parts required are obtained on special order at about twice the cost of the original spare parts
- Maintenance on these breakers can only be done when there is favorable weather.

Table 6 below lists the large customers who would be affected in the event of a failure of the selected circuit breakers:

Table 6: Large Customers Affected in the event of Breaker Failures

Customer Name	Peak kVA	Feeder ID
Customer A	3,386	51M4
Customer B	2,823	51M4
Customer C	1,945	51M4
Customer D	1,651	51M4
Customer E	1,211	51M4
Customer F	1,108	51M4
Customer G	1,047	51M7
Customer H	2,214	53M1
Customer I	5,787	53M11
Customer J	1,644	55M24
Customer K	4,740	55M28
Customer L	6,682	80M3
Customer M	1,105	80M3
Customer N	6,682	80M5
Customer O	1,693	80M5

Customer Name	Peak kVA	Feeder ID
Customer P	1,654	80M5
Customer Q	825	80M5
Customer R	1,923	80M9
Customer S	1,394	80M9
Customer T	1,452	85M2
Customer U	1,363	85M2
Customer V	307	85M2
Customer W	4,740	85M25
Customer X	1,1567	85M4

After analysis of all three alternatives mentioned above, THESL proposes that replacement of the outdoor-mounted oil circuit breakers with vacuum circuit breakers is the preferable option.

3. Avoided Risk Cost of the Selected Option

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

Carrying out immediate work on this asset class will result in the avoided estimated risk cost of approximately $2.6 million (Refer to Appendix 1), as opposed to executing this work in 2015. Therefore, there are distinct economic benefits to executing this work immediately. The methodologies applied within this business case are further referenced within the Appendix.

Table 7: Avoided Risk Cost (Refer to Appendix 1)

Project Element	Station Circuit Breaker Project
Avoided Risk Cost	$2.6 Million

4. Preferred Alternative

Based on comparison of the alternatives as described on section III, replacement of the existing outdoor-mounted oil circuit breakers with vacuum circuit breakers is prudent since it is expected to be the most cost-effective option. As a practical matter, THESL proposes to implement the work over a three-year period to allow design, procurement, and construction mobilization and schedule load transfers which minimize customer outages.

Appendix 1

Stations Circuit Breaker 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 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 that 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.

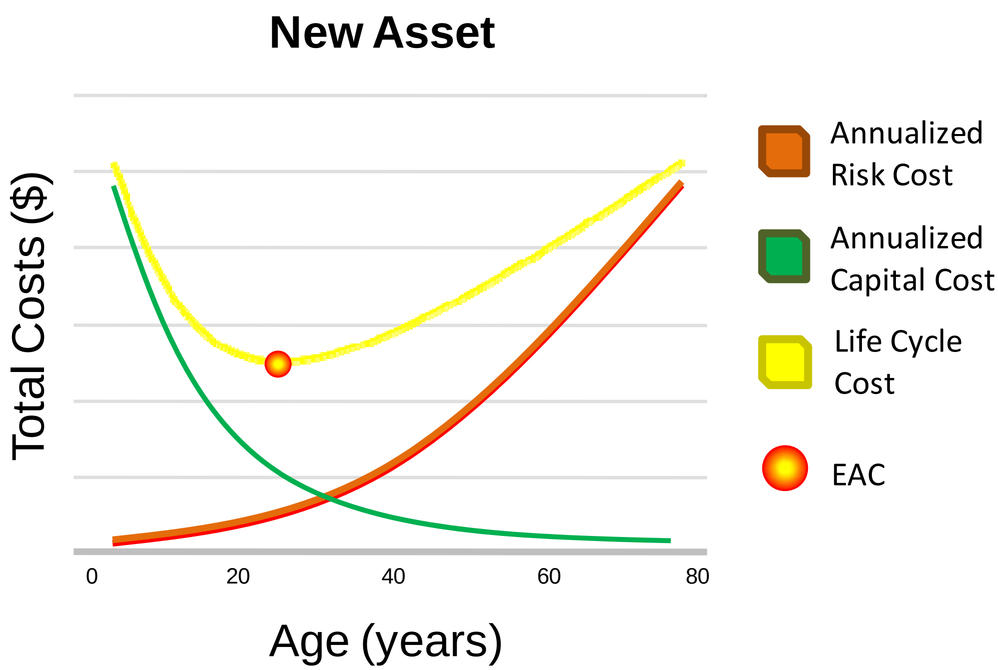


Figure 1: Typical Example of Optimal Intervention Time (New Assets)

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.

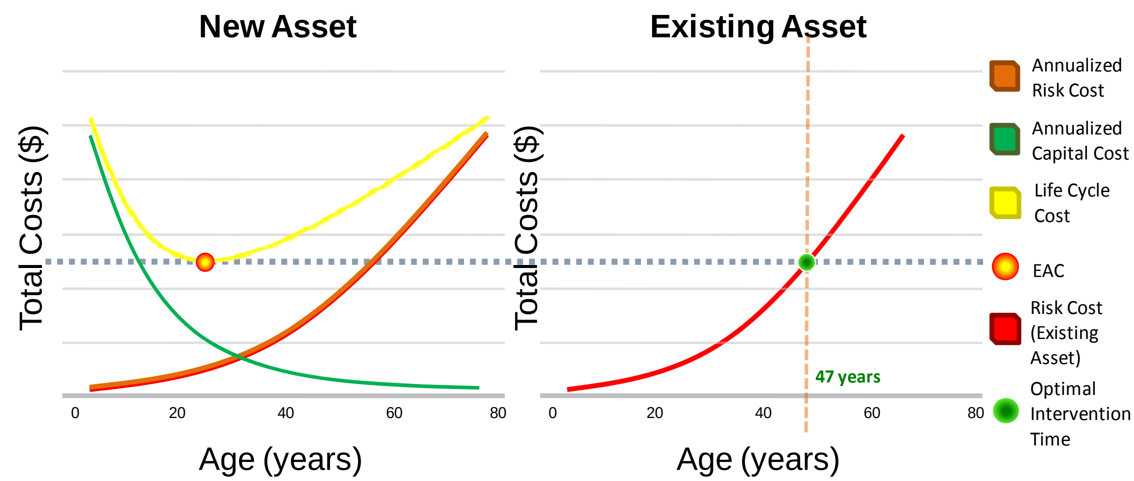


Figure 2: Typical Example of Optimal Intervention Time (Existing Assets)

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.

1.2 Project Evaluation Results

The Stations Circuit Breaker segment represents an “in-kind” replacement project in which the existing circuit breaker 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 this would represent the next available year when THESL may 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 Stations Circuit Breaker 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 and the total costs as the ordinate. As such, the minimum point of this curve provides the highest Net Project Benefit and defines the optimal year to execute the specific project.

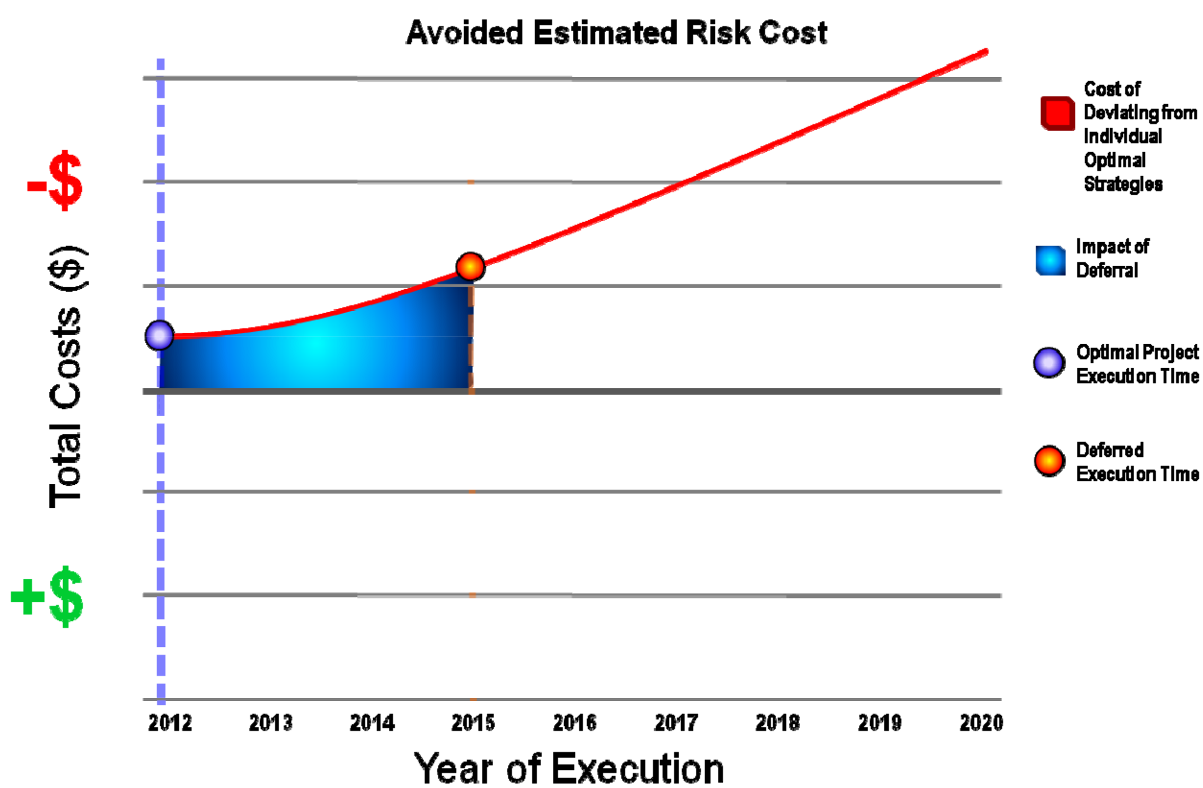


Figure 3: Typical Example of Project Net Benefit Analysis

The effectiveness of the Stations Circuit Breaker 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:

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 Stations Circuit Breaker segment, individual optimal intervention timing results were calculated for each of the circuit breaker assets, 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 circuit breaker assets within this project 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	Estimated Cost (in Millions)
Present Value of Project Net Cost in 2015 (PV(PROJECT$_{NET_COST}$(2015))	\$ 2.784
Project Net Cost in 2012 (PROJECT$_{NET_COST}$(2012))	\$ 0.157
Avoided Estimated Risk Cost = (PV(PROJECT$_{NET_COST}$(2015)) – PROJECT$_{NET_COST}$(2012))	**\$ 2.626**

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.

ICM Project – Station Infrastructure and Equipment

Stations Control and Communication Segment

Toronto Hydro-Electric System Limited (THESL)

I EXECUTIVE SUMMARY

1. Description

THESL relies on an extensive Supervisory Control and Data Acquisition System (SCADA) for control and monitoring of distribution equipment. THESL uses various types of communication (SONET fibre optics, copper lines, radio system and leased telephone lines) to convey information between station assets and distribution system assets. This communication system is vital for operating the system and re-routing electrical supply during planned outages and emergency situations.

Station control and communication work proposed for 2012, 2013, and 2014 consists of improving SONET communication redundancy, upgrading SONET system communication capacity and installing SCADA RTUs. The estimated cost for the work is \$4.6M, which consists of \$2.1M for improving SONET system and \$2.5M for replacing / installing SCADA RTUs, as presented in Table 1 and Table 2 below. Jobs were selected for inclusion in this segment based upon need and execution capacity, and in coordination with other projects.

Table 1: Job Cost Estimates for SONET System Redundancy/Upgrading

Job Title	Job Year	Cost Estimate ($M)
Improve SONET Redundancy: 14 Carlton to George and Duke MS and Esplanade TS	2012	$0.23
Improve SONET Redundancy: Malvern TS to Sheppard TS	2012	$0.22
Improve SONET Redundancy: Split Toronto SONET ring	2012	$0.06
Improve SONET Redundancy: Sheppard TS to Ellesmere TS	2013	$0.17
Upgrade OC3 to OC12	2013	$1.06
Improve SONET Redundancy: Duplex TS to Fairbank TS and Warden TS to Bermondsey TS	2014	$0.39
	Subtotal:	**$2.14**

Table 2: Job Cost Estimates for SCADA RTUs Replacing/Installing

Job Title	Job Year	Cost Estimate ($M)
Replace 15 MOSCAD RTUs in Etobicoke	2012	$0.64
Replace 14 MOSCAD RTUs in Etobicoke	2013	$0.58
Install 5 MS SCADA RTUs	2013	$0.34
Replace 14 MOSCAD RTUs in Etobicoke	2014	$0.59
Install 5 MS SCADA RTUs	2014	$0.36
	Subtotal:	**$2.50**

2. Why This Work is Needed Now

Elements of the SONET system and the radio system have developed reliability and maintenance issues that require immediate attention. This segment will address the communication issues that pose risks for THESL's continued ability to remotely monitor and control the distribution grid.

The SONET fibre optic communication system is normally designed as a redundant ring system between station assets and the Control Centre, but some segments lack redundancy and as these fibre optic lines age or are damaged by adjacent construction, there is a risk of a complete SONET system failure (Section III, 1). Failure of the SONET system would likely result in:

- No communication to support SCADA system, which would prevent system operators from monitoring and controlling vital substation equipment. The result would be longer outages as manual, rather than remote, switching would be required.
- No information to/from the T1 data circuits used for the protection and control of HONI 115kV transmission feeders that supply THESL (i.e., loss of system security and redundancy at HONI supply points and possibly longer outages from poor coordination with HONI).
- No transfer trip protection for HONI 230kV transmission in the Scarborough area, resulting in loss of system security and redundancy at HONI supply points and possibly

longer outages from poor coordination with HONI. Operational flexibility in re-routing loads also would be impacted.

The Motorola radio communication system used in the Etobicoke area (DARCOM radio system and MOSCAD Terminals) has reached the end of its useful life and the equipment is obsolete. As a result, when the communication between the substations in Etobicoke and the SCADA system fails, control for switching restoration is unavailable, increasing the risk of longer customer outages (Section III, 2). This job will ensure reliable communication by adding redundancy to the SONET system and replacing the radio communication system.

The impacts of the deferral are increased risk of prolonged outages to customers served by these communication systems. For example, on December 22, 2011 all control and monitoring capability to 64 substations and 155 overhead Remote Terminal Units (collectively serving 51,937 customers) was lost for 6.5 hours. Although no outages occurred during this event, the loss of SCADA control put the system at risk for longer restoration time. Without remote switching capability, restoration time would move from a few minutes to a few hours, due to the time it takes to send field crews to perform manual switching.

Without SCADA control and system monitoring, control personnel do not have access to the following critical information to minimize outage impacts on customers:

- Alarm for circuit breaker trip (feeder outage)
- Alarm on loss of transformer voltage (transformer outage)
- Alarm on cable overloading
- Alarm on transformer pressure
- Alarm on transformer oil level
- Alarm on transformer temperature
- Alarm on battery system (loss of battery power will prevent protection relay to trip a fault feeder).

3. Why the Project is the Preferred Alternative

3.1. SONET System

Installing redundancy is only effective option to mitigate the SONET system reliability issues and ensure continued service. As the SONET lines age, the risk of losing communications in the area where there is no SONET redundancy will increase. Loss of communication impacts the day to day operational requirements of THESL and the capability to manage the distribution system efficiently (Section IV, 1).

Given modern electrical infrastructure's dependence on reliable communication networks, redundant communication is a requirement.

3.2. MOSCAD Radio System

Mitigation options examined include: 1) repairing the system, replacing the radio system with a wired communication system and replacing it with the MDS TransIT system that THESL uses elsewhere.

The MOSCAD RTU and the associated DARCOM radio system is no longer supported by the manufacturer, spare parts are no longer produced and not available on the market; therefore, repair is not feasible option.

Replacing the radio system with a wired communication system to the stations involved would be more expensive (estimated construction cost of $3 million) and would take longer to implement. This option is not preferred.

The existing MDS TransIT radio system installed in other areas of the THESL distribution system has performed well. MDS continues to supply spare parts to support the system. Replacing the obsolete MOSCAD RTU and DARCOM radio system, with the more reliable MDS TransIT radio system will secure the communication system in the Etobicoke area and ensure the continuity of the communication system. Therefore a replacement of the existing radio system with the MDS TransIT system is the preferred alternative.

II DESCRIPTION OF WORK

1. SONET System Redundancy/Upgrading

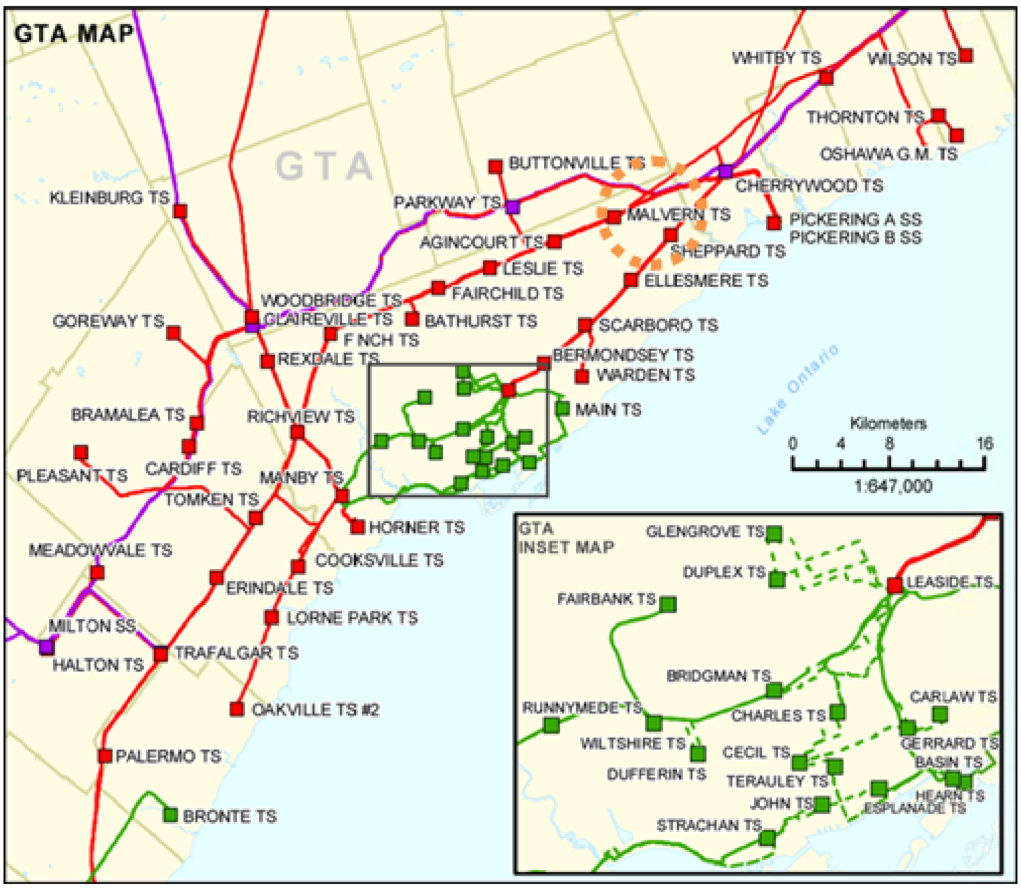
1.1. Job Description

1.1.1. Improve SONET Redundancy: 14 Carlton to George and Duke MS and Esplanade TS (Cost Estimate: $0.23M)

The scope of this job is to add redundancy to the SONET lines between 14 Carlton St. to George and Duke MS and Esplanade TS to improve communication integrity. The distance between 14 Carlton St. and George and Duke MS is approximately 1.8 kilometres and the distance between George and Duke and Esplanade TS is approximately 600 meters.

1.1.2. Improve SONET Redundancy: Malvern TS to Sheppard TS (Cost Estimate: $0.22M)

The scope of this job is to add redundancy to the SONET line between Malvern TS and Sheppard TS to improve communication integrity. The distance between Malvern TS and Sheppard TS is approximately 5.2 kilometres.



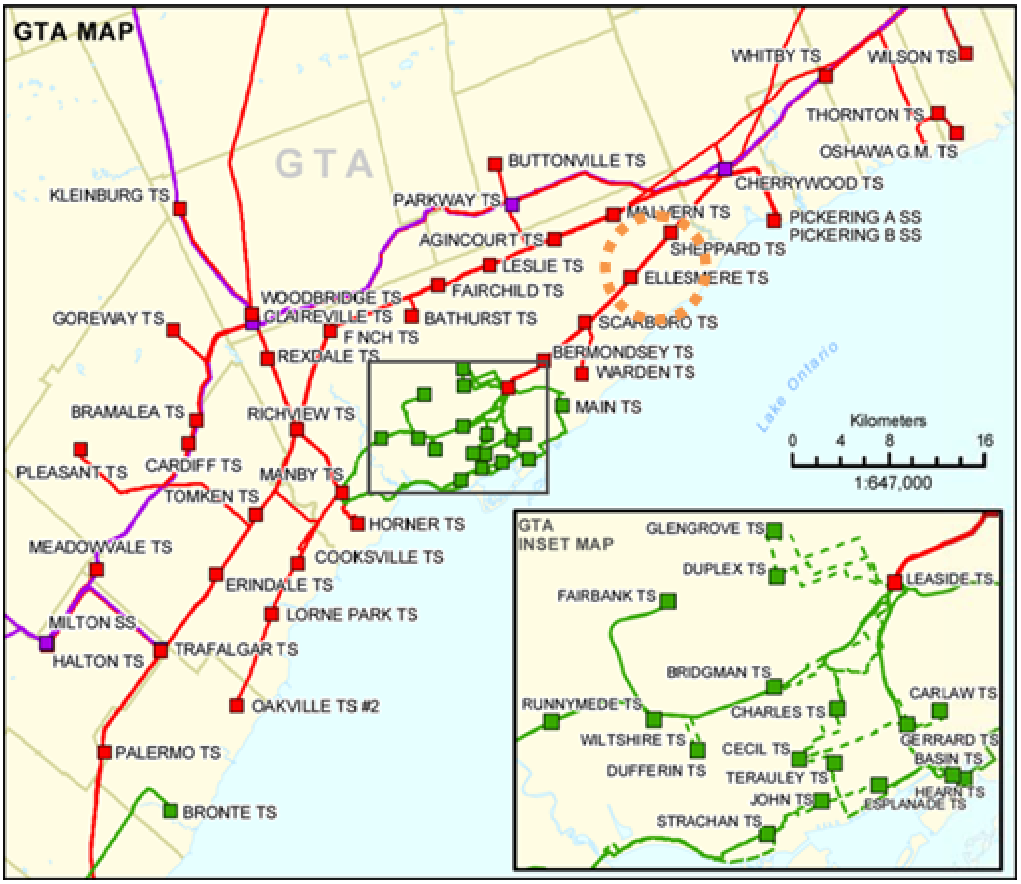
1.1.3. Improve SONET Redundancy: Split Toronto SONET Ring (Cost Estimate: $0.06M)

The scope of this job is to split the downtown SONET ring system into four more manageable rings to improve communication integrity.

ICM Project | Stations Control and Communication Segment

1 **1.1.4. Improve SONET Redundancy: Sheppard TS to Ellesmere TS Cost (Estimate: $0.17M)**

The scope of the job is to add redundancy to the SONET lines from Sheppard TS to Ellesmere TS to improve communication integrity. The distance between Sheppard TS and Ellesmere TS is approximately 3.2 kilometres.



1.1.5. Upgrade OC3 to OC12 (Cost Estimate: $1.06M)

The scope of the job is to replace add/drop multiplexers attached to the system to increase bandwidth from 155.52 Mb/s (OC3) to 622.8 MB/s (OC12). In 2012 there were approximately 35 multiplexers on the system.

ICM Project | Stations Control and Communication Segment

1.1.6. **Improve SONET Redundancy: Duplex TS to Fairbank TS and Warden TS to Bermondsey TS (Cost Estimate: $0.39M)**

Scope of this job is to add redundancy to the SONET lines from Duplex TS to Fairbank TS and Warden TS to Bermondsey TS to improve communication integrity. The distance between Duplex TS and Fairbank TS is approximately 4.5 kilometres. The distance between Warden TS and Bermondsey TS is approximately 5 kilometres.

2. Replacing / Installing SCADA RTUs

2.1. Job Description

2.1.1. Replace 15 MOSCAD RTUs in Etobicoke in 2012 (Cost Estimate: $0.64M)

The scope of work includes replacing the MOSCAD RTU and DARCOM radio system with a MDS TransIT radio system in 15 Etobicoke substations. Testing and commissioning of the new radio system is also included.

The 15 locations were chosen to take advantage of planned station maintenance in 2012 in order to optimize the outage planning process and minimize costs. The numbered MS locations on the map below (Figure 7) are:

1) Delamere MS
2) Enterprise MS
3) Gunton MS
4) Hardwick MS
5) Hartsdale MS
6) Highbury MS
7) Belfield MS
8) Braeburn MS
9) Challenge MS
10) Constellation MS
11) Porterfield MS
12) Berry Road MS
13) Thistletown MS
14) York MS
15) Tidemore MS

Figure 7: Map and Locations

2.1.2. Replace 14 MOSCAD RTUs in Etobicoke in 2013 (Cost Estimate: $0.58M)

Scope of work includes replacing the MOSCAD RTU and DARCOM radio system with MDS TransIT radio system in 14 Etobicoke substations. Testing and commissioning of the new radio system is also included.

The 14 locations were chosen to take advantage of planned station maintenance in 2012 in order to optimize the outage planning process and minimize cost. The numbered locations on the map below (Figure 8) are:

1) Lambton MS
2) Edenbridge MS
3) Ravensbourne MS
4) Bellman MS
5) Brownsline MS
6) Fieldway MS
7) Hollywood MS
8) Humber Bay MS
9) Humberline MS
10) Hunting Ridge MS
11) Index MS
12) Inverness MS
13) Islington MS
14) Marmac MS

Figure 8: Map and Locations

2.1.3. Install 5 MS SCADA RTUs in 2013 (Cost Estimate: $0.34M)

Scope of work includes replacing the protection and control equipment and adding remote terminal units complete with a radio communication system. The numbered MS locations on the map below (Figure 9) are:

1) Estelle MS
2) Pemberton MS
3) Bellamy Lawrence MS

4) Brian Elinor MS

5) Brimley Bernadine MS

Figure 9: Map and Locations

2.1.4. Replace 14 MOSCAD RTUs in Etobicoke in 2014 (Cost Estimate: $0.59M)

Scope of work includes replacing the MOSCAD RTU and DARCOM radio system with MDS TransIT radio system in 14 Etobicoke substations. Testing and commissioning of the new radio system is also included.

The 14 locations were chosen to take advantage of planned station maintenance in 2012 in order to optimize the outage planning process and minimize costs. The numbered MS locations on the map below (Figure 10) are:

1) Albion MS	6) Blaketon MS	11) Chapman MS
2) Allenby MS	7) Burlingame MS	12) Dalegrove MS
3) Annabelle MS	8) Burnhamthorpe MS	13) Dunsany MS
4) Ashley MS	9) Centennial MS	14) Elmhurst MS
5) Blackfriar MS	10) Centre Drive MS	

Figure 10: Map and Locations

2.1.5. Install Five MS SCADA RTUs in 2014 (Cost Estimate: $0.36M)

Scope of work includes replacing the protection and control equipment and adding remote terminal units complete with a radio communication system. The numbered MS locations on the map below (Figure 11) are:

1) Brimley Lawrence MS
2) Ellesmere Kennedy T1 MS
3) Ellesmere Kennedy T2 MS
4) Ellesmere White Abbey MS
5) Greencedar Lawrence MS

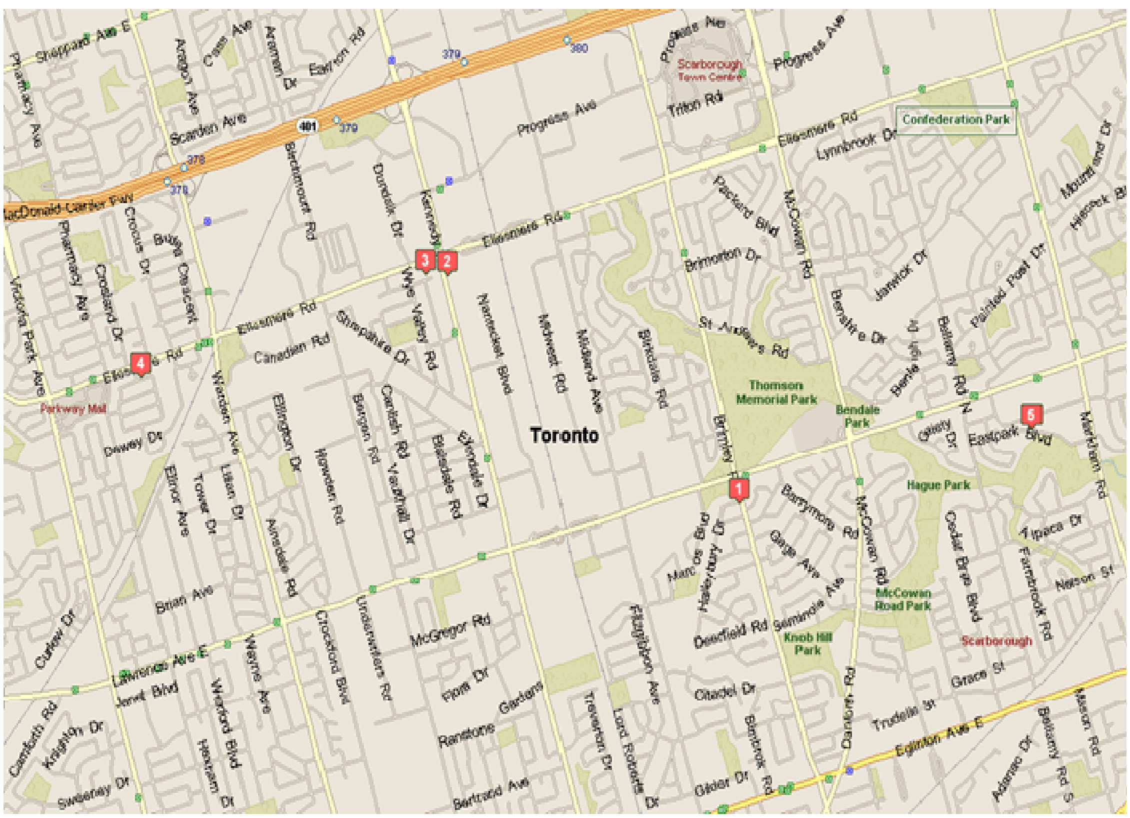


Figure 11: Map and Locations

III NEED

1. Need for SONET System Redundancy/Upgrading

THESL relies on an extensive Supervisory Control and Data Acquisition System (SCADA). THESL uses various types of communication (SONET fibre optics, copper lines, radio system and leased telephone lines) between station assets and distribution system assets. This communication system is vital in controlling the system and re-routing electrical supply during planned outages and emergency situations. Elements of the SONET system and the radio system have developed reliability and maintenance issues which require attention.

The SONET fibre optic communication system is normally designed as a redundant ring system between station assets and the Control Centre, but some segments lack redundancy and as these fibre optic lines age or are damaged by adjacent construction, there is a risk of a complete SONET system failure. Failure of the SONET system would likely result in:

- No communication to support SCADA system and as a result system operators would not be able to control and monitor vital substation equipment thus having an adverse impact on the operational functions of THESL (i.e., longer outages as manual actions (switching) are required in the field vs by remote control).
- No information to/from the T1 data circuits used for the protection and control of HONI 115kV transmission feeders that supply THESL (i.e., loss of system security and redundancy at HONI supply points and possible longer outages from poor coordination with HONI).
- No transfer trip protection for HONI 230kV transmission in Scarborough area, resulting in loss of system security and redundancy at HONI supply points and possible longer outages from poor coordination with HONI. Operational flexibility in re-routing loads would be impacted.

2. Need for Replacing / Installing SCADA RTUs

The radio communication system used in the Etobicoke area (DARCOM radio system and MOSCAD Remote Terminal Units) has reached the end of its useful life and the equipment is obsolete. Motorola, the manufacturer of this equipment is no longer manufacturing the MOSCAD RTU and DARCOM radio system and no longer supports spare parts for this type of system. As a result, when the MOSCAD RTU or DARCOM radio fails, the communication between the substations in Etobicoke and the SCADA system is lost, creating increased risk of longer outages to customers. Customer outage duration will increase from minutes to hours when loss of SCADA communication occurs. There are approximately 50 entries in defective equipment tracking related to Etobicoke RTUs equipment and three MOSCAD system experience communication failure in 2011.

THESL Information Technology's radio group no longer has any spare parts for repair and replacement of the master radio. Replacement parts are not available for other major parts of the system because of obsolescence. This segment work will secure the communication system in the Etobicoke and is necessary to maximize the continuity of the communication system.

IV PREFERRED ALTERNATIVE

1. SONET System

Installing redundancy is the only viable option to mitigate the SONET system reliability issues. Continuing the status quo, and repairing SONET assets after they have failed, will continue to result in periods when the system is out of service and expose customers to longer outages as a result. Building the necessary redundancy into the system is a better approach in order to provide continued service as well as continuity of service during repairs.

As the SONET lines age, the risk of losing communications in the area where there is no SONET redundancy likely increases. Loss of communication impacts the day to day operational requirement of THESL and the capability to manage the distribution system efficiently. The only option to address this situation is to install redundant communication, given modern electrical infrastructure's dependence on reliable communication networks.

2. MOSCAD Radio System

Mitigation options examined include replacing the radio system with a wired communication system to the stations involved. A wired system would be more expensive (estimated construction cost of $3 million) and take longer to implement than a radio system solution.

Replacing the obsolete MOSCAD RTU and DARCOM radio system with the more reliable MDS TransIT radio system assists in securing the communication system in the Etobicoke and ensure communications continuity.

The MDS TransIT radio system is installed in other areas of the THESL distribution system. It has performed well. MDS continues to supply spare parts to support the system. Therefore, it is the preferred replacement alternative for the existing MOSCAD RTU and DARCOM radio system.

3. Benefit Cost Evaluation

The SONET improvement jobs and the MOSCAD replacement jobs will help THESL achieve more reliable communication. This provides more efficient, cost effective outage response and more reliable power supply to its customers since THESL control centre operators can monitor equipment conditions, correct faults remotely, provide automated switching and feeder re-routing in both planned outages and unplanned emergency work.

It is estimated that the duration of system outages can be reduced significantly with proper communication between control room, response crews and equipment. For the last five years (2007-2011), the average number of customers interrupted (CI) in Etobicoke is 181,785 customers per year, and the average customer minutes outage (CMO) is 8,007,263 per year. The average outage duration is 44 minutes with SCADA system in service. Without SCADA system, the outage duration increases from 44 minutes to 175 minutes on average, and therefore the CMO become 31,812,305 (181,785 x 175). As a result, the CMO saving due to a SCADA system in service is 23,805,042. Based on the cost of interruption formula, the benefit can be derived as follow:

Assuming each customer has a load of 3 KVA, and 33% of the outage can be improved by SCADA system.

The kVA load served: 23,805,042 x 3 = 71,415,125 kVA*CMO

The 33% improvement by SCADA system: 71,415,125 x 33% = 23,805,042 kVA*CMO

Using $15 per KVA/hour/customer outage, the cost saving will be:

Outage cost saving = 23,805,042 x $15 / 60 = $5,951,260

The system-wide reduction in Customer Minute Outage (CMO) represents benefits of the order of $5.95 million every year with one time investment of $4.64 million; therefore this initiative has a benefit cost ratio well above unity.

ICM Project – Station Infrastructure and Equipment

Downtown Station Load Transfer Facilities Segment

Toronto Hydro-Electric System Limited (THESL)

ICM Project | Downtown Station Load Transfer Facilities Segment

I EXECUTIVE SUMMARY

1. Project Description

This segment includes the completion of the Dufferin – Bridgman feeder tie work in 2012 that was largely completed in 2011, and six new jobs for 2012, 2013, and 2014 that are required to provide feeder ties between Basin and George and Duke stations; Basin and Carlaw stations; and Dufferin and Wiltshire stations, where no such facilities present exist (See Section II).

About 17% of the $7.45M Dufferin-Bridgman feeder ties work remains for 2012 which includes completion of electrical work, feeder transfers, some feeder capacity upgrades and commissioning (See Section II). This job plus the other six proposed jobs for 2012, 2013, and 2014 combine for a total cost of $6.9M. None of the proposed work is included in existing rates.

Table 1: Proposed Feeder Ties

Job Number	Job Identifier	Cost Estimate ($M)	Year of Execution
X11620	Feeder Tie Dufferin to Bridgman	1.27	2012
X11424	Feeder Tie A203BN to A240GD	0.48	2012
X12086	A204BN tie to new Carlaw feeder	0.39	2013
X12131	Feeder Tie A34W to A256DN	0.79	2013
X12132	Feeder Tie A57W to A273DN	0.40	2013
X12340	Feeder Tie A36DN to A67W	1.78	2014
X12342	Feeder Tie A13DN to A35W	1.81	2014
	Total	6.93	

2. Why the Project is Needed Now

Downtown Toronto, representing approximately one-third of THESL's total customers and load, utilizes a radial design for the distribution system that lacks ties between stations. The design provides quick restoration times for common failure modes, but does not provide back-up for some low probability high impact events such as partial or complete station failure (See Section III).

Many of the switchgear and breakers in the downtown stations are more than 50 years old, are non-arc resistant designs and are fitted with obsolete air blast breakers. These factors raise the risk of partial or complete station outages. Equipment replacement is proposed for some of these stations to mitigate those risks; however, external factors outside of THESL control further raise the risk of outages. Therefore the need for station load transfer capability remains at the stations included in this segment.

Major downtown contingency incidents are normally rare, and consequently most years will not show any difference in reliability data. However, should an incident occur where feeder ties are not available, there is expected to be a major impact on reliability for that year. For example, the one 2009 Dufferin TS incident caused 62% of all downtown customer hours of interruption for all of 2009, with this one incident totalling 626,692 customer hours of interruption and 34,308 customer interruptions.

Dufferin TS is unique in that it has in recent years experienced two contingency incidents that resulted in complete station outages and lengthy customer interruptions. Projects undertaken over the last two years have completed most of the necessary work to provide the ability to transfer customer loads between Dufferin TS and Bridgman TS for four feeder pairs. Without completion of the final electrical portion of the work, the reliability benefits of the previous investments cannot be obtained (See Section III).

The other six jobs listed in Table 1 will allow rapid transfer of customer loads on the feeder pairs between Basin and George and Duke stations; Basin and Carlaw stations; and Dufferin and Wiltshire stations. The load transfer capability that would become available represents up to roughly 3% of Basin TS loading; 3% of George and Duke TS loading; 5% of Carlaw TS loading; 13% of Wiltshire TS loading; and an additional further 11% of Dufferin TS loading. It would provide increased reliability for these feeders, from any HONI or THESL incident that impacts station supply.

These jobs are expected to collectively provide mitigation for a portion of risks identified at six of the 15 downtown stations, and provide back-up supply to a total of 5,197 customers and 52 MVA of load. This capital investment will result in a net benefit of $0.123 million through reduced customer interruption costs.

3. Why the Project is the Preferred Alternative

Six alternatives were considered:

- Status quo
- Mobile generators
- Mobile switchgear
- Inter-station switchgear ties
- Intra-station switchgear ties
- Station-to-Station Feeder ties

Under the status quo, customers will continue to be exposed to long duration outages in the event of a station failure and the benefits from the investments already made to tie Dufferin and Bridgman stations will not be realized (See Section IV, 1). Neither mobile generators nor mobile station-to-station feeder ties can completely address station failures as explained in Section IV, 2. Both inter and intra-station switchgear ties are typically available only for new switchgear installations and will typically not address all types of potential station failures. As such, these options do not represent viable remedies in the near-term (See Section IV, 3). Station to station feeder ties are the only solution capable of completely addressing any loss-of-supply incident (See Section IV, 4). All the other alternatives offer only partial, temporary solutions, or do not offer any relief for partial or complete loss of station supply.

II DESCRIPTION OF WORK

The Dufferin – Bridgman feeder ties were conceived as a multi-year multi-part project back in 2010. The proposed electrical work for 2012 is the final portion and includes the following:

- Complete the electrical work associated with the following previously completed civil projects: (duct work to allow feeder ties)
  - W10356, A31DN to A2B
  - W10357, A30DN to A1B
  - W10358, A35DN to A4B
  - W10359, A38DN to A6B
- Transfer feeders within Bridgman TS as follows:
  - Relocate A1B from circuit #2 to circuit #4 (previously spare)
  - Relocate A91B from circuit #6 to circuit #2 (previously A1B)
  - Relocate A4B from circuit #13 to circuit #10 (previously spare)
  - Relocate A6B from circuit #14 to circuit #6 (previously A91B)
- Replace and upgrade a portion of A7B from 350kcmil PILC HJ to 500kcmil 3-1C CU TRXLPE
- Replace and upgrade a portion of A91B from 350kcmil PILC HJ to 500kcmil 3-1C CU TRXLPE
- Replace and upgrade a portion of A93B from 350kcmil PILC HJ to 500kcmil 3-1C CU TRXLPE

Table 2 identifies the completed Dufferin – Bridgman feeder ties as well as the remaining portion for 2012.

Table 2: Dufferin – Bridgman Feeder Ties

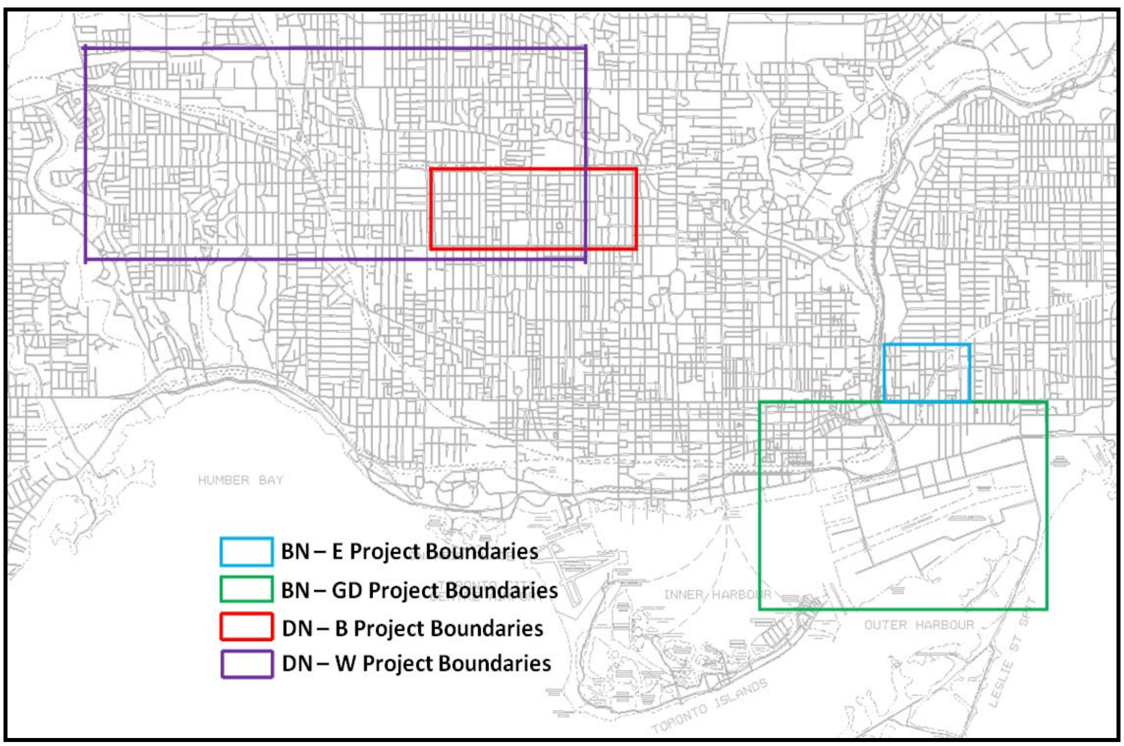
Job Number	Total Cost ($M)	Outstanding Cost ($M)	Year of Execution
W10356	1.33	0	Finished
W10358	1.03	0	Finished
W10359	0.48	0	Finished
W10357	0.73	0	Finished
X11677	0.48	0	Finished
X11620	3.41	1.27	2012
	7.45	1.27	

An expenditure of approximately $1.27 M, representing approximately 17% of the total project cost, is expected to complete the work necessary to provide complete peak load feeder-to-feeder tie capability for four Dufferin – Bridgman feeder pairs. The load transfer capability that would become available represents up to roughly 29% of total Bridgman TS loading and up to roughly 11% of total Dufferin TS loading. The remaining station loading is associated with other feeders and will need to be addressed in future projects.

In addition, six additional feeder-to-feeder tie jobs are proposed. These projects are identified in Table 3, and the geographic boundaries are illustrated in Figure 1, below, respectively.

1 **Table 3: Proposed Feeder Ties – 2012, 2013, 2014**

Job Number	Job Identifier	Cost Estimate ($M)	Year of Execution
X11424	Feeder Tie A203BN to A240GD	0.48	2012
X12086	A204BN tie to new Carlaw feeder	0.39	2013
X12131	Feeder Tie A34W to A256DN	0.79	2013
X12132	Feeder Tie A57W to A273DN	0.40	2013
X12340	Feeder Tie A36DN to A67W	1.78	2014
X12342	Feeder Tie A13DN to A35W	1.81	2014
	Total	**5.65**	



2 **Figure 1: Feeder Ties Area Boundaries**

The scope of each of these jobs is similar to that detailed for each individual Dufferin – Bridgman feeder pair. The proposed feeder ties are expected to allow rapid transfer of customer loads on the feeder pairs between Basin and George and Duke stations; Basin and Carlaw stations; and Dufferin and Wiltshire stations. The load transfer capability that would become available represents up to roughly 3% of Basin TS loading; 3% of George and Duke TS loading; 5% of Carlaw TS loading; 13% of Wiltshire TS loading; and an additional further 11% of Dufferin TS loading. It would provide increased reliability for these feeders, from any HONI or THESL incident that impacts station supply.

These jobs are expected to collectively provide mitigation for a portion of risks identified at six of the 15 downtown stations, and provide back-up supply to a total of 5,197 customers and 52 MVA of load. The jobs will allow 100% load transfer capabilities for the specific feeder pairs under peak conditions. Other feeders from these stations would need to be addressed in future projects. Should this work not take place, customers on these feeders would face unmitigated outage durations for any major loss of supply incident at these stations.

III NEED

The completion of the feeder ties for the four Dufferin-Bridgman feeders is necessary in order to obtain the benefit from the preparatory work completed in 2011. Should this work not take place, the facilities installed to date to provide feeder-to-feeder tie capability for these four feeder pairs would likely remain stranded.

This work is expected to allow rapid transfer of customer loads on these four feeder pairs between Dufferin and Bridgman stations. The load transfer capability that would become available represents approximately 29% of Bridgman TS loading and up to approximately 11% of Dufferin TS loading. The ties are expected to provide back-up supply that is presently missing for these feeders, from any HONI or THESL incident that impacts station supply at Dufferin or Bridgman TS.

The Dufferin-Bridgman ties were justified based on the fact that HONI and THESL facilities in downtown stations are at or approaching end-of-life and pose increasing risks of station failure. THESL expects to be able to reduce the likelihood of high impact station events and is proposing to do so elsewhere in this application with asset replacements. However, THESL customers are also at risk of high impact station events resulting from the failure or operation of HONI assets in these stations such as the Dufferin incident that took place in 2009. Dufferin TS was completely shutdown due to flooding caused by the HONI’s fire suppression system within the station, with no means for load transfer. THESL must take action to provide means of contingency for its distribution system such that these external risks can be appropriately mitigated

The distribution systems employed in downtown Toronto are of radial design. This design lacks ties between feeders originating from different stations. The downtown area distribution system was designed to maximize its installed distribution capacity and relies heavily on the stability of the incoming high voltage supply and redundant station equipment. This design has the benefit of allowing station equipment to be loaded to near 100%, compared with as little as 50% loading limit for surrounding stations that include station-to-station feeder ties. This design also provides quick restoration times for common failure modes, but does not provide back-up from alternate stations for certain uncommon but high impact events, including partial and complete station failure.

Consequently, in the event of a station wide outage, customers fed from that station would be significantly impacted. On average approximately 14,000 customers would be out of power in each such incident in the downtown area.

The 15 downtown stations susceptible to such events include the following:

- Basin TS
- Bridgman TS
- Carlaw TS
- Cecil TS
- Charles TS
- Dufferin TS
- Duplex TS
- Esplanade TS
- Gerrard TS
- Glengrove TS
- Main TS
- Strachan TS
- Terauley TS
- Wiltshire TS
- Windsor TS

These 15 stations supply more than 210,000 customers, representing approximately one-third of THESL's customer base; and 1,866MVA out of 5,298MVA load, representing approximately one-third of THESL's total load. Over the last decade there have been 15 station outage events among these stations, averaging over nine hours of customer interruption. This results in an average annual downtown customer interruption cost of $155 million (based on $30/kW outage event cost, $15/kWh outage duration cost, 1.5 outages per year, 40% of station outage, 9.07-hour outage duration and peak system load).

The downtown radial design is depicted in Figure 2 below.

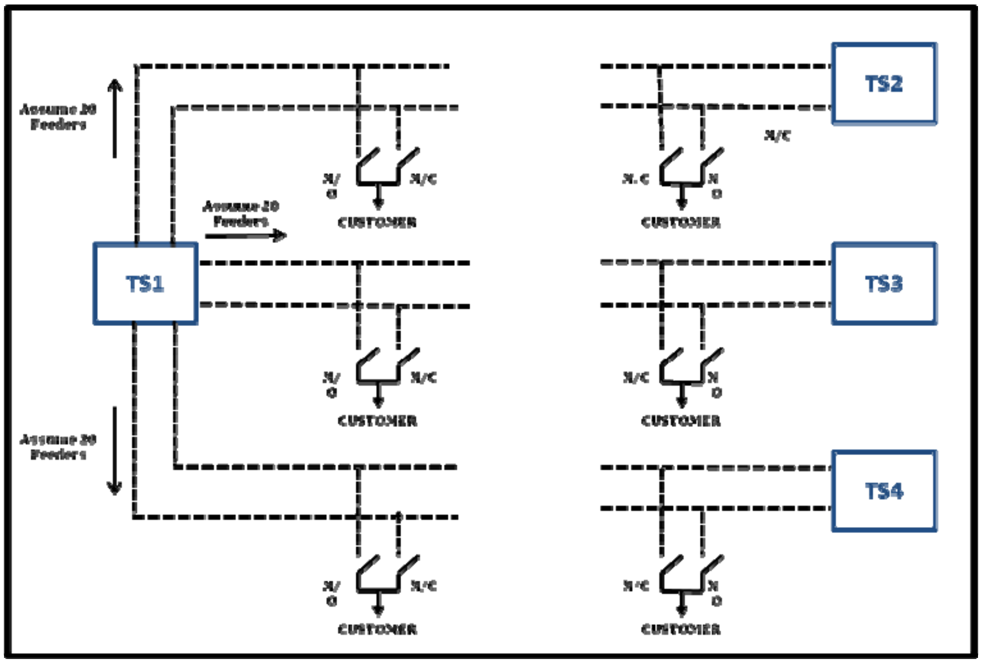


Figure 2: Radial distribution design utilized in downtown area

Outside of the downtown Toronto area, the distribution system is of an open-loop design. This design incorporates many ties between feeders, and in particular, ties between feeders coming from different stations. As a result, most areas can be quickly resupplied by an alternative station when necessary. The open-loop design is depicted in Figure 3 below.

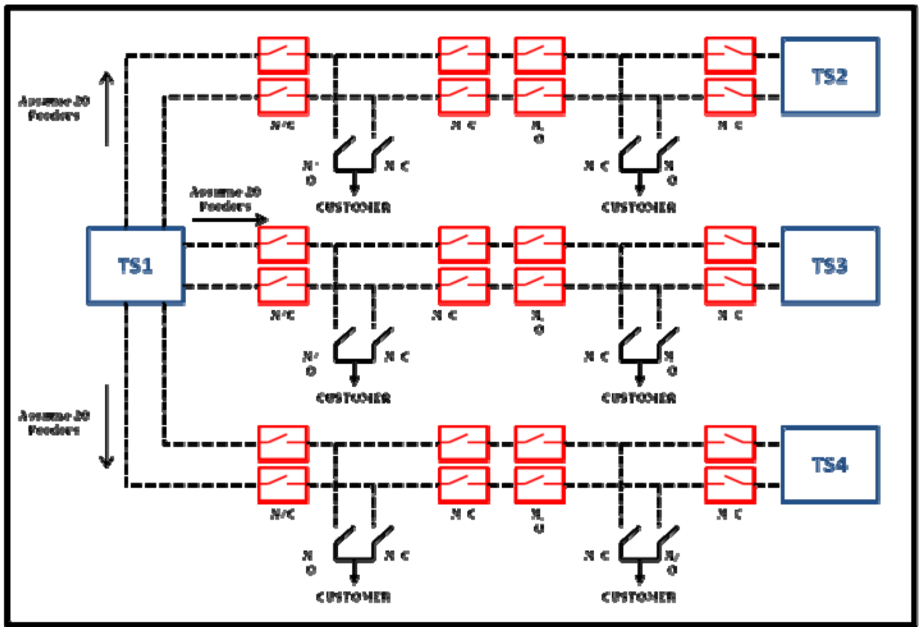


Figure 3: Open loop distribution design applied outside of the downtown area

Over the decade covering 2002 through 2011, downtown contingency events resulted in 934,483 hours of customer interruptions. This period includes all three recent major loss-of-supply incidents in the downtown core. If facilities were available to pick-up customer loads, the customer hours interrupted would have been reduced to 280,570. This represents a 70% improvement as illustrated in Figure 4 below. The jobs in this document are expected to result in average reliability improvements for the particular feeders involved as illustrated in Figure 4.

ICM Project | Downtown Station Load Transfer Facilities Segment

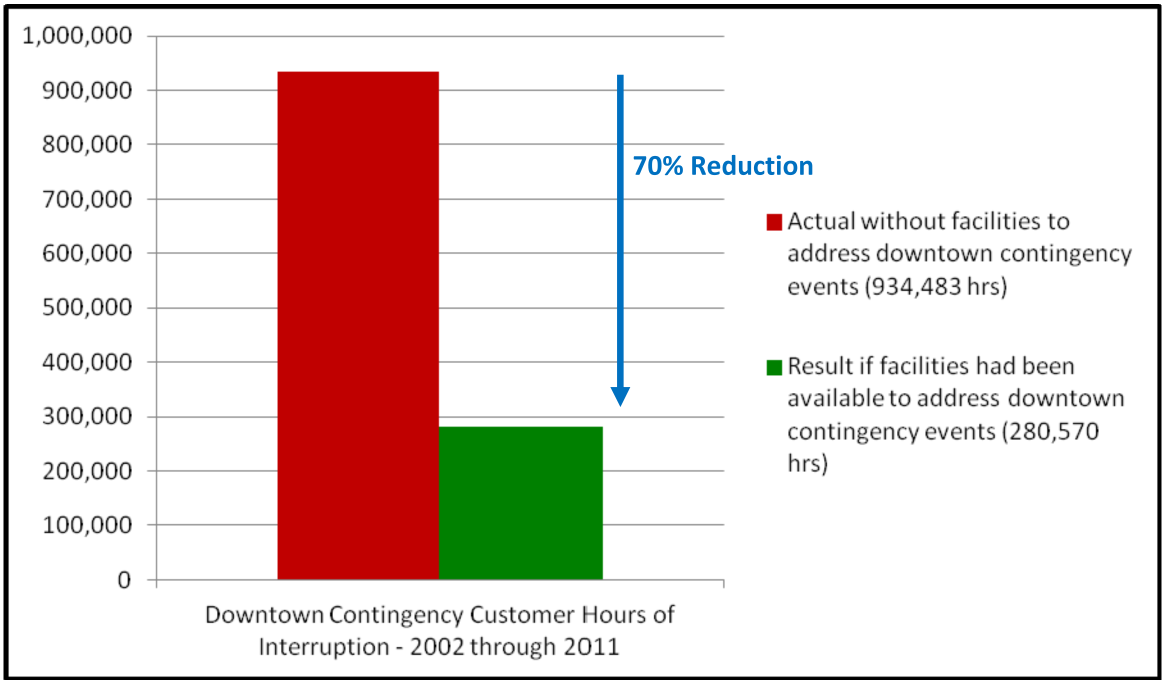


Figure 4: Reliability Impact of Downtown Station Load Transfer Implementation

All four major station outage events in downtown Toronto's history occurred in the last decade. This experience indicates that the conditions in and around the 15 downtown stations are worsening as time progresses, and as a result the risks are increasing. Each of these historical events resulted from causes external to THESL that negatively impacted the station distribution equipment. Therefore, the only certain way to address such failures is to provide a back-up supply to customers.

The purpose of this segment is to provide distribution load transfer capability from one station area to another station area in order to manage the risks of partial, or complete, station outages.

An investment of $6.9M over the period of 2012 through 2014 is expected to complete the work necessary to provide feeder-to-feeder tie capability for ten feeder pairs. This work is expected to allow rapid transfer of customer loads on these feeder pairs should mitigate virtually any loss-of-supply incident occur at any of these stations.

ICM Project | Downtown Station Load Transfer Facilities Segment

The work to enable station load transfers for the downtown stations must be undertaken over many years. The proposed jobs for 2012, 2013, and 2014 represent the highest priority jobs based on reasonable project scope and the ability of each station to pick-up the alternate feeder loads.

IV PREFERRED ALTERNATIVE

Six alternatives were considered:

- Status quo
- Mobile generators
- Mobile switchgear
- Inter-station switchgear ties
- Intra-station switchgear ties
- Station-to-Station Feeder ties

1. Status Quo

Recent downtown contingency incidents have been associated with station flooding. Stations have been modified to reduce the likelihood of reoccurrence of such incidents and limit the consequences. However, downtown contingency incidents may result from a multitude of causes from both inside and outside the station. THESL generally cannot control external causes and can only address such incidents by taking measures to provide effective backup.

Major downtown contingency incidents are rare compared to distribution equipment failures and do not occur most years. However, when such an incident occurs there would likely be a major impact on reliability for that year. The downtown core includes many large, high impact customers such as hospitals and financial institutions. Some of these customers have generators that can cope with THESL's typical 85-minute distribution outages; however, station outages lasting 24 hours and longer exceed the typical back-up capabilities of these facilities. Escalating financial and human consequences would likely follow.

For example, on January 15, 2009, Dufferin TS was completely shutdown due to flooding caused by the HONI fire suppression system within the station. As it was not possible to transfer load to other stations, a total of 34,308 customers were affected; some without electricity for up to 24 hours on a day that ranged between -11.3°C and -18.9°C. This incident occurred due to HONI-owned assets, and would have occurred regardless of any asset renewal activities performed on THESL-owned stations assets.

Since this incident, Dufferin TS has had upgrades to its fire suppression system, water containment and removal systems, and monitoring systems to prevent recurrence. No other transformer, switchgear or circuit breaker work is planned, so the condition of this equipment will not improve over the coming years. Work on distribution and station projects intended to mitigate the impact of a contingency at Dufferin TS by tying feeders to other nearby downtown stations began in 2010 and continued in 2011.

If the Dufferin – Bridgman Feeder tie work is not completed, the facilities to transfer loads from Dufferin TS to Bridgman TS will not be available and the value from the previous investment cannot be obtained. If work on the other Basin, Carlaw, Dufferin and Wiltshire feeder tie jobs is not initiated, customers would continue to be exposed to unmitigated outage consequences associated with any loss of supply incident at these stations.

2. Mobile Generators and Switchgear

Typically no more than twelve 2000kVA generators are available within 24 hours that can be used to pick-up customer loads following a major loss-of-supply incident. Typically three to five generators would be required per feeder for peak loading, with an average of about 35 feeders per station. This represents less than 10% of a typical downtown station's maximum capacity and therefore only provides a partial solution. Mobile switchgear can address loss of THESL switchgear incidents, but not loss of HONI supply incidents. Both of these alternatives can be expected to result in customers experiencing a minimum of three days of interruptions following major loss of supply incidents.

3. Inter and Intra-Station Switchgear Ties

Inter-station switchgear ties (i.e., ties between switchgear in different stations) can address loss of HONI supply incidents but not loss of THESL switchgear incidents, and are generally only practical to add to new station switchgear.

Intra-station switchgear ties (i.e., ties between switchgear within the same station) can address some loss of HONI supply incidents but not loss of THESL switchgear incidents, and are also generally only practical to add to new station switchgear. For the limited types of loss of supply incidents that these alternatives can address, customers would be expected to experience interruptions of a few hours. New THESL station switchgear is now being designed with enhanced provisions for inter- and intra-station switchgear ties. As a result, these facilities will only become available in the long term.

4. Station-to-Station Feeder Ties

Only station-to-station feeder ties are capable of completely addressing any loss-of-supply incident. Customer load restoration times are also generally short, with an estimated 14 hours with local switch operation and an hour with the future addition of remote operation.

Figure 5 illustrates the typical proposed connections between Dufferin and the neighbouring stations. In order to ensure that sufficient spare station capacity exists to pick up the load from Dufferin at the receiving station, ties must be distributed from Dufferin to Bridgman, Cecil, Strachan and Wiltshire stations. The proposed Dufferin - Bridgman work will complete four feeder to feeder ties between Dufferin and Bridgman stations. This portion of the work is highlighted in red in figure 5. Four additional new Dufferin feeder tie jobs; X12131, X12132, X12340 and X12342, are also illustrated in this figure.

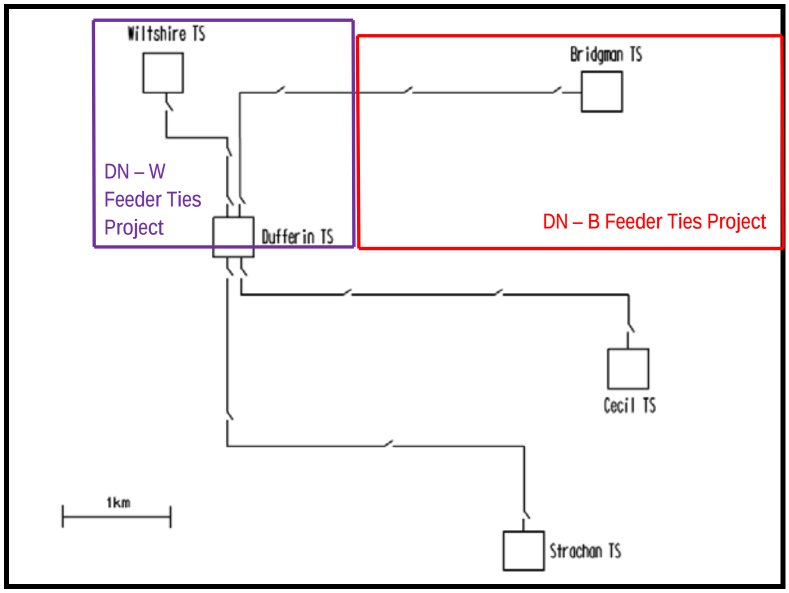


Figure 5: Schematic of Planned 13.8kV Interconnections between Dufferin TS and Neighbouring Stations (Typical)

The approach THESL has taken is to provide feeder ties across the downtown core area, rather than focus on a specific area or station. Feeder-to-feeder tie projects typically involve first installing remotely operable load break switches to permit the isolation of the feeders from the station. Then, remotely operable load break switches would be installed to tie individual feeders to feeders from neighbouring stations. Lastly, cabling is installed to tie feeders to these neighbouring stations. THESL expects that this approach provides the greatest opportunity to mitigate high impact station events for a number of stations and is the most cost effective solution.

In addition to completing the Dufferin-Bridgman feeder ties, six new jobs are required to provide feeder ties between Basin and George and Duke stations; Basin and Carlaw stations; and Dufferin and Wiltshire stations, where no such facilities presently exist. These feeders are presently exposed to unmitigated risks from major loss of supply incidents.

The installation of these feeder-to-feeder ties is expected to ultimately allow future loss-of-supply incidents to be managed in a way that customers won't face extended outages.

5. Economic Benefits of Preferred Alternative

If no proactive work were to take place to mitigate the risks of major downtown contingency incidents, the expected PV of outages would be $7.4 million for the feeders involved in these jobs. By executing the proactive feeder installation work identified in Table 1, the PV of all costs (including reduced customer outage costs, capital investment and increased maintenance) would be reduced to $7.3 million. This represents a net benefit of $0.123 million. The calculations for this analysis can be found in the Appendix.

APPENDIX

Table 3: Benefit-Cost Analysis Summary

DOWNTOWN STATION LOAD TRANSFER FACILITIES ANALYSIS			
A) Base Case – do nothing	**Year 2012**	**Year 2013**	**Year 2014**
Capital Investment by year	$0	$0	$0
PV of Outage Duration Cost	$7,466,913		
Base Case PV	**$7,466,913**		
B) Feeder Tie Case	**Year 2012**	**Year 2013**	**Year 2014**
Capital Investment by year	$1,750,646	$1,585,675	$3,591,941
PV of Capital Investment	$6,438,918		
PV of Maintenance Cost	$81,814		
PV of Outage Duration Cost	$822,951		
Feeder Tie Case PV	**$7,343,684**		
Results			
NPV	**$123,229**		

Scenario A – Base Case:

This is the scenario for run to failure with no proactive investments. Costs expected over the next 20 years are included in the calculations. The station outage incident rate is derived from the last ten years of experience in the downtown Toronto area, and applies to both cases. The historic outages used for the calculations are identified in Table 4. Outage duration for the base case is derived from the average outage duration over the last ten years in downtown Toronto, which is 9.07 hours. The kVA interrupted only includes feeders for which ties are proposed in Scenario B. The discount rate used for calculations is 6.06% in both cases. Customer interruption duration cost used is $15 per kWh in both cases, and represents the opportunity cost to customers from lost power. Outage event costs are not included in the calculations as they are identical in both cases.

Scenario B – Feeder Tie Case:

This is the scenario where feeder ties are installed over the years 2012, 2013 and 2014 as identified in Table 1. Capital costs are identified in Table 1. Other costs (including customer outage costs and increased maintenance costs associated with additional equipment), expected over the next 20 years are included in the calculations. The station outage incident rate is derived from the last ten years of experience in the downtown Toronto area as for the Base Case. Customer outage duration for the feeder tie case is assumed to be an hour for each incident beginning with the year following installation of station-to-station feeder ties. The kVA interrupted only includes feeders proposed to have feeder ties installed as identified in Table 1. Maintenance costs include $190 per year per new vault. The discount rate used is 6.06%; the customer interruption duration cost is $15 per kWh; and the outage event costs are not included, all as per the Base Case.

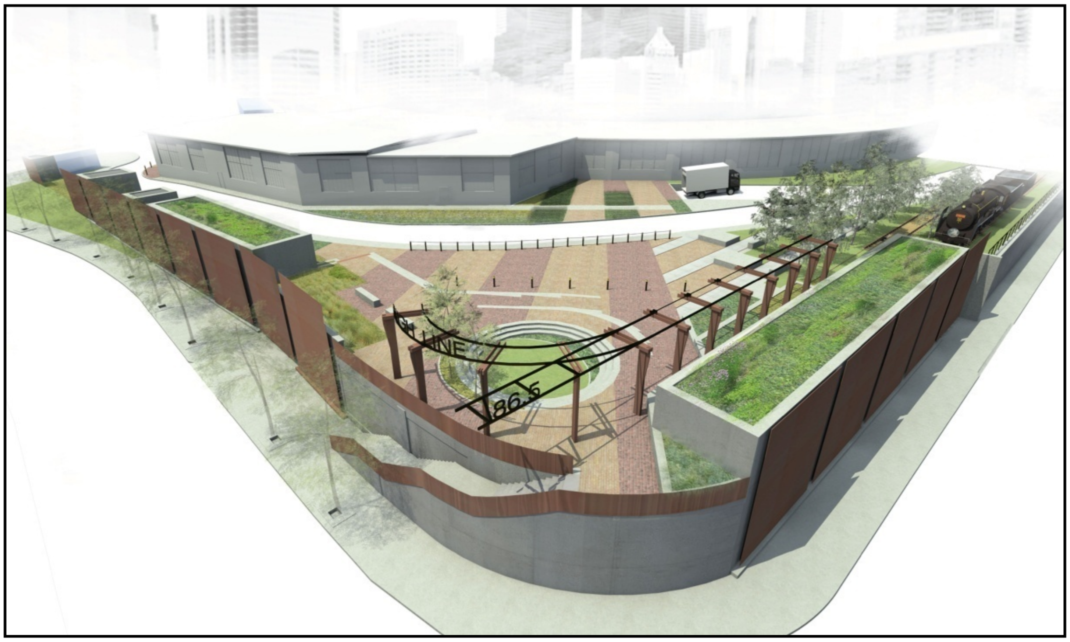
Evaluating both scenarios leads the conclusion that proactive installation of feeder ties is the prudent approach. By mitigating potential customer outages, the net benefit is $0.123 million.

1 **Table 4: Downtown Contingency Outages 2002 through 2011**

YEAR	BUS CODE	INCIDENT NO	START DATE	CMO	CI	OUTAGE DURATION MINUTES	STATION NAME
2003	TOA3A4T	F-2003-1023	11-Jun-03	124343	1703	75	STRACHAN TS
2003			14-Aug-03			2472	DUFFERIN TS
2003	TOA1A2MN	F-2003-2543	01-Dec-03	1573297	10021	157	MAIN TS
2004	TOA7A8A	F-2004-112	27-Jan-04	313774	3555	90	TERAULEY TS
2004	TOA3A4T	F-2004-1252	21-Aug-04	159011	1700	270	STRACHAN TS
2004	TOA3A4WR	F-2004-1277	29-Aug-04	74460	1020	73	WINDSOR TS
2004	TOA17A18WR	F-2004-1602	04-Dec-04	9960	60	243	WINDSOR TS
2005		F-2005-83	23-Jan-05	2304288	3556	632	TERAULEY TS
2005	TOA1A2GD	F-2005-1180	26-Jul-05	4603904	24005	1850	GEORGE & DUKE MS
2007	TOA1A2GL	F-2007-1375	23-Aug-07	1625517	4971	327	GLENGROVE TS
2007	TOA1A2GD	F-2007-1772	27-Nov-07	1023984	6564	156	GEORGE & DUKE MS
2009		F-2009-76	15-Jan-09	37601491	34308	1418	DUFFERIN TS
2009	TOA5A6DN	F-2009-524	09-May-09	2443452	18511	132	DUFFERIN TS
2009	TOA7A8DN	F-2009-525	09-May-09	1104831	8307	133	DUFFERIN TS
2010	TOA1A2T	F-2010-765	05-Jul-10	4022761	36984	138	STRACHAN TS

ICM Business Case Evaluation

Bremner TS



Toronto Hydro-Electric System Limited (THESL)

I EXECUTIVE SUMMARY

In the Ontario Energy Board's (OEB) decision, dated January 5th 2012, it was stated that Toronto Hydro's (THESL) Bremner Transformer Station (TS) Project "appears to be directly analogous to projects that the Board has previously approved under ICM for other distributors". This evidence demonstrates the Bremner project's conformance with the Incremental Capital Module (ICM) model requirements.

The structure of the ICM Business Case for Bremner TS is as follows;

I. Executive Summary
II. Description of Downtown Supply Conditions
III. Need
IV. Options
V. Bremner TS Project Details
VI. Cost Comparison
VII. Conclusions

Also included as attachments to the ICM Business Case are the following appendices:

- Appendix 1: Previous Bremner TS Narratives and Interrogatories
- Appendix 2: Load Growth in the Downtown Toronto area
- Appendix 3: Analysis of Downtown Toronto Supply (Navigant Inc)
- Appendix 4: Decision on Bremner TS Site
- Appendix 5: Bremner TS Site Integration
- Appendix 6: Heritage Impact Assessment
- Appendix 7: Architectural Renderings of Bremner TS
- Appendix 8: Ministry of Environment Decision on Bremner TS EA

The Business Case and supporting appendices describe the Bremner TS project in the context of the developing need for distribution solutions in the Toronto downtown. Previous applications, EB 2009-0139 and EB 2010-0142[1], described the immediate and short term need for a new source of supply. These applications followed over 20 years of study by THESL and Hydro One Networks Inc. (formerly Ontario Hydro) and the Independent Electrical Supply Operator (IESO, formerly IMO) of the immediate and short term need for additional supply in the downtown and the alternative options available to achieve this. The need horizons are illustrated in Figure 1 below.

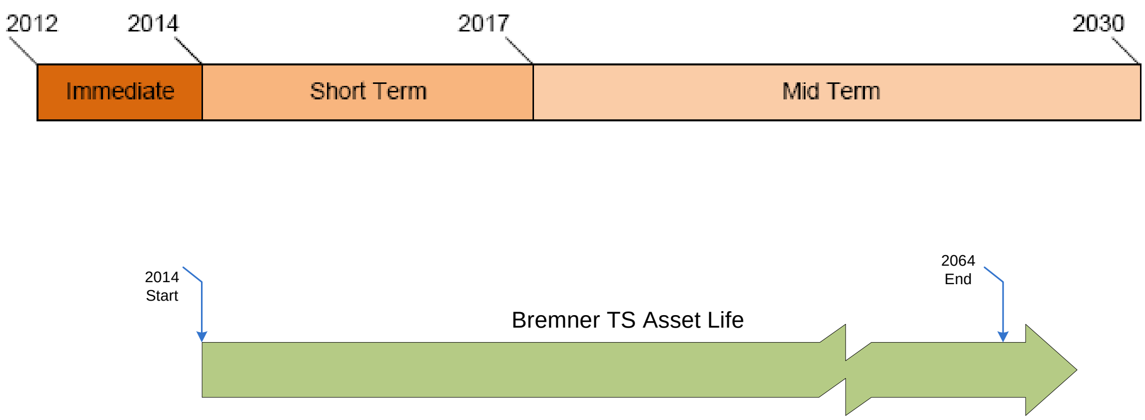


Figure 1: Immediate, Short term and Mid-term Need Timeline

In downtown Toronto, there is an immediate need for additional capacity at Windsor TS in order to enable staged replacements of its end-of-life, air-blast switchgear. There is also a short- and mid-term need for additional capacity to serve load growth in the downtown core. Analysis undertaken by THESL and an external consultant indicates that the requirement for upgrades at the existing Windsor TS is urgent, and when coupled with the foreseeable load growth in the downtown core, the analysis demonstrates that immediate action should be taken to address these issues in the year 2012. The potential consequences of inaction, deferral or embarking on an alternative include increased risk of sustained power outages to the downtown core, directly impacting key customers such as the financial district (housing the Toronto Stock Exchange and the headquarters of at least four of Canada's leading banking institutions), Union Station, the

[1] Detailed in Appendix 1: Previous Bremner TS pre-filed evidence and Interrogatory responses

Canadian Broadcasting Company (CBC), Rogers Centre and the Metro Toronto Convention Centre (MTCC).

As identified and explained in this evidence, the most cost effective and viable options to enable both Windsor switchgear replacement and address future capacity needs, are: the construction of a new station, Bremner TS, on Bremner Boulevard at Rees Street (the "Bremner TS Project"); or the expansion of the existing Esplanade TS and Strachan TS. Bremner TS is preferable due to several factors, including the electrically central location of the station, the ability to back-up feeders from adjacent substations, and the need to provide back-up to Windsor while switchgear is replaced. The alternative solution relies on the expansion of Esplanade TS and Strachan TS, which are both located outside the existing downtown (Windsor TS) supply area. Installation work for medium voltage cables to pick up downtown loads would require extensive disruption in the downtown core in order to extend the supply area of Esplanade and Strachan over two kilometres.

The Bremner TS project is expected to effectively address all identified needs. The site of the project presently houses the historic John Street Roundhouse and Machine Shop, opposite the CN Tower. The proposed Bremner Transformer Station will be a site-integrated facility, consisting of a structure bounded at the north by Bremner Boulevard and to the south by Lakeshore Boulevard, above which the existing Machine Shop will be re-assembled. The Machine Shop will house the protection and control and station service equipment, while the major equipment (transformers, switchgear, cabling, etc) will be housed below. The electrical supply for the station will be taken from existing 115kV electrical circuits within Hydro One's Front St tunnel. From the tunnel, cables will be routed via a new underground cable tunnel to the Bremner TS where the 115kV voltages will be stepped down, through transformers, for distribution to customers.

The Roundhouse site area, where the Bremner TS will be constructed, is both a federally and municipally designated heritage site. Therefore, the building is required to comply architecturally with heritage requirements applicable to the site as discussed in Appendix 6.

ICM Project | Bremner TS

THESL is requesting, under Section 84(a) of the OEB act, that Bremner TS be deemed a distribution asset, for which cost recovery is through distribution rates.

The preliminary development work, including detailed engineering design and land acquisition has been completed on Bremner TS with expenditures approved in EB-2009-0139 and EB-2010-0142. Successful stakeholder engagement has been completed, including Public Information Centres (PICs). Information from these PICs as well as detailed information on the Environmental Site Reports has been compiled and made public on the Toronto Hydro Bremner TS website[2]. A Bremner TS presentation was delivered to the OEB staff on August 19, 2011. The Environmental Assessment for Bremner TS has been completed and THESL has received approval to proceed. Detailed drawings and specifications have been prepared as well as many procurement documents. Requests for Proposals (RFPs) have been issued on long-lead equipment.

THESL proposes to execute Bremner in two phases. For 2012, THESL proposes to begin the first phase and enter into commitments with suppliers and contractors so that construction can be initiated by Q3 of that year. Construction for the project is expected to be completed over a 24 month period and, if construction begins in Q3 2012, the Transformer Station is scheduled to be constructed by Q2 2014. A block diagram has been included in Figure 10 of this document to set out the tasks to be completed in 2012 in order to start construction. The 2014 completion date is aligned with the THESL TS Switchgear Replacement ICM for the Windsor TS A5-6WR replacement. In order to enter into long-term commitments with suppliers and contractors, approval for multi-year funding is required from the OEB.

THESL's project budget for Phase 1 of Bremner TS is an estimated $194.9 million. The project estimate has increased by $66.3 million over the previous budget reported in EB 2010-0142. This cost increase is attributed to the progression of the project from the conceptual design phase to the detailed design phase. The three largest factors are Hydro One capital contribution increases ($40 million), building cost increases ($21.3 million) and tunnel construction ($14.6

[2] See http://www.torontohydro.com/sites/electricsystem/powerup/Pages/BremnerStationProject.aspx

million). In addition, project savings have been estimated at $9.6 million due to reductions in costs for substation equipment, distribution modification and design. Also, THESL is continuing to work with Hydro One to explore opportunities to reduce the costs associated with detailed design and construction of the transmission component of the project. Total project expenditures to date are $10.8 million, of which $5.6 million was for the purchase of the land and $5.2 million was for the detailed design and environmental assessment costs.

Recognizing the significance of this capital expenditure, THESL conducted an analysis of deferring Bremner TS and pursuing other supply alternatives, to ensure cost effectiveness.

Deferring Bremner TS would result in the expansion of Esplanade TS and Strachan TS to address the immediate, short term and mid-term needs. However, load growth beyond 2030 would require another solution beyond that point. As a result, THESL conducted a cost analysis of an Esplanade TS and Strachan TS expansion, followed by Bremner TS Phase 1, and then compared this solution to the alternative approach of executing Bremner Phase 1, Bremner Phase 2 and Esplanade TS in succession as discussed in Section VI below and detailed in Appendix 3.

Although comparison of the asset life for the transformer stations has not been formally included in the cost analysis, an additional reason for preferring construction of Bremner TS is that it will create a brand new asset in contrast to alternatives that would continue reliance on rapidly aging distribution assets.

THESL also reviewed solutions for TS installations in other metropolitan jurisdictions to compare and validate current plans and estimates. The conclusions from this analysis reaffirmed that proceeding with the current course of the Bremner TS project is THESL’s preferred option.

For 2012, an estimated total of $37.7 million has been requested (for THESL and Capital Contribution to Hydro One) so that the 24-month construction phase can be initiated. For 2013, an estimated total of $96.4 million has been requested to continue the construction phase. For 2014, an estimated total of $50.0 million has been requested to complete the construction phase. The total amount requested for 2012 to 2014 is $184.1 million.

ICM Project | Bremner TS

1 **Table 1: Requested costs for Bremner TS Phase 1**

Estimated Project Costs ($, millions)	2012 Test	2013 Test	2014 Test	Total
THESL Budget	31.7	69.4	23.0	124.1
Capital Contribution to Hydro One	6	27.0	27.0	60.0
Total	**37.7**	**96.4**	**50.0**	**184.1**

II DESCRIPTION OF DOWNTOWN SUPPLY CONDITIONS

The City of Toronto is the fifth largest metropolitan area in terms of population in North America. Between 2006 and 2011, the City's downtown core experienced an increase in population by over 50%, while the City as a whole experienced an increase of 9.2%.

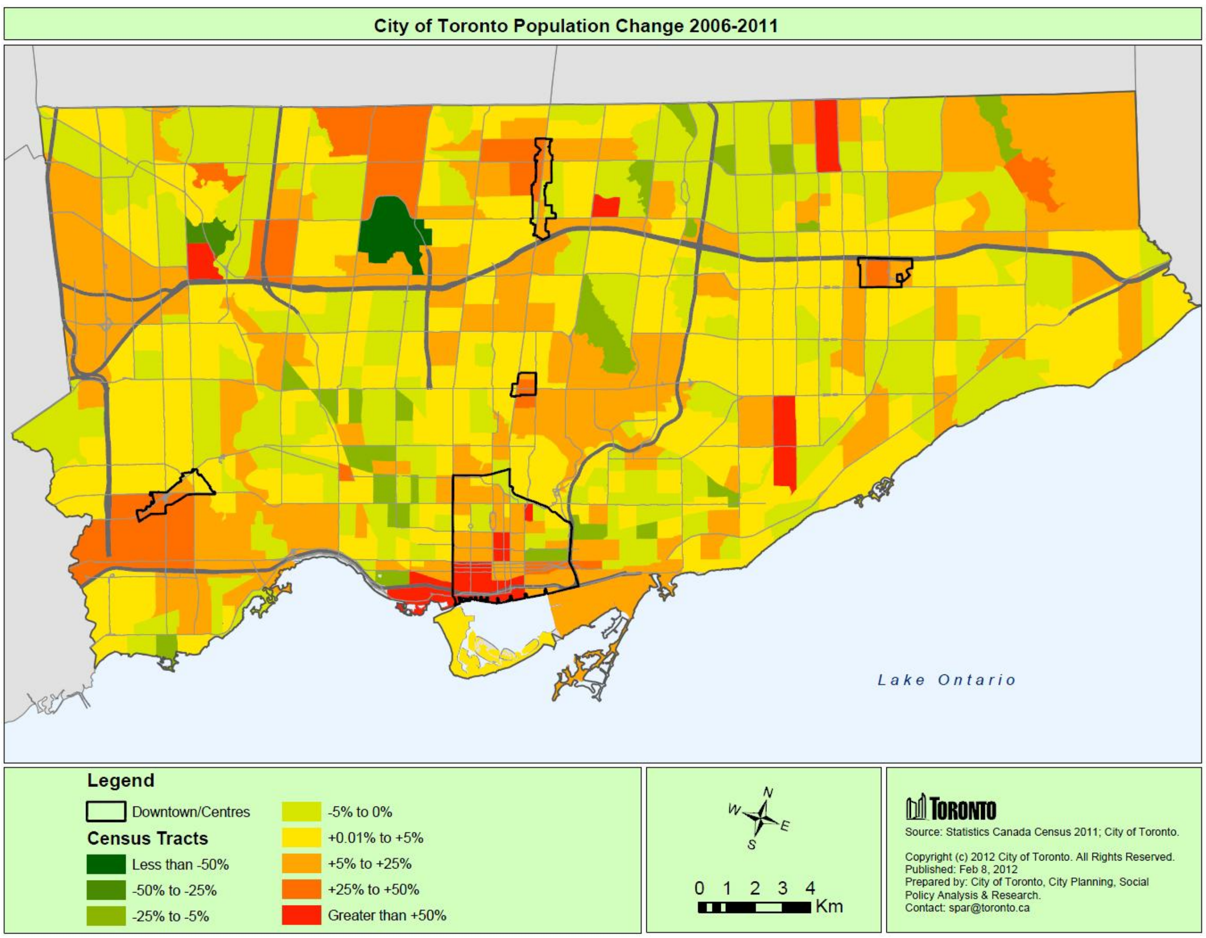


Figure 2: City of Toronto Population Change, 2006-2011

In the downtown core of the City, the load density and type of load served are such that continuity of service to electric load cannot be compromised. A key example of uninterruptable load served in the downtown core is the city's financial district. The district is home to the Toronto Stock Exchange for which a total capitalization of $1.9 trillion US dollars makes it the largest stock exchange in Canada, the third largest stock exchange in North America and the eighth largest stock exchange in the world[3]. Also located in the financial district are the headquarters of at least four of Canada's leading banking institutions. In addition, the downtown core is composed of a number of major commercial high-rises, hotels, tourist destinations and residential condominiums. As a result of Toronto's high rise boom (for which it has been recognized as the leading North American City in number of high rises under construction[4]), a large number of new commercial and residential high rises are under construction in the area.

The total load served by Toronto Hydro to the City of Toronto (in its entirety) is approximately 5,000 MW, supplied by 35 stations. Of this 5,000 MW total load, the downtown Toronto load is approximately 2,000 MW. Of the downtown load of 2,000 MW, about one-half (or 1,000 MW) is supplied by five stations in the core of downtown Toronto. Figure 3 below highlights the location of these five stations (Strachan TS, Cecil TS, Windsor TS, Terauley TS and Esplanade TS) and areas served.

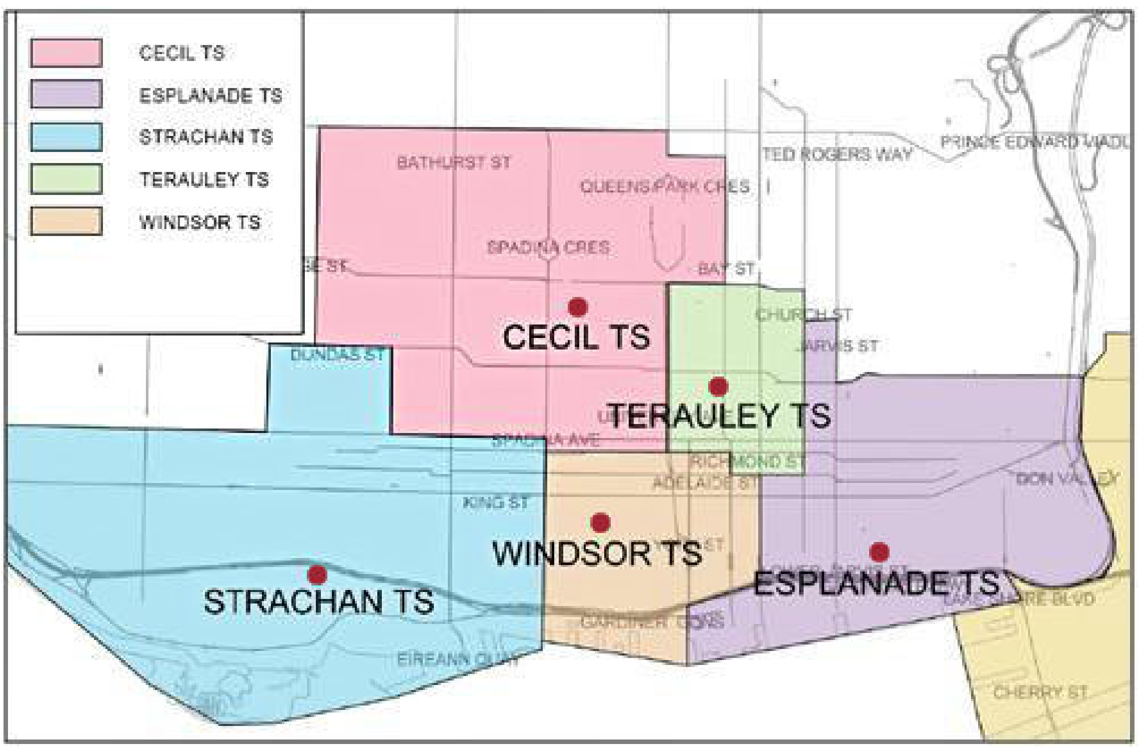


Figure 3: 5 Transformer Stations in downtown Toronto

[3] http://www.world-exchanges.org/files/file/stats%20and%20charts/2011%20WFE%20Market%20Highlights.pdf
[4] http://www.toronto.ca/legdocs/mmis/2011/ed/bgrd/backgroundfile-41174.pdf

III NEED

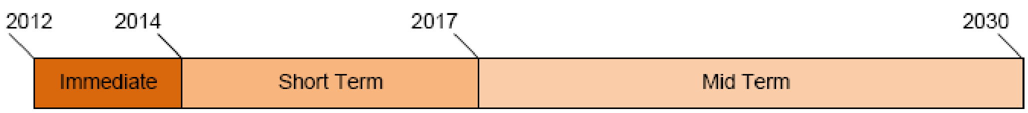


Figure 4: Immediate, Short Term and Mid-Term need timeline

1. Immediate Need (By 2014)

Windsor TS is currently using end-of-life air blast switchgear to supply key customers in Toronto's financial district. This 13.8 kV air blast switchgear, which was installed in 1956, needs to be replaced in stages (one bus at a time). In order to do so, existing loads served by the affected equipment will need to be transferred to another supply source, with 72 MVA capacity. This is an immediate need and action should be taken to complete this transfer as soon as is physically possible. The Windsor TS switchgear upgrade work has been included separately in the Stations Switchgear segment found at Tab 4, Schedule B13.2, Section II, 4.

2. Short-term need (2014 to 2017)

In the short-term, additional capacity will be required to avoid overloading at three of the five key downtown stations.

THESL completes load forecasts for each of the 35 stations in downtown Toronto on a yearly basis. The methodology associated with these forecasts has been summarized in Appendix 2 to this narrative.

Based on THESL's load forecast, Table 2 below summarizes the anticipated load increases for the five downtown stations to 2017. As indicated in Table 2, overloading at Windsor TS is expected to occur by 2017. In addition, overloads at Esplanade TS, Terauley TS, and Cecil TS are expected to occur soon thereafter (2018, 2020 and 2021 respectively). Action must therefore be taken to have new total capacity of 144 MVA available to avoid these overloads prior to 2017.

Table 2: Load Forecasts for five downtown Toronto Stations (Highlighting Shows Overload)

Station	Station Rating	Year						
		2011	2012	2013	2014	2015	2016	2017
Cecil	224	182	189	196	199	203	207	212
Esplanade	198	175	173	177	182	187	192	196
Strachan	175	122	127	130	131	133	140	143
Terauley	240	199	205	211	215	220	225	229
Windsor	340	304	306	315	324	328	335	342
Total	1,177	982	1,000	1,029	1,051	1,071	1,099	1,122

3. Mid-term need (2018 – 2030)

Also based on THESL's load forecast, Figure 5 below indicates a consistent load growth to 2030 with a load of approximately 288 MVA over and above the total station capacity that is available today. Therefore, for effective life cycle planning it would be prudent to at least incorporate incremental growth options for future expansion, by having the space ready to accommodate for additional switchgear that could supply these loads in future.

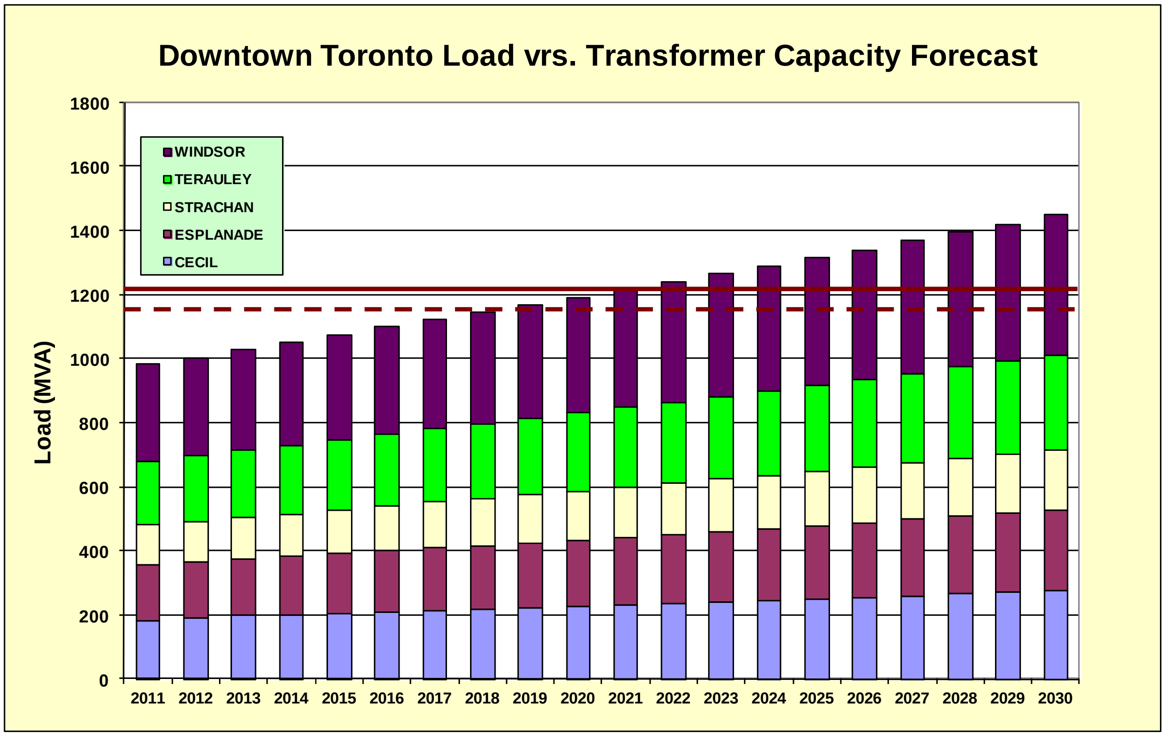


Figure 5: Load Forecasts by station

Note: Dashed horizontal line represents 95% firm capacity of five stations, solid horizontal line represents 100% firm capacity of firm stations.

4. Consequences of Deferral

In addition to the above noted capacity constraints, the equipment asset condition at Windsor presents what THESL regards as an unacceptable risk. Deferring switchgear replacement at Windsor TS will lead to continued reliance on custom equipment repairs on the aging, obsolete equipment. This stopgap approach is unsustainable and, even with these actions, the reliability of this obsolete equipment will continue to decline, leading to increased risk of failure. Equipment failure at Windsor TS is considered one of THESL's highest risk events due to both the state of equipment and the critical loads it supplies. There is no alternate supply to customers should a switchgear fail, and restoration time would be measured in days, possibly weeks, depending on the failure scenario. The work associated with upgrading Windsor TS has already been planned for 2014 and is discussed separately at Tab 4, Schedule B13.2, Section II, 4.

In addition, Windsor TS and its neighbouring stations will be unable to accommodate additional load growth in the short-term and mid-term due to the high loading already experienced at these existing stations.

IV OPTIONS

1. Assessment and Selection Criteria

Based on the previously defined supply needs in Section III of this document, potential solutions have been selected, based on their ability to simultaneously address the following:

Table 3: Criteria for selection of options

Criteria	Need	Description	Incremental Capacity Required (MVA)
1	Immediate	Windsor Upgrades	72
2	Short-Term	Overloading at key stations	72
3	Mid-Term	Load Growth to 2030	144
		Total Supply Capacity Required	**288**

2. Options Reviewed

A number of potential solutions to address the aforementioned needs were assessed as part of the attached Analysis of Downtown Toronto Supply in Appendix 3. A summary is given below.

2.1. Bus-to-bus Load Transfer and/or Addition of buses within Windsor TS

There is insufficient capacity available on the bus structure within Windsor TS to support load transfer or load growth due to high loading. Furthermore, there is insufficient physical space in the station, or room in the yard for station expansion, to accommodate additional capacity by way of new switchgear. This alternative would be unable to address any of the immediate, short or mid-term needs and has therefore been ruled out.

2.2. Upgrade of Existing Adjacent Hydro One Transformer Stations

As evidenced by loading data presented earlier in this document, the four existing stations adjacent to Windsor TS have insufficient firm existing capacity to accommodate a load transfer and would therefore have to be upgraded to do so. Of the four stations, only two (Hydro One's

Esplanade TS and Strachan TS) have the space for expansion to provide new capacity. Table 4 below indicates the estimated capacity that can be added to Esplanade TS and Strachan TS based on available space:

Table 4: Potential capacity for Esplanade TS and Strachan TS

Station	Capacity	
	Number of 13.8 kV switchgear	Added capacity (MVA)
Esplanade TS	3	216
Strachan TS	1	72

Therefore, either Strachan TS or Esplanade TS could potentially be expanded to address the immediate need (72 MVA). However, the two stations are each just over two kilometres away from Windsor TS and thus outside of the existing Windsor TS supply area. In order to offload Windsor, feeders would have to be routed from each of the expanded stations to the Windsor area. Installation work for underground cables to pick up Windsor TS feeders would be required across existing supply areas, and disruption due to construction would be extensive on city streets such as Wellington Street, John Street, Windsor Street and Front Street. This would affect area businesses which include the CBC, Metro Hall and the Metro Toronto Convention Centre, as well as the financial district. In addition, Esplanade TS and Strachan TS have to maintain enough capacity to supply load to future developments within their supply area. For example, Esplanade TS will need to be utilized to supply the coming loads as a result of the City of Toronto's West Don Lands[5] and East Bayfront[6] projects in its vicinity.

In order to address all three criteria (288 MVA total), Strachan TS and Esplanade TS would have to both be expanded. As with the solution for the immediate need, distribution from the two stations to the projected load center (roughly in the vicinity of the Bremner site) would be extensive and highly disruptive to businesses in the area. In addition, this approach would likely involve development of two separate project sites that would each require separate designs and environmental assessments.

[5] http://www.waterfrontoronto.ca/explore_projects2/west_don_lands
[6] http://www.waterfrontoronto.ca/explore_projects2/east_bayfront

In summary, these solutions are technically viable and physically executable, but not ideal due to distance from the load center, complexity of construction and risks associated with site approvals.

2.3. Bremner TS

THESL owns a property bounded by Bremner Blvd, Rees St and Lakeshore Blvd. As illustrated in Figure 6 below, the site is within the existing supply area of Windsor TS, as well as the new supply area that is emerging in downtown Toronto and the Waterfront area.

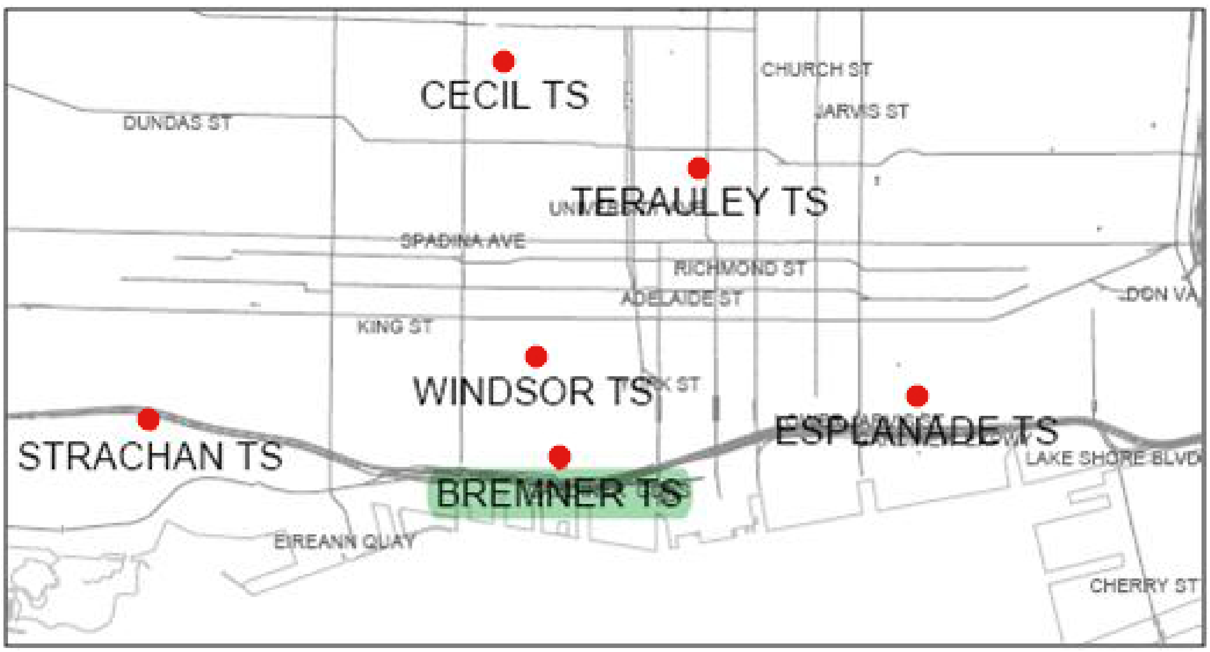


Figure 6: Proposed location for Bremner TS

Once developed, the site footprint would be sufficient to accommodate 288 MVA of additional capacity and would therefore be able to meet the immediate, short-term and mid-term needs.

Table 5: Potential capacity for Bremner TS

Bremner	Cumulative Additions	
	Number of 13.8 kV switchgear	Added capacity (MVA)
Phase 1	2	144
Phase 2	4	288

In order to address the immediate need, Bremner TS can incorporate dedicated 13.8 kV switchgear to relieve Windsor TS. There are existing cable ducts installed by THESL along Bremner Boulevard to facilitate feeder egress from Bremner TS, minimizing the distribution infrastructure work that would be required. The same feature applies also to both the short- and mid-term needs.

This makes the Bremner TS solution advantageous from a distribution perspective.

3. Summary

A summary of the five options reviewed and the suitability for meeting the aforementioned criteria is presented in Table 6 below.

Table 6: Options available to meet criteria

Criteria	Description	Estimated Capacity Required	Bus transfer/addition at Windsor	Expansion of Esplanade TS (216 MVA)	Expansion of Strachan TS (72 MVA)	Expansion of Esplanade TS and Strachan TS (288 MVA)	Bremner TS (288 MVA)
1	Windsor upgrades	72 MVA	N	Y	Y	Y	Y
2	Avoid overloading at key stations	144 MVA	N	Y	N	Y	Y
3	Address load growth to 2030	288 MVA	N	N	N	Y	Y

('Y' indicates that option is able to meet criteria; 'N' indicated that option is unable to meet criteria)

Based on the above assessment, the two options available to meet both the Windsor switchgear replacement and future capacity needs include the implementation of the new Bremner Transformer Station or expansion of the existing Esplanade and Strachan Transformer Stations. Bremner is the preferred option for the reasons provided in the following paragraphs.

Bremner TS would be able to address the immediate need of offloading Windsor TS by 2014 whereas Esplanade/Strachan expansion will do so by 2016. Bremner TS would achieve the Windsor TS offloading by 2014 due to the extensive planning, design and procurement work that has already been completed for Phase 1 of the Bremner TS project. By comparison, no planning, design or procurement work has been completed for either Strachan TS or Esplanade TS and this would delay an in-service date for new switchgear at the site to 2016.

Distribution infrastructure is already installed to interconnect Bremner TS and Windsor TS. If Bremner TS is brought into service in 2014, minimal work would be required in order to establish the tie between the two stations and enable the load transfer from Windsor TS to Bremner TS. However, if Bremner TS is delayed, and Esplanade TS and Strachan TS are developed instead, significant underground distribution infrastructure work would have to be completed in order to establish the ties between these stations and Windsor TS. This work will be highly disruptive to the Rights of Way of the City of Toronto over a series of months and, as a result, impact the businesses located in the immediate area.

Based on this analysis, and the cost comparison in Section VI, Bremner TS is THESL's preferred approach for addressing the supply needs for downtown Toronto.

V BREMNER TS PROJECT DETAILS

1. History

For over 20 years, Bremner TS (formerly "Roundhouse TS", "Railway Lands TS") has been a key component of plans to provide additional electrical supply in the downtown Toronto core. As evidenced in Appendix 4 to this document, the current Bremner TS site was previously owned by Hydro One from 1992 to 2010, with the intent of developing it into a new transformer station. This intent is further evidenced in a 2003 joint study by Hydro One and THESL titled *Electrical Supply for the City of Toronto*[7], in which Bremner TS was previously referenced as "Roundhouse TS." In addition, a System Impact Assessment (SIA) was completed by the Independent Electricity System Operator (IESO, formerly IMO) in 2004, which references a "Railway Lands TS" as part of the plans.[8]

2. Project Objectives

The site of Bremner TS is located in downtown Toronto, in close electrical proximity to Windsor TS, and to existing THESL duct banks that will permit the linking of the two stations. The site is well located with respect to the high voltage connection, and provisions exist for the interconnection at 115 kV. Its location and the planned design satisfy the objectives of:

- permitting the removal from service and the replacement of end-of-life switchgear at Windsor TS;
- mitigating the effects of high-impact low probability station events (i.e., major station outages) by enabling load transfers between stations; and
- providing a source of supply for anticipated load growth within downtown Toronto.

In order to address the immediate need defined in section II of this document, the Bremner TS project is expected to provide the required capacity needed to facilitate staged replacements of end-of-life, air-blast switchgear at Windsor TS, reducing the risk of customer outages due to equipment failure. Over the short and mid-term, it will also reduce the overall loading levels at Windsor TS, thereby diversifying customer supply and mitigating high impact, low probability

[7] http://www.ontarioenergyboard.ca/documents/cases/EB-2005-0315/report_150405.pdf
[8] http://www.ieso.ca/imoweb/pubs/caa/caa_SIA_Toronto_ThirdSupply.pdf

station events. Lastly, the project will also provide capacity relief to neighbouring stations by enabling distribution load transfers to occur, and provide increased capacity to accommodate the large-scale customer growth in downtown Toronto.

Windsor TS (referred to as John TS by Hydro One) was built in 1950 and expanded in 1968 to become one of the largest 13.8 kV substations in Toronto, serving 6% of the City's load. The 13.8 kV air-blast switchgear, installed in 1956, is at end-of-life and needs to be replaced in stages, one bus at a time. In order to replace the end-of-life switchgear at Windsor TS, existing bus loads of 72 MVA on the affected equipment will need to be supplied from a new source first. In addition, a new source is also needed to reduce the increasing loading levels at the five downtown core TS, because no spare feeder positions are available and there is insufficient room for additional switchgear at these stations. The supply to existing downtown customers also needs to be diversified to mitigate the effects of high-impact, low-probability station events such as fire or flooding.

3. General Scope

Early in the design process, the decision was made to integrate the station into its surroundings. The details of this decision making process are included in Appendix 5 to this document.

The Bremner Transformer Station will be a site-integrated facility, consisting of a structure bounded at the north at Bremner Boulevard and to the south at Lakeshore Boulevard, above which the existing Machine Shop will be re-assembled. The Machine Shop will house the protection and control and station service equipment, while the major equipment (transformers, switchgear, cabling, etc.) will be housed below. The protection and control equipment within the Machine Shop facility will be designed in compliance with NERC (North American Electric Reliability Corporation) standards for reliability.

An underground cable tunnel will be constructed from the existing Front St underground tunnel (linking Windsor TS and Esplanade TS) to the proposed site for the station on Bremner Blvd. Figure 7 shows a plan layout for the scope of work.

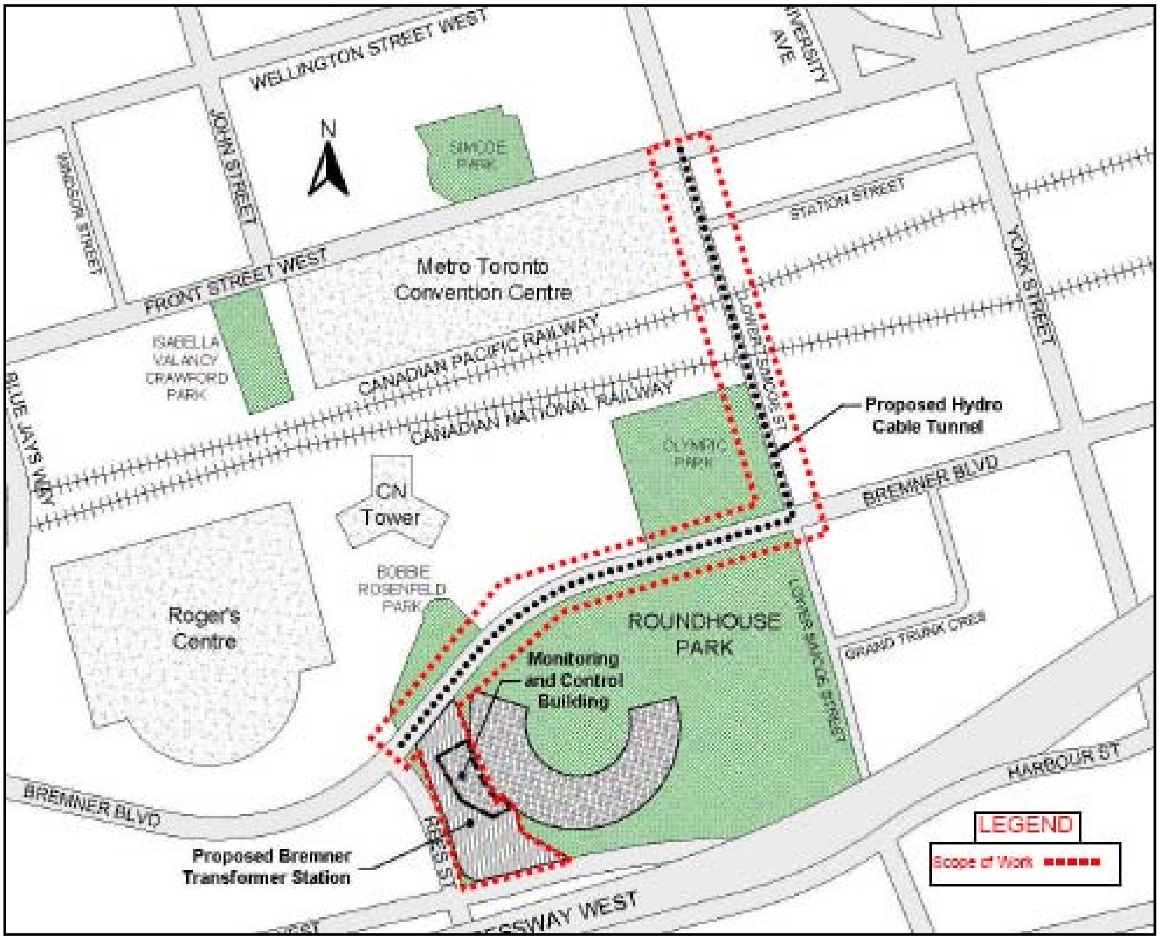


Figure 7: Plan layout of project scope

The electrical supply for the station will be taken from existing electrical circuits within Hydro One's Front Street tunnel. From there, the cables will be routed to the Bremner Transformer Station where the 115 kV will be stepped down to 13.8 kV for distribution to customers.

Electrically, the major components of the station will ultimately consist of interface equipment with Hydro One incoming circuits, 115 kV switchgear, five 144 MVA 115 kV/13.8 kV-13.8 kV transformers, five 13.8 kV switchgear, protection and control and other ancillary equipment. In its first phase, the project will provide 144 MVA of new capacity. Table 7 shows the capacities and associated quantity of major equipment for the 2012 to 2014 construction for the project (Phase 1) and the ultimate completed station at full capacity (Phase 2).

Table 7: Station Capacity for Bremner TS

Equipment	Phase 1 of Bremner TS, 2012-2014	Total Ultimate (Phase 1 and Phase 2)
Station Capacity (MVA)	144	288
Qty, 115 kV Switchgear	1	1
Qty, 144 MVA Transformers	2	5
Qty, 13.8 kV Switchgear	2	5

4. Work completed to date

4.1. Land acquisition

As summarized in Appendix 4 to this document, the Bremner Transformer Station site is the ideal location to address the supply needs for downtown Toronto. In December 2010, the site was purchased from Hydro One by THESL.

4.2. Detailed engineering design

From January 2011 to December 2011, detailed engineering design was completed for the Bremner Transformer Station and cable tunnel. The design work was completed by external consultants selected through competitive bids (IBI Group for transformer station, MMM Group for cable tunnel) who relied on input from key THESL departments.

The end products of the design process were detailed project specifications and drawings packages. The table of contents for the Transformer Station design documents is set out below in Table 8.

1 **Table 8: Table of Contents for Bremner TS Drawings and Specifications**

Package	Div	Description	Number of Pages
Specification	0	Procurement	55
	1	General Requirements	100
	2	Existing Conditions	48
	3	Concrete	18
	4	Masonry	33
	5	Metals	13
	6	Wood, Plastics and Composites	65
	7	Thermal and Moisture Protection	87
	8	Openings	55
	9	Finishes	8
	10	Specialties	3
	11	Roof Anchor System	14
	14	Conveying Equipment	31
	21	Fire Suppression	41
	22	Plumbing	239
	23	Heating, Ventilating and Air-conditioning	69
	25	Integrated Automation	200
	26	Electrical	54
	28	Electronic Safety and Security	33
	31	Earthwork	39
	32	Exterior Improvements	58
	33	Utilities	12
	41	Trolley, Hoist and Bridge crane	11

Package	Div	Description	Number of Pages
Drawings	C	Civil	10
	L	Landscape	11
	A	Architectural	43
	S	Structural	82
	M	Mechanical	40
	E	Electrical	123
		Total	**1,595**

4.3. Stakeholder Engagement

From January 2011 to present, extensive communication has been successfully completed with key stakeholders for the project. A summary of these communications is in the table below:

Table 9: Summary of external stakeholder engagements

Stakeholder	Event	Discussion	Dates
Ontario Energy Board Staff	Status update	Status update	Aug 19th, 2011
General Public	Public Information Centre	Bremner-specific discussion inviting members of public interested in learning more on the project.	Mar 16th 2011 May 2nd 2011
	Town Halls	General THESL town hall meeting of which Bremner TS was a featured project.	Nov 15th 2011 Nov 17th 2011 Nov 28th 2011 Nov 30th 2011

Stakeholder	Event	Discussion	Dates
Roundhouse Stakeholders	Regular project meeting	Status update on Bremner TS project	March 24th, 2011 May 10th, 2011 Jul 26th, 2011 Sep 14th, 2011 Oct 25th, 2011 Nov 28th , 2011 Jan 31st, 2012
City of Toronto (various departments)	Status update	Status of permits / agreements, etc/	March 16th, 2011 – Planning May 2nd, 2011 – Planning June 14th, 2011 – Heritage Nov 10th, 2011 – Heritage Nov 22nd, 2011 - Real Estate
Stakeholders in geographical vicinity of project	Status update	Status update	May 27th, 2011 – Ripley's Aug 26th, 2011 – Ripley's Oct 18th, 2011 – Metro Toronto Convention Centre Nov 15th, 2011 – CN Tower Aug 31st, 2011 - 100th Anniversary CFL Dec 1st, 2011 - Enwave

Stakeholder	Event	Discussion	Dates
Hydro One	Regular project meetings	Technical, legal, regulatory details for the project	July 14th, 2011 July 19th, 2011 July 26th, 2011 July 28th, 2011 Aug 11th, 2011 Aug 25th, 2011 Oct 28th, 2011 Dec 19th, 2011 Feb 13th, 2012 Feb 15th, 2012

In addition, THESL created a public website where information on the project could be readily accessed by interested members of the public. Between October 2011 and March 2012, the site had registered a total of almost 2,000 unique page views. A screen capture of the site is presented in the figure below:

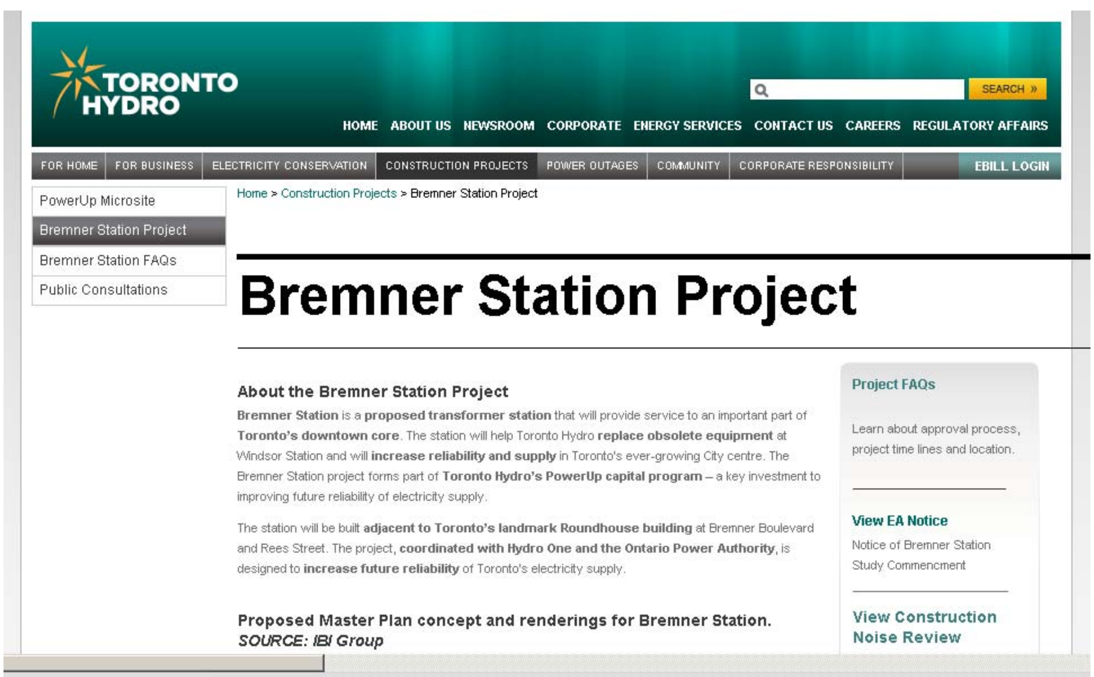


Figure 8: Screen Capture of THESL public website for Bremner TS

4.4. Environmental Assessment

Detailed Environmental Study Reports were completed and posted on the aforementioned THESL website in August 2011. From August 2011 to April 2012, more work was done with the Ministry of Environment (MOE) to clarify the environmental impacts of the project to the immediate surroundings. In April 2012, the MOE advised THESL that the Environmental Assessment was complete and that THESL had approval to proceed. The letter from the Ministry of Environment is included as Appendix 8 to this document.

4.5. Procurement

With a 95% complete detailed design, THESL was able to prepare Requests for Proposals (RFPs) associated with key components of the project. RFPs that have already been issued, or are ready to be issued, issue are summarized below:

- Gas Insulated Transformers, issued June 27, 2011
- High Voltage Switchgear, issued November 17, 2011
- Construction Services, ready for issue

5. Work to be completed

5.1. Phase 1 of Construction of the Transformer Station (2012 - 2014).

Phase 1 is the basis of the 2012-2014 ICM filing and is detailed below.

5.1.1. Disassembly of Machine Shop

The existing Machine Shop, located upon the land owned by Toronto Hydro, must be removed in order to proceed with development of the Transformer Station. Since the site is a designated historic site, the Machine Shop must be disassembled in compliance with the heritage requirements. Specifically, the Machine Shop must be disassembled, catalogued and stored off-site in anticipation for eventual reassembly once construction of the Transformer Station is completed. The heritage requirements for disassembly are detailed in the Heritage Impact Assessment, which has been included as Appendix 6 to this document.

5.1.2. Shoring and Excavation

Once the Machine Shop has been disassembled, the site is expected to be shored and excavated. Since portions of the Transformer Station will be below grade, soil will be excavated below the current Bremner Boulevard grade level to accommodate the structure. Tests indicate that some percentage of the excavated soil is likely to be contaminated and will therefore have to be remediated in compliance with applicable laws.

5.1.3. Structural Work (Construction of the Transformer Station building)

Upon completion of the shoring and excavation components of the work, the structure of the Transformer Station is expected to be constructed in the open pit using poured concrete and structural rebar. The ventilation stacks for the Transformer Station building, visible along Rees Street and Lakeshore Boulevard, will be dressed with corten steel panels in order to maintain the heritage aesthetic of the site.[10] As a demonstration of this, architectural renderings of the completed building have been included in Appendix 7 to this document.

5.1.4. Equipment Installation

With the structure completed, all major equipment (2 transformers, high voltage gas insulated switchgear, medium voltage switchgear) is expected to be installed and interconnected. In addition, mechanical and electrical building services will be installed and interior finishes will be completed.

5.1.5. Reassembly of Machine Shop

Once the structure is built, the Machine Shop is expected to be re-assembled directly above, using the same building materials that were stored during the disassembly phase. The Machine Shop building is expected to be used to house the protection and control equipment for the Transformer Station. By code, the Machine Shop will therefore have to be built to post-disaster requirements, which involves strengthening its structure to withstand potentially disastrous events. As with the disassembly process, the reassembly of the structure will also be in

[10] Corten steel is specially formulated to weather to an aged patina.

compliance with the heritage requirements summarized in the Heritage Impact Assessment in Appendix 6 of this document.

5.1.6. Construction of cable tunnel

Concurrent with the building construction work, a 600-metre underground cable tunnel is expected to be constructed from the existing Front Street tunnel to the Transformer Station. The existing Front St tunnel has accommodated this by way of a 'break-out' (depicted in Figure 9 below) from which the new tunnel for Bremner TS can be constructed.

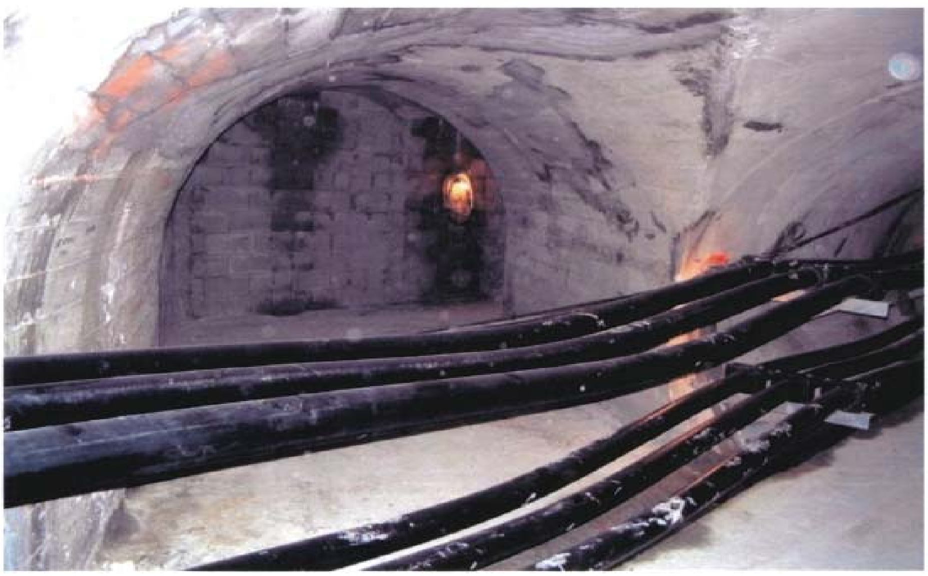


Figure 9: Breakout at existing Front Street tunnel

5.1.7. Station Commissioning

With all civil work and electrical interconnections completed, the station will be tested and commissioned before it will be able to supply new load.

5.2. Phase 2 of Construction of the Transformer Station (2021)

This involves the installation of additional transformers and medium voltage switchgear within the available space in the Transformer Station to supply additional loads as they increase from 2021 to 2030. This scope of work is not included in the capital costs requested in this filing.

5.2.1. Project Timelines

In 2010, with approval from the Ontario Energy Board (EB-2009-0139), THESL acquired the land for the new station and engaged a consultant (IBI Group) to start detailed engineering.

In 2011, with approval from the OEB for that year (EB-2010-0142), detailed design for the station was completed to 95%. Concurrently, stakeholder engagement was completed by way of Public Information Centres (PICs) and presentations to key parties. THESL has also been working with IBI Group to process Requests for Proposals (RFPs) for major equipment and construction services for the Transformer Station.

For 2012, THESL's objective is to initiate Bremner TS Phase 1 and enter into commitments with suppliers and contractors so that construction can begin by August of that year. In order to enter into long-term commitments with suppliers and contractors, approval is required for 2012, 2013 and 2014 funding.

For 2013, THESL's objective is to complete construction of the cable tunnel and the Transformer Station building.

For 2014, THESL's objective is to complete reassembly of the Machine Shop building and commission the site in Q3 of that year.

A summary of tasks requiring execution for the two-year construction process for Bremner TS has been illustrated in Figure 10.

ICM Project | **Bremner TS**

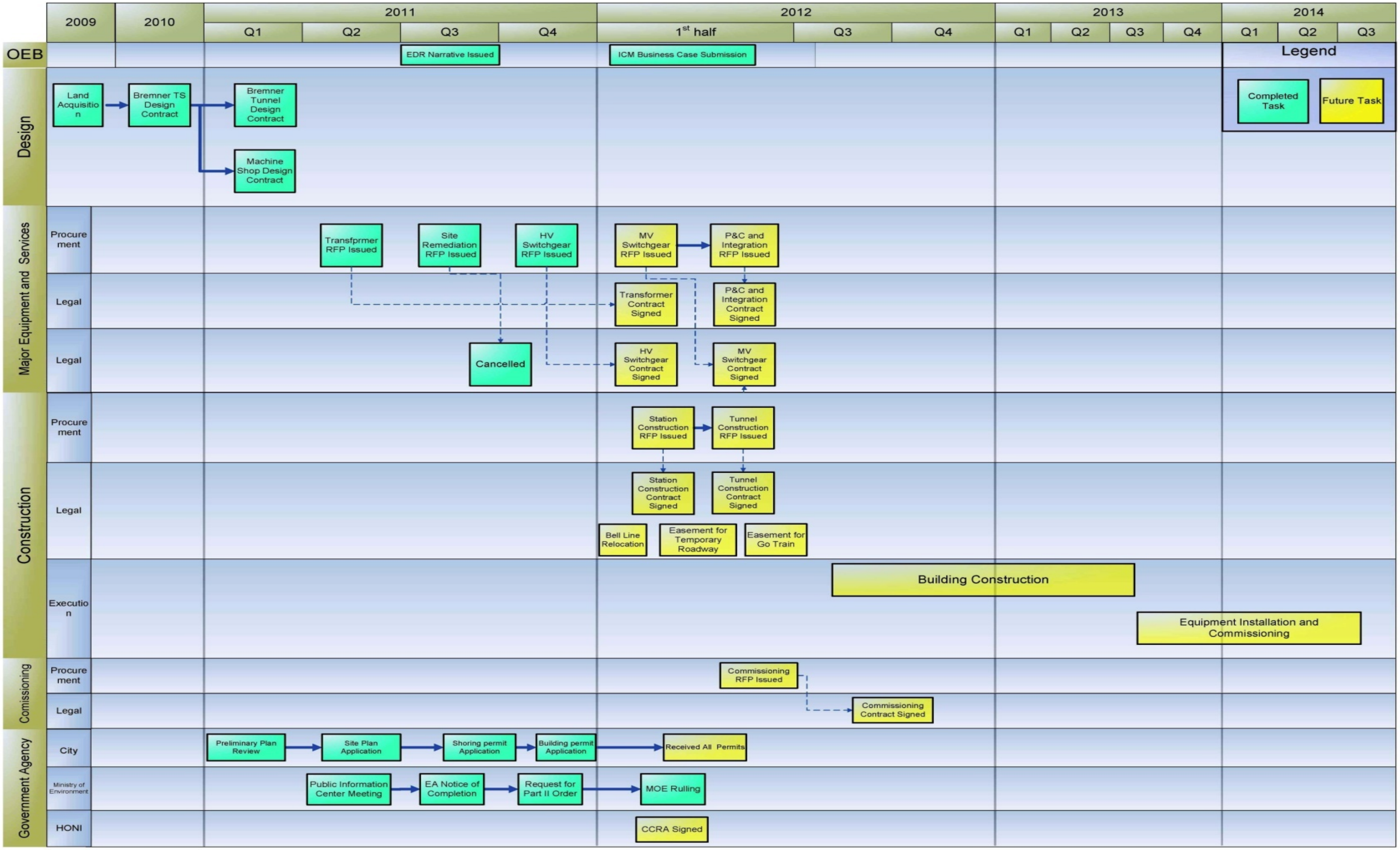


Figure 10: Tasks required for executing Bremner TS project

5.2.2. Windsor TS Switchgear Upgrades

Completion of the Bremner TS project by Q3 2014 will enable initiation of the much needed switchgear upgrades at Windsor TS in that same year. A separate request for Windsor TS has been included in Tab 4, Schedule B13.2, Section II, 4.

5.2.3. Asset Classification

THESL intends to use Bremner TS solely to provide distribution services to customers at voltages less than 50kV. Though technically a transmission asset, THESL is requesting, under Section 84(a) of the OEB act, that Bremner TS be deemed a distribution asset, and that cost recovery be effected through distribution rates. Such a classification has been granted in the past by the OEB for similar Transformer Station assets for THESL, Oakville Hydro and Guelph Hydro.

5.2.4. Required Capital Cost Estimates

5.2.4.1. Total THESL Cost Estimates for Bremner TS Project, Phase 1

In 2010, order of magnitude costs for the completion of Phase 1 of Bremner TS were the basis for the decision to proceed with the Bremner TS project and were derived from the best information available at the time.

In 2011, upon completion of detailed engineering design for the Bremner TS Project, an updated cost estimate was completed. Table 10 below compares the 2010 and 2012 cost estimates.

Table 10: THESL Cost Estimates to Complete Phase 1 of Bremner TS project

Item	Description	Cost Estimate ($ million)		
		2010 -Order of Magnitude	**2012 – 95% Design Complete**	**Difference**
Station Costs	Land	5.6	5.6	0
	Building	32.0	53.3	21.3
	Substation equipment	57.0	52.6	-4.4
	Distribution modification	6.7	2.3	-4.4
	Design – substation	7.0	6.2	-0.8
Tunnel	Design	0.0	0.6	0.6
	Construction	0.0	14.0	14.0
HONI	Capital Contribution to HONI	20.3	60.4	40.1
	Total	**128.6**	**194.9**	**66.3**

The overall increase in estimated cost of $66.3 million results from scope changes and the firming of prices by way of competitive RFPs for major equipment. A summary of the scope increases is listed below:

1) Station Costs (Building), $21.3 million

- Machine Shop disassembly/reassembly, including:
  - Requirement to disassemble and reassemble the Machine Shop in accordance with more stringent heritage best practices (identified in Heritage Impact Assessment in Appendix 6).
  - Requirement to upgrade the Machine Shop structure to post-disaster specifications (identified in Heritage Impact Assessment in Appendix 6).
- Shoring and excavation, including:
  - Increased shoring requirements due to an increase in depth of the station to accommodate mechanical equipment and a larger cable basement in the Transformer Station.

- o Remediation of contaminated soil at site. Contaminated soil was discovered upon completion of Environmental Site Assessment reports and Geotechnical studies of the site in 2011.
- Finishes, including:
  - o Addition of corten steel panels on building exterior, in order to blend building with surroundings. (The necessity for this finish is explained in the Heritage Impact Assessment in Appendix 6 to this document).

2) Tunnel Costs, $14.6 million

- Previously, HONI was to construct the cable tunnel for the high voltage supply. However, THESL has since taken on the responsibility for construction of the cable tunnel in an effort to both reduce costs and expedite the schedule. This is an increase in cost for THESL, but a decrease in HONI contribution costs and therefore in the resulting net costs for the project.

3) Hydro One Costs, $40.1 million

- The estimated cost of the Capital Contribution to Hydro One in 2010 was $20.3 million.
- By the end of 2011, this amount had increased to $25.4 million based on a Connection Cost Recovery Agreement (CCRA) received from Hydro One.
- By March 2012, Hydro One requested an increase to $60 million noting that the previously issued CCRA did not effectively capture the full scope of the project.
- In April 2012, THESL sent a letter to HONI requesting a re-evaluation of Hydro One's budgetary estimate in an effort to reduce the costs below $60 million.

5.2.4.2. Year-to-Year Costs for Bremner TS Project - THESL

The year-by-year cost estimates associated with completing the Bremner TS Project are summarized in Table 11 below.

Table 11: Estimated THESL Costs for Bremner TS, listed by task ($ million)

(Excluding HONI Capital Contribution)

Task	2010 Actual	2011 Actual	Total Actual	2012 Test	2013 Test	2014 Test	Total Test	Grand Total
Land acquisition	5.6		5.6					5.6
Construction of Building				12.6	34.12	6.60	53.3	53.3
Procurement of Major Equipment				13.2	26.31	13.15	52.6	52.6
Distribution Modification		0.8	0.8	1.5	-	-	1.5	2.3
Detailed Design / Construction PM		4	4	1.7	0.56	0.47	2.73	6.7
Construction of Cable Tunnel				2.8	8.39	2.80	14.0	14.0
Total	5.6	4.8	**10.4**	31.7	69.4	23.0	**124.1**	**134.5**

As stated in the "Project Timelines" section of this document, the year-by-year cost estimates are based on construction starting in August 2012, completion of the TS building and cable tunnel by end of 2013 and completion of the Machine Shop building and total site commissioning by Q3 2014.

5.2.4.3. Year-by-Year Cost Estimates for Bremner TS Project - Hydro One

A separate ICM project for the capital contribution to Hydro One has been included at Tab 4, Schedule B18, Section II, 1.

5.2.4.4. Year-by-Year Cost Estimates for Bremner TS Project - Combined

The combined THESL and Hydro One cost estimates to complete the Bremner TS project are summarized in Table 12 below:

Table 12: Estimated Capital costs for Bremner TS Project

	2010 Actual	**2011 Bridge**	**2012 Test**	**2013 Test**	**2014 Test**	**Total**
THESL Budget	5.6	4.8	31.7	69.4	23.0	134.5
Capital Contribution to Hydro One		0.4	6	27.0	27.0	60.4
Total	**5.6**	**5.2**	**37.7**	**96.4**	**50.0**	**194.9**

VI COST COMPARISON

1. Deferral of Bremner TS

Recognizing the significance of this capital expenditure, as well as the need for additional supply beyond 2030, a comparison was made between the currently estimated cost for Bremner TS and the cost of the potential alternative. This analysis was performed using the cost estimate established for Bremner TS as a result of the detailed design process ($194.9 million for Phase 1, approximately $47.3 million for Phase 2). The original order of magnitude cost estimates for expansion of Esplanade TS ($146 million) and Strachan TS ($56 million) were used as these are the most recent cost estimates available for these projects. This analysis is explained in more detail in Appendix 3 to this document. The resulting comparison is summarized in the table below:

Table 13: PV assessment of Bremner TS deferral

Options	(1) 2014 Bremner - Phase 1 2021 Bremner - Phase 2 2030 Esplanade	(2) 2016 Esplanade 2021 Strachan 2030 Bremner - Phase 1	Difference (PV) (2) – (1)	Percent
Base case (Price escalation 5%, Discount rate 6%)	$281	$333	$51	18%
Sensitivity cases:				
Price escalation 6%	$303	$374	$71	24%
Price escalation 4%	$262	$297	$34	13%
Discount factor 4.5%	$319	$403	$84	26%
Discount factor 7.5%	$251	$278	$27	11%

Based on the revised Bremner TS costs estimate, it has been re-affirmed that Option 1 (investment order of Bremner TS Phase 1, Bremner TS Phase 2, Esplanade TS expansion) is preferable to Option 2 (investment order of Esplanade TS expansion, Strachan TS expansion, Bremner TS Phase 1).

2. Transformer Stations in other jurisdictions

In downtown areas, transformer stations are typically integrated into their surroundings. Many metropolitan utilities have utilized this approach in their transformer station implementations. Appendix 5 to this document explores this in more detail.

Downtown transformer stations generally require a higher investment than traditional rural/suburban, outdoor type transformer stations because of:

- The costs incurred to integrate the stations into the surrounding area
- Technology used within enclosed stations
- Higher land costs
- Smaller land size, which complicates construction and design
- Zoning issues
- Logistics
- Constructability (for example, shoring and tiebacks, etc)

In this context, THESL reviewed how other jurisdictions have addressed TS installations in the city core. The information gathered is summarized in the table below.

Table 14: Site-integrated Transformer Stations in other jurisdictions

Location	Utility	Station	Year Completed	Transformer Nameplate MVA*	Transformer Nameplate MVA *(ultimate)	Costs (2012 $ million CAD)[12]
Toronto, Ontario	THESL	Bremner Transformer Station, Phase 1	Proposed for 2014	288	720	195
New York City, USA	Con Edison	Mott Haven Substation[13]	2007	900		379
Nagoya, Japan	Chubu Electric Company	Meijo Substation, Phase 1[14]	1999	900	1350	2,100[15]
Sydney, Australia	Transgrid	Haymarket Substation[16]	2004	1,200	1,200	321[17]
London, England	EDF Energy	Leicester Square Substation[16]	1989	180	180	179
Vancouver, British Columbia	BC Hydro	Cathedral Square Station[18]	1984	600	600	118**

*Capacities are based on total rated transformer nameplate capacity

**Transmission expansion not included in costs. Also, land leased not purchased.

[12] 2012 Costs calculated using inflation rates, rather than escalation rates.
[13] http://www.nytimes.com/2008/08/05/nyregion/05substation.html?_r=2andpagewanted=all
[14] http://www.manhattan-institute.org/pdf/crd_neighborly_substation_emb.pdf
[15] http://www.enaa.or.jp/GEC/active/gecnews/118.htm#FIVE
[16] http://www.energy.siemens.com/nl/pool/hq/energy-topics/living-energy/downloads/Social_acceptance_substations_that_embelish.pdf
[17] http://www.accc.gov.au/content/item.phtml?itemId=471851andnodeId=4c2cbf5a18f8fdfe2531a87fd912cd78andfn=PWC%20Metro Grid%20Review%20Implementation.pdf
[18] http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=andarnumber=4647020

It is important to note that, while these jurisdictions all are integrating transformer stations into their surroundings, there is significant variance in design and technology. These differences are attributed to the distinct constraints of the individual sites, and the technologies available at the time of design/construction.

The compilation of sites in Table 14 above shows a range in capacity from 180 MVA to 1200 MVA and a range in cost from $179 million to $2.1 billion. The approaches used vary from fully below grade to fully above grade (enclosed). Based on this analysis of other urban stations, the current Bremner TS project costs are reasonably comparable to those experienced in other jurisdictions.

3. Conclusion

The projected costs for the Bremner TS project have increased substantially since EB-2010-0142. This increase in costs can be attributed to development of the design from the conceptual phase to the detailed design phase and a revised cost estimate from Hydro One. Notwithstanding these increases, THESL's review based on the costs developed at the detailed design stage indicates that proceeding with Bremner TS at this time is cost effective and aligned with the experience of other jurisdictions.

VII CONCLUSIONS

In the OEB's decision, dated January 5, 2012, THESL's Bremner Transformer Station Project was noted as being potentially eligible for ICM funding.

An immediate need for new capacity exists in the City of Toronto in order to upgrade end of life equipment at Windsor TS. The City also has short term (increasing loads at five key stations downtown) and mid-term (future load growth) needs.

Having Bremner TS in service by Q3 2014 is the preferred solution to address these needs.

Preliminary work for the Bremner TS project has been approved in past applications to the OEB (EB-2009-0139, EB-2010-0142).

THESL is requesting, under Section 84(a) of the OEB act, that Bremner TS be deemed a distribution asset, with cost recovery provided through distribution rates.

Construction of Bremner TS Phase 1 is the next stage of the project and requires approval for multi-year funding so that long-term commitments to suppliers and contractors can be made.

Bremner TS would be built in 2 phases. Phase 1, the phase covered by this ICM filing, would last from 2012 to 2014 and would address the immediate need to upgrade Windsor TS. Phase 2 is expected to commence in 2021 and would involve installation of new equipment in the Bremner TS facility in order to address future loads. Funding for Bremner TS Phase 2 is not included in this application.

The total project budget for Phase 1 (2012-2014), including Hydro One and THESL costs, is $194.9 million. To date, a total of $ 10.8 million has been spent on land acquisition and design services. For 2012, a total of $37.7 million has been requested so that development can continue and the multi-year construction of Phase I can be initiated. For 2013, a total of $96.4

million has been requested to continue construction. For 2014, a total of $50.0 million has been requested to complete the construction of Phase I.

Table 15: Summary of Actual and Estimated Costs for Bremner TS Phase 1

	2010 Actual	2011 Bridge	2012 Test	2013 Test	2014 Test	Total
THESL Budget	5.6	4.8	31.7	69.4	23.0	134.5
Capital Contribution to Hydro One	-	0.4	6	27.0	27.0	60.4
Total	**5.6**	**5.2**	**37.7**	**96.4**	**50.0**	**194.9**

Appendix 1

EB 2009-0139 & EB 2010-0142

Bremner Transformer Station Narratives and Interrogatories

Contents

Bremner Project Narratives

EB-2009-0139

Stations System Enhancements (Bremner Station)

The purpose of this project is to develop a new substation, Bremner TS, to be located at Bremner Boulevard and Rees Street in downtown Toronto. Electrically, the substation will consist of interface equipment with HONI incoming circuits, two 60/80/100 MVA 115 kV/13.8 kV transformers, 13.8 kV switchgear, protection and control and other ancillary equipment. The project will provide about 72 MVA of new firm capacity. The substation will also include space provisions for future transformers and 13.8 kV switchgear, to provide an additional 216 MVA firm capacity in three future stages (3x72 MVA) as the need arises.

The existing area is supplied by Windsor TS (referred to as John TS by HONI). Windsor TS was built in 1950, and expanded in 1968. Windsor TS has become the largest 13.8 kV substation in Toronto. The 13.8 kV air-blast switchgear, first installed in 1956, needs to be replaced in three stages. The substation is fully occupied with no room for further switchgear. In order to replace the end-of-life switchgear at Windsor TS, the existing customers from the affected equipment need to first be supplied from a new source. In addition, a new source is also needed to reduce the overall loading level at Windsor TS as no spare feeder positions are available. The supply to the existing downtown customers also needs to be diversified to mitigate the effects of high-impact low-probability station events such as fire or flooding. Details are provided at Exhibit D1, Tab 9, Schedule 6.

Secondary Upgrade

During the level III contact voltage inspection work carried out in February 2009, hand well and street lighting pole locations across the city were inspected. Secondary wires were reconnected with standard water proof connectors where needed to standardize the installation. However, there were a number of locations identified during the Level III inspection that require additional follow up work to bring them up to an acceptable operating condition. Those locations include work that is required to reinstall secondary wires between hand wells, fuse installation in street lighting poles and replacement of poles etc. It is essential that the required work be completed to maintain the physical and electrical integrity of the system. Details are provided at Exhibit D1, Tab 9, Schedule 7.

Table 2 below shows THESL's capital costs for 2010, together with the 2008 actual capital costs and the 2009 forecasted capital costs for each category of investment. The table presents operational investments in a similar format as was presented in EB-2007-0680 for consistency and comparative purposes. Additional investment categories have been added to the table which represent emerging requirements new to this filing. This presentation allows THESL to show new categories of investment to satisfy emerging requirements, and to continue to present a view of its investment needs to modernize the distribution plant.

It is clear that the level of sustaining capital investment resulting from the Board's reduction to THESL's proposed 2008 and 2009 program presented in EB-2007-0680 is insufficient. A significant "catch-up" is required and proposed in 2010. Additionally THESL is faced with very significant emerging requirements over and above its infrastructure renewal plans, which comprise more than 25 percent of the test year capital program. THESL has amended its infrastructure renewal plans to reflect the Board's previous decisions in EB-2007-0680, and has incorporated refinements in its asset condition assessment and risk-based modeling to more effectively direct capital investments. Improvements to the long-term planning and work prioritization methods used by THESL are filed at Exhibit C1, Tab 6, Schedules 1 and 2, respectively. THESL's updated 2010-2019 Electrical Distribution Plan is filed at Exhibit D1, Tab 8 Schedule 10, and updated Asset Condition Study is filed at Exhibit Q1, Tab 3, Schedule 1.

EMERGING REQUIREMENTS

STATIONS SYSTEM ENHANCEMENT – BREMNER TS PROJECT

DESCRIPTION

The purpose of this project is to develop a new substation, Bremner TS, to be located at Bremner Boulevard and Rees Street in downtown Toronto. This site is currently owned by Hydro One Networks Inc. ("HONI"). THESL will be the station developer. The project will include site preparation, construction of the substation building, installation of electrical equipment and site landscaping work. Electrically, the substation will consist of interface equipment with HONI incoming circuits, two 60/80/100 MVA 115 kV/13.8 kV-13.8 kV transformers, 13.8 kV switchgear, protection and control and other ancillary equipment. The project will provide about 72 MVA of new firm capacity. The substation will also include space provisions for future transformers and 13.8 kV switchgear, to provide an additional 216 MVA firm capacity in three future stages (3x72 MVA), as the need arises.

JUSTIFICATION

The existing area is supplied by Windsor TS (referred to as John TS by HONI). Windsor TS was built in 1950, and expanded in 1968. Windsor TS has become the largest 13.8 kV substation in Toronto. The 13.8 kV air-blast switchgear, first installed in 1956, needs to be replaced in three stages. The substation is fully occupied with no room for further switchgear. In order to replace the end-of-life switchgear at Windsor TS, the existing customers from the affected equipment need to be supplied from a new source first. In addition, a new source is also needed to reduce the overall loading level at Windsor TS as no spare feeder positions are available. The supply to existing downtown customers also needs to be diversified to mitigate the effects of high-impact low-probability station events such as fire or flooding.

The chosen site of Bremner TS is in relatively close electrical proximity to Windsor TS. The site is also in close proximity to existing THESL duct banks that will permit the linking of the two stations. The site is well-located with respect to the high voltage connection and provisions exist for the interconnection at 115 kV. Its location and the planned design satisfy the objectives of:

- providing a new source of supply to the area's customers,
- permitting the removal from service and the replacement of end-of-life switchgear at Windsor TS,
- providing capacity relief to Windsor TS and to neighbouring stations and
- mitigating the effects of high-impact low probability stations events.

ALTERNATIVES CONSIDERED

Status Quo

THESL will need to continue to have custom-made parts replaced and air-supply systems rebuilt at a significant cost. Even with these actions, however, reliability necessarily will continue to decline, eventually leading to failure. Switchgear failure at Windsor TS will have a high impact on customers in the area, which would include many of the downtown business towers and the financial district. There is no alternate supply to customers should a switchgear fail, and restoration time would be measured in days, possibly weeks. This alternative has been ruled out.

Bus-to-bus Load Transfer within Windsor TS

There is not enough firm capacity available on the bus structure within Windsor TS, to support load transfer to alternate positions because of the high load factor. This alternative is not feasible.

Load Transfer to Existing Adjacent Substations

There are four existing substations adjacent to Windsor TS. None of these adjacent substations has enough firm capacity available, because of high loading. Of the four, two substations (Strachan TS and Esplanade TS) have the space for expansion to provide new capacity. Compared to Bremner TS, these two substations are further away from Windsor TS, and outside of the existing Windsor TS supply area. Installation work for underground cables to pickup Windsor feeders will be required across existing supply areas, and disruption due to construction will be more extensive on city streets. This is not a preferred alternative.

Bremner TS

HONI has acquired the site for Bremner TS, and it is designated for electric substation use. The site is within the existing supply area of Windsor TS. The new Bremner TS has been planned to relieve Windsor TS, and facilitate load transfers in the area to relieve the adjacent substations. There are existing cable ducts installed by THESL along Bremner Blvd. to facilitate feeder egress from Bremner TS. According to current forecasts, Windsor TS and its adjacent substations as a group will require new capacity by 2018. As Bremner TS is already within the supply area of Windsor TS, advancing Bremner TS can provide the capacity required to offload Windsor TS for switchgear replacement. This is the preferred alternative.

BENEFITS

The project will provide capacity required to facilitate the staged replacement of old air-blast switchgear at Windsor TS, reducing the risk of customer outage due to equipment failure at Windsor TS. It also reduces the overall loading level at Windsor TS, thereby diversifying customer supply, and mitigating the impact of high-impact low-probability station events. The project will also provide capacity relief to neighboring stations by enabling distribution load transfers to occur.

IMPACT OF DEFERRAL/CANCELLATION

If other alternatives are selected and an adjacent substation is expanded to facilitate cross-supply area load transfers, then there will be more extensive installation work of underground cables on city streets, and cross-supply area load transfers. If the project does not move ahead, and no other alternatives are selected, then the commissioning date of the proposed Bremner TS will be delayed, increasing the risk of customer outages because of equipment failure at Windsor TS.

PLAN

Planned 2009 Activities

- Begin Environmental Assessment work.
- Public review of draft Environmental Study Report.
- Begin basic design from conceptual plan.

Planned 2010 Activities

- Continuation of Environmental Assessment work, to be completed by February.
- Begin connection application to HONI and IESO.
- Continuation of basic design, to be completed by April.
- Begin detailed design, to be completed by December, with drawing package issued for construction.
- Begin specification and procurement of long delivery items.
- Pre-construction public information centre.
- Begin obtaining approvals for construction.
- Begin site formation.

Future Year Activities

- Begin design modification from site conditions.
- Continue construction work, to be completed by December 2012.

- Begin substation equipment installation and commissioning, to be completed by April 2013.

COST

The cost estimate for the station is presented below in Table 1. Engineering design activities for 2010 will include detailed engineering design and estimates. Expenditures planned for beyond the test year will be included in future rate applications.

Table 1: Estimated Capital Costs ($ millions)

2009	2008 Historical	2009 Bridge	2010 Test	2011	2012	2013	Total
Station[1]	0	0	15.2	37.8	30.5	12.0	95.5
Capital contribution to HONI	0	0	1.1	0	10.6	5.3	17.0
Total	0	0	16.3	37.8	41.1	17.3	112.5

[1] Station costs include land, building, substation equipment, and distribution system modification costs.

Interrogatories

EB-2009-0139

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 76:

Reference(s): D1/ T9/ S6

This exhibit describes the development of a new substation, Bremner TS, located at Bremner Boulevard and Rees Street in downtown Toronto. The proposed cost for this project in the 2010 test year is $16.3 million. On page 4 THESL has provided a list of planned activities for the 2010 test year.

Please provide a detailed breakdown of the proposed costs for the 2010 test year that is linked to the outlined planned activities.

RESPONSE:

Table 1 contains a detailed breakdown of the proposed cost for the 2010 test year that has been linked to the outlined planned activities. The outlined planned activities have been regrouped to facilitate presentation of the breakdown. The $1.1 million proposed cost in (a) of Table 1 is capital contribution to Hydro One Networks Inc. for the high voltage connection.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 1: Cost Breakdown by Planned 2010 Activities ($ millions)

Planned 2010 Activities		2010 Test ($M)
(a)	• Begin connection application to HONI and IESO.	1.1
(b)	• Continuation of Environmental Assessment work, to be completed by February. • Continuation of basic design, to be completed by April. • Begin detailed design, to be completed by December, with drawing package issued for construction.	7.0
(c)	• Begin specification and procurement of long delivery items.	2.1
(d)	• Pre-construction public information centre. • Begin obtaining approvals for construction.	0.5
(e)	• Begin site formation.	5.6
	Total 2010 test year cost	16.3

Bremner Project Narratives

EB-2010-0142

EMERGING REQUIREMENTS

STATIONS SYSTEM ENHANCEMENT – BREMNER TS PROJECT

DESCRIPTION

The purpose of this project is to develop a new substation, Bremner TS, to be located at Bremner Boulevard and Rees Street in downtown Toronto. This site is currently owned by Hydro One Networks Inc. ("HONI"). THESL will be the station developer. The project will include site preparation, construction of the substation building, installation of electrical equipment and site landscaping work. Electrically, the substation will consist of interface equipment with HONI incoming circuits, two 60/80/100 MVA 115 kV/13.8 kV-13.8 kV transformers, 13.8 kV switchgear, protection and control and other ancillary equipment. The project will provide about 72 MVA of new firm capacity. The substation will also include space provisions for future transformers and 13.8 kV switchgear, to provide an additional 216 MVA firm capacity in three future stages (3x72 MVA), as the need arises.

JUSTIFICATION

The existing area is supplied by Windsor TS (referred to as John TS by HONI). Windsor TS was built in 1950, and expanded in 1968. Windsor TS has become the largest 13.8 kV substation in Toronto. The 13.8 kV air-blast switchgear, first installed in 1956, needs to be replaced in three stages. The substation is fully occupied with no room for further switchgear. In order to replace the end-of-life switchgear at Windsor TS, the existing customers from the affected equipment need to be supplied from a new source first. In addition, a new source is also needed to reduce the overall loading level at Windsor TS as no spare feeder positions are available. The supply to existing downtown customers also needs to be diversified to mitigate the effects of high-impact low-probability station events such as fire or flooding.

The chosen site of Bremner TS is in relatively close electrical proximity to Windsor TS. The site is also in close proximity to existing THESL duct banks that will permit the linking of the two stations. The site is well-located with respect to the high voltage connection and provisions exist for the interconnection at 115 kV. Its location and the planned design satisfy the objectives of:

- providing a new source of supply to the area's customers,
- permitting the removal from service and the replacement of end-of-life switchgear at Windsor TS,
- providing capacity relief to Windsor TS and to neighbouring stations and
- mitigating the effects of high-impact low probability stations events.

ALTERNATIVES CONSIDERED

Status Quo

THESL will need to continue to have custom-made parts replaced and air-supply systems rebuilt at a significant cost. Even with these actions, however, reliability necessarily will continue to decline, eventually leading to failure. Switchgear failure at Windsor TS will have a high impact on customers in the area, which would include many of the downtown business towers and the financial district. There is no alternate supply to customers should a switchgear fail, and restoration time would be measured in days, possibly weeks. This alternative has been ruled out.

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There is not enough firm capacity available on the bus structure within Windsor TS, to support load transfer to alternate positions because of the high load factor. This alternative is not feasible.

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There are four existing substations adjacent to Windsor TS. None of these adjacent substations has enough firm capacity available, because of high loading. Of the four, two substations (Strachan TS and Esplanade TS) have the space for expansion to provide new capacity. Compared to Bremner TS, these two substations are further away from Windsor TS, and outside of the existing Windsor TS supply area. Installation work for underground cables to pickup Windsor feeders would be required across existing supply areas, and disruption due to construction will be more extensive on city streets. This is not a preferred alternative.

Bremner TS

HONI has acquired the site for Bremner TS, and it is designated for electric substation use. The site is within the existing supply area of Windsor TS. The new Bremner TS has been planned to relieve Windsor TS, and facilitate load transfers in the area to relieve the adjacent substations. There are existing cable ducts installed by THESL along Bremner Blvd. to facilitate feeder egress from Bremner TS. According to current forecasts, Windsor TS and its adjacent substations as a group will require new capacity by 2018. As Bremner TS is already within the supply area of Windsor TS, advancing Bremner TS can provide the capacity required to offload Windsor TS for switchgear replacement. This is the preferred alternative.

BENEFITS

The project will provide capacity required to facilitate the staged replacement of old air-blast switchgear at Windsor TS, reducing the risk of customer outage due to equipment failure at Windsor TS. It also reduces the overall loading level at Windsor TS, thereby diversifying customer supply, and mitigating the impact of high-impact low-probability station events. The project will also provide capacity relief to neighboring stations by enabling distribution load transfers to occur.

IMPACT OF DEFERRAL/CANCELLATION

If other alternatives are selected and an adjacent substation is expanded to facilitate cross-supply area load transfers, then there will be more extensive installation work of underground cables on city streets, and cross-supply area load transfers. If the project does not move ahead, and no other alternatives are selected, then the commissioning date of the proposed Bremner TS will be delayed, increasing the risk of customer outages because of equipment failure at Windsor TS.

PLAN

Planned 2011 Activities

- Building construction
- Equipment milestone payments

Planned 2012-2013 Activities

- Building construction work completion
- Equipment installation and commissioning
- Substation energization
- Substation in-service

COST

The cost estimate for the station is presented below in Table 1. Expenditures planned for beyond the test year will be included in future rate applications.

Table 1: Estimated Capital Costs ($ millions, escalated)

	2009 Historical	2010 Bridge	2011 Test	2012	2013	Total
Station costs[1]	0	15.2	33.1	45.6	14.3	108.2
Capital contribution to HONI	0	1.1	0	12.6	6.7	20.4
Total	**0**	**16.3**	**33.1**	**58.3**	**21.1**	**128.6**

Table 2 below contains a detailed breakdown of the proposed cost for the 2011 test year linked to the outlined planned activities.

Table 2: Cost Breakdown by Planned 2011 Activities ($ millions, escalated)

Planned 2011 Activities	2011 Test
Building construction 2011	11.7
Equipment 2011	21.4
Total 2011 test year costs	**33.1**

[1] Station costs include land, building, substation equipment, and distribution system modification costs.

Interrogatories

EB-2010-0142

INTERROGATORIES OF SCHOOL ENERGY COALITION

INTERROGATORY 56:

Reference(s): D1/7/1 p. 5, 13

With respect to the capital contribution to HONI:

a) Please explain in detail all measures THESL has taken and is taking to ensure that the capital contributions required by HONI for the Leaside-Birch reinforcement, Windsor/John TS and Bremner TS are optimized and that the required improvements could not be achieved at lower cost through alternative procurement approaches, whether self-supply by THESL or contracting out.

b) Please comment on the design decision at Bremner TS and John TS to rely on 13.8 kV secondary side voltage including the impact on line losses over the long term of not employing a higher voltage.

RESPONSE:

a) For the Leaside-Birch reinforcement project, THESL concluded that the most cost effective solution was to address the transmission line constraint through a transmission rather than a distribution solution. The transmission reinforcement is being performed in concert with HONI's sustainment work for the affected cable. As a result, HONI and THESL are sharing the costs in proportions which are prescribed by the Transmission System Code. This is an optimal solution for THESL and is a lower cost solution when coordinated with HONI's sustainment work.

For the Bremner project, please see the reply in Exhibit R1, Tab1, Schedule 77 b). Further, a capital contribution to HONI will depend upon the extent to which HONI

INTERROGATORIES OF SCHOOL ENERGY COALITION

is involved. A final decision has not yet been made as to the level of involvement. THESL will ensure that an optimal procurement approach will be taken.

b) All of downtown Toronto is at the 13.8 kV voltage level. One of Bremner TS's benefits is to relieve pressure at Windsor TS and provide capacity benefits to a number of surrounding stations. This capacity relief can only occur if load can be transferred from Windsor TS to Bremner TS, and between the neighbouring stations and Bremner TS. As the customers involved are currently supplied at 13.8 kV, a voltage change for Bremner would diminish some of the benefits of the station.

Note that in the downtown core, 13.8 kV feeders are quite short as compared to the rest of the system and would therefore have lower losses. A voltage change would necessitate a larger plan that would need to be applied to a broad group of stations and customers' equipment and not just to Bremner TS. This is out of scope for the Bremner project.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 77:

Reference(s): D1/ T9/ S6

In this section, THESL discusses a project to develop a new substation, Bremner TS. THESL states that this site is currently owned by HONI and that THESL will be the station developer. On page 5, Footnote 1 states that station costs include land, building, substation equipment and distribution system modification costs.

a) Please clarify the respective roles and ultimate ownership of the development, by explaining what system elements are being constructed by Hydro One.

b) On page 5, Table 1 "Estimated Capital Costs" shows capital contribution to HONI totalling $20.4 million by 2013. Please explain which elements of this project require capital contributions and why.

c) Please state whether or not the contribution of $20.4 million constitutes the whole cost of Hydro One's investment or not.

d) Given that distribution asset voltage goes as high as 50 kV and THESL's evidence states that Bremner TS goes above this level, please provide an explanation as to why this asset should be considered a distribution asset.

e) Please indicate whether THESL is planning to apply to have this asset classified as a distribution asset for rate making purposes and when.

f) Please provide a detailed chronology of the project and provide an in-service-date for this asset.

g) Please state whether or not THESL is proposing to incorporate any costs related to this project into rate base in this application or at any time prior to the asset being used and useful. If THESL is making such a proposal, please provide the justification for it and whether THESL is proposing similar treatment for any other assets in the

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

present application. If there are no other assets for which similar treatment is being requested, please explain why this asset should be treated differently.

RESPONSE:

a) Hydro One will be providing the 115kV supply connection between their John x Esplanade transmission cable circuits and the THESL-owned 115kV switchgear at the proposed Bremner TS. All other elements will be constructed by THESL and its contractors. THESL intends to own all elements it constructs.

b) The estimated capital contribution to Hydro One will be required for Hydro One to carry out design and installation of the 115kV cable circuit connection between their John x Esplanade circuits and the proposed Bremner TS. THESL will be exploring carrying out this work itself, after considering regulatory and cost issues. These issues include the classification of the transmission line work and the costs of Hydro One relative to independent contractors for the same.

c) The estimated capital contribution of $20.4 million is the forecasted amount THESL will be paying to Hydro One for the connection of the station to the 115kV grid. HONI will not be investing in the station itself.

d) THESL does not request that assets operating at voltages above 50kV be considered distribution assets generally or that the definitions be changed. However, the Board can deem transmission assets to be distribution assets for the purposes of ratemaking. The final EDR Rate Handbook provides as follows at page 25:

> "A distributor wishing to have any assets included in the distribution rate base that would not be included in the definition of the distribution rate

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

base, as specified in Appendix A (e.g. Account 1815 Transformer Station Equipment – normally primary above 50 kV), should request in the summary of the application that the Board, in its decision on the application, deem such assets to be distribution assets."

e) THESL does plan to request that the Board deem the Bremner Station to be a distribution asset on or before the date that the station is forecast to come into service.

f) The planned major milestones are:
   - August 2011 – design complete
   - August 2012 – building construction complete
   - March 2013 – commissioning commences
   - July 2013 – in-service

g) Capital contributions to HONI, pursuant to the 2006 EDR Handbook and the TSC are the only costs capitalized prior to energization.

TECHNICAL CONFERENCE QUESTIONS OF ONTARIO ENERGY BOARD STAFF

QUESTION 19:

Reference(s): **Board Staff Interrogatory #73**
EP Interrogatory #42

In response to Board Staff interrogatory #77 THESL states that:

> Hydro One will be providing the 115 kV supply connection between their John x Esplanade transmission cable circuits and the THESL-owned 115kV switchgear at the proposed Bremner TS…The estimated capital contribution to Hydro One will be required for Hydro One to carry out design and installation of the 115kV cable circuit connection between their John x Esplanade circuits and the proposed Bremner TS…THESL will be exploring carrying out this work itself, after considering regulatory and cost issues. The issues include the classification of the transmission line work and the costs of Hydro One relative to independent contractors for the same.

a) Please confirm that THESL is not planning to include capital contributions to Hydro One for this project in the 2011 rate base.
b) Please elaborate on what steps have been taken at this point to assist in the determination as to whether Hydro One or independent contractors for THESL will be contracted to do this work.
c) Please state if THESL has received any cost estimates for this work from Hydro One and/or independent contractors.
   (i) If no, why not.
   (ii) If yes, please provide a copy of the estimates.

TECHNICAL CONFERENCE QUESTIONS OF ONTARIO ENERGY BOARD STAFF

d) Please confirm that in the case where THESL decides to subcontract the building of the 115kV supply connection to a party other than Hydro One, capital contributions to Hydro One for this project will not be required in the future.

RESPONSE:

a) The Bremner project is not expected to be ready for energization in 2011 and therefore will not be included in rate base.

b) It is THESL's intent to issue a Request for Proposal for this work. Hydro One will be invited to participate along with independent contractors and their reply will be rated using evaluation criteria that will be applied to all respondents in accordance with our Procurement Policy.

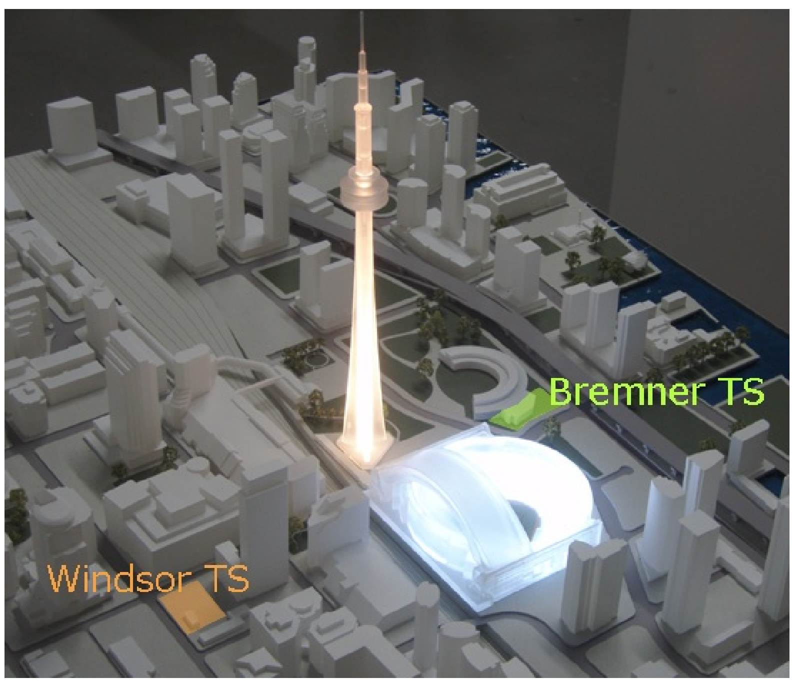
c) THESL has not received any cost estimates for this work from Hydro One and/or independent contractors. A Request for Proposal for the design of the tunnel will be issued in late January 2011 with a subsequent contract to the successful respondent in March 2011. The issue of the Request for Proposal for the construction of the tunnel is planned for August 2011 with subsequent award to the successful respondent planned for October 2011.

d) In the case where THESL decides to subcontract the building of the 115kV supply connection to a party other than Hydro One, it is expected that some capital contributions to Hydro One will still be required for other aspects of connection to Hydro One's transmission system. These costs have yet to be estimated by Hydro One.

Appendix 2: Load Growth

In Downtown Toronto Area

Figure 1 Downtown Core (photo courtesy Myles Burke Architectural Models)



Contents

1. Introduction:

1.1 Purpose[1]

This appendix further discusses load growth of Toronto downtown transformer stations based upon stated assumptions and THESL methodology. The primary purpose of this appendix is to demonstrate the load growth in proximity of the Bremner Transformer Station by examining forecasts, historical data and proposed customer connections in the Toronto downtown area circumscribed by the service areas of the five downtown transformer stations.

Two important components of the THESL load forecast are the natural load growth and the new customer connection requests. In this document, THESL validates the assumptions associated with calculation of natural load growth in the downtown Toronto core (2% growth per year). THESL also examines the magnitude of actual customer connection requests and future developments in the City of Toronto.

Table 1 Load Forecasts (MVA) by Station

Station	Station Rating	Year															
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Cecil	224	182	189	196	199	203	207	212	216	220	224	229	233	239	242	248	252
Esplanade	198	175	173	177	182	187	192	196	199	204	208	212	216	221	225	230	234
Strachan	175	122	127	130	131	133	140	143	147	151	153	157	159	163	166	169	172
Terauley*	240	199	205	211	215	220	225	229	234	238	243	248	252	258	263	269	273
Windsor	340	304	306	315	324	328	335	342	349	355	362	371	377	383	391	399	405
Total	1177	982	1000	1029	1051	1071	1099	1122	1145	1168	1190	1217	1237	1264	1287	1315	1336

1.2 Background

THESL distributes electricity to its customers in downtown corridor via 13.8kV feeders from the 115kV/13.8kV substations. This appendix does not focus on transmission planning issues directly nor does it reflect transmission capacity limitations. However, it is worth noting that the

[1] This document is not replacement for official THESL stations load forecast which includes all THSEL's Stations

new Bremner TS has for many years been included in HONI plan to meet the future load growth of the Toronto downtown area. For example, Figure 2 below indicates a 'break out' at HONI's existing Front Street tunnel, installed in 2007 with the intention of connecting said tunnel to Bremner TS.

Figure 2 Existing break out at HONI transmission tunnel for Bremner TS tunnel

The resolution of the transmission capacity issue of downtown Toronto is considered in ongoing cooperative planning between THESL and HONI.

2. Load Growth methodology

2.1 Forecasting Process

As the purpose of the forecast is to assess station bus capacity adequacy, the summer and winter maximum peak demands are forecast, rather than monthly peak demands.

The process for calculating peak demands follows three steps:

a) Historical summer/winter peak demand for a bus is weather corrected,

b) New loads are added to the weather- corrected demands according to the build-up formula, and

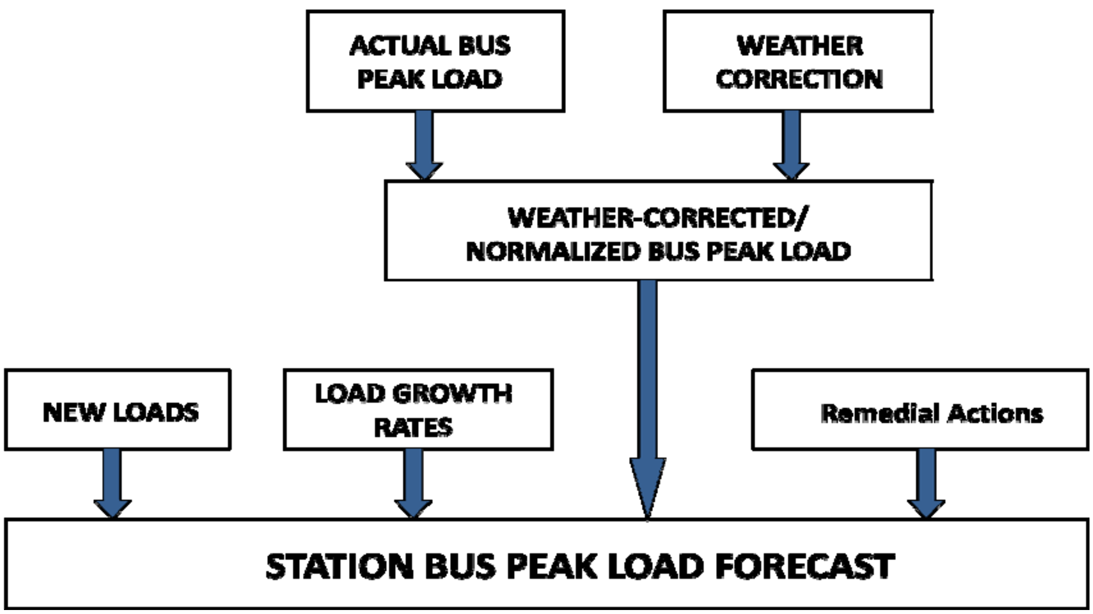
c) Growth rates are applied to obtain annual peak demand forecasts for the Study period. The natural growth rate for the first two years of the study period is assumed to be zero. The forecast increase in demand is exclusively driven by new customer connections.

When projected load for a station bus exceeds the bus capacity during the first five years of the study period, remedial action is proposed and then the forecast is repeated to include the remedial action.

The following alternatives are considered, in order of preference, to remedy the bus/station capacity shortfall:

1. Load transfer to another bus or station;
2. Upgrade of station bus capacity;
3. Upgrade of station transformer capacity;
4. Station expansion, i.e. new bus;
5. New station.

Figure 3 Forecasting Methodology Schematics



2.2 Model

2.2.1 Weather Sensitivity

THESL normalizes downtown station bus peak demands to a mean daily temperature of 27°C for the summer forecast. The summer forecast is the most restrictive. This temperature is the average of the recorded mean daily temperature of the days that the buses reached highest peak demand over the period of 1998 to 2008.

A linear regression model is used to calculate bus weather sensitivity (b) and the intercept parameter (a) from historical daily peak load (Y) and daily mean temperature (X) observations. The mathematical equation is:

$$Y = bx + a$$

Where,

Y = the daily peak load (MVA)

b = the slope of the trend line (MVA/°C),

X = the daily mean temperature (°C), and

a = the y-axis intercept (MVA).

The daily station bus peak demand data is obtained from station revenue metering. Daily mean temperature data is obtained from Environment Canada's Monthly Meteorological Summary Report. Since extreme temperature-load behaviour is of interest, only data for the summer and winter months are used for the regression model. Data for the months of June, July and August are used for the calculation of bus summer-season sensitivity. Data for the months of December, January and February are used for bus winter-season sensitivity. Weekends and holidays are excluded from model data as they differ dramatically from the weekday loads

If 'N' is the number of Y-X readings, then the value of 'b', bus weather sensitivity(MVA/ C°) can be found by using the Method of Least Squares, as follows:

$$b = \frac{N \times \left\{\sum_{i}^{N}(X_i Y_i)\right\} \quad \left(\sum_{i}^{N}(X_i)\right)\left(\sum_{i}^{N}(Y_i)\right)}{N \times \left\{\sum_{i}^{N}(X_i^2)\right\} - \left(\sum_{i}^{N}(X_i)\right)^2}$$

Using spreadsheet programs, bus weather sensitivity calculations and normalization of starting bus peak demands are performed.

2.2.2 Peak Demand Growth Rate

To determine demand growth rate, five year actual peak load data for the five downtown transformer stations was studied. Load growth rates are determined using a Time-Trend model. The relationship between x and y in the Time-Trend model is exponential, taking the form y = ab^x. After taking natural logarithms of the equation it becomes:

$$\ln y = \ln a + x \ln b$$

Where 'ln a' and 'ln b' represent the constants in the equation. 'ln y' and 'x' now have a linear relationship and the Least Squares method can be applied. The equation can be simplified as:

$$Y = A + Bx$$

Where,

A = 'ln a' as described before,

B = 'ln b' which is the slope of the trend line,

x = time (i.e.; 2007, 2008, 2009, …)

Y = the natural logarithm of bus summer/winter peak load (MVA).

The annual peak load data is obtained from station revenue metering. As with the weather sensitivity model in section 2.2.1, the extreme temperature-load behaviour of the Time-Trend model is of interest. Data for the months June, July and August were used for calculation of the summer peak load, and data for the months of December, January and February are used for bus winter peak load. If 'N' is the number of data, then the value of 'B', which is the slope of the line, can be found by using the Method of Least Squares. The following equation is used to compute the slope 'B'.

$$B = \frac{N \times \left\{ \sum_{i}^{N} (x_i Y_i) \right\} - \left(\sum_{i}^{N} (x_i) \right) \left(\sum_{i}^{N} (Y_i) \right)}{N \times \left\{ \sum_{i}^{N} (x_i)^2 \right\} - \left(\sum_{i}^{N} (x_i) \right)^2}$$

Table 2: 5 Year Historical load data

x_i	2007	2008	2009	2010	2011[2]
Cecil	169	164	176	181	187
Strachan	118	104	119	117	138
Windsor	284	277	295	303	311
Terauley	194	194	188	185	190
Esplanade	168	164	169	176	180
Sum (MVA)	**933**	**903**	**947**	**962**	**1006**
Y_i : ln (load)	**6.84**	**6.81**	**6.85**	**6.87**	**6.91**

The value for *B* was established using the actual five year peak load.

$$B = \frac{N \times \{\sum_{2007}^{5} x_i Y_i\} - \left(\sum_{2007}^{5}(x_i)\right)\left(\sum_{2007}^{5}(Y_i)\right)}{N \times \{\sum_{2007}^{5}(x_i)^2\} - \left(\sum_{2007}^{5} x_i\right)^2} = 0.0214$$

The original exponential model $y=ab^x$ can be re-written as $y=a(1+g)^x$, where g is the annual growth rate. Thus, the bus percentage growth rate '**g**' is calculated using equation:

$$g = (e^{B} - 1) \times 100\ \%$$

The growth rate for the past five years based upon a *B* of 0.0214 was determined.

$$g = 2.16\%$$

2.2.3 Assumptions

2.2.3.1 New Customer Connections Load Build-up

New customer load is included in the forecast only for known projects for which THESL has been approached for service connections.

[2] Actual data as of April 2012.

The following load build-up guidelines are used in absence of customer load build-up:

Table 3 Load Build Up

Proposed Load	% Load Build Up		
	Year 1	Year 2	Year 3
Up to 0.5 MVA	100%		
0.6 MVA to 2 MVA	70%	30%	
Over 2 MVA	60%	20%	20%

Based upon past experience, not all projects materialize and those that do materialize usually overestimate their peak demand. Therefore prospective new customer peak demand estimates are reduced by 50% to achieve a more realistic peak demand estimate. Section 2.3.3 shows a subset of new customer requests received by THESL.

2.2.3.2 Load Growth Rate for New Loads

For new customer loads, a zero percent growth rate is used for the first two years of the forecast period.

2.2.3.3 Conservation and Demand Management (CDM)

The Ontario Power Authority and THESL have both developed and implemented complementary projects over the past few years. The major program portfolios are:

1. Conservation
2. Demand Response
3. Distributed Energy

In the shorter term, where committed projects are known, the potential impact of the project is taken into account in the forecasts. Committed generation projects are easier to quantify, as their location and size are clear and potential contributions could be estimated from signed agreements. At this time, THESL takes into consideration new committed generation projects that are over 10MW in size when performing the forecast. Once the unit is in service, in the absence of physical assurance of operation, the actual impact on the bus load is reflected in the actual historical bus load data and therefore it is accounted for in the forecast. Where CDM projects are installed and commissioned, the actual impact on bus load is reflected in the actual historical bus load data, and therefore accounted for in the forecasts.

2.3 Anticipated Growth

For the first three years of forecast period new loads are added only when THESL has direct knowledge of new customer connections by means of requests. This mechanism enables THESL to forecast the immediate need of distribution system while forecasting long term growth using a calculated load growth rate.

Downtown Toronto is a focal point of development, growth and urbanization. Toronto has recently experienced a surge of both residential and non-residential growth with construction cranes maintaining a constant presence on the City's skyline. As result, increases in electrical demand will be experienced by THESL in the near future.

2.3.1 City of Toronto Vision

Toronto's Official Plan, which came into force in June 2006, is a road map for how the city will develop over the next 20 years. Most of the new developments will take place in target areas such as the downtown Toronto area. As result of the Official Plan, Toronto's development industry is strong and continually invests in new projects in the City. In the 4½ years after Official Plan came into force, 1,696 development projects, with 106,848 residential units and over 4.23 million m^2 of non-residential gross floor area ("GFA") proposed, have been submitted to the City Planning Division for approval.

Figure 4: Downtown and Central Waterfront development Activity

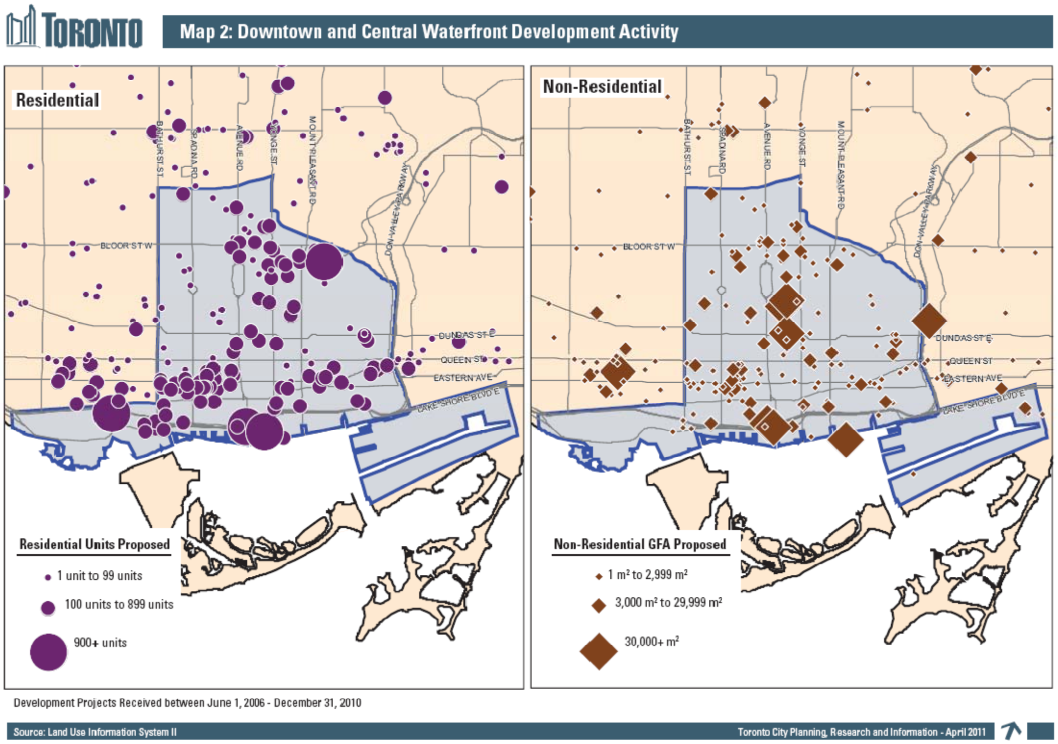


Figure 5: Proposed Development in City of Toronto

Table 3: Proposed Development in City of Toronto

Applications Received between June 1, 2006 and December 31, 2010	Number of Projects	% of Projects	Proposed Residential Units	% of Proposed Res Units	Proposed Non-Residential GFA (m^2)	% of Prop. Non-Res GFA
City of Toronto	**1,696**		**106,848**		**4,231,517**	
Growth Areas						
Downtown and Central Waterfront	204	12.0%	34,533	32.3%	977,153	23.1%
Centres	55	3.2%	11,298	10.6%	225,838	5.3%
Etobicoke Centre	*12*	*21.8%*	*2,333*	*20.6%*	*46,641*	*20.7%*
North York Centre	*26*	*47.3%*	*4,113*	*36.4%*	*81,269*	*36.0%*
Scarborough Centre	*9*	*16.4%*	*3,684*	*32.6%*	*49,798*	*22.1%*
Yonge/Eglinton Centre	*8*	*14.5%*	*1,168*	*10.3%*	*48,130*	*21.3%*
Avenues	246	14.5%	29,463	27.6%	661,934	15.6%
Other Mixed Use Areas	104	6.1%	10,240	9.6%	134,963	3.2%
All Other Areas	1,087	64.1%	21,314	19.9%	2,231,628	52.7%
Stage of Development						
Projects Submitted (not approved)	490	28.9%	53,219	49.8%	1,347,671	31.8%
Projects Approved (no permits issued)	472	27.8%	36,790	34.4%	1,472,440	34.8%
Projects with Permits Issued	734	43.3%	16,839	15.8%	1,411,406	33.4%

Source: City of Toronto, City Planning: Land Use Information System.

The Downtown and Central Waterfront area are two of the driving forces of development in the City of Toronto. Over 34,500 units and 977,000 m^2 of non-residential GFA were proposed in the area between June 2006 and December 2010. This is almost one- third of the residential units and one- quarter of the non-residential GFA proposed in the entire city. Figure 4 shows the distribution of residential units and non-residential GFA throughout the Downtown. Despite these large magnitudes of development, anticipated load for these projects is not included in the forecast due to unknown construction and occupancy timeline as well as absence of customer connection for proposed projects.

2.3.2 New Building Permit Applications and Zoning Applications

A large number of building permit applications and zoning applications for significant developments have been submitted to the City of Toronto. Since these projects are in early stages of development, new customer connection requests have not yet been submitted to THESL and therefore, additional demands for such projects are not included in the forecast. A number of large proposed developments in the proximity of Windsor TS and Bremner TS are summarized in Table 4. Although there is not any accurate information on load requirements of proposed projects, conservative estimates were made based on gross floor area (GFA) to quantify impact of the developments on the THESL distribution system.

Table 4: Selected New Building Permit and zoning applications

Address	Add. Load (kVA)	Address	Add. load (kVA)
<confidential customer information>	3,326	<confidential customer information>	976
<confidential customer information>	3,226	<confidential customer information>	681
<confidential customer information>	2,799	<confidential customer information>	754
<confidential customer information>	2,486	<confidential customer information>	TBD
<confidential customer information>	2,386	<confidential customer information>	TBD
<confidential customer information>	2,278	<confidential customer information>	TBD
<confidential customer information>	1,386	<confidential customer information>	TBD
<confidential customer information>	1,210	<confidential customer information>	TBD
<confidential customer information>	1,182	<confidential customer information>	TBD
<confidential customer information>	1,147	<confidential customer information>	TBD
<confidential customer information>	1,020	<confidential customer information>	TBD
<confidential customer information>	988	<confidential customer information>	TBD

If GFA is unavailable, additional load is denoted by 'TBD'

2.3.3 New Customer Connections

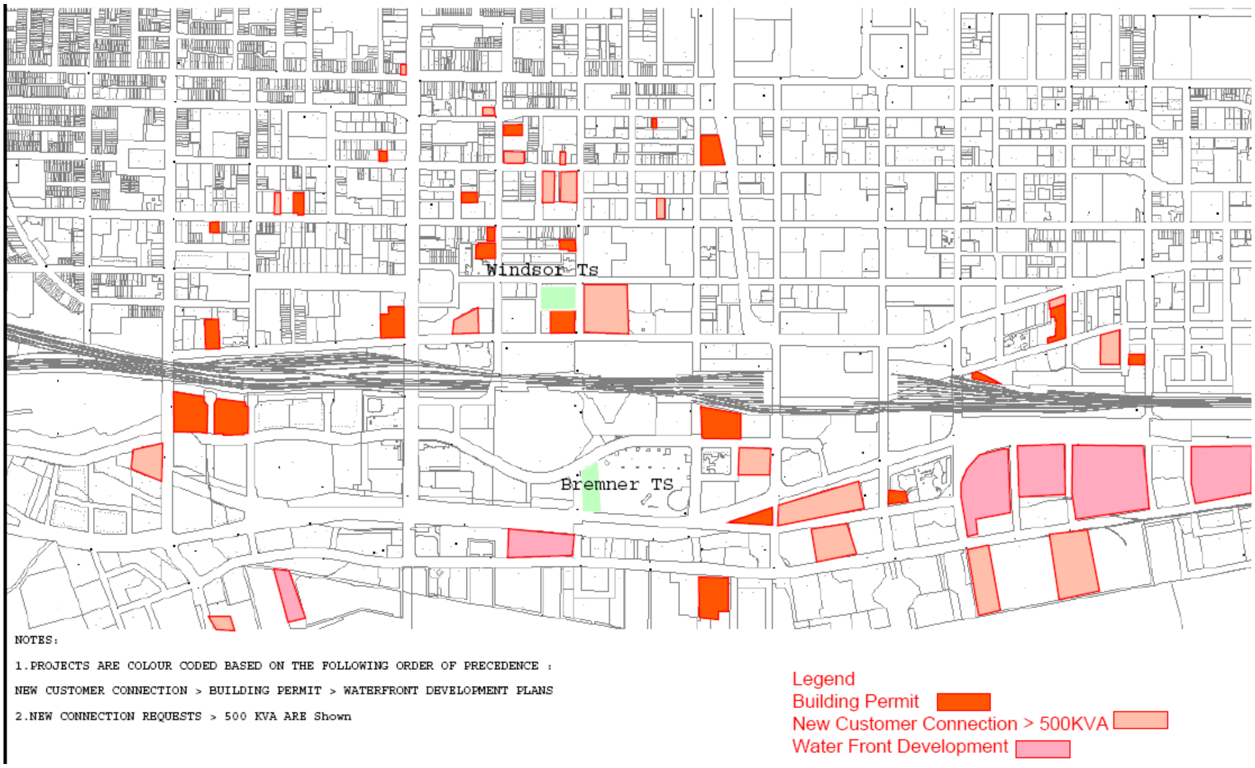
Toronto Hydro has received customer connection requests for 65.9 MVA of additional loads for both existing building and new buildings in the proximity of the future Bremner station and existing Windsor station. The geographical location of the requests is shown in Table 5. As mentioned earlier, customer connection requests have been accounted for in the load forecast using applicable assumptions.

Table 5: Customer Connection Requests in Proximity of Future Bremner TS

Request Date	Customer Name	Customer Address	Additional Load (KVA)
May 17, 2010	<confidential>	<confidential>	14500
August 2, 2012	<confidential>	<confidential>	10000
June 12, 2011	<confidential>	<confidential>	8000
July 11, 2011	<confidential>	<confidential>	5241
November 1, 2012	<confidential>	<confidential>	4600
September 26, 2011	<confidential>	<confidential>	3792
October 16, 2008	<confidential>	<confidential>	3500
April 4, 2011	<confidential>	<confidential>	2800
May 16, 2011	<confidential>	<confidential>	1801
January 30, 2012	<confidential>	<confidential>	1487
July 3, 2012	<confidential>	<confidential>	1250
February 26, 2010	<confidential>	<confidential>	1200
July 11, 2011	<confidential>	<confidential>	1500
March 16, 2012	<confidential>	<confidential>	1049
July 11, 2011	<confidential>	<confidential>	1209
February 11, 2011	<confidential>	<confidential>	750
February 3, 2012	<confidential>	<confidential>	750
Various	Incremental requests	Various (not mapped)	2470

Energization dates may vary depending on infrastructure (Service dates 2011 to 2014)

Figure 6 Downtown Toronto Load Growth



3. Summary

The natural load growth in the downtown core has been set at 2% since 2009 for the purposes of the load forecast. In previous sections, THESL has shown that load growth over the last 5 years is 2.16%, validating the load growth assumptions.

It should be noted that over the last 4 years, THESL has experienced an elevated growth rate of approximately 3.5% in the downtown core as a result of the local construction boom. This growth is consistent with the City of Toronto Official Plan and THESL customer connection requests.

Therefore, the 2% natural growth assumptions used in THESL midterm load forecasts to 2030 can be characterized as conservative.